Woodside Petroleum Ltd.
ACN 004 898 962
Mia Yellagonga
11 Mount Street
Perth WA 6000
Australia
T +61 8 9348 4000
www.woodside.com.au

ASX Announcement

Friday, 8 April 2022

ASX: WPL
OTC: WOPEY

INDEPENDENT EXPERT REPORT

Attached is the Independent Expert Report for the proposed merger between Woodside and BHP's petroleum business.

The report should be read in conjunction with the Explanatory Memorandum released to the ASX today.

Contacts:

INVESTORS

Damien Gare
W: +61 8 9348 4421
M: +61 417 111 697
E: investor@woodside.com.au

MEDIA

Christine Forster
M: +61 484 112 469
E: christine.forster@woodside.com.au

This ASX announcement was approved and authorised for release by Woodside's Disclosure Committee.

KPMG Corporate Finance
A division of KPMG Financial Advisory Services (Australia) Pty Ltd
Australian Financial Services Licence No. 246901
Level 8
235 St Georges Terrace
Perth WA 6000

GPO Box A29
Perth WA 6837
Australia

ABN: 43 007 363 215
Telephone: +61 8 9263 7171
Facsimile: +61 8 9263 7129
www.kpmg.com.au

The Directors
Woodside Petroleum Ltd
Mia Yellagonga
11 Mount Street
Perth WA 6000

8 April 2022

Dear Directors

Independent Expert Report and Financial Services Guide

Part One – Independent Expert Report

1 Introduction

On 16 August 2021, Woodside Petroleum Ltd (**Woodside**) announced that it was engaged in discussions with BHP Group Limited (**BHP**) regarding a potential merger involving BHP's petroleum business (**the Initial Announcement**).

On 17 August 2021, Woodside and BHP jointly announced that they had entered into a merger commitment deed whereby, subject to confirmatory due diligence and the negotiation and execution of full form transaction documents, they would combine their respective oil and gas portfolios by way of an all-stock merger (**the Proposed Transaction**).

On 22 November 2021, Woodside announced that it had entered into a binding share sale agreement (**SSA**) with BHP in relation to the Proposed Transaction.

Under the Proposed Transaction, Woodside will acquire 100% of the issued share capital of BHP Petroleum International Pty Ltd (**BHP Petroleum**)[1] with an effective date of 1 July 2021 (**Effective Date**), in exchange for the issue of 914,768,948 new ordinary shares in Woodside, which will be distributed in-specie as a dividend on a prorated basis to BHP shareholders (**the Merger Consideration**).

Prior to completion, Woodside and BHP Petroleum will carry on their respective businesses in the normal course.

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[1] References to BHP Petroleum include relevant BHP Petroleum controlled entities

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On completion:

- BHP will transfer to Woodside 100% of the issued capital of BHP Petroleum on a cash and debt-free basis, based on the balance sheet at the Effective Date, subject to various exclusions including certain legacy assets and liabilities that will remain with BHP
- BHP shareholders will hold approximately 48% of the issued capital in the post-merger Woodside[2] (**the Merged Group**)[3], which will remain listed on the Official List of ASX Limited (**ASX**) and will seek secondary listings on the New York Stock Exchange (**NYSE**) and the London Stock Exchange (**LSE**)
- BHP will make a cash payment to Woodside for the net cash flow generated by BHP Petroleum between the Effective Date and completion[4]
- Woodside will make a cash payment to BHP in relation to cash dividends paid by Woodside between the Effective Date and completion that would have been received by BHP had the Merger Consideration been paid on the Effective Date.

BHP has agreed to certain exclusivity arrangements with Woodside. These arrangements do not restrict BHP from considering superior proposals for BHP Petroleum in prescribed circumstances. Woodside has agreed to similar exclusivity arrangements in connection with any competing proposal for Woodside.

Completion of the Proposed Transaction requires the satisfaction of various conditions precedent and the approval of Woodside shareholders (**Woodside Shareholders**)[5] under ASX Listing Rule 7.1.

The directors of Woodside (**Directors**) have, subject to the satisfaction of various conditions precedent, including an independent expert concluding, and continuing to conclude, that the Proposed Transaction is in the best interests of Woodside Shareholders, unanimously recommended Woodside Shareholders vote in favour of the Proposed Transaction and as at the date of this report have not withdrawn that support.

The Proposed Transaction is described more fully in section 5 of this report and in sections 3 and 10 of Woodside's Merger Explanatory Memorandum (**Explanatory Memorandum**) to which this report is attached.

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[2] Woodside shares that would otherwise have been issued to "Ineligible Foreign Shareholders", being a BHP shareholder whose address shown in the register of members of BHP is in a jurisdiction where BHP determines (acting reasonably and following consultation with Woodside) that it would be unlawful, unduly impracticable (in each case in respect of either BHP or Woodside) to distribute the new Woodside shares, will be sold by a nominated sales agent and the net proceeds after costs remitted to the relevant BHP shareholder and potentially "Selling Shareholders" where BHP may, at its discretion, offer Selling Shareholders a voluntary sale facility, whereby BHP Shareholders with less than a certain number of BHP Shares may elect for Woodside shares that would otherwise be issued to them to be sold and the sale proceeds remitted to that Selling Shareholder
[3] which will comprise the combined oil, natural gas and natural gas liquids asset portfolios of Woodside and BHP Petroleum
[4] or, if that amount is negative, Woodside will make a cash payment to BHP
[5] Woodside has obtained relief from the Australian Securities and Investments Commission (**ASIC**) in relation to the operation of section 606 of the Corporations Act (**the Act**) with the result that shareholder approval is not being sought for the purpose of item 7 of s611 of the Act.

Woodside is an Australian integrated supplier of energy, holding a portfolio of operated and non-operated production, development and exploration oil, gas and liquefied natural gas (**LNG**) upstream/midstream projects. Woodside's principal petroleum assets include:

- its 16.67% operating interest in the North West Shelf Project, Western Australia (**NWS Project**), producing LNG, pipeline natural gas, condensate and liquefied petroleum gas (**LPG**)
- its 90% operating interest in the Pluto LNG Project, Western Australia (**Pluto LNG**), producing LNG, pipeline natural gas and condensate
- its 60% and 33.33% respective operating interests in two floating production, storage and offloading (**FPSO**) vessels operating offshore Western Australia (**Australia Oil**), producing oil and gas
- its 13% non-operating interest in the Wheatstone LNG project, Western Australia (**Wheatstone LNG**), producing LNG, pipeline natural gas and condensate, including from the Julimar-Brunello Project in which Woodside holds a 65% interest.

Woodside also has a number of advanced development projects in progress, including amongst others, the separate developments of the Scarborough gas resources located offshore Western Australia, the onshore Pluto Train 2 LNG processing facility and the Sangomar oil and gas field located offshore Senegal. In addition, Woodside holds an interest in a number of other Australian and international longer-term development/exploration assets.

Woodside also carries on marketing, trading and shipping activities and is developing a new energy business which is focused on maturing a portfolio of hydrogen and ammonia opportunities in Australia and internationally.

As at 24 March 2022, Woodside had a market capitalisation of A$32,668 million[6].

BHP is the world's largest diversified natural resources company by market capitalisation with over 80,000 employees and contractors, operating in over 90 locations around the world.

BHP Petroleum holds conventional oil and gas assets in the US Gulf of Mexico (**GOM**), Australia, Trinidad and Tobago, Algeria[7] and Mexico, as well as appraisal and exploration options in Egypt, Trinidad and Tobago, central and western GOM, Eastern Canada and Barbados.

The Directors have requested KPMG Financial Advisory Services (Australia) Pty Ltd (of which KPMG Corporate Finance is a division) (**KPMG Corporate Finance**) prepare an Independent Expert Report (**IER**) to Woodside Shareholders in relation to the Proposed Transaction. The purpose of the IER is to set out whether, in our opinion, the Proposed Transaction is in the best interests of Woodside Shareholders as a whole.

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[6] All amounts are stated in Australian dollars (A$ or AUD) unless specifically noted otherwise
[7] BHP Petroleum is currently in the process of divesting its Algerian assets. The treatment of the Algerian assets is discussed in more detail in Section 9.2.8 below.

The specific terms of the resolutions to be approved by Woodside Shareholders in relation to the Proposed Transaction are set out in the Notice of Annual General Meeting and Explanatory Memorandum to which this report is attached (together the **Meeting Documents**).

The sole purpose of this report is an expression of the opinion of KPMG Corporate Finance as to whether the Proposed Transaction is in the best interests of Woodside Shareholders. This report should not be used for any other purposes or by any other party. Our opinion should not be interpreted as representing a recommendation to Woodside Shareholders to either vote for or against the Proposed Transaction, which remains a matter solely for individual Woodside Shareholders to determine.

This report should be considered in conjunction with and not independently of the information set out in the Meeting Documents in their entirety.

KPMG Corporate Finance's Financial Services Guide is contained in Part Two of this report.

2 Technical Requirements

There is no statutory requirement for Woodside to commission an IER in the present circumstances. However, it is a condition precedent to the Proposed Transaction that an IER is obtained, and the Directors recommendation of the Proposed Transaction is subject to, amongst other things, an independent expert concluding, and continuing to conclude, that the Proposed Transaction is in the best interests of Woodside Shareholders.

Accordingly, the Directors have engaged KPMG Corporate Finance to prepare an IER setting out whether, in our opinion, the Proposed Transaction is "in the best interests" of Woodside Shareholders taken as a whole.

2.1 Basis of assessment

In undertaking our work, we have referred to guidance provided by ASIC in its Regulatory Guides, in particular Regulatory Guide 111 'Content of expert reports' (**RG 111**) which outlines the principles and matters which it expects a person preparing an IER to consider.

Whilst RG 111 focuses principally on reports prepared for change of control transactions, it notes that the principles set out in the guide may be relevant to independent expert reports commissioned for other purposes. It also provides that in deciding on the appropriate form of analysis for a report, an expert should bear in mind that the main purpose of the report is to adequately deal with the concerns that could reasonably be anticipated of those persons affected by the proposed transaction.

Having regard to the purpose of our report, we consider that the principal matter required to be considered by us in assessing whether the Proposed Transaction is "in the best interests" of Woodside Shareholders, is whether the proposed transaction is "fair and reasonable" to Woodside Shareholders. RG111.18 notes in the context of a change of control transaction that:

- 'fair and reasonable' is not regarded as a compound phrase
- an offer is 'fair' if the value of the consideration is equal to or greater than the value of the shares subject to the offer
- an offer is 'reasonable' if it is 'fair'

- an offer might also be ‘reasonable’ if, despite being ‘not fair’, the expert believes that there are sufficient reasons for shareholders to accept the offer in the absence of any higher bid before the close of the offer.

In a change of control transaction, the independent expert report is prepared for the benefit of target company shareholders and the comparison of value is made assuming 100% ownership of the ‘target’ company. In the current circumstances:

- Woodside is the acquiring company and BHP Petroleum is the target
- Woodside Shareholders will, as a block, hold 52% of the Merged Group, and current Woodside Directors are expected to hold the significant majority of Board positions following completion of the Proposed Transaction
- Woodside Shareholders will continue to hold the same number of shares in Woodside both prior to and following completion of the Proposed Transaction[8]
- our report is being prepared for the benefit of Woodside Shareholders not BHP shareholders
- following completion, there will be no individual shareholder holding more than 7% in the Merged Group.

Accordingly, we consider the appropriate test in assessing whether the Proposed Transaction is fair to Woodside Shareholders is whether the value of a share in the Merged Group is greater than or equal to the value of a Woodside share prior to the Proposed Transaction.

In assessing the value of a share in the Merged Group, we have considered those synergies and cost savings reasonably able to be achieved that are expected to be available to Woodside in combining its existing portfolio of oil and gas assets with those held by BHP Petroleum. In addition, in order to ensure a consistent approach in the assessment of value, our analysis of both Woodside and the Merged Group has been undertaken on a 100% basis.

Reasonableness involves an analysis of qualitative and other factors that shareholders might consider prior to accepting an offer, such as, but not limited to:

- the rationale for the Proposed Transaction
- the relative contribution of each party to the Merged Group, including Reserves and Resources and near-term production levels
- the impact of the Proposed Transaction on Woodside’s gearing, near-term earnings per share (**EPS**), asset backing per share
- the impact on Woodside’s share register and the liquidity of the market in Woodside’s shares
- any conditions associated with the Proposed Transaction

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[8] Excluding the impact of new Woodside shares that might be issued to existing Woodside shareholders who are also shareholders in BHP at the record date

- the consequences of not approving the Proposed Transaction.

3 Opinion

As the Proposed Transaction is not a "control transaction" as defined by ASIC Regulatory Guides, the appropriate test in assessing whether it is fair to Woodside Shareholders is whether the value of a share in the Merged Group is greater than or equal to the value of a Woodside share prior to the Proposed Transaction.

We have assessed the full underlying value of Woodside as a standalone entity to be in the range of US$16,978 million to US$19,424 million, which equates to an assessed value per Woodside share of between A$23.09 and A$26.42[9]. This compares to our assessed full underlying value for the Merged Group in the range of US$37,242 million to US$42,302 million, which equates to an assessed value per Merged Group share of between A$26.25 and A$29.81.

We have also considered that based on our assessment of the full underlying value of Woodside and BHP Petroleum as standalone entities[10], the aggregate 52% interest that Woodside Shareholders will hold in the Merged Group is broadly consistent with Woodside's contribution to the Merged Group.

Based on these measures, the Proposed Transaction is, in our opinion, fair to Woodside Shareholders.

However, in considering this outcome we note that the Proposed Transaction is being undertaken:

- at a time of significant geopolitical unrest. The recent invasion of Ukraine by Russia has resulted in a large number of Russia's trading partners imposing targeted trade and financial system sanctions on Russia, significantly impeding Russia's ability to undertake foreign trade, including in respect to oil and gas transactions.

  In addition, the United States (**US**), the United Kingdom (**UK**) and Australia have all announced bans on imports of Russian oil and gas and it is reported that the European Union (**EU**) is actively investigating ways in which it can reduce its reliance on Russian sourced oil and gas over the medium and long term.

  This has led to significant global uncertainty in relation to both immediate supply shortfalls and longer-term continuity and security of supply chains, which in turn has resulted a sharp and rapid increase in benchmark oil prices

- during a period of continuing uncertainty as to the rate of overall global and regional recovery from the impact of Covid-19 variants

- against a background of increasing focus by the global community on environmental, social and governance issues (**ESG**), including in relation to climate change and the contribution of fossil fuels to global warming and the transition to clean energy alternatives.

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[9] Based on an AUD:USD exchange rate of approximately 0.747
[10] Before the benefit of cost savings and other synergies expected to be realised as a result of the Proposed Transaction

Whilst the impact of Covid-19 can be expected to be resolved over the short to medium term, the war in Ukraine and the transition to clean energy have a much greater potential to bring about significant long term structural change in global energy markets.

For instance, it is not inconceivable that the UK's and EU's efforts to reduce reliance on Russian sourced oil and gas could, over the longer term, result in a redirection of volumes by other market participants away from Woodside's and BHP Petroleum's principal markets, allowing the Merged Group to increase sales in these markets. In addition, Russia is a significant supplier of LNG into Asia, and any ongoing reluctance in this market to accept delivery from Russia would potentially add further demand for Australian supply.

In terms of the transition to clean energy, it is generally accepted that over the period to at least 2050, there is likely, based on current policy settings, to be a significant increase in the level of global consumption of energy; however market opinion in relation to the role oil and gas will play in meeting that demand is much more unsettled, with the final outcome expected to be heavily influenced by the speed, extent and success at which the global community transitions to clean energy alternatives, including hydrogen.

In addition, various regulatory and commercial market risks have been amplified in recent times for participants in the fossil fuel sector, including amongst other things, the possibility of executive and legislative change, in relation to tightening of restrictions on emissions, approach to carbon pricing, tax structures and requirements for regulatory approvals. Furthermore, there is evidence that ESG issues are impacting the flow of capital market and debt funding to oil and gas companies.

Each of these issues are evolving market dynamics, which clearly won't be fully resolved in the short term, however, it is clear that oil and gas companies with strong cash flow generation supported by well-balanced asset portfolios and a robust financial position will be best placed to navigate the energy market transition. In our view, the Proposed Transaction strengthens Woodside's position in each of these areas.

It is important that Woodside Shareholders recognise oil and gas asset values are inherently subjective. Whilst we consider the production and operational assumptions developed by us in conjunction with Gaffney, Cline & Associates Pty Ltd (**GaffneyCline**)[11] in valuing the asset portfolios of Woodside and BHP Petroleum to be reasonable, and the macroeconomic assumptions adopted by us to reflect an appropriate mix of short-term factors and the potential for longer term structural change in the oil and gas industry, estimates of oil and gas asset values can change quickly and a range of credible operational and development scenarios could have been adopted, particularly in the current volatile environment, all of which could significantly impact value.

This being the case, whilst we have determined the Proposed Transaction to be fair and therefore, in accordance with RG111, the Proposed Transaction is also considered reasonable, we believe that proper evaluation of the Proposed Transaction requires Woodside Shareholders to consider both matters of value and also the broader commercial and qualitative aspects of the Proposed Transaction in deciding whether or not to vote for the Proposed Transaction, including:

[11] the independent petroleum industry specialist engaged by Woodside, but with its scope of work set by us

- the investment characteristics of holding a share in the Merged Group compared to continuing to hold a share in Woodside as a standalone entity
- the relative contribution by each entity to the Merged Group based on various metrics compared to the exchange ratio
- the implications for Woodside shareholders in the event the Proposed Transaction is not approved.

Having considered the issue of fairness and each of the factors above, including the consequences of not approving the Proposed Transaction, we are of the opinion that, in the absence of a superior offer, the Proposed Transaction is in the best interests of Woodside Shareholders.

Further information in relation to each of the above and other matters we have considered in forming our opinion is set out below.

The decision whether or not to approve the Proposed Transaction is a matter for individual Woodside Shareholders based on their views as to value, expectations about future market conditions and their particular circumstances including investment strategy and portfolio structure, risk profile and tax position. Woodside Shareholders should consult their own professional advisor, if in doubt, regarding the action they should take in relation to the Proposed Transaction.

3.1 Assessment of fairness

We have assessed the underlying value of Woodside on a 100% basis prior to the Proposed Transaction to be in the range of US$16,978 million to US$19,424 million; which equates to an assessed value per Woodside share of between approximately A$23.09 to A$26.42 as summarised in the table below.

Table 1: Summary of Woodside standalone assessed market values

		Assessed Values	
All figures in US$ million (unless otherwise stated)	**Reference**	**Low**	**High**
Market values of Woodside's interests in petroleum assets	11.3	**23,180**	**25,615**
Less: Net (debt) / cash	11.3.12	(3,101)	(3,101)
Less: Net financial liabilities and other assets	11.3.12	(171)	(171)
Less: Put option for Scarborough (payable to BHP)	11.3.12	(593)	(419)
Less: Regret costs	11.3.12	(70)	(70)
Less: NPV of NWC movements	11.3.12	(687)	(703)
Less: NPV of future corporate overheads	11.3.12	(1,581)	(1,727)
Total equity value		**16,978**	**19,424**
Number of ordinary shares (millions)[2]	11.3	984.0	984.0
Value per share - US$		**17.25**	**19.74**
Value per share - A$[3]		**23.09**	**26.42**

*Source: GaffneyCline's Independent Technical Specialist Report (**ITSR**) and KPMG Corporate Finance analysis*
Notes:
1. *May not add due to rounding*
2. *Current ordinary shares on issue include dividend reinvestment plan shares issued in March 2022*
3. *Based on an exchange rate of approximately AUD:USD 0.747*

In comparison, we have assessed the value of a share in the Merged Group on an equivalent basis to be in the range of US$37,242 million to US$42,302 million, which equates to an assessed value per Merged Group share of between approximately A$26.25 to A$29.81, as summarised below.

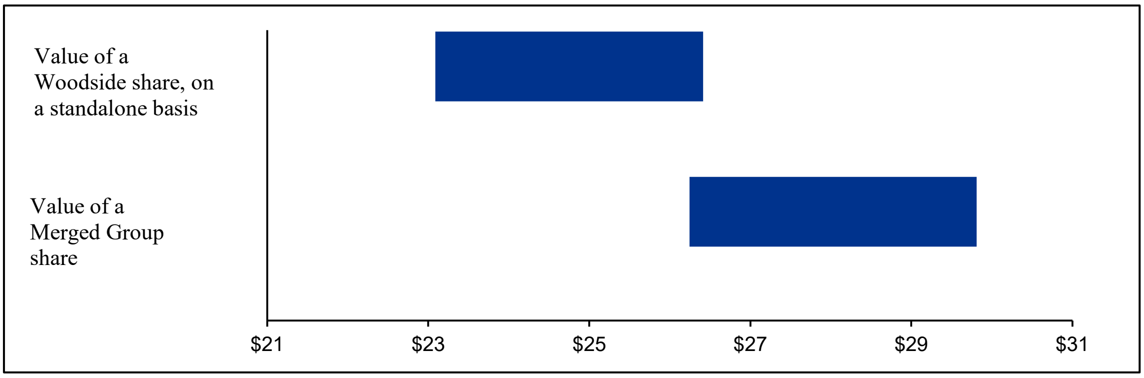
Table 2: Summary of Merged Group assessed market values

All figures in US$ million (unless otherwise stated)	Reference	Assessed Values Low	Assessed Values High
Woodside equity value	11.3	16,978	19,424
BHP Petroleum equity value	11.5	19,064	20,443
Add: Synergies expected to be achieved	11.7	2,364	3,599
Add: Woodside regret costs	11.7	70	70
Less: Transaction costs	11.7	(287)	(287)
Less: Dividend payment	11.7	(830)	(830)
Less: Locked box payment	11.7	(117)	(117)
Merged Group equity value		**37,242**	**42,302**
Woodside ordinary shares		984.0	984.0
Add: New Woodside shares to be issued	11.7	914.8	914.8
Merged Group shares (diluted)		**1,898.7**	**1,898.7**
Merged Group value per share (US$/share)		**19.61**	**22.28**
Merged Group value per share (A$/share)[2]		**26.25**	**29.81**

Source: GaffneyCline's ITSR and KPMG Corporate Finance analysis
Notes:
1. *May not add due to rounding*
2. *Based on an exchange rate of approximately AUD:USD 0.747.*

As our range of assessed values for a Woodside share prior to the Proposed Transaction lies predominately below our range of assessed values for a share in the Merged Group on an equivalent basis, as shown in the chart below, the Proposed Transaction is fair to Woodside Shareholders.

Figure 1 - Comparison of assessed values



Source: KPMG Corporate Finance analysis

We have assessed the value of the equity in Woodside prior to the Proposed Transaction on a "sum-of-the-parts" basis by aggregating the estimated market values of its interest in each of its current and planned operations on a standalone basis, its other petroleum related assets and assets considered to be surplus to the petroleum assets and deducting net borrowings and non-trading liabilities.

Similarly, we have assessed the value of the equity of the Merged Group on a "sum-of-the-parts" basis by aggregating the estimated market values of Woodside and BHP Petroleum interests in each of their current and planned operations, their other petroleum related assets and assets considered to be surplus to the petroleum assets and deducting net borrowings and non-trading liabilities.

Our range of values for the Merged Group also includes the benefit of various costs savings and operational benefits expected to be realised by the Merged Group in bringing together the separate asset portfolios of Woodside and BHP Petroleum.

Woodside expects these benefits to total more than US$400 million per annum (pre-tax), of which in excess of US$250 million relates to operating and corporate cost savings, which are typically easier to identify and realise, with the remaining US$150 million relating to exploration expenditure. The benefit of these cost savings and synergies is expected to be realised progressively, with the full annual benefit achieved by 2024.

Woodside estimates that the implementation of the identified synergy opportunities would require one-off costs in the order of US$500 million to US$600 million to be incurred in the first two years following completion of the Proposed Transaction.

Whilst we consider there is a clear logic and basis for the level of synergies identified by Woodside, it is important to note that the realisation and final quantum of any benefit is not assured and will depend upon Woodside's ability to successful integrate the two businesses. After assessing the risk that the cost savings and synergies may not emerge to the extent anticipated, the timing for realisation may take longer than planned and that additional unanticipated costs of realisation may emerge, we have adopted a range of US$2,364 million to US$3,599 million in relation to the post-tax net present value of annual cost savings and synergies for the purpose of our assessed values of the Merged Group rather than a single point estimate. This equates to a value per share in the Merged Group of approximately A$1.67 to A$2.54.

Whilst the abovementioned synergies and cost savings are expected to be realised as a result of combining the operations of Woodside and BHP Petroleum, having regard to the nature of these synergies and the likely profile of an alternative acquirer, we do not consider them to be unique to a business combination with BHP Petroleum only and would be available to a pool of purchasers.

In arriving at our range of values for Woodside and the Merged Group, we have placed reliance on the assumptions prepared by GaffneyCline in relation to reasonable production scenarios, including appropriate production inventories, operational expenditure (**Opex**), capital expenditure (**Capex**) and decommissioning and restoration (**D&R**) profiles for each of Woodside's and BHP Petroleum's near-term and planned production projects. In addition, GaffneyCline has assessed the value of other petroleum assets where discounted cash flow (**DCF**) was not considered an appropriate valuation methodology.

3.1.1 Relative contributions – Full underlying value

The table below summarises the values contributed by Woodside and BHP Petroleum based on our range of full underlying values for each of Woodside and BHP Petroleum as standalone entities.

Table 3: Summary of Relative contributions – full underlying value

US$m	Section ref	Low	Relative contribution %	High	Relative contribution %
Full Underlying Value					
Woodside	11.3	16,978	48	19,424	50
BHP Petroleum[1]	11.5	18,234	52	19,613	50

Source: KPMG Corporate Finance analysis
Note 1: BHP Petroleum's underlying values have been reduced to reflect the dividend payable to BHP of US$830 million in the event the Proposed Transaction is completed.

Woodside shareholders will collectively hold approximately 52% of the issued capital of the Merged Group, which exceeds Woodside's relative contribution to the underlying value of the Merged Group. We note that the above assessed values represent the full underlying value of Woodside and BHP Petroleum as standalone entities but do not include the benefit of any cost savings and other synergies that may be realised. Woodside Shareholders will collectively participate to the extent of 52% in any additional benefits realised.

Our assessed values for a Merged Group share of between A$26.25 and A$29.81 lie below Woodside's closing price of A$33.20 per share on 24 March 2022. This may reflect:

- whilst our valuation of the Merged Group incorporates an uplift for the benefits of the Proposed Transaction, including for potential up to US$400 million in annual pre-tax synergies and other costs savings expected by Woodside to be realised progressively over the period to 2024, it does not include any uplift for Woodside's expectation that the final quantum of costs savings and synergies could potentially exceed this amount
- the market is more bullish in relation to the value of the Merged Group's asset portfolio, either in relation to the technical and operational assumptions estimated by GaffneyCline, including GaffneyCline's assessment of the chance of development of various pre-production assets, or in relation to the macroeconomic assumptions adopted by us, including future commodity prices and discount rates. As noted, previously, given the current volatility in commodity markets, a range of macroeconomic assumptions could credibly be adopted, which has the potential to be accretive or dilutive to value. To assist readers in this regard we have included sensitivity analysis around key value drivers for each project in sections 11.3 and 11.5 of this report.

Our valuations of each of Woodside and BHP Petroleum and their underlying asset portfolios are set out in greater detail in Sections 11.3 and 11.5 of this report and in GaffneyCline's report is attached as Appendix 15.

We would normally also compare the share price implied by our standalone valuation of Woodside to Woodside's share price immediately prior to the Initial Announcement. However given the significant movement in the key commodity prices since the Initial Announcement, which are reflected in our valuation but not the Initial Announcement share price, we do not consider such an analysis would be meaningful.

3.2 Assessment of reasonableness

Whilst we have determined the Proposed Transaction to be fair based on our assessment of values and therefore, in accordance with RG 111, the Proposed Transaction is also considered reasonable, we have considered various matters that we believe Woodside Shareholders should also consider in deciding whether or not to vote for the Proposed Transaction. These include:

- the change in the investment characteristics of holding a share in the Merged Group compared to Woodside as a standalone entity, including that Woodside Shareholders will benefit from a larger, more financially robust, geographically diverse business, with the potential for increased liquidity and investor interest
- the Proposed Transaction is expected to increase Woodside's capacity to successfully navigate and take a leading position in relation to the transition to new energy
- the potential for Woodside Shareholders to participate in further operational and strategic synergies over and above those included by us in our assessed values for the Merged Group
- BHP Petroleum's asset base provides Woodside with immediate access to significant development and growth opportunities, within a timeframe that is unlikely to otherwise have been available to Woodside as a standalone entity
- Woodside has indicated that it does not intend, at this time, to change its dividend policy
- the exchange ratio is broadly supported by various financial and other relative contribution measures
- it is arguable that, in theory, completion of the Proposed Transaction may reduce the prospect of Woodside Shareholders receiving an offer for their shares inclusive of a full premium for control
- the Directors of Woodside have advised the market that they intend to unanimously recommend Woodside Shareholders approve the Proposed Transaction[12].

Having considered each of these factors and the consequences of not accepting the Proposed Transaction, we are of the opinion that, whilst there are various factors that may not be attractive to Woodside Shareholders, the benefits of holding a share in the Merged Group are sufficient to conclude that Woodside Shareholders will, on balance, be better off by approving the Proposed Transaction.

Further information in relation to each of the above and other matters we have considered in forming our opinion is set out below.

[12] Subject to no superior offer being received and the Independent Expert continuing to conclude that the Proposed Transaction is in the best interest of Woodside Shareholders

3.2.1 Investment characteristics of holding a share in the Merged Group

In our view there are a number of investment benefits for Woodside Shareholders in holding an interest in the Merged Group compared to that of holding a share in Woodside as a standalone entity:

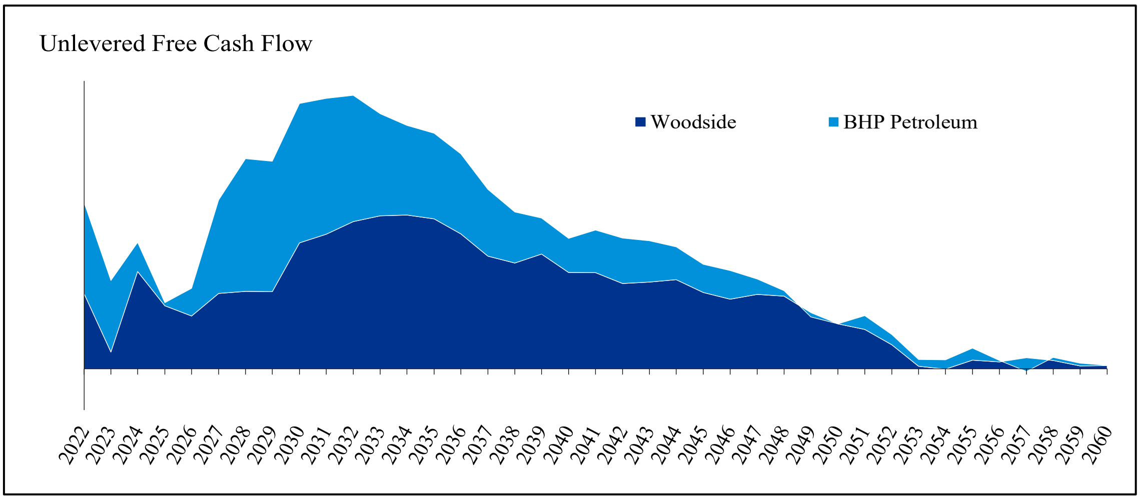
Stronger financial position

On completion of the Proposed Transaction, the Merged Group will hold, on a proforma 31 December 2021 basis, net tangible assets of approximately US$29,389 million, with a relatively modest gearing in the order of 8%[13], which compares to a net tangible asset base for Woodside on a standalone basis in the order of US$14,229 million, with gearing of 22%. The fall in relative gearing levels reflects the benefit of BHP Petroleum's net assets being acquired on a "cash-free, debt-free basis" and the acquisition being funded by the issue of new scrip rather than by cash.

This level of gearing compares to Woodside's stated target gearing for the Merged Group in range of 15% - 35%, which is broadly consistent with the level of gearing currently employed by other large conventional oil and gas producers.

We also note that, as illustrated in figure 2 below, the combination of Woodside's and BHP Petroleum's assets is expected to significantly improve the level of net free cash flows available to the Merged Group, crucially, in the initial years when Woodside is looking to bring Scarborough/Pluto Train 2 and Sangomar into production, whilst also continuing to advance other growth opportunities, including its New Energy ambitions.

Figure 2 – Profile of net free cash flows over the period to 2060[14]



Source: KPMG Corporate Finance analysis

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[13] which includes lease labilities and other financial liabilities. In the event these liability categories are excluded, the Merged Group's proforma gearing falls to 4%, which compares to the gearing of Woodside's as a standalone entity of 15% on the same basis.
[14] Net free cash flows are based on the production; and operational, capital and D&R expenditure profiles assessed by GaffneyCline and the macroeconomic assumptions determined by KPMG Corporate Finance but are before exploration expenditure and the realisation of any operational and other cost savings and synergies.

On 16 December 2021, Moody's re-affirmed Woodside's Baa1[15] investment grade credit rating, with a negative outlook, noting that as a result of the significant spending and execution risks associated with the Scarborough/Pluto Train 2 project, it expected that, in the absence of the Proposed Transaction and/or further sell downs of project stakes, Woodside's credit metrics "*will be at weak levels for the rating, which could lead to a downgrade without other initiatives to improve its financial profile*".

Moody's also observed that Woodside's credit profile could weaken further in the absence of the Proposed Transaction, in part, reflecting BHP's put option for the sale of its stake in the Scarborough project to Woodside, which if exercised, would require Woodside to fund in the order of an additional US$1,000 million without the cash flow that completion of the Proposed Transaction would provide.

Moody's advised that its affirmation also considered the potential positive impacts of the Proposed Transaction, which "*would significantly increase the scale of Woodside's production and reserves, while materially improving diversity and providing substantial additional cash flow to fund growth*" and that, completion of the Proposed Transaction would strengthen Woodside's credit profile to more appropriate levels for its rating.

On 31 December 2021, S&P Global Ratings affirmed Woodside's at BBB+[16] investment grade credit rating, with a negative outlook.

Accordingly, in comparison to Woodside as a standalone entity, completion of the Proposed Transaction can be expected to provide greater scope for the Merged Group to source additional, and potentially cheaper, funding to progress its strategic initiatives.

Geographical, end-market and product mix diversification

At present, Woodside's asset portfolio is principally focussed on LNG production and development projects, largely concentrated on the west coast of Australia, with its current LNG, LPG, condensate and oil production sold to customers primarily in Asia and its domestic gas (**domgas**) sold to customers in Western Australia. Whilst Woodside also holds interests in overseas oil and gas development projects, including in Senegal (Sangomar), Canada and Timor-Leste[17], none of these are currently in production.

In contrast, the Merged Group will, in addition to the Woodside's existing projects, also hold BHP Petroleum's producing and development conventional oil and gas assets located in the GOM, Trinidad and Tobago and Mexico and on the east coast of Australia. In addition, BHP Petroleum also holds interests in the Woodside operated NWS Project and the Scarborough project, which will be consolidated by the Merged Group.

BHP Petroleum's domgas production is largely sold on the east coast of Australia, whilst crude oil and gas is sold to customers in Japan, South Korea and China. Crude oil production from BHP Petroleum's operations in the GOM is sold into global oil markets, with gas volumes sold into the US domestic gas

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[15] Obligations rated Baa are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category
[16] Obligations rated BBB are considered to have adequate capacity to meet financial commitments, but more subject to adverse economic conditions
[17] Woodside has indicated it intends to exit its current projects in Myanmar

market. Crude oil from BHP Petroleum's Trinidad and Tobago operations is similarly sold into global oil markets, with gas volumes sold into the local gas market.

As a result of the combination of the oil and gas assets of Woodside and BHP Petroleum, the Merged Group will have a more balanced geographical, production and customer mix, which should translate to a reduced level of risk to overall portfolio values from any economic, regulatory or other shocks in any individual market.

Potential for increased liquidity in share trading and increased investor interest, but also for short term overhang

With a pro-forma market capitalisation following completion of the Proposed Transaction of A$63,038 million[18], the Merged Group will be a top 10 company by market capitalisation[19] on the ASX. This should result in a greater weighting being applied to its shares by fund and index managers in terms of investment allocations. Coupled with a much broader shareholder base and secondary listings on the NYSE and LSE, there is a reasonable basis to expect an increased level of trading in Woodside shares and a growing level of interest by international investors, which may translate into a positive re-rating of the Merged Group compared to Woodside as a standalone company (although it is arguable given the time that has elapsed since the Initial Announcement, an element of re-rating may already be reflected in Woodside's current share price).

Potentially offsetting this benefit to some extent, at least in the short term, is the prospect for increased volatility in the Merged Group's share price immediately following completion of the Proposed Transaction.

Woodside shares that would otherwise have been issued to "Ineligible Foreign Shareholders"[20] and potentially "Selling Shareholders"[21] for the purpose of the Proposed Transaction will be sold by a nominated sales agent and the net proceeds after costs remitted to the relevant BHP shareholder. Depending upon the volume of shares to be sold and the structure of the realisation program followed by the nominated sales agent, there is a potential for a temporary overhang in Woodside shares, adversely impacting trading prices, until cleared.

Furthermore, as noted previously in section 1 above, BHP is the world's largest diversified natural resources company by market capitalisation. It is possible that certain current BHP shareholders may not wish to hold shares in a company with a principal focus and exposure to oil and gas assets and, as a result, may also seek to realise the Woodside shares issued to them in the period following completion of the Proposed Transaction.

[18] Based on Woodside's closing share price of A$33.20 on 24 March 2022 and 1,898.7 million shares on issue in the Merged Group
[19] as at 24 March 2022
[20] being a BHP shareholder, whose address shown in the register of members of BHP is in a jurisdiction where BHP determines (acting reasonably and following consultation with Woodside) that it would be unlawful, unduly impracticable (in each case in respect of either BHP or Woodside) to distribute the new Woodside shares
[21] BHP may, at its discretion, offer Selling Shareholders a voluntary sale facility, whereby BHP Shareholders with less than a certain number of BHP Shares may elect for Woodside shares that would otherwise be issued to them to be sold and the sale proceeds remitted to that Selling Shareholder

As a result, existing Woodside Shareholders wishing to realise their existing Woodside shares in an orderly manner, may not be able to do so at an "undisturbed" price for an unknown period of time.

3.2.2 The Proposed Transaction is expected to allow Woodside to take a leading position in relation to the transition to new energy

Woodside has previously announced that it is targeting a 15% equity net emissions reduction by 2025, and a 30% equity net emissions reduction by 2030, with an aspiration to achieve net zero by 2050[22]. Woodside expects these targets to be maintained for the Merged Group.

In addition, Woodside is pursuing opportunities to commercialise new energy products and lower-carbon services as part of its broader product mix. In December 2021, Woodside announced a new target to invest US$5,000 million in new energy products and lower-carbon services by 2030, assuming the Proposed Transaction is completed.

In addition to being more financially robust and better placed to pursue its new energy initiatives, the combination of the Woodside's and BHP Petroleum's skilled workforce can also be expected to deepen the Merged Group's technical capabilities and its ability to manage the new energy transition issues facing the company.

3.2.3 Potential to realise further synergies and cost savings over and above those included in our range of assessed values for the Merged Group

Woodside's evaluation of synergy opportunities yielded an initial target of over US$400 million in annual cost savings, which are expected to be realised progressively in the period after completion of the Proposed Transaction, with full implementation expected by early 2024. These costs savings and synergies have been reflected in our range of assessed values for the Merged Group.

As the integration process of Woodside and BHP Petroleum is undertaken, Woodside expects to identify further synergies and value creation opportunities in addition to the identified synergy opportunities above.

To the extent that further benefits are realised, Woodside Shareholders will, in aggregate, have a 52% interest in any upside realised.

3.2.4 Completion of the Proposed Transaction provides immediate access to development and growth opportunities

Woodside will, in addition to various production assets, gain immediate access to a suite of project development options through the acquisition of BHP Petroleum's asset portfolio, including various sanctioned (being executed) and unsanctioned projects (unexecuted and awaiting FID) projects.

Immediate access to the operational cash flows provided by BHP Petroleum's production assets and to a wider suite of development opportunities provides Woodside with increased optionality in terms of

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[22] Target is for net equity Scope 1 and 2 greenhouse gas emissions, relative to a starting base of the gross annual average equity Scope 1 and 2 greenhouse gas emissions over 2016-2020 and may be adjusted (up or down) for potential equity changes in producing or sanctioned assets with a Final Investment Decision (**FID**) prior to 2021. Following completion of the Proposed Transaction, the starting base will be adjusted for the combined Woodside and BHP petroleum portfolio

capital allocation and project sequencing with the view to maximising return on both Woodside's existing development portfolio and those acquired with BHP Petroleum.

Woodside's capital requirements in relation to the Scarborough/Pluto Train 2 and Sangomar projects over the near future, mean that it is unlikely that Woodside would, in the absence of the Proposed Transaction or a similar inorganic transaction, be able to replicate a similar project portfolio in the foreseeable future, nor would it be able to pursue its investment into new energy initiatives to the same extent.

3.2.5 Woodside dividend policy is expected to remain unchanged

Woodside has indicated that its current dividend policy is expected to be unchanged following completion of the Proposed Transaction.

The Woodside Board has the responsibility of approving dividends. The Woodside Board has determined there will be no change to Woodside's dividend policy of a minimum of 50% of net profit after tax excluding non-recurring items in dividends. The Woodside Board's dividend payout ratio target is between 50% to 80% of net profit after tax, excluding non-recurring items, subject to market conditions and investment requirements. Woodside will maintain the flexibility to consider opportunities to provide additional returns to shareholders through special dividends and share buy-backs in periods of excess cash generation.

3.2.6 The relative contribution of each entity to the Merged Group is broadly consistent with the exchange ratio

The table below shows the contribution of Proved and Probable (**2P**) Reserves[23] and 2C Contingent Resources[24], production and certain earnings measures that Woodside and BHP Petroleum will make to the Merged Group relative to the merger terms.

Table 4: Relative contributions to the Merged Group as at 31 December 2021

Relative Contributions	Woodside	BHP Petroleum	Contribution % Woodside	Contribution % BHP Petroleum
Reserves and Resources as at 31 December 2021[1, 2]				
2P (liquids[3]) million barrels (**MMbbl**)	247.0	560.4	30.6%	69.4%
2P (gas) million barrels oil equivalent (**MMboe**)[4]	2,157.4	916.7	70.2%	29.8%
Total 2P (MMboe)	2,404.3	1,477.1	61.9%	38.1%
2C (liquids[3]) (MMbbl)	590.0	558.8	51.4%	48.6%
2C (gas) (MMboe)	3,961.0	823.8	82.8%	17.2%
Total 2C (MMboe)[5]	4,551.0	1,382.6	76.7%	23.3%
Production (MMboe)				
CY21 (actual)[6]	91.1	102.3	47.1%	52.9%
CY22 (projected)[7]	93.2	114.5	44.9%	55.1%

[23] 2P Reserves are proved reserves plus reserves that are deemed probable (at least 50 per cent likely) to be commercially recoverable

[24] 2C Contingent Resources is the best estimate of contingent resources. 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.

Relative Contributions	Woodside	BHP Petroleum	Contribution % Woodside	Contribution % BHP Petroleum
Earnings ($ millions)				
CY21 Underlying EBITDA[8,9]	4,135	4,349	48.7%	51.3%
CY21 Underlying NPAT[10,11]	1,620	885	64.7%	35.3%

Source: GaffneyCline's ITSR, Woodside 2021 Annual Report, BHP Petroleum 2HY21, FY21 and 2HY20 financial reports and KPMG Corporate Finance analysis

Notes:

1. *Reserves and Resources included in the table above may differ from those reported by Woodside and BHP Petroleum (including those reported in Tables 7, 8, 9, 22 and 23 below) as the above figures reflect GaffneyCline's assessment of Reserves and Resources as set out in the ITSR*
2. *Gas Reserves in the table above are inclusive of volumes consumed in operations (CIO or fuel) per GaffneyCline's ITSR*
3. *Liquids reserves and resources includes oil, condensate, natural gas liquids and LPG*
4. *BHP Petroleum's net gas Reserves and Resources have been converted from billion cubic feet (**Bcf**) to MMBoe by dividing by a conversion factor of 6.0 for all assets except the NWS Project, NWS Oil and Scarborough (including Thebe and Jupiter), where a conversion factor of 5.8 has been adopted (consistent with the factor adopted by KPMG Corporate Finance for the Woodside interest in those projects)*
5. *2C Contingent Resources in this table are BHP Petroleum's working interest fraction of the gross field resources*
6. *Production from Algeria and Neptune is excluded from BHP Petroleum production*
7. *Projected CY22 production has been based on the aggregate of the production profiles prepared by GaffneyCline for each of the individual assets*
8. *Underlying EBITDA for Woodside has been calculated as profit before tax add net finance costs, depreciation and amortisation and net impairment costs*
9. *Underlying EBITDA for BHP Petroleum has been calculated as profit before tax add net finance costs, depreciation and amortisation, net impairment costs, onerous lease costs, exploration leases and other one-off costs*
10. *Underlying NPAT for Woodside excludes amounts relating to cost write-offs, impairment losses, impairment reversals and prior period impacts*
11. *Underlying NPAT for BHP Petroleum has been calculated as profit before tax add net finance costs, net impairment costs, office onerous lease costs, exploration lease costs and other costs.*

This analysis indicates that:

- whilst BHP Petroleum is contributing significantly less than the exchange ratio in relation to both aggregate 2P Reserves and 2C Contingent Resources on an MMboe basis, it is contributing approximately 69% of 2P liquids Reserves and 49% of 2C liquids Contingent Resources, which we consider to be one of the key drivers of the Proposed Transaction in terms of the Merged Group's near term cash flows and earnings
- BHP Petroleum is contributing approximately 53% of actual CY21 MMboe production and a similar contribution to projected CY22 MMboe production
- BHP Petroleum is contributing approximately 51% of underlying CY21 EBITDA
- BHP Petroleum is contributing approximately 35% to the Merged Group's CY21 underlying NPAT. This figure includes US$311 million in relation to BHP Petroleum pre-tax finance charges, which given the BHP Petroleum assets are being acquired on a cash-free, debt-free basis should be added-back. In addition, Woodside has identified that in order to achieve consistency with its accounting

policies, a further net negative post tax adjustment of US$156 million is required. Adjusting for these would increase BHP Petroleum's relative contribution to 39%.

Having regard to each of the above measures individually and in aggregate, we consider the relative contribution of BHP Petroleum to be broadly supportive of the exchange ratio.

3.2.7 The potential for Woodside Shareholders to receive an offer for their shares inclusive of a full control premium may, in theory, be reduced

Whilst following completion of the Proposed Transaction the Merged Group's share register will be open, with no single shareholder holding over 7% of its share capital, Woodside will be of a size that:

- there is no other logical domestic industry purchaser for the whole of Woodside
- the pool of potential international purchasers with the financial capacity to complete a takeover will be reduced and the likelihood of receiving approval for any acquisition under Australia's Foreign Acquisition and Takeovers Act may be problematic.

However, with a current market capitalisation of A$32,668 million, as at 24 March 2022, it is reasonably arguable that the pool of potential acquirers for Woodside as a standalone entity is already limited and would likely face the same regulatory hurdles.

Accordingly, whilst in theory completion of Proposed Transaction may reduce the prospects of Woodside Shareholders receiving an offer for their shares, this is unlikely to be a significant disadvantage.

3.3 Consequences of not approving the Proposed Transaction

In the event that the Proposed Transaction is not approved or any conditions precedent prevents the Proposed Transaction from being implemented, Woodside will continue to operate in its current form and remain listed on the ASX. As a consequence:

- Woodside Shareholders will collectively continue to hold 100% of the issued capital of Woodside
- the implications of the Proposed Transaction, as summarised above, will not occur
- Woodside Shareholders will continue to be exposed to the benefits and risks associated with an investment in Woodside, which, over the medium to longer term, will, based on its current strategy, be closely aligned to the success or otherwise of the future development of the Scarborough/Pluto Train 2 and Sangomar projects as they move through their development and operational cycles
- BHP Petroleum will retain the right to exercise the put option for the sale of its interest in the Scarborough project, which, if exercised, will result in a significant leakage of funds from Woodside, along with, in the absence of a sell-down, an increased capital commitment during Scarborough's construction phase, placing pressure on Woodside's free cash flow position ahead of production, currently scheduled for 2026
- there is the potential for Woodside's credit rating to be downgraded, which, all other things equal, could lead to an increase in Woodside's cost of funding
- the Woodside dividend payable to BHP in the event the Proposed Transaction is completed will not be paid. This payment, which totals approximately US$830 million is, in effect, the payment to BHP

representing the cash dividend that would have been received by BHP shareholders had they had Woodside shareholders as at 1 July 2021

- Woodside will not receive any "locked box payment" representing the net cash flow generated by BHP Petroleum over the period since 1 July 2021 to completion. Woodside has estimated this net cash inflow to be in the order US$900 million as at 31 December 2021 prior to accounting for any cash held in bank accounts beneficially controlled by BHP Petroleum
- A break fee may be payable depending upon the circumstances leading to the Proposed Transaction not proceeding
- Woodside will have incurred various costs related to the Proposed Transaction that will still be required to be paid. Woodside estimates that costs incurred will total in the order of US$100 million, pre-tax.

Our opinion is based solely on information available as at the date of this report as set out in Appendix 2 of this report. We note that we have not undertaken to update our report for events or circumstances arising after the date of this report other than those of a material nature which would impact upon our opinion. We also refer readers to the limitations and reliance on information set out below in section 6 of our report.

4 Other matters

In forming our opinion, we have considered the interests of Woodside Shareholders as a whole. This advice therefore does not consider the financial situation, objectives or needs of individual Woodside shareholders. It is not practical or possible to assess the implications of the Proposed Transaction on individual Woodside shareholders as their financial circumstances are not known to us. The decision of Woodside shareholders as to whether to approve the Proposed Transaction is a matter for individuals based on, amongst other things, their risk profile, liquidity preference, investment strategy and tax position. Individual Woodside shareholders should therefore consider the appropriateness of our opinion to their specific circumstances before acting on it. As an individual's decision to vote for or against the proposed resolutions may be influenced by his or her particular circumstances, we recommend that individual Woodside Shareholders, including residents of foreign jurisdictions, seek their own independent professional advice.

We understand that Woodside intends to seek a secondary listing of its shares on certain overseas stock exchanges and that this report may be required to be filed, purely for information purposes, with certain overseas regulatory authorities, along with other documentation, to facilitate these secondary listings. Readers of this report should note that our report has been prepared:

- having principal regard to relevant provisions of Australian legislation and other applicable Australian regulatory requirements
- solely for the purpose of assisting Woodside Shareholders in considering the Proposed Transaction and for no other purpose.

We do not assume any responsibility or liability to any other party as a result of reliance on or use of this report for any other purpose.

Neither the whole nor any part of this report or its attachments or any reference thereto may be included in or attached to any document, other than the Meeting Documents to be sent to Woodside Shareholders in relation to the Proposed Transaction, without the prior written consent of KPMG Corporate Finance as to the form and context in which it appears. KPMG Corporate Finance consents to the inclusion of this report in the form and context in which it appears in the Explanatory Memorandum.

All figures set out in this report are in nominal terms unless otherwise noted.

References to:

- financial years have been abbreviated to FY
- calendar years have been abbreviated to CY (where different to the relevant entity's FY)
- 6-month periods of a financial year have been abbreviated to HY.

The above opinion should be considered in conjunction with and not independently of the information set out in the remainder of this report, including the appendices.

Yours faithfully

Jason Hughes Authorised Representative	Bill Allen Authorised Representative	Sean Collins Authorised Representative

Contents

5 Summary of the Proposed Transaction

5.1 Consideration

The principal terms of the Proposed Transaction as they affect Woodside Shareholders are, in broad terms, that in consideration for the acquisition of 100% of the issued capital of BHP Petroleum on a cash and debt free basis with an effective date of 1 July 2021, Woodside will:

- issue new ordinary Woodside shares to BHP, equivalent to an approximate 48% shareholding in the Merged Group upon implementation. BHP will in turn immediately distribute these new Woodside shares to eligible BHP shareholders as a special dividend, which BHP intends to fully frank
- in the event that the net post-tax cashflows from the ordinary operations of BHP Petroleum (including any capital expenditure and/or receipts from the disposal of specified fixed assets) in the period between the Effective Date and completion of the Proposed Transaction are negative, re-imburse BHP the shortfall, or, in the event these net post-tax cash flows are positive, BHP will pay to Woodside this amount
- make a cash payment to BHP in relation to cash dividends paid by Woodside between the Effective Date and completion that would have been received by BHP had the Merger Consideration been paid on the Effective Date
- settle/receive the benefit of any other adjustments to the purchase consideration that may be required, either positive or negative, as a result of the operation of the SSA not captured in the abovementioned limbs.

5.2 Conditions precedent

Completion of the Proposed Transaction is subject to the satisfaction[25] of a number of conditions precedent as set out in the SSA, including, but not limited to:

- all regulatory and other approvals, consents, clearances and permissions to give the Proposed Transaction effect having been obtained from all relevant bodies, including, amongst others, the Australian Competition and Consumer Commission (**ACCC**), the National Offshore Petroleum Titles Administrator, ASIC, ASX, the Committee on Foreign Investment in the US, and, if required, the Foreign Investment Review Board
- Woodside Shareholders approving the merger resolution
- the independent expert concluding that the Proposed Transaction is in the best interests of Woodside Shareholders and maintaining that opinion until Woodside Shareholders meet to vote on the Proposed Transaction
- each US Registration Statement has been declared effective by the US Securities and Exchange Commission (**SEC**) in accordance with the provisions of the US Securities Act and the US Exchange Act, as applicable

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[25] Certain conditions precedent are able to be waived

- approval by various foreign jurisdiction regulatory competition authorities including in Trinidad and Tobago, the People's Republic of China, Japan, Mexico, Vietnam and Barbados.

As at the date of this report, Woodside has confirmed that it is not aware of any reason to expect that the conditions precedent will not be satisfied or waived as required.

5.3 London Stock Exchange and New York Stock Exchange listings

Woodside must use its reasonable to endeavours to secure the approval of the regulatory authorities, the LSE and the NYSE that its shares, including the Woodside securities to be issued as consideration for the Proposed Transaction, will be listed on each bourse.

5.4 Termination

Both Woodside and BHP have the right to terminate the SSA in certain specified circumstances, including as a result of, inter alia:

- the inability to satisfy a specified condition precedent by 30 June 2022[26] (**the Cut-Off Date**)
- a material breach by the other party of its obligations and/or the warranties given under the SSA, provided that in the case of a warranty breach, the loss can reasonably be expected to exceed US$500 million
- a half or more of the other party's Board members or (only as expressly permitted under the SSA) a majority of the company's own Board withdraw their support for the Proposed Transaction
- a material adverse event or change in condition or circumstances of the other party as defined in the SSA
- certain prescribed circumstances.

5.5 Reimbursement fee

Woodside must pay to BHP and BHP must pay to Woodside a reimbursement fee of US$160 million in certain specified events and circumstances (**Reimbursement Fee**), including, inter alia, due to the termination of the SSA for a material breach of obligations or warranties which is unable to be remedied as required.

Further details in relation to the Proposed Transaction are set out in sections 3 and 10 of the Explanatory Memorandum to which this report is attached, and in Woodside's and BHP's announcements to the ASX on 17 August 2021 and 22 November 2021.

[26] which may be extended by agreement between the parties or in limited circumstances set out in the SSA

6 Scope of the report

6.1 Purpose

This report has been prepared by KPMG Corporate Finance for inclusion in the Explanatory Memorandum to accompany the Notice of Meeting convening a meeting of Woodside Shareholders on or around 19 May 2022. The purpose of the meeting will be to seek approval of the Proposed Transaction.

6.2 Limitations and reliance on information

In preparing this report and arriving at our opinion, we have considered the information detailed in Appendix 2 of this report. In forming our opinion, we have relied upon the truth, accuracy and completeness of any information provided or made available to us without independently verifying it. Nothing in this report should be taken to imply that KPMG Corporate Finance has in any way carried out an audit of the books of account or other records of either Woodside or BHP Petroleum for the purposes of this report.

Further, we note that an important part of the information base used in forming our opinion is comprised of the opinions and judgements of management. In addition, we have also had discussions with Woodside's management and BHP Petroleum in relation to the nature of Woodside's and BHP Petroleum's business operations, its specific risks and opportunities, its historical results and its prospects for the foreseeable future. This type of information has been evaluated through analysis, enquiry and review to the extent practical. However, such information is often not capable of external verification or validation.

Woodside has been responsible for ensuring that information provided by it or its representatives is not false, misleading or incomplete. Complete information is deemed to be information which at the time of completing this report should have been made available to KPMG Corporate Finance and would have reasonably been expected to have been made available to KPMG Corporate Finance to enable us to form our opinion.

We have no reason to believe that any material facts have been withheld from us but do not warrant that our inquiries have revealed all of the matters which an audit or extensive examination might disclose. The statements and opinions included in this report are given in good faith, and in the belief that such statements and opinions are not false or misleading.

The information provided to KPMG Corporate Finance and GaffneyCline, the independent oil and gas technical specialist retained to assist us in the valuation of Woodside and BHP Petroleum, included forecasts/projections and other statements and assumptions about future matters (**forward-looking financial information**) prepared by the management of Woodside, including, but not limited, to cash flow forecasts for each of Woodside's and BHP Petroleum's production and development/growth assets.

Whilst KPMG Corporate Finance and GaffneyCline have relied upon this forward-looking financial information in preparing this report, Woodside remains responsible for all aspects of this forward-looking financial information. The forecasts and projections as supplied to us, including those provided by GaffneyCline, are based upon assumptions about events and circumstances which have not yet transpired. We have not tested individual assumptions or attempted to substantiate the veracity or integrity of such assumptions in relation to any forward-looking financial information, however we have made sufficient enquiries to satisfy ourselves that such information has been prepared on a reasonable basis. In making this assessment we have taken the following into account:

- Woodside has sophisticated management and reporting processes and is subject to the reporting requirements of a public company listed on the ASX and registered under the Act
- Woodside completed a significant level of due diligence enquiry in relation to the BHP Petroleum assets and the findings of these enquiries were reflected in Woodside's forecast operational cash flows for BHP Petroleum
- KPMG Corporate Finance issued GaffneyCline, an independent and highly experienced petroleum industry technical specialist, with a scope of work to undertake various enquiries in relation to the forecast project information for Woodside and BHP Petroleum, including a review of technical and operational data and holding discussions with management in regard to the technical and operational assumptions underlying the forecast operations of both Woodside and BHP Petroleum. GaffneyCline has, where necessary, made adjustments to reflect its judgement and provided its preferred forecast production, operational and cost schedules to KPMG Corporate Finance
- the starting point for GaffneyCline's work was operational plans provided by Woodside to GaffneyCline for each production/development asset. GaffneyCline also received information directly from BHP
- GaffneyCline has considered the requirements of the VALMIN Code in relation to appropriate valuation methodologies having had regard to the development status of each project
- Woodside reports its petroleum resource estimates using definitions and guidelines consistent with the 2018 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 / European Association of Geoscientists & Engineers Petroleum Resources Management System
- BHP Petroleum's proved reserves (**1P**)[27] are estimated and reported according to the United States Securities and Exchange Commission (**SEC**) regulations and determined in accordance with SEC Rule 4-10(a) of Regulation S-X
- GaffneyCline held discussions with both Woodside's and BHP Petroleum's management teams and technical experts and considered both in-house and external supporting information, including economic models and other technical data, in determining its underlying assumptions
- where relevant, GaffneyCline has adopted macroeconomic assumptions determined by us.

[27] 1P Reserves are proved reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs and under existing economic and operating conditions. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Further detail in relation to the involvement of GaffneyCline and a summary of its projections is set out in sections 9 and 10. A copy of GaffneyCline's full report is also included at Appendix 15 to this report.

Notwithstanding the above, KPMG Corporate Finance cannot provide any assurance that the forward-looking financial information will be representative of the results which will actually be achieved during the forecast period. Any variations in the forward-looking financial information may affect our valuation and opinion.

It is not the role of the independent expert to undertake the commercial and legal due diligence that a company and its advisers may undertake. The Directors of Woodside, together with its legal and financial advisers, are responsible for conducting due diligence in relation to the Proposed Transaction. KPMG Corporate Finance provides no warranty as to the adequacy, effectiveness or completeness of the due diligence process, which is outside our control and beyond the scope of this report. We have assumed that the due diligence process has been and is being conducted in an adequate and appropriate manner.

The opinion of KPMG Corporate Finance is based on prevailing market, economic and other conditions at the date of this report but corresponds with a period of significant geopolitical unrest as a result of the invasion of Ukraine by Russia, which has resulted in a large number of Russia's trading partners imposing targeted trade and financial system sanctions against Russia, significantly impeding Russia's ability to undertake foreign trade, including in respect to oil and gas transactions. In addition, various countries have implemented a ban on imports of Russian oil and gas and the European Union is actively investigating ways in which they can reduce its reliance on Russian sourced oil and gas over the medium and long term. Both of these factors have contributed to a rapid and sharp increase in spot prices of various commodities on supply concerns, this, coupled with the uncertainty as to the rate of recovery from the unprecedented social and community disruption as a result of Covid-19 and the uncertainty as to the extent and rate of take of alternative clean energy sources, means various estimates of macroeconomic inputs to assessment of value have required a greater degree of subjectivity than usual. To the extent possible, we have reflected these conditions in our report. However, any subsequent changes in these conditions on the global economy and financial markets generally, and Woodside and BHP Petroleum specifically, could impact upon value in the future, either positively or negatively. We note that we have not undertaken to update our report for events or circumstances arising after the date of this report other than those of a material nature which would impact upon our opinion.

Certain market and industry data used in this presentation may have been obtained from research, surveys or studies conducted by third parties, including industry and general publications, KPMG Corporate Finance has not verified any market or industry data provided by third parties or industry or general publications.

6.3 Disclosure of information

In preparing this report, KPMG Corporate Finance has had access to all financial information considered necessary in order to provide the required opinion. Woodside has requested KPMG Corporate Finance limit the disclosure of some commercially sensitive information relating to Woodside, BHP Petroleum and their subsidiaries. This request has been made on the basis of the commercially sensitive and confidential nature of the operational and financial information of the operating entities comprising Woodside and BHP Petroleum. As such the information in this report has been limited to the type of information that is regularly placed into the public domain by Woodside.

6.4 Reliance on Technical Expert

ASIC Regulatory Guides envisage the use by an independent expert of specialists when valuing specific assets. To assist KPMG Corporate Finance in the valuation of both Woodside's and BHP Petroleum's portfolios of assets the subject of the Proposed Transaction, GaffneyCline was engaged by Woodside, but with its scope of work determined by us, to prepare an ITSR in relation to the forecast development, operational and cost assumptions for each of Woodside's and BHP Petroleum's production and, where appropriate, development/growth assets as well as the valuation of any other petroleum interests, such as contingent and/or prospective resources and other early stage petroleum assets or targets held by the entities. A copy of GaffneyCline's ITSR, dated March 2022, is attached to this report at Appendix 15.

GaffneyCline's ITSR was prepared in accordance with the requirements of the Australasian Code for Public Reporting of Technical Assessment and Valuation of Mineral and Petroleum Assets (2015 Edition) (**the VALMIN Code**) to the extent applicable and ASIC Regulatory Guides.

ASIC Regulatory Guides recommend the fees payable to the technical specialists be paid in the first instance by the independent expert and claimed back from the party commissioning the independent expert. KPMG Corporate Finance's preferred basis for appointment of independent technical specialists is that the client commissions, and pays the fees directly to, the technical specialist, whilst KPMG Corporate Finance defines the scope of work for the technical specialist. We do not consider that the independence of the technical specialist is impaired by this arrangement.

We have satisfied ourselves as to GaffneyCline's qualifications and independence from Woodside and BHP Petroleum, and have placed reliance on its report.

Following discussion and enquiry with GaffneyCline, the development, operational and cost assumptions recommended by GaffneyCline have been adopted in the cash flow projections used by us in assessing the value of Woodside's and BHP Petroleum's interests in their respective production and, where appropriate, development and growth assets. KPMG Corporate Finance was responsible for the determination of certain macroeconomic and other assumptions such as commodity prices, exchange rates, discount rates, inflation and taxation assumptions.

The valuation methodologies adopted by GaffneyCline in respect of petroleum assets not captured in the above assessments of value are based on the expected monetary value, comparable transactions and sunk costs methods as appropriate.

Due to the various uncertainties inherent in the valuation process, GaffneyCline has estimated a range of values within which it considers the value of each of these additional petroleum assets to lie. The valuations ascribed by GaffneyCline to the other petroleum assets of Woodside and BHP Petroleum have been adopted in our report.

7 Industry overview

The oil and gas industry consists of the upstream and midstream segments, which extract, produce and process crude oil, natural gas liquids and natural gas.

Accordingly, in order to provide a context for assessing the prospects of Woodside and BHP Petroleum, we have set out at Appendix 3 an overview of recent trends and outlook in international oil and LNG markets and Australian domgas markets.

We would highlight however that this industry overview was prepared just prior to the breakout of hostilities between Russia and the Ukraine, and the consequent trade and other economic sanctions imposed on Russia by various countries. Given the short period of time that has elapsed since Russia's invasion on 24 February 2022, the evolving nature of the situation and uncertainty as to the impact of these events over the medium to longer term, it is not practicable within the time frame available to update our analysis to reflect these rapidly changing circumstances.

8 Profile of Woodside

8.1 Company overview

Woodside was incorporated in Victoria as Woodside (Lakes Entrance) Oil Company NL in July 1954. The company was formed to search for oil in the Gippsland region of South East Victoria, taking its name from a small town in the Lakes Entrance district.

Woodside shifted its focus to Western Australia in the early 1960s following the acquisition of a permit to explore 370,000 km^2 off the Western Australian coast, resulting in the formation of the original North West Shelf Venture between the Burmah Oil Company of Australia, Shell Development Australia and Woodside.

Woodside was listed on the ASX in November 1971 and adopted its current name in May 1977.

Today, Woodside is an Australian based oil and gas production, development and exploration company headquartered in Perth, Western Australia. Woodside holds a portfolio of oil and gas and associated infrastructure assets both in Australia and internationally and has a market capitalisation as at 24 March 2022 of approximately A$32,668 million.

8.2 Production assets

An overview of the Woodside principal oil and gas and LNG assets are set out below. Further discussion in relation to the background and technical aspects of each of Woodside's principal production and development oil and gas projects are set out GaffneyCline's ITSR which is attached to this report at Appendix 15.

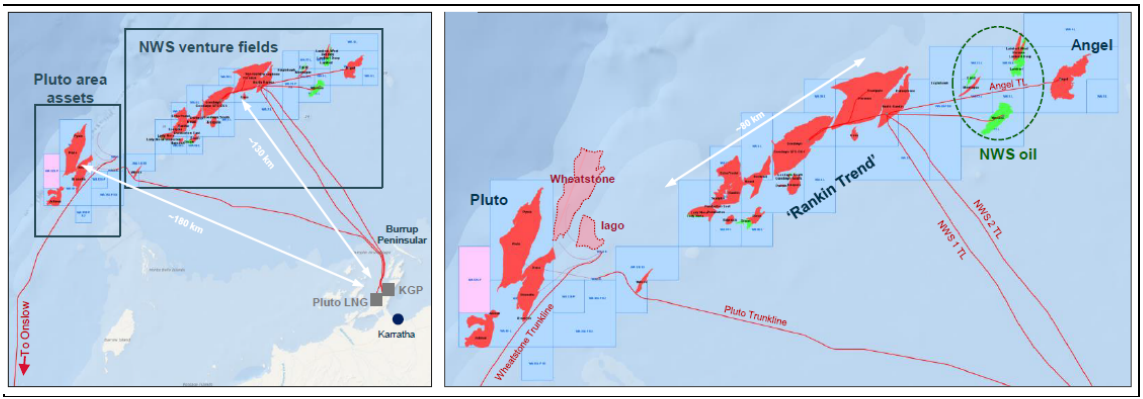
8.2.1 NWS Project

Made up of several joint ventures between seven major companies[28], the Woodside-operated NWS Project is one of Australia's largest producing oil and gas projects. The NWS Project supplies oil and gas

[28] Ownership of the NWS Project and associated production is split between several joint ventures with different participating interests. Woodside owns a one-sixth stake in the original NWS LNG joint venture, which was responsible for all LNG production and sale at the NWS Project. Other NWS LNG joint venture participants, which also own one-sixth stakes, include BHP Petroleum, BP plc (**BP**), Chevron Corporation (**Chevron**), Royal Dutch Shell plc (**Shell**) and Japan Australia LNG (MIMI) Pty Ltd. CNOOC Limited also has a participating interest in the NWS Project through the joint venture that is responsible for supplying LNG to the Guangdong Dapeng LNG Project in China (**China LNG JV**) (Woodside participating interest 12.5%). There are other joint ventures within the NWS Project, which are responsible for Western Australian domgas (Woodside participating interest 15.78%) and production of additional "equity lifted LNG" (the proportion of LNG which Woodside is entitled to lift and sell, in its own right, as a result of its participating interest in the relevant project) above joint contract quantities (Woodside

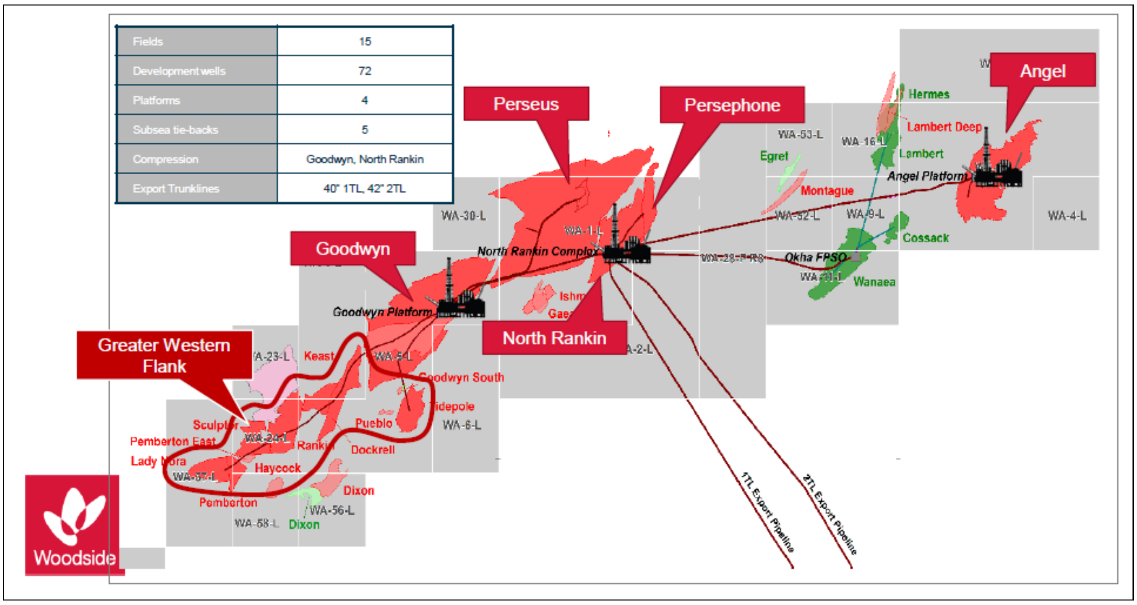
to Australian and international markets from gas, oil and condensate fields off the north-west coast of Australia.

Figure 3 – NWS Project location



Source: Woodside

Figure 4 – NWS Project field and platforms



Source: Woodside

First gas was produced in 1984 and first LNG shipped from the Karratha Gas Plant (**KGP**) located onshore on the Burrup Peninsula in 1989. Since first gas, 12 further fields have been brought online, with 3 having ceased production.

participating interest 15.78%). There is also an oil joint venture in relation to the Okha FPSO vessel (discussed later below) with different parties and ownerships.

Today, the North Rankin, Perseus, Goodwyn and Lady Nora-Pemberton (part of the Greater Western Flank) gas fields collectively account for in excess of 80% of the NWS Project's gross 2P gas Reserves.

The NWS Project's offshore production facilities include four natural gas platforms.

- *The North Rankin Complex*

  The North Rankin Complex (**NRC**) includes the North Rankin A and North Rankin B platforms. Connected by two 100 metre (**m**) bridges, the platforms operate as a single integrated facility. Located 135 kilometres (**kms**) north-west of Karratha, Western Australia, the NRC stands in 125m of water and has a production capacity of up to 60,000 tonnes per day (**tpd**) of dry gas and 6,200 tpd of condensate from the North Rankin and Perseus fields.

- *The Goodwyn A platform*

  The Goodwyn A platform is connected to the condensate rich Goodwyn gas field, located 23 kms south-west of the North Rankin A platform and about 135 kms north-west of Karratha. Dry gas and condensate produced from the Goodwyn area reservoirs, and Perseus satellite field reservoirs, is transported via a trunkline system to the KGP for processing.

- *The Angel platform*

  The Angel platform is located about 120 kms north-west of Karratha and is connected to the NRC via a 50km subsea pipeline. The Angel offshore platform ceased production in September 2020 however its infrastructure will be further utilised for the development of the Lambert Deep reserves (discussed further below).

The NWS Project's onshore KGP includes five LNG processing trains, two domgas trains and three LPG fractionation units. The facility is located 1,260 kms north of Perth, Western Australia and covers about 200 hectares (**ha**). The KGP has an export capacity of 16.9 million tonnes per annum (**Mtpa**).

Since 2020, production from NWS Project has been constrained by offshore supply, with production declining in most fields, leading to available ullage at the KGP. As a result, Woodside is currently pursuing various initiatives to underpin the long-term use of existing NWS Project production and processing infrastructure and the commercialisation of existing resources, including:

- the processing of third-party gas as NWS Project reserves decline, including the potential to backfill through the development of the Browse fields (discussed further at 8.4.3 below)
- the Greater Western Flank Phase-3 (**GWF-3**) and Lambert Deep project, which targets estimated recoverable gas reserves of 400 Bcf.

As at 31 December 2021, Woodside's share of NWS Project Proved (**1P**) and 2P Reserves was 135.4 MMboe and 170.3 MMboe respectively.

8.2.2 Pluto LNG

Woodside holds a 90% interest in Pluto LNG and operates the Pluto LNG facilities[29], which processes gas from the Pluto and Xena gas fields located offshore Western Australia (refer figure 3 above) and is continuing to develop the Pyxis field, which came on stream in November 2021.

The Pluto field was discovered in 2005, the Xena gas field in 2006 and Pyxis gas field discovered in 2015. Five Pluto appraisal wells and two Xena appraisal wells were subsequently drilled, with Pluto LNG taking development FID in 2007. First cargo from the project's single-train onshore LNG facility was delivered in 2012.

The Pluto/Xena gas fields have been partially developed with seven subsea wells in Pluto and one subsea well in Xena. All wells are still on production except for one well that watered-out.

The Pluto-A Platform is a not-normally manned platform, located 180 kms north-west of Karratha in 85m of water. Gas is piped through a 180 km trunkline to an onshore processing facility, comprising a single 5 Mtpa LNG processing train (**Pluto Train 1**), two LNG and three condensate storage tanks and an LNG and condensate export jetty on the Burrup Peninsula, together with up to 25 million standard cubic feet per day (**MMscfd**) of domestic gas supply.

Pluto LNG is underpinned by long-term sales agreements with Kansai Electric Australia Pty Ltd and Tokyo Gas Australia Pty Ltd.

Woodside is currently undertaking various initiatives to position Pluto LNG for long term production through the development of additional offshore resources and improvements to the onshore facility, including the subsea tie-back of the Pyxis, Pluto North and Xena fields to the Pluto-A platform, which is approaching cold commissioning and start-up for the initial wells.

Woodside is also proposing a brownfields expansion of Pluto LNG through:

- modifications to Pluto Train 1 to facilitate processing of up to approximately 3.0 Mtpa of Scarborough gas and the installation of domgas infrastructure to increase domgas capacity to approximately 250 Terajoules per day (**TJpd**)
- the construction of a second gas processing train (**Pluto Train 2**), which will have a capacity in the order of 5 Mtpa (Woodside's project interest has been sold down to 51% as discussed later below).

A pipeline connecting Pluto LNG and the KGP (**Pluto–KGP Interconnector**) was completed in March 2022. This infrastructure allows the transfer of gas between the plants to optimise production across both facilities and enable future development of additional gas reserves.

As at 31 December 2021, Woodside's share of Pluto LNG 1P and 2P Reserves was 271.0 MMboe and 348.7 MMboe respectively.

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[29] The remaining 10% interest is held equally between Kansai Electric Australia Pty Ltd and Tokyo Gas Australia Pty Ltd

8.2.3 Wheatstone LNG

The Chevron operated Wheatstone LNG[30] processes gas from two separate upstream developments:

- the Wheatstone Project, which comprises the Wheatstone and Iago fields
- the Julimar Development Project, which comprises the Woodside operated offshore Julimar and Brunello gas fields which tie back to the central processing platform. In the initial phase, which came on stream in 2017, the Brunello field was developed with five producing wells tied back to Wheatstone. Woodside is currently undertaking work to extend the project's gathering system to tie in the Julimar field.

Figure 5 – Wheatstone Project location

Source: Chevron Australia website

Woodside holds a 13%[31] and 65%[32] participation interest in the Wheatstone Project facilities and the Julimar Development Project respectively.

The Julimar Development Project contributes approximately 20% of total gas processed by Wheatstone LNG.

Wheatstone LNG consists of an offshore platform located approximately 220 km from Onslow, Western Australia in approximately 70m of water, connected by a trunkline to an onshore processing plant

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30 Wheatstone LNG is a joint venture between Australian subsidiaries of Chevron (64.14%), Kuwait Foreign Petroleum Exploration Company (13.4%), Woodside (13%), Kyushu Electric Power Company (1.46%) and PE Wheatstone Pty Ltd (8%).

31 Woodside's 13% participation interest includes the offshore platform, the pipeline to shore and the onshore plant, but excludes the Wheatstone and Iago fields and associated subsea infrastructure. The Wheatstone Iago fields are operated by Chevron Australia in joint venture with Australian subsidiaries of Kuwait Foreign Petroleum Exploration Company (**KUFPEC**) and Kyushu Electric Power Company, together with PE Wheatstone Pty Ltd

32 the remaining 35% project interest is held by KUFPEC

consisting of two LNG trains with a combined capacity of 8.9 Mtpa, a 200 TJpd domgas plant and associated infrastructure. The Wheatstone platform, pipeline and onshore LNG are operated by Chevron. After separation on the platform, Julimar and Brunello gas and condensate are dehydrated and compressed for transport to the onshore LNG plant, along with gas and condensate from the Chevron-operated Wheatstone and Iago fields.

Wheatstone LNG was sanctioned in late 2011, with first shipment of LNG announced in October 2017. Natural gas from the domgas plant is delivered via pipeline to an inlet point on the Dampier Bunbury Natural Gas Pipeline.

As at 31 December 2021, Woodside's share of Wheatstone LNG 1P and 2P Reserves[33] was 109.6 MMboe and 165.8 MMboe respectively.

8.2.4 Australia Oil

Woodside operates and holds a 60% participation interest in the Ngujima-Yin FPSO[34], which produces from the Vincent and Greater Enfield oilfields.

The Vincent field was discovered in 1998, achieved first oil in 2008, and is developed with thirteen horizontal wells (seven bi-laterals and six tri-laterals). Two water injection wells are provided for water disposal from both the Vincent and Greater Enfield fields and one vertical gas injector for disposal of surplus gas.

The Greater Enfield Development consists of three separate oil accumulations - Laverda Canyon, Norton over Laverda, and Cimatti - located offshore Exmouth, Western Australia. Oil was discovered in the Laverda Canyon in 2000, at Cimatti in 2010 and at Norton over Laverda in 2011. First oil from the development was achieved in August 2019.

The Ngujima-Yin FPSO is a conversion of the Ellen Maersk, a very large crude carrier from the Maersk fleet (type E). It was constructed in 2000, then converted to an FPSO facility in Singapore during 2007-2008. The Ngujima-Yin FPSO was transferred to Woodside operatorship in 2012. Topside processing facilities include oil, water and gas separation systems, water injection and gas compression, plus injection equipment. The topsides are designed to process 120,000 barrels (**bbl**) of oil and up to 55 MMscfd of free gas production.

Woodside also holds a 33.33% participation interest in, and is the operator of, the Okha FPSO, which produces oil from the Cossack, Wanaea, Lambert and Hermes (**CWLH**) fields on behalf of the NWS Project.

The Okha FPSO vessel is an oil production facility moored to a riser turret between the Wanaea and Cossack oil fields, 34 kilometres east of the NRC. The Cossack, Wanaea, Lambert and Hermes oil fields are connected by flexible flowlines. Crude oil is offloaded from the facility via a flexible line to bulk tankers, while a pipeline exports LPG-rich gas from the Cossack and Wanaea fields to the NRC, before being transferred to the KGP for processing. The CWLH oil fields are located offshore Western Australia, between 125-145 km north-west of Karratha and 35-40 km east of the North Rankin platform. The

[33] comprising the Julimar and Brunello fields
[34] The balance of the participation interest is held by Mitsui E&P Australia Pty Ltd

Lambert and Hermes fields are situated 15 kms to the north of the Wanaea and Cossack fields. The fields lie on the inner continental shelf, in water depths of 75-135 m. Lambert was discovered in 1973, but at the time was considered too small to justify development on its own. Wanaea was discovered in June 1989 and Cossack the following year. Hermes was discovered in 1996, drilled to test a mapped northern extension of the Lambert accumulation.

The Okha FPSO commenced production in September 2011. Prior to this, the oil and gas from the CWLH fields was produced through the Cossack Pioneer FPSO, which commenced production in 1995.

The offshore production system consists of subsea wells and infrastructure, a riser turret production and mooring system, the FPSO and the gas export line.

As at 31 December 2021, Woodside's share of 1P and 2P Reserves was 21.6 MMboe and 25.3 MMboe respectively.

8.2.5 *Production summary*

Woodside's share of production for FY19, FY20 and FY21 is summarised in the table below.

Table 5: Woodside historical production

Production			FY19	FY20	FY21
LNG	NWS Project	t	2,507,017	2,597,155	2,296,202
	Pluto LNG	t	3,837,059	4,553,351	4,504,937
	Wheatstone	t	1,253,233	1,276,981	1,146,567
	Total LNG[1]	**boe**	**67,657,836**	**75,050,986**	**70,778,296**
Domgas	Australia[2]	TJ	34,280	32,108	15,313
	Canada[3]	TJ	3,052	-	-
	Total domestic gas[1]	**boe**	**6,107,283**	**5,252,792**	**2,505,260**
Condensate	NWS Project	bbl	4,697,633	4,213,992	3,364,104
	Pluto LNG	bbl	2,608,860	3,097,175	3,036,442
	Wheatstone	bbl	2,317,821	2,470,846	2,328,828
	Total condensate[1]	**boe**	**9,624,314**	**9,782,013**	**8,729,374**
Oil	Ngujima-Yin[4]	bbl	4,024,246	8,282,343	7,113,172
	Okha[5]	bbl	1,598,684	1,420,849	1,516,067
	Total oil[1]	**boe**	**5,622,930**	**9,703,192**	**8,629,239**
LPG	NWS Project	t	66,724	62,922	60,822
	Total LPG[1]	**boe**	**546,249**	**515,177**	**497,990**
Total		**boe**	**89,558,612**	**100,304,160**	**91,140,159**

Source: Woodside Fourth Quarter Report for Period Ended 31 December 2020 and 31 December 2021
Notes:

1. *Conversion factors are identified at Table 6*
2. *Includes jointly and independently marketed gas sales*
3. *Produced into the Canadian gas network for distribution in North America*
4. *The Ngujima-Yin FPSO produces oil from the Vincent and Greater Enfield resources*
5. *The Okha FPSO produces oil from the Cossack, Wanaea, Lambert and Hermes resources*
6. *Figures may not add exactly due to rounding.*

Table 6: Conversion factors

Product	Factor	Conversion factors[1]
Pipeline natural gas	1 TJ	163.6 boe
Liquefied natural gas (LNG)	1 tonne	8.9055 boe
Condensate	1 bbl	1.000 boe
Oil	1 bbl	1.000 boe
Liquefied petroleum gas (LPG)	1 tonne	8.1876 boe
Natural gas	1 MMBtu	0.1724 boe
Dry gas	1 MMboe	5.7 Bcf

Source: Woodside 2021 Annual Report
Note 1: Minor changes to some conversion factors can occur over time due to gradual changes in the process stream

8.3 Marketing, Trading and Shipping

In addition to LNG, Woodside markets crude oil, condensate, LPG and pipeline natural gas through its trading office in Singapore, which was established in 2013, and through its office in Perth.

Woodside manages its LNG portfolio through a mix of short-, mid- and long-term contracts, supplied by Woodside equity cargoes and supplemented by third-party purchases. A portion of production is also kept available for the spot market.

Woodside maintains an LNG shipping fleet of six ships under long-term contracts and one vessel on short-term charter, which allows Woodside to protect against fluctuations in the shipping market and to also deliver third-party cargoes through sub-chartering activities.

A truck loading facility was also built at Pluto LNG to provide LNG for distribution by truck to the Pilbara, Kimberley and Gascoyne regions of Western Australia.

8.4 Development assets

Woodside, together with its joint venture participants, is currently advancing a number of development activities.

8.4.1 Scarborough/Pluto Train 2

Scarborough

Woodside, as operator of the Scarborough Joint Venture[35], announced on 22 November 2021 that FIDs had been made to approve the proposed development of the Scarborough gas resource through new offshore facilities connected by a 430 km pipeline to Pluto Train 2, utilising the NWS Project shipping

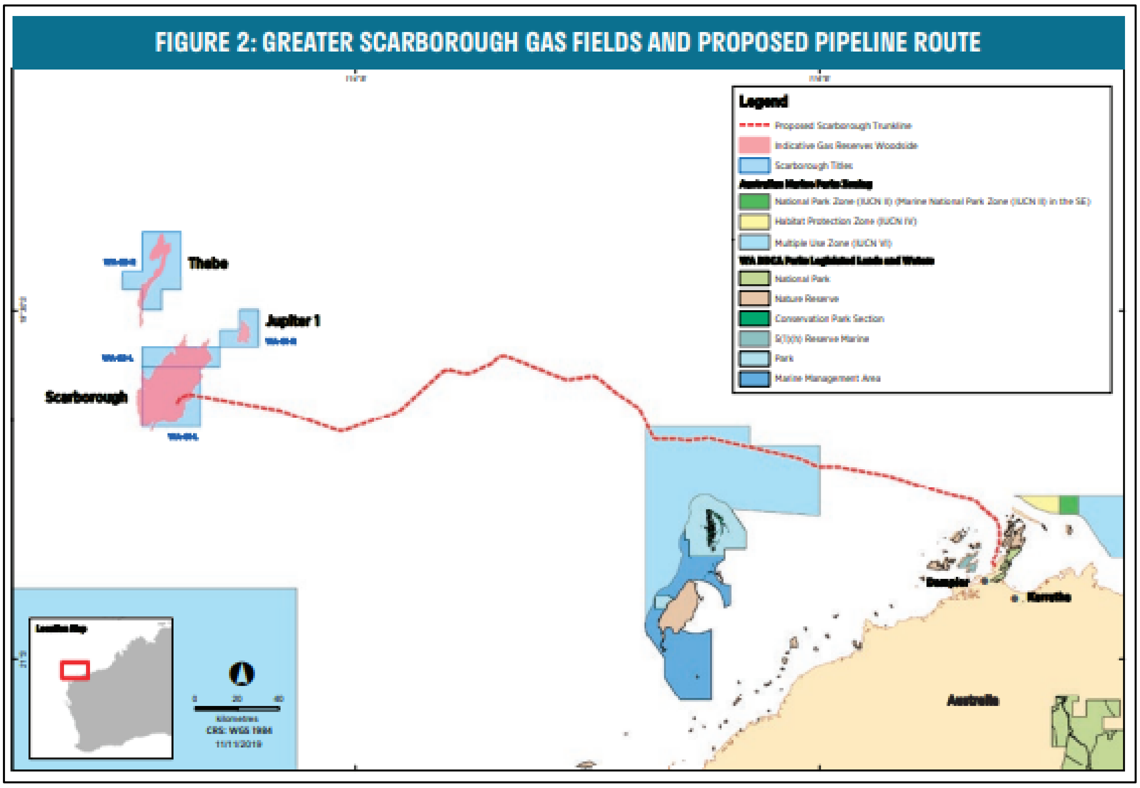
[35] Woodside holds a 73.5% interest in WA-61-L and WA-62-L covering the Scarborough and North Scarborough, fields and a 50% interest in WA-63-R and WA-61-R covering the Thebe and Jupiter gas fields. BHP Petroleum holds the balance of the participation interests in these fields. Woodside and BHP Petroleum have entered into an option agreement for BHP Petroleum to sell its 26.5% interest in the Scarborough Joint Venture to Woodside and its 50% interest in the Thebe and Jupiter joint ventures. The option is exercisable at BHP Petroleum's option in the second half of calendar year 2022 and, if exercised, consideration of US$1,000 million is payable by Woodside to BHP Petroleum, with adjustment for capital expenditure incurred by the joint venture from an effective date of 1 July 2021. An additional US$100 million is payable contingent upon a future FID for the Thebe development.

channel and existing shore crossing corridors created by the Pluto foundation project, along with new domgas facilities and modifications to Pluto Train 1.

The Scarborough gas resource is located offshore, approximately 375 kms west-northwest of the Burrup Peninsula and is part of the Greater Scarborough gas fields which Woodside estimates to include Scarborough (11.1 trillion cubic feet (**Tcf**) of 2P dry gas[36], 100%), Thebe (1.2 Tcf of 2C[37] dry gas, 100%) and Jupiter (0.3 Tcf of 2C dry gas, 100%).

As a result of the FID, Woodside's share of Greater Scarborough 1P Undeveloped Reserves is 956.6 MMboe, 2P Undeveloped Reserves[38] 1,432.7 MMboe and 2C Contingent Resource of 165.3 MMboe.

Figure 6 – Greater Scarborough Gas Field and Proposed Pipeline Route



Source: Woodside

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[36] Net of non-saleable inerts and upstream fuel and flare gas
[37] Best estimate of contingent resources. 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.
[38] 'Undeveloped reserves' are those reserves for which wells and facilities have not been installed or executed but are expected to be recovered through future investments

The proposal is to initially develop the Scarborough gas field with a phased development drilling program of eight initial high-rate gas wells, tied back to a semi-submersible floating production unit (**FPU**) moored in 950m of water close to the Scarborough field, with a total of 13 wells over field life dependent upon reservoir performance. The relevant offshore petroleum titles are all located in Commonwealth waters.

The Thebe dry gas field will comprise eight vertical subsea wells, tied back to the FPU and will backfill production from the Scarborough gas field. The development of Jupiter dry gas field will comprise two vertical subsea wells, tied back to the FPU, providing backfill to the Scarborough and Thebe fields.

Gas will be dehydrated and compressed on the FPU and transported to the onshore Pluto LNG plant.

Woodside is pursuing a sell down of its interest in the upstream Scarborough development, with a targeted equity interest of 51% or greater.

Pluto Train 2

In 2019, Woodside completed front-end engineering and design (**FEED**) for the construction of Pluto Train 2 for processing up to 5.0 Mtpa of gas from the proposed Greater Scarborough field development at the existing Pluto LNG onshore facility. Expansion activities also include modifications to Pluto Train 1 to facilitate processing of up to approximately 3.0 Mtpa of Scarborough gas and the installation of domgas infrastructure to increase capacity to approximately 225 TJpd.

The development of Pluto Train 2 is supported by a fully termed processing and services agreement (**PSA**) entered into between the Pluto Train 2 and Scarborough Joint Ventures. The PSA provides for the Scarborough Joint Venture to access LNG and domestic gas processing services at a rate of up to 8 Mtpa of LNG and up to 225 TJpd of domgas for an initial period of 20 years, with options to extend.

The PSA is supported by associated processing and services agreements executed with the Pluto Joint Venture in respect of access to the existing Pluto LNG facilities. First cargo is targeted for 2026, with approximately 60% of Woodside's 73.5% participation interest in production volumes contracted.

At commencement, Woodside's intention is that gas flows are biased to Pluto Train 2, with 5 Mtpa of gas directed to Pluto Train 2 as it is being designed for the Scarborough gas composition. Scarborough gas flow to Pluto Train 1 will initially co-mingled with Pluto LNG gas while that project is still online, with an expectation of an initial flow rate of 2Mtpa from Scarborough, increasing to 3 Mtpa when Pluto goes offline.

On 15 November 2021, Woodside announced that it had entered into a sale and purchase agreement for the sale to Global Infrastructure Partners (**GIP**) of a 49% non-operating participating interest in Pluto Train 2, which will require GIP to meet 49% of future Pluto Train 2 capital expenditure from the effective date of 1 October 2021, estimated by Woodside to total US$5,600 million (100% project), along with an additional amount of construction capital expenditure of approximately US$822 million[39].

[39] The 15 November 2021 ASX announcement referred to an amount of up to US$835 million but noted that the final amount was dependent on interest rate swaps and foreign exchanges rates on the date of the FID for Scarborough and Pluto Train 2, which was taken on 22 November 2021

If total development capital expenditure incurred is less than US$5,600 million, GIP will pay Woodside an additional amount equal to 49% of the under-spend. In the event of a cost overrun, Woodside will fund up to US$822 million in respect of GIP's 49% share of any overrun.

Delays to the expected start-up of production will result in payments by Woodside to GIP in certain circumstances.

The transaction includes a number of other related agreements between Woodside and GIP including a project commitment agreement (**PCA**). The PCA includes provisions for GIP to be compensated for exposure to additional Scope 1 emissions liabilities above agreed baselines, and to sell its 49% interest back to Woodside if the status of key regulatory approvals materially changes.

Woodside announced on 18 January 2022 that the sell down to GIP had been completed.

Established in 2006, GIP is one of the world's leading specialist infrastructure investors managing over US$79,000 million for its investors. The funds and investment platforms managed by GIP make equity and debt investments in infrastructure assets and businesses, targeting investments in the energy, transport, water / waste and digital infrastructure sectors. GIP's funds currently own 40 portfolio companies which have combined annual revenues of c.US$34,000 million and employ in excess of 58,000 people.

The Scarborough/Pluto Train 2 project is expected by Woodside to be one of the lowest carbon intensity projects for LNG delivered to customers in north Asia.

On 30 November 2021, Woodside announced that it had received a proceeding in the Supreme Court of Western Australia commenced by the Conservation Council of Western Australia challenging a Western Australian State Government works approval for the Pluto Train 2 project. Woodside has advised that it has complied with regulatory requirements and environmental processes in seeking and receiving its approvals and intends to vigorously defend its position.

Pluto-KGP Interconnector

Woodside is also progressing the 3.2km, 30-inch Pluto–Karratha Interconnector pipeline connecting Pluto LNG with the NWS Project's KGP. The interconnection, constructed along the existing Dampier to Bunbury Natural Gas Pipeline corridor, will facilitate the transfer of gas between the plants to optimise production across both facilities and enable future development of additional gas reserves. Woodside is targeting "Ready for Start Up" status in 2022. The infrastructure will have the capacity to transport wet gas quantities of more than 5 Mtpa (100% project, LNG production equivalent).

In November 2019, Woodside announced FID on the pipeline component of the Interconnector and entered into contractual arrangements for the construction of the pipeline and its ongoing operation and maintenance. Construction activities for the pipeline commenced in 2021 and were completed in fourth quarter of 2021.

8.4.2 *NWS Project Extension*

The NWS Project Extension proposes to secure the long-term use of NWS Project production and processing facilities through:

- the long-term processing of third-party gas and fluids

- further development of NWS Project resources without the need for constructing new processing facilities.

Third-party processing

The NWS Project participants have executed fully-termed gas processing agreements (**GPAs**) for processing third-party gas through the NWS Project facilities in respect of gas from the Pluto fields and from the Waitsia Gas Project Stage 2.

Construction of two new onshore gas receiving points and tie-in infrastructure at KGP commenced in January 2021, which will allow KGP to receive gas from both the Pluto fields and the Waitsia Gas Project Stage 2. Arrangements with the Western Australian Government for the processing of gas from Pluto and Waitsia were finalised in January 2021.

Development of NWS Project resources

The GWF–3 and Lambert Deep development is located in Commonwealth waters off the coast of north-western Australia and targets estimated recoverable gas reserves of 400 Bcf. It involves the drilling of three production wells in the Greater Western Flank regions and one production well in the Lambert Deep development, with subsea tieback to the Goodwyn A and Angel fixed platforms of the NWS Project respectively.

The GWF-3 development is located within the Goodwyn Field south-west of the GWA platform in 125 m water depth. GWF-3 intends to develop incremental volumes from the Goodwyn GH reservoir via existing infrastructure, providing gas and condensate production to partially fill ullage at the KGP emerging from 2021.

The Lambert Deep field lies in 130 m water depth and is located approximately 15 km north-west of the Angel Platform.

The NWS Project joint venture partners took FID approval on the project in January 2020 followed by the award of key contracts in the second quarter of 2020. First gas from the project is expected in 2022.

8.4.3 Browse

Woodside, as operator for and on behalf of the Browse Joint Venture (**Browse JV**)[40], is proposing to develop the Brecknock, Calliance and Torosa fields located approximately 425 km north of Broome, Western Australia, in the offshore Browse Basin. Seventeen wells have been drilled across the fields, with twelve drilled since the petroleum retention leases were first granted in 2003. Hydrocarbon resources contained in these fields are predominately gas, with 2C Contingent Resources of 4.3 Tcf of dry gas and 119 MMbbl of condensate (Woodside share).

The Brecknock and Calliance fields lie in water depths of between 500m and 700m, while the Torosa field lies in water depths varying between 0m and 475m.

[40] Woodside has a 30.6% participation interest. Other participants include Shell Australia (27%), BP (17.33%), Japan Australia LNG (14.4%) and PetroChina (10.67%)

The Browse JV proposes to develop the Browse hydrocarbon resources using two 1,100 MMscfd (annual daily export average) FPSO facilities, which will provide gas/liquids separation, gas processing and dehydration, condensate treatment and stabilisation, and gas export compression. The FPSO facilities will be supplied by a subsea production system and will transport gas to existing NWS Project infrastructure via an approximate 900km pipeline which will tie in near the existing NRC in Commonwealth waters.

The development is envisaged to be phased, with 12 high-rate subsea wells drilled on the Calliance and Torosa fields over phase 1. Three further phases will, subject to the performance of phase 1 wells, see an additional 20 subsea wells in the base case.

8.4.4 *Sangomar*

The Sangomar field (formerly the SNE field), containing both oil and gas, is located 100 kms south of Dakar, Senegal. Execution work on the Sangomar field development phase 1 commenced in early 2020 and first oil production is targeted in 2023.

In July 2021, Woodside completed the acquisition of the participating interest of FAR Senegal RSSD S.A. (**FAR**) in the project joint venture, which increased Woodside's participating interest in the Sangomar exploitation area to 82% and to 90% for the remaining project evaluation area.

The initial phase of the project is focussed on developing less complex reservoir units and testing other reservoirs to support future phases of development and potential gas export to shore. This phase of the development will target approximately 230 MMbbl of crude oil and will include the installation of a standalone FPSO facility and subsea infrastructure that will be designed to allow subsequent development phases.

In July 2021, Woodside as operator of the joint venture commenced drilling of up to 23 production, gas and water injection wells. The 23 wells will be connected to the FPSO through a network of flowlines and subsea infrastructure.

The FPSO is expected to have an oil production capacity of 100,000 bbl per day, with gas handling capacity of 130 MMscf/d. The FPSO has the flexibility for up to 65 wells in total.

Woodside has commenced engagement with interested parties to sell down its participating interest in the Sangomar Joint Venture to a targeted 40-50%.

8.4.5 *Myanmar A-6 Development*

The Myanmar A-6 Development is a joint venture operated by TotalEnergies SE (**TotalEnergies**)[41] and is targeting the delivery of natural gas to Myanmar and Thailand.

Block A-6 is in the Rakhine Basin, offshore Myanmar, and covers approximately 10,000 km^2 in water depths of up to 2,400m. The A-6 Development concept includes the drilling of up to 10 deep-water wells (six wells in Phase 1 and up to four additional wells in Phase 2) tied back to a new dehydration and

[41] The joint venture comprises TotalEnergies (40%), Woodside (40%) and Myanmar Petroleum Resources Limited (Government Liaison operator, 20%) Woodside's current working interest of 40% is subject to Myanma Oil and Gas Enterprise's (**MOGE**) right to acquire a working interest of up to 20%. If MOGE elects to acquire the full 20%, Woodside's working interest will reduce to 32%.

compression platform located approximately 65 km away, with gas exported by a 265 km pipeline to a riser platform located near the existing Yadana platform complex, with the riser platform distributing gas through existing pipeline infrastructure.

Woodside announced on 27 January 2022 its intention to withdraw from Myanmar following the State of Emergency declared in that country in February 2021 and the continuing deterioration in the human rights situation.

8.4.6 Sunrise LNG

The Sunrise development comprises the Sunrise and Troubadour gas and condensate fields, collectively known as Greater Sunrise, located in the Timor Sea approximately 150km south-east of Timor-Leste and 450km norther-west of Darwin, Australia. The fields contain an estimated 2C Contingent Resource of 5.1 Tcf of dry gas and 226 MMbbl of condensate, 100% (1.7 Tcf of dry gas and 76 MMbbl of condensate Woodside share).

Following the establishment of a new maritime boundary treaty between Australia and Timor-Leste in 2019, negotiations between the two Governments and the Sunrise Joint Venture on a new Greater Sunrise Production Sharing Contract have been ongoing. The Sunrise Joint Venture[42] remains committed to the development of Greater Sunrise provided there is the fiscal and regulatory certainty necessary for a commercial development to proceed.

8.4.7 Kitimat LNG

The development concept for the proposed Kitimat LNG project in Canada includes natural gas resources in the Liard Basin in north-east British Columbia, transportation by the 471 km Pacific Trail Pipeline and a liquefaction facility at Bish Cove near Kitimat, British Columbia.

Woodside is in the process of exiting its 50% non-operated participating interest in the Kitimat LNG development. Exit activities including the divestment or wind-up and restoration of assets, leases and agreements covering the site for the proposed LNG facility are well underway. Sale of the Pacific Trail Pipeline was completed in December 2021. In support of potential future natural gas, ammonia, and hydrogen opportunities in Canada, Woodside will however continue to hold the Liard Basin upstream gas assets.

8.5 Exploration

Woodside holds interests in a number of Australian and international exploration assets, including in oil and/or gas prone basins located in Myanmar, the Republic of Korea, Bulgaria, Ireland, Senegal and Congo.

An overview of significant exploration assets is contained in GaffneyCline's ITSR, which is attached as Appendix 15.

[42] Woodside has a 33.44% participation interest and is the operator. Other participation interests are held by Timor GAP (56.56%) and Osaka Gas (10%)

8.6 Reserves and Resources

Woodside's share of 1P and 2P Developed[43] and Undeveloped Reserves and Best Estimate 2C Contingent Resources by region as at 31 December 2021 are summarised in the tables below.

Table 7: Woodside 1P Developed and Undeveloped Reserves as at 31 December 2021

	Dry gas Bcf		Condensate MMbbl		Oil MMbbl		Total MMboe		
	Developed	Undeveloped	Developed	Undeveloped	Developed	Undeveloped	Developed	Undeveloped	Total
Greater Pluto[1]	1,123.1	309.2	15.8	4.0	-	-	212.8	58.2	271.0
NWS[2]	550.5	91.1	12.3	2.1	8.4	-	117.3	18.1	135.4
Greater Exmouth[3]	-	-	-	-	21.6	-	21.6	-	21.6
Wheatstone[4]	279.3	284.7	5.4	5.3	-	-	54.4	55.2	109.6
Senegal	-	-	-	-	-	98.0	-	98.0	98.0
Greater Scarborough[5]	-	5,452.8	-	-	-	-	-	956.6	956.6
Reserves	**1,952.9**	**6,137.8**	**33.5**	**11.3**	**30.0**	**98.0**	**406.1**	**1,186.2**	**1,592.3**

Source: Woodside 2021 Annual Report

Notes:

1. *The 'Greater Pluto' region comprises the Pluto-Xena, Pyxis, Larsen, Martell, Martin, Noblige, and Remy fields*
2. *The 'North West Shelf' region includes all oil and gas fields within the North West Shelf Area*
3. *The 'Greater Exmouth' region comprises Vincent, Enfield, Greater Enfield, Greater Laverda, Ragnar and Toro fields*
4. *The 'Wheatstone' region comprises the Julimar and Brunello fields*
5. *The 'Greater Scarborough' region comprises the Jupiter, Scarborough, and Thebe fields*
6. *Figures may not add exactly due to rounding*
7. *Conversion factors are identified at Table 6.*

[43] 'Developed reserves' are those reserves that are producible through currently existing completions and installed facilities for treatment, compression, transportation and delivery, using existing operating methods and standards

Table 8: Woodside 2P Developed and Undeveloped Reserves as at 31 December 2021

	Dry gas Bcf		Condensate MMbbl		Oil MMbbl		Total MMboe		
	Developed	Undeveloped	Developed	Undeveloped	Developed	Undeveloped	Developed	Undeveloped	Total
Greater Pluto[1]	1,511.6	333.6	20.7	4.3	-	-	285.9	62.8	348.7
NWS[2]	689.0	118.6	15.8	2.8	10.1	-	146.7	23.6	170.3
Greater Exmouth[3]	-	-	-	-	25.3	-	25.3	-	25.3
Wheatstone[4]	434.3	415.7	8.9	7.7	-	-	85.1	80.6	165.8
Senegal[5]	-	-	-	-	-	148.7	-	148.7	148.7
Greater Scarborough[6]	-	8,166.6	-	-	-	-	-	1,432.7	1,432.7
Reserves	**2,634.9**	**9,034.6**	**45.4**	**14.8**	**35.5**	**148.7**	**543.1**	**1,748.5**	**2,291.7**

Source: Woodside 2021 Annual Report
Notes:
1. *The 'Greater Pluto' region comprises the Pluto-Xena, Pyxis, Larsen, Martell, Martin, Noblige, and Remy fields*
2. *The NWS region includes all oil and gas fields within the North West Shelf Area*
3. *The 'Greater Exmouth' region comprises Vincent, Enfield, Greater Enfield, Greater Laverda, Ragnar and Toro fields*
4. *The 'Wheatstone' region comprises the Julimar and Brunello fields*
5. *The 'Senegal' region comprises the Sangomar field. The Developed and Undeveloped reserves comprise of oil estimates. The Best Estimate 2C Contingent Resources include gas and oil estimates*
6. *The 'Greater Scarborough' region comprises the Jupiter, Scarborough, and Thebe fields*
7. *Figures may not add exactly due to rounding*
8. *Conversion factors are identified at Table 6.*

Table 9: Woodside 2C Contingent Resources by region as at 31 December 2021

	Dry gas Bcf	Condensate MMbbl	Oil MMbbl	Total MMboe
Greater Browse[1]	4,257.8	119.4	-	866.4
Greater Sunrise[2]	1,716.8	75.6	-	376.7
Greater Pluto[3]	1,116.5	22.5	-	218.3
Greater Exmouth[4]	307.4	2.2	26.7	82.9
NWS[5]	282.4	9.7	11.7	71.0
Wheatstone[6]	37.4	0.7	-	7.3
Canada[7]	25,373.3	-	-	4,451.5
Senegal[8]	232.2	-	231.2	271.9
Greater Scarborough[9]	820.2	-	-	143.9
Myanmar[10]	624.0	-	-	109.5
Total	**34,768.0**	**230.1**	**269.7**	**6,599.4**

Source: Woodside 2021 Annual Report

Notes:

1. *The 'Greater Browse' region comprises the Brecknock, Calliance and Torosa fields*
2. *The 'Greater Sunrise' region comprises the Sunrise and Troubadour fields*
3. *The 'Greater Pluto' region comprises the Pluto-Xena, Pyxis, Larsen, Martell, Martin, Noblige, and Remy fields*
4. *The 'Greater Exmouth' region comprises Vincent, Enfield, Greater Enfield, Greater Laverda, Ragnar and Toro fields*
5. *The NWS region includes all oil and gas fields within the North West Shelf Area*
6. *The 'Wheatstone' region comprises the Julimar and Brunello fields*
7. *The 'Canada' region comprises unconventional resources in the Liard Basin*
8. *The 'Senegal' region comprises the Sangomar field*
9. *The 'Greater Scarborough' region comprises the Jupiter, Scarborough and Thebe fields*
10. *The 'Myanmar' region comprises the fields within the A-6 development*
11. *Figures may not add exactly due to rounding*
12. *Conversion factors are identified at Table 6.*

8.7 New Energy

Woodside's new energy business is focused on maturing its portfolio of hydrogen and ammonia opportunities in Australia and internationally. Woodside has publicly announced a target to invest US$5,000 million in new energy products and lower-carbon services by 2030.

Currently, Woodside's activity in this area includes investigating the feasibility of 3 hydrogen projects.

8.7.1 H2Perth

Woodside, with the support of the State Government of Western Australia, is progressing concept plans to establish a world-scale hydrogen and ammonia production facility on approximately 130 ha of vacant industrial land to be leased from the State Government in the Kwinana Strategic Industrial Area and Rockingham Industry Zone.

H2Perth is a phased development that, at full potential, would be one of the largest facilities of its kind in the world. It would produce up to 1,500 tpd of hydrogen for export in the form of ammonia and liquid hydrogen.

Initially, H2Perth will target 300 tpd of hydrogen production, which can be converted into 600,000 tonnes per annum (**tpa**) of ammonia or 110,000 tpa of liquid hydrogen.

8.7.2 H2TAS

In January 2021, Woodside signed a memorandum of understanding with the Government of Tasmania for the phased development of the H2TAS Bell Bay Renewable Hydrogen Project.

H2TAS would use a combination of hydropower and wind power to create a 100% renewable ammonia product for export as well as renewable hydrogen for domestic use. The initial phase would have an electrolysis component of up to 300 megawatts (**MW**) and target production of 200,000 tpa of ammonia.

In May 2021, Woodside announced a project consortium under a Heads of Agreement with Japanese companies Marubeni Corporation and IHI Corporation. The parties have completed initial feasibility studies and concluded that it is technically and commercially feasible to export ammonia to Japan from the Bell Bay area.

Woodside has also signed a term sheet with Tasmanian natural gas retailer Tas Gas to facilitate blending of hydrogen into the Tasmanian pipeline gas network.

8.7.3 H2OK

On 7 December 2021, Woodside announced it had secured a lease and option to purchase 94 acres (38 ha) of vacant land in Oklahoma, United States for future development of a modular hydrogen facility and entering a memorandum of understanding with Hyzon Motors.

Subject to approvals and customer demand, the H2OK concept involves construction of an initial 290 MW facility, which will use electrolysis to produce up to 90 tpd of liquid hydrogen for the heavy transport sector. The location offers the capacity for expansion up to 550 MW and 180 tpd.

The project is targeting a FID in the second half of 2022, and first liquid hydrogen production in 2025.

8.7.4 Heliogen

Woodside and Heliogen, a renewable energy technology company based in the US, are progressing plans for a 5 MW commercial-scale demonstration facility in California, using Heliogen's Artificial Intelligence-enabled concentrated solar technology.

In October 2021, having completed front-end engineering and design, Woodside issued a limited notice to proceed (**LNTP**) to Heliogen, to begin procurement of key equipment. Woodside and Heliogen also announced their intent to jointly market Heliogen's technology in the US and Australia under a proposed joint marketing arrangement.

Heliogen's technology is a modular, turnkey, artificial intelligence-enabled concentrated solar energy system that aims to deliver clean energy with nearly 24/7 availability. The facility will utilise advanced computer vision software that precisely aligns an array of mirrors to reflect sunlight to a single target on the top of a solar tower, thereby enabling low-cost storage in the form of high-temperature thermal energy.

8.7.5 Power for base business

Woodside is proposing to develop a solar photovoltaic power facility, located approximately 15 km southwest of Karratha, Western Australia, for use on the Burrup Peninsula, with an initial 50 MW to be supplied to Pluto LNG and a further 50 MW to the proposed Perdaman urea plant. Woodside is engaging with the community to further understand the impacts and benefits of this opportunity to reduce emissions and increase ammonia production in the Pilbara.

8.8 Historical financial performance

Woodside's historical audited consolidated financial performance for each of FY19, FY20 and FY21 is summarised below.

Table 10: Woodside's historical consolidated financial performance

US$ million unless otherwise stated	FY19	FY20	FY21
Liquefied natural gas	3,664	2,519	5,359
Domestic Gas	85	73	43
Condensate	586	411	643
Oil	360	432	673
Liquefied petroleum gas	44	16	60
Other revenue	134	149	184
Other income	100	31	139
Total income	**4,973**	**3,631**	**7,101**
Costs of Production	(686)	(623)	(713)
Other cost of sales	(467)	(673)	(1,583)
General, administrative and other costs	(80)	(190)	(158)
Restoration movement	(77)	(28)	(68)
Other	17	(126)	(125)
EBITDAX	**3,680**	**1,991**	**4,454**
Exploration and evaluation	(149)	(69)	(319)
EBITDA	**3,531**	**1,922**	**4,135**
Depreciation and amortisation	(1,703)	(1,824)	(1,690)
Impairment losses	(737)	(5,269)	(10)
Impairment reversals	-	-	1,058
EBIT	**1,091**	**(5,171)**	**3,493**
Net financing costs	(229)	(269)	(203)
Profit before Income Tax	**862**	**(5,440)**	**3,290**
Income Tax benefit/(expense)	(511)	1,026	(957)
Petroleum resource rent tax benefit/(expense)	31	439	(297)
Net Profit after Income Tax	**382**	**(3,975)**	**2,036**
Gain/(loss) on hedges	2	(59)	(329)
Remeasurement gains on defined benefit plan	2	2	13
Other Comprehensive Income/(Loss)	**4**	**(57)**	**(316)**
Total Comprehensive Income/(Loss) attributable to shareholders	**347**	**(4,085)**	**1,667**
Statistics			
Production volumes (MMboe)	90	100	91
Sales volumes (MMboe)	97	107	112
Average realised price (US$/boe)	49	32	60
EBITDAX growth	(9%)	(46%)	124%
EBITDA growth	(7%)	(46%)	115%
EBITDA margin	71%	53%	58%
Basic earnings per share (US cents)	37	(424)	206
Dividends per share (US cents)	91	38	135
Net borrowings/EBITDA	0.8	2.0	0.9
EBITDA interest cover (times)[1]	11.0	5.9	18.0

Source: Woodside 2020 and 2021 Annual Reports

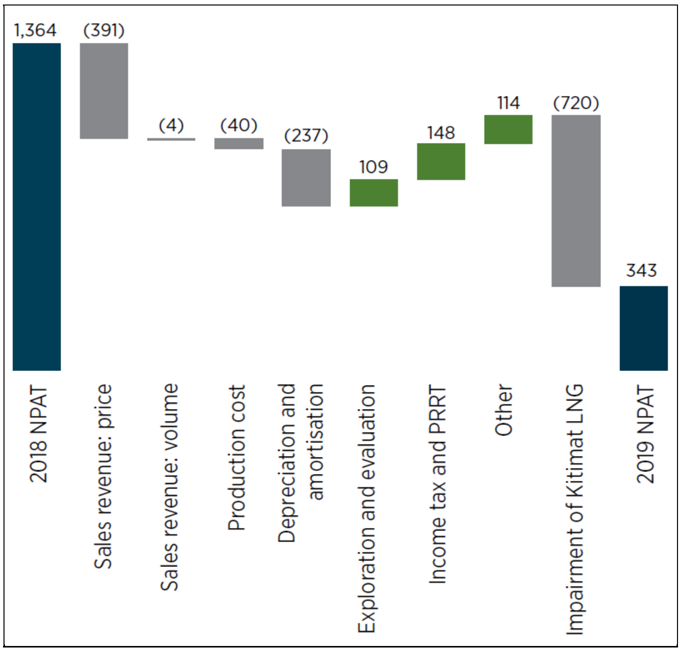
Notes:

1. *EBITDA interest cover (times), is calculated as EBITDA, divided by finance costs*
2. *Figures may not add exactly due to rounding.*

We note the following in relation to Woodside's recent financial performance:

8.8.1 FY19

Figure 7 – NPAT reconciliation from FY18 to FY19 (exclusive of non-controlling interest)



Source: Woodside 2019 Annual Report

Woodside's FY19 results reflect a 9% decrease in average realised sales price over the year to US$49/boe, which in turn reflected lower global commodity prices during the year. Production volumes decreased from 91 MMboe in FY18 to 90 MMboe in FY19, largely due to the Pluto Train 1 and NWS Project facilities undergoing scheduled maintenance turnarounds as well as the planned cessation of Nganhurra FPSO production over the Enfield oil field, partially offset by the completion of the Greater Enfield project during the year and a full year of production from Wheatstone Train 2.

Total costs of production of US$686 million increased from the prior year primarily due to scheduled turnaround activity at Pluto LNG and the NWS Project, offset by the planned cessation of the Nganhurra FPSO.

Depreciation and amortisation expense increased by US$237 million from the prior year primarily due to the completion of the Greater Enfield project in August 2019 and start-up of Wheatstone Train 2 in June 2018, partially offset by the reduced production volumes in FY19.

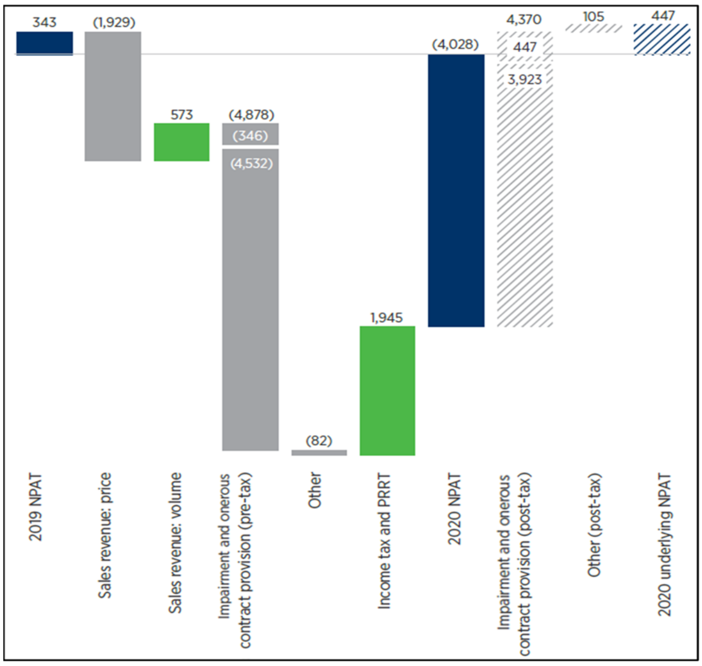
Exploration and evaluation expenditure reduced to US$149 million, primarily due to reduced exploration activity, offset by lower write-offs of US$46 million of unsuccessful wells during the period compared to US$94 million written off in FY18.

An impairment expense to exploration and evaluation asset of US$720 million was recognised in relation to the Kitimat LNG project. This was a result of the operator announcing a decision to exit the project on

10 December 2019 and subsequently announcing an impairment to the operator's interest in the project on 31 January 2020. The impairment reflected a continuing oversupply in the North American gas markets. An additional impairment to oil and gas properties of US$17 million was recognised through the sale of two LNG vessels in the NWS Project as the assets' carrying value exceeded the fair value less costs of disposal.

8.8.2 FY20

Figure 8 – NPAT reconciliation from FY19 to FY20 (exclusive of non-controlling interest)



Source: Woodside 2020 Annual Report

Woodside's FY20 results reflect a 26% decrease in revenue from the prior year to US$3,600 million. This was primarily driven by a 35% decrease in average realised prices to US$32/boe as the Covid-19 pandemic caused volatility in oil and gas prices. The reduction in realised prices was partially offset by an increase in sales volumes from 97 MMboe in FY19 to 107 MMboe in FY20, primarily due to planned delays in non-essential maintenance, no major asset turnarounds and a full year of operations at the Ngujima-Yin FPSO.

Impairment losses of US$5,269 million were recognised for oil and gas properties and exploration and evaluation assets driven by a reduction in oil and gas price assumptions, demand uncertainty through the Covid-19 pandemic and increased risk of higher carbon pricing. US$3,712 million of the impairment recognised was attributable to oil and gas properties through NWS (US$454 million), Pluto LNG (US$862 million), Wheatstone LNG (US$1,401 million), Australia Oil (US$674 million) and Sangomar (US$321 million). The remaining impairment expense of US$1,557 million was attributable to exploration and evaluation assets through Pluto Train 2 (US$429 million), Kitimat LNG (US$809 million), Sunrise (US$168 million) and other segments (US$151 million).

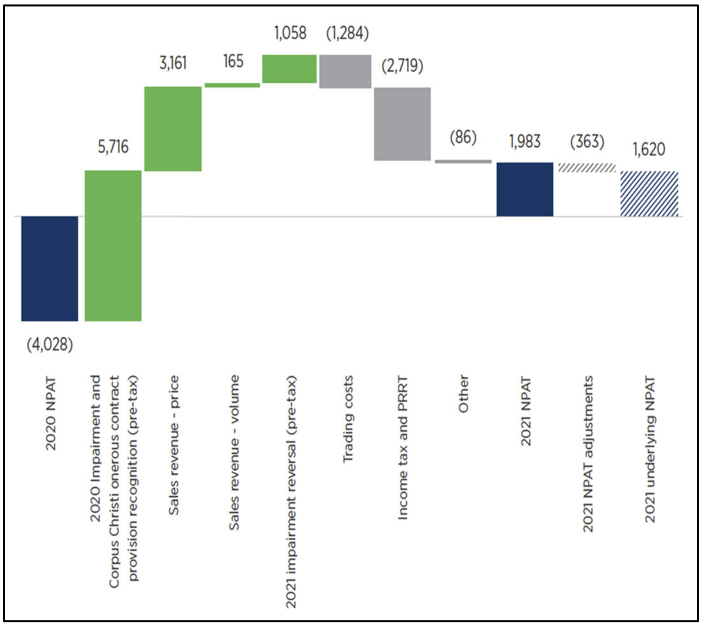
Woodside recognised an onerous contract provision of US$447 million in relation to a Corpus Christi LNG sale and purchase agreement in June 2020. The provision was partially utilised during the period and was revalued at 31 December 2020 with a further reduction of US$59 million to US$346 million.

Exploration and evaluation expenditure reduced by 54% to US$69 million in FY20 reflecting reduced exploration activity through Covid-19.

Depreciation of oil and gas properties increased primarily due to an increase in production quantities from 90 MMboe in FY19 to 100 MMboe in FY20 compounded by a full year of operations at the Ngujima-Yin FPSO.

8.8.3 FY21

Figure 9 – NPAT reconciliation from FY20 to FY21 (exclusive of non-controlling interest)



Source: Woodside 2021 Annual Report

Woodside's FY21 results reflect a 93% increase in operating revenue from the prior year to approximately US$6,962 million. This was primarily driven by an increase in realised prices for oil and gas from US$32/boe (FY20) to US$60/boe (FY21) with continued recovery in market prices during 2021, compounded by an increase in sales volumes from 107 MMboe in FY20 to 112 MMboe in FY21. There was an approximate ten-fold increase in the number of traded LNG cargoes in 2021 in response to the favourable market conditions, as well as an approximate three-fold increase in the number of Corpus Christi cargoes lifted. This was partially offset by fewer condensate cargoes sold, lower facility reliability on the Ngujima-Yin FPSO as well as weather events in the first half of 2021.

Reversals of the previously recognised non-cash impairment of US$1,058 million (pre-tax) included the US$682 million reversal for the Scarborough and Pluto Train 2 projects following FID as announced on 22 November 2021 and the US$376 million reversal for the NWS Project supported by updated cost and production profiles and an improved price environment for the NWS Project.

Trading costs increased by US$1,284 million to US$1,495 million in FY21 due to a higher number of traded cargoes in 2021.

Income tax and Petroleum Resource Rent Tax (**PRRT**) expense increased by US$2,719 million primarily due to the effect of higher operating revenue in FY21.

FY21 NPAT was adjusted for Myanmar exploration and evaluation write-offs (US$209 million), various costs resulting from Woodside's exit from the Kitimat LNG development (US$33 million), one-off reconciliation of joint venture costs from prior years (US$4 million); offset by the impact of impairment reversals of oil and gas properties (US$582 million) and prior period impacts of price reviews (US$27 million).

8.9 Outlook

Other than in respect of targeted FY22 production volumes, which are summarised below, Woodside has not publicly released earnings guidance for FY22 or beyond due to commercial sensitivities.

Table 11: Woodside FY22 production volumes guidance

	FY22 Guidance (MMboe)
LNG	71 – 74
Liquids[1]	16 – 18
Australian domestic gas[2]	4 – 5
LPG	~ 0.5
Total	**92 - 98**

Source: Woodside full-year 2021 results announced on 17 February 2022
Notes:
1. *Liquids includes oil and condensate*
2. *Includes pipeline gas production from NWS, Pluto and Wheatstone.*

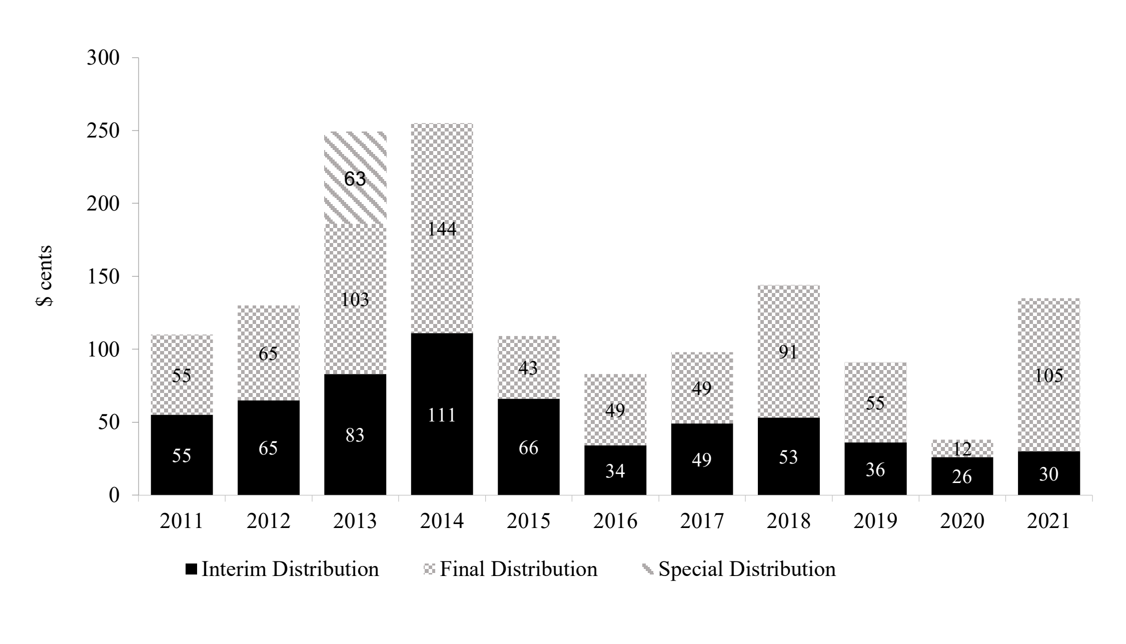
8.10 Dividends, payout ratio, dividend re-investment plan and franking credits

Woodside operates a dividend policy which aims, subject to the satisfaction of statutory requirements and other commercial considerations, to maintain a minimum dividend payment payout ratio of 50% of net profit excluding non-recurring items (expressed in USD).

Woodside dividends are determined and declared in USD. However, shareholders will receive their dividend in Australian dollars unless their registered address is in the United Kingdom, where they will receive their dividend in British pounds, or in the US, where they will receive their dividend in US dollars. Shareholders who reside outside of the US can elect to receive their dividend in US dollars, payable into a US financial institution account. Currency conversion is based on the foreign currency exchange rates on the relevant dividend record date.

Whilst Woodside has an established track record of paying fully franked dividends, the dividend per share has, in absolute terms, exhibited volatility over the past ten years as illustrated in the figure below.

Figure 10 – Historical distributions paid to Woodside shareholders



Source: Woodside website

Woodside operates a dividend reinvestment plan (**DRP**). The number of shares to be issued to individual shareholders under the DRP is calculated at the arithmetic average of the Volume Weighted Average Price (**VWAP**) (rounded to the nearest cent) during each of the ten trading days commencing on the second trading day following the record date in respect of the relevant dividend, or any other period specified by the Directors, less a discount (if any) determined by the Board from time to time. The DRP discount in relation to the FY21 interim and final dividend was 1.5%.

As at 31 December 2021, Woodside had US$1,744 million of franking credits available (based on a tax rate of 30%).

8.11 Historical financial position

Woodside's historical audited consolidated financial position as at each of 31 December 2019, 31 December 2020 and 31 December 2021 is summarised below.

Table 12: Woodside's historical consolidated financial position

US$ million unless otherwise stated	2019	2020	2021
Cash and cash equivalents	4,058	3,604	3,025
Receivables	343	303	368
Inventories	176	125	202
Other financial assets	28	172	320
Other assets	42	48	109
Non-current assets held for sale	-	-	254
Total Current Assets	**4,647**	**4,252**	**4,278**

US$ million unless otherwise stated	2019	2020	2021
Receivables	245	423	686
Inventories	-	40	19
Other financial assets	35	54	107
Other assets	21	55	34
Exploration and evaluation assets	3,809	2,045	614
Oil and gas properties	18,298	15,267	18,434
Other plant and equipment	177	199	215
Deferred tax assets	1,173	1,304	1,007
Lease assets	948	984	1,080
Total Non-Current Assets	**24,706**	**20,371**	**22,196**
Total Assets	**29,353**	**24,623**	**26,474**
Payables	581	505	639
Interest-bearing liabilities	77	776	277
Other financial liabilities	12	37	411
Other liabilities	34	136	86
Provisions	272	500	605
Tax payable	86	46	413
Lease liabilities	69	94	191
Total Current Liabilities	**1,131**	**2,094**	**2,622**
Interest-bearing liabilities	5,602	5,438	5,153
Deferred tax liabilities	2,193	549	878
Other financial liabilities	15	34	161
Other liabilities	46	42	36
Provisions	1,856	2,407	2,219
Lease liabilities	1,101	1,184	1,176
Total Non-Current Liabilities	**10,813**	**9,654**	**9,623**
Total Liabilities	**11,944**	**11,748**	**12,245**
Net Assets	**17,409**	**12,875**	**14,229**
Statistics			
Shares on issue period end – m	942	962	970
Weighted average number of securities – m	936	951	963
Net assets per security ($)[1]	18.48	13.38	14.67
Gearing - %[2]	9%	18%	15%
Gearing incl lease liabilities - %	14%	24%	22%
Current Ratio - %[3]	4.1	2.0	1.6

Source: Woodside 2019, 2020 and 2021 Annual Reports

Notes:

1. *Net assets per security represents net assets divided by shares on issue at period end*
2. *Gearing represents net debt divided by net assets, where net debt is total external borrowings, less cash and cash equivalents*
3. *Current ratio represents current assets divided by current liabilities*
4. *Figures may not add exactly due to rounding.*

We note the following in relation Woodside's consolidated financial position as at 31 December 2021:

8.11.1 Cash and cash equivalents

Cash and cash equivalents comprised US$300 million of cash at bank and US$2,725 million in term deposits with a maturity of 3 months or less. US$108 million of this balance was held in currencies other than USD.

The decrease in cash and cash equivalents from FY20 to FY21 of US$573 million largely reflects a repayment of borrowings of US$784 million, additional investment in capital and exploration expenditure of US$2,406 million, dividends paid to shareholders of US$289 million (net of the DRP amounts) and income tax paid of US$271 million, offset by cash generated from operations of US$4,222 million.

8.11.2 Other working capital items

Trade receivable balances are held at transaction price while other receivable items are recorded at fair value. Woodside's trade receivables, depending on the product, have settlement terms of 14 to 30 days from date of invoice or bill of lading. Woodside held US$121 million of receivables in currencies other than USD at the end of the period, with the predominant amount in AUD.

Included within the receivables balance is a secured loan agreement with Petrosen (the Senegal National Oil Company) entered into by Woodside Energy Finance (UK) Ltd on 9 January 2020 to provide up to US$450 million for the purpose of funding Sangomar project costs. The facility has a maximum term of 12 years and semi-annual repayments of the loan are due to commence at the earlier of "Ready for Start - Up" (**RFSU**) or 30 June 2025. The carrying amount of the loan receivable is US$335 million, which represents its fair value.

Payables primarily relate to operational expenses payable to vendors.

8.11.3 Other financial assets

Other financial assets include derivative financial instruments designated as hedges as well as receivables subject to provisional pricing adjustments, which are held at fair value with movements recognised in the income statement.

8.11.4 Non-current assets held for sale

As at 31 December 2021, Woodside reclassified US$252 million of Pluto Train 2 assets, US$1 million of the Wheatstone construction village assets and US$1 million of the Pluto residential housing to non-current assets held for sale. There are no recognised liabilities associated with the non-current assets held for sale.

8.11.5 Exploration and evaluation assets

As at 31 December 2021, exploration and evaluation assets were located predominantly within the Oceania region. Underlying projects comprising the exploration and evaluation asset include exploration in the Browse and Sunrise projects. Exploration and evaluation assets declined significantly over FY21 from US$2,145 million to US$614 million. This movement comprised the write-off of Myanmar exploration and evaluation (US$209 million), costs of unsuccessful wells (US$56 million) and the transfer of the attributable balances of the Scarborough and Pluto Train 2 developments

(US$1,664 million in total) to oil and gas properties following the announcement of FID on 22 November 2021.

8.11.6 *Oil and gas properties*

Projects that underpin the oil and gas properties assets include the NWS Project, Pluto LNG, Australia Oil, Wheatstone, Sangomar, Pluto Train 2 and Scarborough, with Sangomar, Pluto Train 2 and Scarborough not yet in production.

The largest categories comprising the US$18,434 million balance of oil and gas properties is plant and equipment of US$12,313 million and projects in development of US$4,848 million. Total accumulated depreciation expense incurred against the balance amounted to US$22,437 million, with US$19,928 million of this attributable to plant and equipment. Of the impairment reversals recognised, US$1,058 million related to oil and gas properties, with US$911 million of this attributable to plant and equipment.

Capital commitment expenditure not provided for in the financial statements is US$7,875 million, increasing from US$1,569 million in 2020 as a result of the increased activity around the Scarborough Project development.

8.11.7 *Deferred tax assets*

As at 31 December 2021, Woodside had deferred tax assets of US$1,007 million and deferred tax liabilities of US$878 million.

8.11.8 *Lease assets and liabilities*

Lease assets comprises land and buildings of US$377 million, plant and equipment of US$167 million and marine vessels and carriers of US$536 million. Lease liabilities contain US$437 million attributable to land and buildings, US$192 million of plant and equipment and US$738 million of marine vessels and carriers. Approximately 42% of lease commitments are more than 5 years in length.

Woodside held US$476 million of lease liabilities in currencies other than USD (predominantly AUD).

8.11.9 *Derivative financial instruments*

Commodity hedges

During the period Woodside hedged a percentage of its oil-linked exposure by entering into oil swap derivatives settling between 2021 and 2023 in order to achieve a minimum average sales price per barrel. Woodside also entered into separate Henry Hub commodity swaps to hedge the purchase leg of the Corpus Christi volumes and separate title transfer facility (**TTF**) commodity swaps to hedge the sales leg of the Corpus Christi volumes. As a result of hedging and term sales, Woodside considers approximately 97% of the Corpus Christi volumes in 2022 and 70% in 2023 have hedged pricing risk. Woodside also entered into TTF commodity swaps to hedge equity LNG cargoes expected to be exposed to winter 2021 / 2022 natural gas pricing.

Foreign currency hedges

Woodside has a fixed medium term note of 175 million Swiss Francs (**CHF**), which it hedges with cross-currency interest rate swaps designated in both fair value and cash flow hedge relationships. The cross-currency interest rate swaps are referenced to the London Interbank Offered Rate (**LIBOR**). In addition, Woodside has taken out interest rate swaps to hedge the LIBOR interest rate risk associated with the US$600 million syndicated facility, designated as cash flow hedges and entered into foreign exchange forward to contracts to fix the AUD to USD exchange rate in relation to A$934 million, being a portion of the AUD denominated capital expenditure expected to be incurred under the Scarborough development.

8.11.10 Financing arrangements

Woodside has 14 bilateral loan facilities totalling US$1,900 million with terms ranging between 3 and 5 years. Interest rates of these facilities are based on USD LIBOR and margins are fixed at the commencement of the drawdown period. Interest is paid at the end of the drawdown period and the facilities may be extended continually by a year subject to the bank's agreement.

On 3 July 2015, Woodside entered into an unsecured US$1,000 million syndicated loan facility, which increased to US$1,200 million on 22 March 2016 and was amended to US$800 million on 15 November 2017. On 14 October 2019, Woodside increased the facility to US$1,200 million, with US$400 million expiring on 11 October 2022 and US$800 million expiring on 11 October 2024. Interest rates are based on USD LIBOR and margins are fixed at the commencement of the drawdown period. On 17 January 2020, Woodside completed a new US$600 million syndicated facility with a term of 7 years. Interest is based on the USD LIBOR plus 1.2% and is paid quarterly.

On 24 June 2008, Woodside entered into a two-tranche committed loan facility of US$1,000 million and US$500 million, respectively. The US$500 million tranche was repaid in 2013. There is a prepayment option for the remaining balance. Interest rates are based on LIBOR. Interest is payable semi-annually in arrears and the principal amortises on a straight-line basis, with equal instalments of principal due on each interest payment date. Under this facility, 90% of the receivables from designated Pluto LNG sale and purchase agreements are secured in favour of the lenders through a trust structure, with a required reserve amount of US$30 million. To the extent that this reserve amount remains fully funded and no default notice or acceleration notice has been given, the revenue from Pluto LNG continues to flow directly to Woodside from the trust account.

On 28 August 2015, Woodside established a US$3,000 million Global Medium Term Notes Programme listed on the Singapore Stock Exchange. Three notes have been issued under this program. A summary of the terms of these notes has been set out in the table below.

Table 13: Woodside medium term notes held as at 31 December 2021

Maturity date	Currency	Carrying amount (million)	Nominal interest rate
15 July 2022	USD	200	Floating three-month USD LIBOR
11 December 2023	CHF	175	1%
29 January 2027	USD	200	3%

Source: Woodside 2021 Annual Report

Woodside has 4 unsecured bonds issued in the US, as summarised below. Interest on the bonds is payable semi-annually in arrears.

Table 14: Woodside's unsecured bonds issued in the US as at 31 December 2021

Maturity date	Carrying amount (USD million)	Nominal interest rate
5 March 2025	1,000	3.65%
15 September 2026	800	3.70%
15 March 2028	800	3.70%
4 March 2029	1,500	4.50%

Source: Woodside 2021 annual report

8.12 Statement of cash flows

Woodside's historical audited consolidated statement of cash flows for each of FY19, FY20 and FY21 are summarised below.

Table 15: Woodside's historical consolidated statement of cash flows

US$ million unless otherwise stated	FY19	FY20	FY21
Profit/(loss) after tax for the period	**382**	**(3,975)**	**2,036**
Adjustments for:			
Non-cash items			
Depreciation and amortisation	1,617	1,730	1,582
Depreciation of lease assets	86	94	108
Change in fair value of derivative financial instruments	(1)	31	31
Net finance costs	229	269	203
Tax (benefit)/expense	480	(1,465)	1,254
Exploration and evaluation written off	46	2	265
Impairment loss	737	5,269	10
Impairment reversals	-	-	(1,058)
Restoration movement	77	28	68
Onerous contract provision	-	347	(95)
Other	39	(12)	30
Changes in assets and liabilities			
Decrease/(increase) in trade and other receivables	118	41	(39)
(Increase)/decrease in inventories	(21)	51	(4)
Increase/(decrease) in provisions	33	155	(16)
Increase in lease liabilities	-	40	(75)
(Increase)/decrease in other assets and liabilities	(48)	(137)	(25)
Decrease in trade and other payables	(11)	(121)	(128)
Cash generated from operations	**3,763**	**2,347**	**4,222**
Purchases of shares and payments relating to employee share plans	(66)	(32)	(47)
Interest received	85	64	11
Dividends received	5	4	6
Borrowing costs relating to operating activities	(157)	(180)	(91)
Income tax paid	(313)	(331)	(271)
Payments for restoration	(12)	(23)	(38)
Net cash from operating activities	**3,305**	**1,849**	**3,792**
Cash flows used in investing activities			
Payments for capital and exploration expenditure	(1,213)	(1,418)	(2,406)
Proceeds from disposal of non-current assets held for sale	12	-	-
Borrowing costs relating to investing activities	(37)	(57)	(126)

US$ million unless otherwise stated	FY19	FY20	FY21
Advances to other external entities	-	(110)	(206)
Proceeds from disposal of non-current assets	-	-	9
Payments for acquisition of joint arrangements net of cash acquired	-	(527)	(212)
Net cash used in investing activities	**(1,238)**	**(2,112)**	**(2,941)**
Cash flows from/(used in) financing activities			
Proceeds from borrowings	1,700	600	-
Repayment of borrowings	(84)	(83)	(784)
Borrowing costs relating to financing activities	(30)	(21)	(15)
Repayment of lease liabilities	(41)	(71)	(155)
Borrowing costs relating to lease liabilities	(89)	(86)	(89)
Contributions to non-controlling interests	(77)	(111)	(92)
Dividends paid (outside of DRP)	(852)	-	-
Dividends paid (net of DRP)	(210)	(454)	(289)
New proceeds from share issuance	-	23	-
Net cash from/(used in) financing activities	**317**	**(203)**	**(1,424)**

Source: Woodside 2019, 2020 and 2021 Annual Reports

Note 1: Figures may not add exactly due to rounding

8.13 Taxation

Under the Australian tax consolidation regime, Woodside and its wholly owned Australian controlled entities have elected to be taxed as a single entity. As at 31 December 2021, Woodside had:

- carried forward Australian tax losses of US$nil
- estimated tax effected foreign income tax losses of US$497 million relating to foreign operations; none of which were recognised in the balance sheet as it is not considered probable by Woodside that the losses will be utilised based on current planned activities in those regions
- US$1,744 million of accumulated franking credits (based on a tax rate of 30%)

All of Woodside's Australian petroleum projects are subject to the PRRT. PRRT is payable on the excess of revenue over expenses (including augmentation on general project and exploration expenditures) derived from petroleum projects. PRRT is assessed before company income tax and is deductible for the purpose of calculating company income tax. The PRRT rate is currently 40%.

8.14 Contingent liabilities

As at 31 December 2021, contingent liabilities of US$202 million included contingent payments of US$155 million relating to the Sangomar development, dependent on commodity prices and the timing of first oil. Contingent liabilities declined from US$597 million as at 31 December 2020 as contingent payments of US$450 million were paid during 2021 as a result of the FID to develop the Scarborough field.

There were no contingent assets as at 31 December 2021.

8.15 Board of Directors

The current Directors of Woodside are set out in the table below.

Table 16: Woodside's Board of Directors

Board member	
Richard Goyder, AO Non-Executive Chairman of the Board	**Meg O'Neill** Managing Director, CEO
Larry Archibald Non-Executive Director	**Frank C Cooper, AO** Non-Executive Director
Swee Chen Goh Non-Executive Director	**Christopher M Haynes, OBE** Non-Executive Director
Ian Macfarlane Non-Executive Director	**Ann Pickard** Non-Executive Director
Sarah Ryan Non-Executive Director	**Gene T Tilbrook** Non-Executive Director
Ben Wyatt Non-Executive Director	

Source: Explanatory Memorandum, FY21 Annual Report

Further details in relation to the experience and other directorships of the Directors of Woodside are set out in section 6 of the Explanatory Memorandum and on pages 61 to 64 of the FY21 Annual Report.

8.16 Capital structure and ownership

As at 24 March 2022, Woodside had 983,980,823 million ordinary shares on issue, along with 7,489,385 unquoted shares reserved for employees under employee share plans.

Woodside operates a number of employee share plans:

- Woodside's CEO and senior executives are offered equity rights (**ERs**) through Woodside's Executive Incentive Scheme (**EIS**), under which 87.5% of the variable reward component of eligible executives' annual remuneration is paid in the form of Performance Rights (30%) and Restricted Shares (57.5%)[44].

  Performance Rights are subject to a five-year deferral period with a RTSR test five years after the date of allocation; with one-third of performance rights tested against the ASX 50 companies and the remaining two-thirds against a group of international oil and gas companies.

  Restricted Shares are divided into two tranches. The first tranche comprises 27.5% of any variable award and is subject to a three-year deferral period. The second tranche represents 30% of any variable award and is subject to a five-year deferral period. Vesting is subject to continued

[44] Whilst this is the structure of the EIS, for the FY20 performance year the Board applied its discretion whereby 100% of the CEO's variable award was paid in the form of Performance Rights subject to a 3 year deferral period with an Relative Total Shareholder Return (**RTSR**) test hurdle; while Senior Executive variable award was paid in the form of 40% Performance Rights, subject to a 5 year vesting period, 30% in Restricted Shares, subject to a 3 year deferral period and 30% in Restricted Shares, subject to a 5 year deferral period.

employment during the deferral period. There are no further performance conditions attached to these awards

- ERs are offered to eligible Woodside employees (other than the participants in the EIS) under the Woodside Equity Plan. Each ER represents a right to receive one fully paid share in Woodside on the vesting date at no cost provided all terms and conditions are satisfied and the employee remains employed by Woodside at that date. The number of ERs offered to each eligible employee is determined by the Board, based on individual performance. There are no further ongoing performance conditions.

  75% of awarded ERs vest three years after the effective grant date, with the balance vesting five years after the effective grant date.

  As at 31 December 2021, there were 5.6 million unvested ERs issued under the Woodside Equity Plan

- ERs are offered under the Supplementary Woodside Equity Plan (**SWEP**) as a retention award to certain targeted Woodside staff identified for key capability. The SWEP awards have service conditions and no performance conditions. Each ER entitles the participant to receive a Woodside share on the vesting date three years after the effective grant date

- In February 2018, the Board approved the Equity Award rules which apply to EIS and discretionary executive allocations. This allows the Board and CEO to award discretionary allocations of Restricted Shares or Performance Rights. An award of 133,366 Restricted Shares was made to Ms Meg O'Neill upon commencement of employment with Woodside on 1 May 2018.

As at 31 December 2021, there were 2.4 million unvested Performance Rights, 1.0 million unvested Restricted Shares and nil other unvested ERs on issue.

8.16.1 Substantial shareholders

Woodside's substantial shareholders so far as known to Woodside based on substantial shareholder notices filed with the ASX as at 31 December 2021 are set out in the table below.

Table 17: Woodside's substantial shareholders as at 31 December 2021

Substantial shareholder	Interest in Woodside shares	Voting power in Woodside
BlackRock Group (BlackRock Inc. and subsidiaries)	57,411,550	6.13%
State Street Corporation and subsidiaries	50,409,641	5.20%

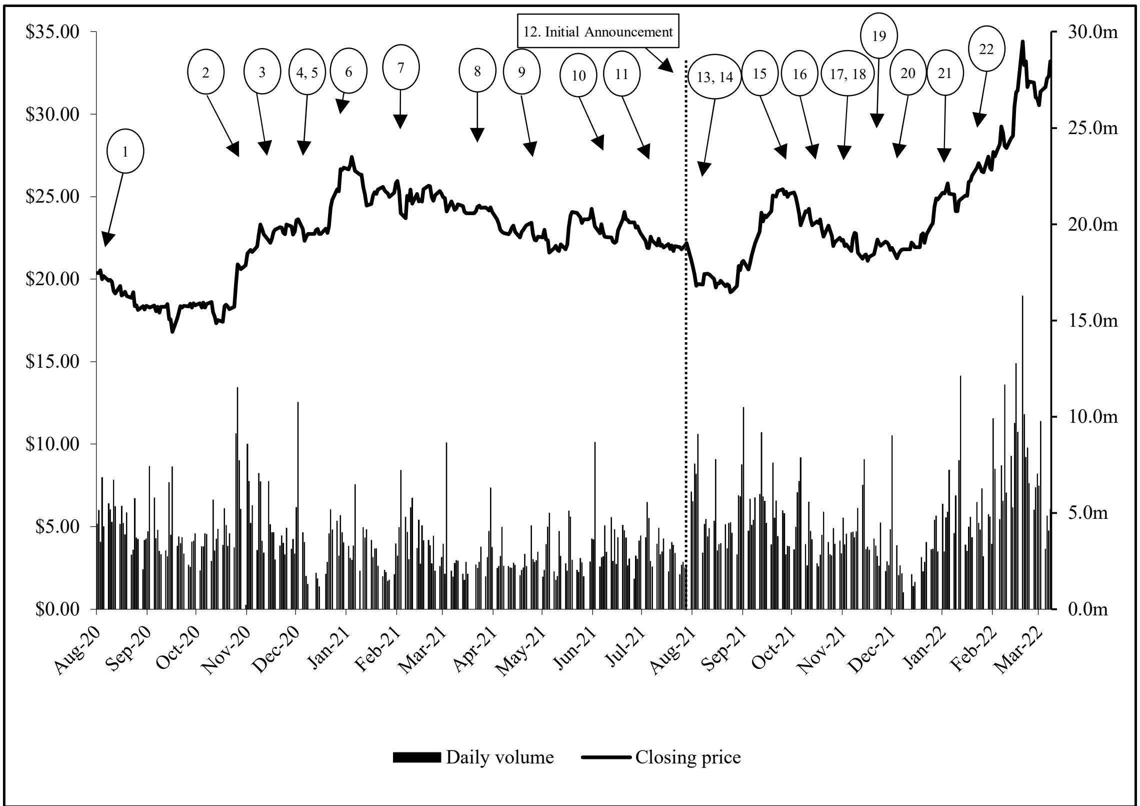
Source: Woodside 2021 Annual Report and ASX Announcements

8.17 Share price and volume trading history

8.17.1 Recent trading in ordinary shares

The chart below depicts Woodside's daily closing price on the ASX over the 12 month period to 13 August 2021[45], and for the period subsequent to that date to 24 March 2022, along with the daily volume of shares traded on the ASX and Chi-X over the period.

Figure 11 – Woodside's closing share price and trading volume



Source: S&P Capital IQ, IRESS Trading Data and KPMG Corporate Finance analysis

In addition to Woodside's normal annual, half year and quarterly results and dividend distribution announcements, other significant announcements made by Woodside over this period that may have had an impact on its share price include:

1. On 17 August 2020, Woodside announced that it had given notice exercising its right to pre-empt the sale by Capricorn Senegal Limited (**Capricorn**) of its entire participating interest in the Sangomar Joint Venture.

[45] Being the last day trading prior to Woodside's announcement to the market that it was in discussion with BHP in relation to a potential merger involving BHP's petroleum assets

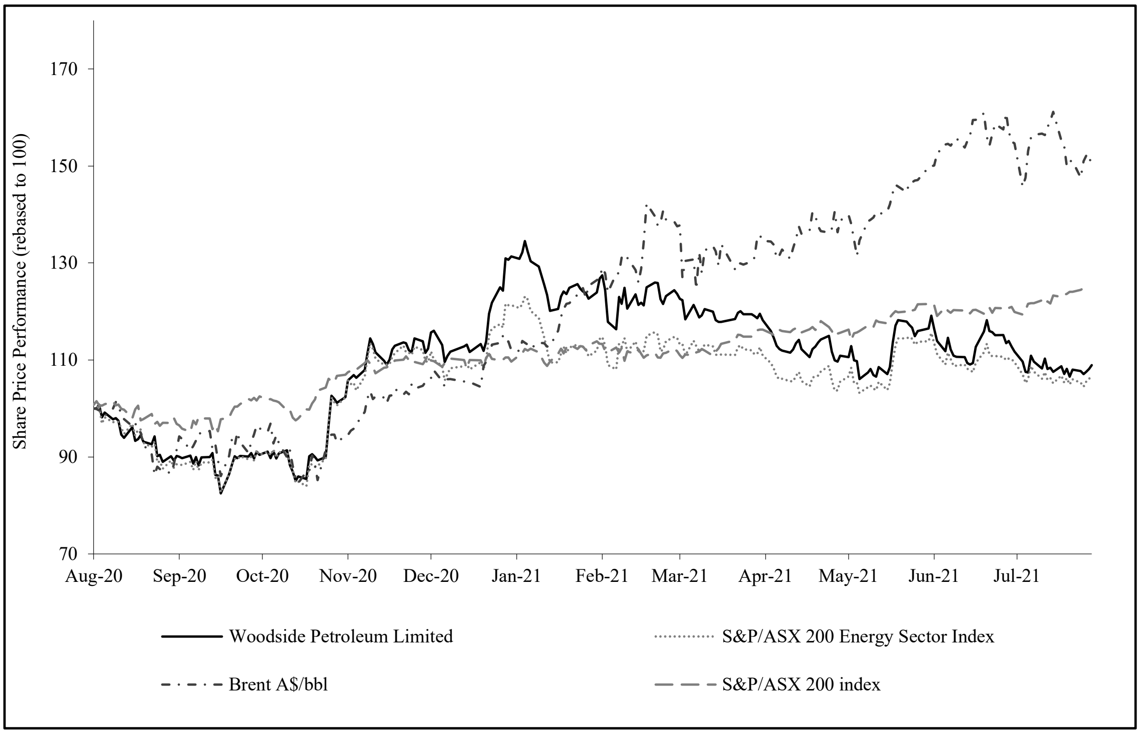
2. On 3 December 2020, Woodside announced that it had given notice exercising its right to pre-empt the sale by FAR of its entire participating interest in the Sangomar Joint Venture.
3. On 8 December 2020, Woodside announced that it been advised by then CEO Peter Coleman of his intention to retire in the second half of 2021.
4. On 23 December 2020, Woodside announced that it had completed the acquisition of Capricorn's entire participating interest in the Sangomar Joint Venture.
5. On 23 December 2020, Woodside announced that NWS Project participants had executed GPA**s** for processing third-party gas through the NWS Project facilities regarding gas from the Pluto fields in respect of the Waitsia Gas Project Stage 2.
6. On 18 January 2021, Woodside announced that it had agreed with Uniper Globale Commodities SE (**Uniper**) to increase the supply of LNG from Woodside's global portfolio to Uniper.
7. On 19 February 2021, Woodside announced that it had entered into an agreement with RWE Supply & Trading GMbH for the supply of LNG from Woodside's global portfolio for a term of seven years, commencing in 2025.
8. On 13 April 2021, Woodside announced that it had agreed with Peter Coleman that he would retire from Woodside on 3 June 2021.
9. On 18 May 2021, Woodside announced it had decided to exit its 50% non-operated participating interest in the proposed Kitimat LNG development, located in British Columbia, Canada.
10. On 7 July 2021, Woodside announced that it had completed the acquisition of FAR's participating interest in the Sangomar Joint Venture.
11. On 4 August 2021, Woodside announced an update to the Scarborough project, outlining that it had finalised technical work to support execution readiness and completed an update of the capital expenditure requirements for the Scarborough development.
12. On 16 August 2021, Woodside announced that it was engaged in discussions with BHP regarding a potential merger involving BHP's entire petroleum business through a distribution of Woodside shares to BHP shareholders.
13. On 17 August 2021, Woodside announced that Ms Meg O'Neill had been appointed as acting CEO and Managing Director.
14. On 17 August 2021, Woodside announced that it had entered into a merger commitment deed with BHP to combine their respective oil and gas portfolios.
15. On 5 November 2021, Woodside announced that it had completed a review of the reserves and resource estimates for the Greater Pluto Region, with 1P total reserves, excluding 2021 production to date, increasing by approximately 10% and 2P total Reserves decreasing by approximately 10%.
16. On 15 November 2021, Woodside announced it had entered into a sale and purchase agreement with GIP for the sale of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture.

17. On 22 November 2021, Woodside announced FID had been made to approve the Scarborough and Pluto Train 2 developments, including new domgas facilities and modifications to Pluto Train 1.
18. On 22 November 2021, Woodside announced it had signed a binding share sale agreement with BHP for the merger of BHP's oil and gas portfolio with Woodside, with Woodside to acquire the entire share capital of BHP Petroleum in exchange for new Woodside shares.
19. On 8 December 2021, Woodside announced its energy transition strategy, which included a target to invest US$5,000 million in emerging new energy markets by 2030.
20. On 16 December 2021, Woodside filed a copy of the ACCC media release, announcing that the ACCC will not oppose Woodside's proposed acquisition of BHP Petroleum.
21. On 18 January 2022, Woodside announced it had completed the sale of 49% non-operating interest in the Pluto Train 2 Joint Venture to GIP.
22. On 27 January 2022, Woodside announced it has decided to withdraw from its interests in Myanmar, including Blocks AD-1, AD-8, the A-6 Joint Venture and the A-6 production sharing contract (**PSC**) held with MOGE.

8.17.2 Relative share price performance

As depicted in the figure below, Woodside's share price generally matched the S&P / ASX 200 Energy Sector Index but underperformed against the broader S&P / ASX 200 Index and the AUD spot Brent price over the 12 months to 13 August 2021, being the last trading day prior to the Initial Announcement.

Figure 12 – Relative share price performance



Source: S&P Capital IQ, IRESS Trading Data and KPMG Corporate Finance analysis

8.17.3 *Trading liquidity on the ASX*

An analysis of volume of trading in Woodside's shares over various periods in the 12 months to 13 August, being the last trading day prior to the Initial Announcement .

Table 18: Trading liquidity in Woodside Petroleum Limited Securities prior to the Initial Announcement

Period up to and including 13 Aug 21	Price (low) A$	Price (high) A$	Price VWAP A$	Cumulative value A$m	Cumulative volume m	% of issued capital
1 day	21.91	22.19	22.09	50.5	2.3	0.2%
1 week	21.78	22.19	21.98	240.7	11.0	1.1%
1 month	21.56	23.50	22.22	1,585.4	71.3	7.4%
3 months	21.54	24.53	22.72	4,592.6	202.1	21.0%
6 months	21.54	26.27	23.49	9,161.2	389.9	40.5%
12 months	16.80	27.60	22.11	19,730.3	892.5	92.8%

Source: S&P Capital IQ, IRESS Trading Data and KPMG Corporate Finance analysis

Note 1: Security price data represents intra-day trading rather than closing prices

Woodside shares exhibited strong liquidity over the 12 month period to 13 August 2021 (inclusive), with an average of 3.5 million shares, representing approximately 0.4% of issued capital, traded per day, with a daily value of approximately A$78 million. Over this period, Woodside shares were traded on all available trading days on the ASX.

An analysis of the volume of trading in Woodside's shares in the period from 14 August 2021 to 24 March 2022 inclusive is set out in the table below, noting Woodside shares were traded on all trading days.

Table 19: Trading liquidity in Woodside Petroleum Limited Securities post the Initial Announcement

Period from 14 Aug 21 to 24 Mar 22 incl.	Price (low) A$	Price (high) A$	Price VWAP A$	Cumulative value A$m	Cumulative volume m	% of issued capital
159 days	19.15	34.60	24.93	18,996.1	761.9	77.3%

Source: S&P Capital IQ, IRESS Trading Data and KPMG Corporate Finance analysis

9 Profile of BHP Petroleum

9.1 Company overview

BHP Petroleum, which operates as a wholly owned subsidiary of BHP, was incorporated in 1988 and is based in Houston, Texas.

BHP Petroleum comprises conventional oil and gas operations, as well as exploration and development activities. BHP Petroleum has oil and gas assets located in Algeria[46], Australia, Trinidad and Tobago and the GOM, and appraisal and exploration options in Barbados, Eastern Canada, Mexico, Trinidad and Tobago, the Western GOM and Egypt. The crude oil and condensate, gas and natural gas liquids that are produced by BHP Petroleum are predominantly sold on the international spot market or domestic market.

9.2 Production assets

An overview of the BHP Petroleum's principal oil, gas and LNG assets are set out below and discussed in more detail in GaffneyCline's ITSR which is attached as Appendix 15 to this report. All Reserves and Resources estimates shown in this section are BHP Reserves and Resources estimates as detailed in the Explanatory Memorandum and all Gas volumes include gas equivalent NGL volumes, which have been converted to Bcf by multiplying by a conversion factor of 6.0.

9.2.1 Shenzi

BHP Petroleum is the operator of the Shenzi deep-water offshore oil and gas field, which is located approximately 195 km off the coast of Louisiana, US in the Green Canyon area of the GOM.

BHP Petroleum entered into a membership interest purchase and sale agreement with Hess Corporation on 6 November 2020 to acquire an additional 28% interest in Shenzi, bringing its total interest in Shenzi

[46] BHP Petroleum is currently in the process of divesting its Algerian assets. The treatment of the Algerian assets is discussed in more detail in Section 9.2.8 below.

to 72%[47,48]. Shenzi, whose first oil and natural gas production was achieved in 2009, is a standalone tension leg platform (**TLP**) that is installed in approximately 1,340m of water.

Shenzi oil is transported via a dedicated oil pipeline to third party infrastructure, while Shenzi gas goes through the Cleopatra gas pipeline[49]. The normal production capacity of the Shenzi field is 0.1 MMbbl/d of oil and 50 MMscf/d of gas.

BHP Petroleum is currently pursuing various initiatives to underpin the long-term use of the existing Shenzi infrastructure and production facilities, including:

- the introduction of the Shenzi Subsea Multi-Phase Pumping (**SSMPP**) to increase production rates from existing wells, with potential first production in CY22
- the development of the Shenzi North project, a two-well subsea tieback to the existing Shenzi TLP, which is targeting potential first production in CY24
- the development of the Wildling project, which incorporates a further two-well subsea tieback to Shenzi TLP via Shenzi North. The project's FID is currently anticipated to be made between CY22 and CY23, with potential first production between CY24 and CY25
- additional infill opportunities to increase production, with three producing and two water injection wells tied back to Shenzi TLP. A FID for these projects is currently anticipated to be made between CY22 and CY25, with potential first production between CY24 and CY26.

Each of the above initiatives are discussed further in sections 9.4 and 9.5 below.

As at 31 December 2021, BHP Petroleum's share of Shenzi's net oil and condensate 1P Reserves and 2P Reserves was 64.0 MMbbl and 92.1 MMbbl, respectively and gas 1P Reserves and 2P Reserves was 33.3 Bcf and 49.7 Bcf, respectively[50]. BHP Petroleum's share of Shenzi's net oil and condensate 2C Contingent Resources was 83.9 MMbbl and gas 2C Contingent Resources was 59.2 Bcf[51].

9.2.2 Atlantis

The Atlantis deep-water offshore oil and gas field is located approximately 210 km off the coast of Louisiana, US in the Green Canyon area of the GOM. BHP Petroleum has a total interest in Atlantis of 44%[52]. The field was first discovered in 1998 comprises a moored semi-submersible platform that is installed in approximately 2,155m of water.

Oil and gas from the field is transported through the Caesar oil pipeline and the Cleopatra gas pipeline. The normal production capacity of the Atlantis field is 0.2 MMbbl/d of oil and 180 MMscf/d of gas.

The Atlantis Phase 3 project has been developed and sanctioned to increase production and grow the resources at the existing Atlantis field. The Atlantis Phase 3 project is a new subsea production system

[47] The remaining interest is held by Repsol S.A. (**Repsol**).
[48] Shenzi continues to be accounted for as a joint operation after BHP Petroleum's additional purchase of a 28% interest in the deep-water oil and gas field.
[49] BHP Petroleum holds a 22% membership interest in Cleopatra Gas Gathering Company LLC.
[50] Net reserves include volumes consumed in operations (CIO or fuel).
[51] Net resources include volumes consumed in operations (CIO or fuel).
[52] The remaining 56% interest is held by joint venture partner and operator, BP.

that will tie back to the existing Atlantis production facility and has the capacity to produce up to approximately 0.04 MMbbl/d. The project recorded its first production in July 2020 (discussed further in section 9.4.4).

As at 31 December 2021, BHP Petroleum's share of Atlantis' net oil and condensate 1P Reserves and 2P Reserves was 62.3 MMbbl and 144.3 MMbbl respectively and gas 1P Reserves and 2P Reserves was 57.4 Bcf and 139.2 Bcf respectively[53]. BHP Petroleum's share of Atlantis' net oil and condensate 2C Contingent Resources was 155.1 MMbbl and gas 2C Contingent Resources was 405.7 Bcf[54].

9.2.3 Mad Dog

The Mad Dog deep-water offshore oil and gas field is located approximately 210 km off the coast of Louisiana, US in the Green Canyon area of the GOM. BHP Petroleum has a total interest in Mad Dog of 23.9%.[55] Installed in approximately 1,310m of water, Mad Dog is a moored integrated truss spar host (**A Spar**) that facilitates simultaneous production and drilling operations.

Oil and gas from the field is transported through the Caesar oil pipeline and the Cleopatra gas pipeline systems. The normal production capacity of A Spar is 0.1 MMbbl/d of oil and 60 MMscf/d of gas handling[56].

BHP Petroleum is currently completing several development and growth projects at the Mad Dog field, including:

- the installation of up to four infill wells tied to Mad Dog A Spar, with potential first production in CY23
- the completion of the Mad Dog Phase 2 project, which involves the development of a semi-submersible floating production facility with 22 subsea wells. The project, which is an extension to the existing Mad Dog field, is targeting potential first production in CY22
- the development of nine new wells that will tie back to the existing Mad Dog Phase 2 facility. The project's FID is currently anticipated to be made between CY25 and CY26, with potential first production between CY26 and CY28
- the installation of two water injector wells, which will provide pressure support to Mad Dog A Spar production wells. The project's FID is currently anticipated to be made in CY24, with potential first production in CY25.

Each of the above initiatives are discussed further in sections 9.4 and 9.5 below.

As at 31 December 2021, BHP Petroleum's share of Mad Dog net oil and condensate 1P Reserves and 2P Reserves was 126.8 MMbbl and 178.2 MMbbl respectively and gas 1P Reserves and 2P Reserves was

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[53] Net reserves include volumes consumed in operations (CIO or fuel).
[54] Net resources include volumes consumed in operations (CIO or fuel).
[55] The remaining interests are held by joint venture partners, BP (60.5%), which is the operator of the field, and Chevron (15.6%).
[56] Gas handling capacity includes 20MMcf/d for gas lifting wells. The net production gas capacity is 40MMcf/d.

48.2 Bcf and 67.2 Bcf respectively[57]. BHP Petroleum's share of Mad Dog's net oil and condensate 2C Contingent Resources was 164.5 MMbbl and gas 2C Contingent Resources was 52.3 Bcf[58].

9.2.4 *NWS Project*

As discussed previously at section 8.2, the NWS Project is a joint venture between seven major companies[59], with Woodside as the operator.

BHP Petroleum currently holds between 12.5% and 16.7% non-operated interests across nine separate joint venture agreements in the NWS Project.

As at 31 December 2021, BHP Petroleum's share of NWS Project's net oil and condensate 1P Reserves and 2P Reserves was 17.8 MMbbl and 22.2 MMbbl respectively and gas 1P Reserves and 2P Reserves was 728.9 Bcf and 913.4 Bcf respectively[60]. BHP Petroleum's share of NWS Project's net oil and condensate 2C Contingent Resources was 11.9 MMbbl and gas 2C Contingent RResources was 140.5 Bcf[61].

Further detail in relation to the profile of the NWS Project is set out in section 8.2.1 above.

9.2.5 *Bass Strait*

BHP Petroleum holds a non-operated interest in Bass Strait, consisting of a collection of offshore installations and onshore processing facilities, producing oil and gas. Located between 25 km and 80 km off the south-east coast of Australia and onshore Victoria, Bass Strait consists of the Gippsland Bass Joint Venture (**GBJV**) and Kipper Unit Joint Venture (**KUJV**).

BHP Petroleum has a total interest in the GBJV of 50%[62]. GBJV currently holds 20 production licenses and two retention leases for the exploration, development and production of oil, LPG and gas from Bass Strait.

BHP Petroleum has a total interest in the KUJV of 32.5%[63]. The Kipper gas field is located in around 100m of water, approximately 45 km from Ninety Mile Beach on the Gippsland coast of Victoria. Operated by Esso Australia, production at the field commenced in 2017. Raw gas is transported from the

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57 Net reserves include volumes consumed in operations (CIO or fuel).
58 Net resources include volumes consumed in operations (CIO or fuel).
59 Ownership of the NWS Project and the associated production is split between several joint ventures with different participating interests. Woodside owns a one-sixth stake in the original NWS LNG joint venture, which was responsible for all LNG production and sales at the NWS Project. Other NWS LNG joint venture participants, which also own one-sixth stakes, include BHP Petroleum, BP, Chevron, Shell and Japan Australia LNG (MIMI) Pty Ltd. CNOOC also has a participating interest in the NWS Project through the joint venture that is responsible for supplying LNG to the China LNG JV (BHP Petroleum's participating interest: 12.5%). There are other joint ventures within the NWS Project, which are responsible for Western Australian domestic gas production (BHP Petroleum's participating interest: 15.78%) and production of additional "equity lifted LNG" (the proportion of LNG which Woodside is entitled to lift and sell, in its own right, as a result of its participating interest in the relevant project) above joint contract quantities (BHP Petroleum's participating interest: 15.78%). There is also an oil joint venture (OKHA FPSO) with different parties and ownerships.
60 Net reserves include volumes consumed in operations (CIO or fuel).
61 Net resources include volumes consumed in operations (CIO or fuel).
62 The remaining 50% is held by joint venture partner and operator, Esso Australia.
63 The remaining interests are held by Esso Australia holding (32.5%) and Mitsui E&P Australia (35%).

field to the nearby West Tuna facility from where it is processed under agreement with GBJV through both offshore infrastructure and onshore facilities before being made available to market at Longford (natural gas) and Long Island Point (Condensate & LPG).

Bass Strait's first oil and gas production was recorded in 1969. The facility now includes 23 offshore platforms and installations and a 600km subsea pipeline network. The nominal processing capacity is 65 Mbbl/d of oil, 1,040 TJpd of domgas, 5,150 tpd of LPG and 850 tpd of ethane.

As at 31 December 2021, BHP Petroleum's share of Bass Strait's net oil and condensate 1P Reserves and 2P Reserves was 10.0 MMbbl and 18.6 MMbbl respectively and gas 1P Reserves and 2P Reserves was 488.5 Bcf and 869.6 Bcf respectively[64][65]. BHP Petroleum's share of Bass Strait's net oil and condensate 2C Contingent Resources was 57.8 MMbbl and gas 2C Contingent Resources was 906.1 Bcf[66].

9.2.6 *Pyrenees*

The Pyrenees oil fields, first discovered in 1993, are located approximately 45 km north-west of Exmouth, Western Australia. The initial development comprised three fields in the Exmouth Sub-Basin, split between two production permits.

The Ravensworth field is located in both production permits WA-42-L and WA-43-L. The Crosby and Stickle fields are located exclusively in WA-42-L. BHP Petroleum holds a 71.43% interest in WA-42-L[67] and a 39.999% interest in WA-43-L.[68] BHP Petroleum is the operator of both these permits.

The Pyrenees development commenced oil production in 2010. The current development consists of six separate fields with 26 subsea wells, (21 production wells, four water disposal wells and one gas injection/production well) tied back via subsea infrastructure to the Pyrenees Venture FPSO. The FPSO has a production capacity of 0.01 MMbbl/d and storage of 0.9 MMbbl of crude oil.

As at 31 December 2021, BHP Petroleum's share of Pyrenees' net oil and condensate 1P Reserves and 2P Reserves was 10.1 MMbbl and 18.8 MMbbl respectively and gas 1P Reserves and 2P Reserves was 11.2 Bcf and 1.1 Bcf respectively[69]. BHP Petroleum's share of Pyrenees' net oil and condensate 2C Contingent Resources was 15.8 MMbbl[70].

9.2.7 *Macedon*

The Macedon gas operations comprise of an offshore gas field located approximately 100 km west of Onslow, Western Australia and an onshore gas processing facility located approximately 17 km south-west of Onslow. The Macedon gas field was first discovered in 1992, with first sales gas having commenced in 2013. BHP Petroleum, who is the operator of Macedon, holds a 71.43% interest in the

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[64] Net reserves include volumes consumed in operations (CIO or fuel).
[65] Gas Reserves and Resources includes the NGL volumes which have been converted to Bcf by multiplying by a conversion factor of 6.0.
[66] Net resources include volumes consumed in operations (CIO or fuel).
[67] The remaining interest is held by Santos (28.57%).
[68] The remaining interests are held by Santos (31.501%) and Inpex Alpha Ltd (**Inpex Alpha**) (28.5%).
[69] Net reserves include volumes consumed in operations (CIO or fuel).
[70] Net resources include volumes consumed in operations (CIO or fuel).

project.[71]. The operation involves the offshore production of gas via four subsea wells and associated subsea field infrastructure, which is then piped to an onshore processing plant, before being sold to the Western Australian domestic market via the Dampier to Bunbury natural gas pipeline.

The processing capacity of the Macedon gas plant is 220 MMscf/d of gas and 110 bbl/d of condensate.

As at 31 December 2021, BHP Petroleum's share of Macedon's net gas 1P Reserves and 2P Reserves was 222.7 Bcf and 300.2 Bcf respectively[72]. BHP Petroleum's share of Macedon's net gas 2C Contingent Resources was 107.0 Bcf[73].

9.2.8 *ROD Integrated Development*

The Rhourde Ouled Djemma (**ROD**) Integrated Development project is an onshore oil project, located approximately 900 km south-east of Algiers, Algeria.

BHP plans to divest its assets in Algeria. These assets are not covered by this IER as Woodside and BHP have agreed that BHP will retain the economic benefits from the Effective Date, including the net proceeds from the divestment. If the divestment of the ROD Integrated Development has not completed prior to completion of the Proposed Transaction, Woodside will run the ROD Integrated Development on behalf of BHP under an arrangement whereby BHP will retain all economic exposure and indemnify Woodside for any costs and liabilities associated with the ROD Integrated Development until such time as both parties agree alternative arrangements or the ROD Integrated Development lapses (whichever is earlier).

9.2.9 *Trinidad and Tobago (Angostura and Ruby)*

BHP Petroleum is the operator of both the Greater Angostura and Ruby offshore shallow-water oil and gas fields. The integrated oil and gas development consists of two fields located between 40 km and 45 km offshore east of Trinidad. BHP Petroleum holds a 68.5% interest in Ruby and a 45.0% interest in Greater Angostura, with separate production sharing contracts for Block 2(c) and Block 3(a).

Greater Angostura consists of a central processing platform connected to four wellhead platforms and a gas export platform. There are 31 wells completed for production and injection including 17 oil producers, 7 gas producers (three of which are subsea) and 7 gas injectors. Angostura was discovered by BHP Petroleum in 1999. Phase 1 started oil production in 2005. Phase 2 of the project included a new gas export platform and two pipelines with gas sales to Trinidad and Tobago, commencing production from 2011. Phase 3 comprising of 3 subsea wells started gas production in 2016. Normal production capacity of Greater Angostura is 0.1 MMbbl/d of oil and 340 MMscf/d of gas.

The Ruby project was developed through a single wellhead protector platform consisting of five oil and gas producers and one gas injector tied back to the existing facilities in the Greater Angostura block. Ruby achieved first oil production in May 2021. Drilling and completion of the remaining wells at Ruby is ongoing with project completion expected in the first half of CY22. The normal production capacity of Ruby is 16 Mbbl/d of oil and 80 MMscf/d of gas.

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[71] The remaining interest is held by Santos (28.57%).
[72] Net reserves include volumes consumed in operations (CIO or fuel).
[73] Net resources include volumes consumed in operations (CIO or fuel).

As at 31 December 2021, BHP Petroleum's share of Greater Angostura's net oil and condensate 1P Reserves and 2P Reserves was 1.6 MMbbl and 2.1 MMbbl respectively and gas 1P Reserves and 2P Reserves was 165.4 Bcf and 251.5 Bcf respectively[74]. BHP Petroleum's share of Greater Angostura's net oil and condensate 2C Contingent Resources was 0.9 MMbbl and gas 2C Contingent Resources was 188.1 Bcf[75].

As at 31 December 2021, BHP Petroleum's share of the Ruby project's net oil and condensate 1P Reserves and 2P Reserves was 0.8 MMbbl and 1.4 MMbbl respectively and gas 1P Reserves and 2P Reserves was 16.1 Bcf and 37.1 Bcf respectively[76]. BHP Petroleum's share of the Ruby project's net oil and condensate 2C Contingent Resources was 3.2 MMbbl and gas 2C Contingent Resources was 45.6 Bcf[77].

9.2.10 Production summary

BHP Petroleum's share of production for each of the 12 months ended 30 June 2019, 30 June 2020 and 30 June 2021 and for the six months ended 31 December 2021 is summarised in the table below.

Table 20: BHP Petroleum's share of production

Production			12 months 30-Jun-19	12 months 30-Jun-20	12 months 30-Jun-21	6 months 31-Dec-21[1]
Crude oil and condensate	Bass Strait	Mboe	5,193	4,993	4,372	2,172
	NWS Project	Mboe	5,822	5,239	4,511	2,000
	Pyrenees	Mboe	3,324	3,801	3,032	1,433
	Other Australian[2]	Mboe	28	11	3	2
	Atlantis[3]	Mboe	14,487	11,276	10,513	6,393
	Mad Dog[3]	Mboe	4,932	4,867	4,449	2,292
	Shenzi[3,4]	Mboe	7,646	6,245	7,510	4,351
	Trinidad/Tobago	Mboe	1,166	510	573	887
	Other Americas[3,5]	Mboe	981	957	693	164
	UK	Mboe	72	-	-	-
	Algeria	Mboe	3,645	3,313	3,073	1,530
	Total Crude oil and condensate	**Mboe**	**47,296**	**41,212**	**38,729**	**21,224**
Natural gas liquids	Bass Strait	Mboe	5,435	5,666	5,315	2,795
	NWS Project	Mboe	830	796	692	328
	Atlantis	Mboe	1,006	669	690	408
	Mad Dog	Mboe	196	189	220	102
	Shenzi	Mboe	353	298	375	236
	Other Americas	Mboe	28	33	21	3
	UK	Mboe	42	-	-	-
	Total natural gas liquids	**Mboe**	**7,890**	**7,651**	**7,313**	**3,872**

[74] Net reserves include volumes consumed in operations (CIO or fuel).
[75] Net resources include volumes consumed in operations (CIO or fuel).
[76] Net reserves include volumes consumed in operations (CIO or fuel).
[77] Net resources include volumes consumed in operations (CIO or fuel).

Production			12 months 30-Jun-19	12 months 30-Jun-20	12 months 30-Jun-21	6 months 31-Dec-21[1]
Natural gas	Bass Strait	Bcf	111.9	110.9	113.0	61.6
	NWS Project	Bcf	145.5	135.2	117.6	50.1
	Other Australian	Bcf	52.9	46.5	50.3	25.3
	Atlantis	Bcf	7.6	5.6	5.3	3.2
	Mad Dog	Bcf	0.8	0.9	0.7	0.3
	Shenzi	Bcf	1.6	1.2	1.1	0.8
	Trinidad/Tobago	Bcf	74.8	58.9	52.4	27.2
	Other Americas	Bcf	0.4	0.4	0.2	-
	UK	Bcf	1.4	-	-	-
	Total natural gas	**Bcf**	**396.9**	**359.6**	**340.6**	**168.5**
Total		**Mboe[6]**	**121,336**	**108,796**	**102,809**	**53,179**

Source: BHP Operational Review for the year ended 30 June 2020 and 30 June 2021 and for the half year ended 31 December 2021

Notes:

1. *BHP Petroleum's production for the half year ended 31 December 2021*
2. *Other Australian includes Minerva and Macedon. Minerva ceased production in September 2019*
3. *GOM volumes are net of royalties*
4. *BHP Petroleum completed the acquisition of an additional 28% interest in Shenzi on 6 November 2020, taking its total interest to 72%*
5. *Other Americas includes Neptune (divested May 2021) and Overriding Royalty Interest*
6. *BHP Petroleum conversion factors are identified at Table 21*
7. *Figures may not add exactly due to rounding.*

Table 21: BHP Petroleum Conversion factors

Product	Factor	Conversion factors[1]
Dry gas	1 MMboe	6.0 Bcf

Source: BHP Operational Review for the year ended 30 June 2020 and 30 June 2021 and for the half year ended 31 December 2021

Note 1: Minor changes to some conversion factors can occur over time due to gradual changes in the process stream

9.3 Growth assets

BHP Petroleum holds operating and non-operating interests in a number of growth projects, including Trion and Calypso. These growth projects are set out below and discussed in more detail in GaffneyCline's ITSR which is attached as Appendix 15 to this report.

9.3.1 Trion

The Trion project is a large greenfield development located in the deep-water GOM, on the Mexico side of the Perdido fold belt. Trion was initially discovered in 2012 by Petróleos Mexicanos (**PEMEX**). During the year ended 30 June 2017, BHP Petroleum acquired a 60% operating interest and ownership in the Trion project[78].

[78] PEMEX retained a 40% interest in the Trion project.

The proposed development plan consists of 14 producers supported by ten peripheral water injectors and three crestal gas injectors. Production is to be delivered via subsea flowline to a 100 Mbbl/d nameplate FPU prior to sending oil to a Floating Storage and Offloading system for tanker export. Gas export is expected to occur via a sales pipeline.

As at 31 December 2021, BHP Petroleum's share of Trion's net oil and condensate 2C Contingent Resources was 241.0 MMbbl and gas 2C Contingent Resources was 204.0 Bcf[79].

9.3.2 Calypso

The Calypso project is an operated deep-water advantaged gas discovery through the Trinidad and Tobago Northern Gas licences, located in two blocks in north-east Tobago. BHP Petroleum is the operator and holds a 70% operating interest in both blocks.[80] There are currently multiple development concepts under evaluation for the Calypso project.

As at 31 December 2021, BHP Petroleum's share of Calypso's net gas 2C Contingent Resources was 2,456.3 Bcf[81].

9.4 Sanctioned assets

BHP Petroleum is currently progressing a number of sanctioned projects (in execution). These sanctioned projects are set out below and discussed in more detail in GaffneyCline's ITSR which is attached as Appendix 15 to this report.

9.4.1 Bass Strait Kipper/West Tuna compression

A recent GBJV investment decision to install Kipper compression facilities on the West Tuna facility enables incremental resource capture from the Kipper field. This project was sanctioned in October 2021.

9.4.2 Scarborough

The Scarborough Joint Venture is a Woodside-operated project, with gas resources located in the Carnarvon Basin approximately 375 km west-northwest of the Burrup Peninsula in Western Australia. The Scarborough Joint Venture received FID approval on 22 November 2021 for the development of the Scarborough gas resource through new offshore facilities, to be connected by a 430 km pipeline to the proposed Pluto Train 2.

BHP Petroleum currently holds a 26.5% non-operating interest in the Scarborough Joint Venture, which covers the Scarborough and North Scarborough gas fields, and a 50% non-operating interest in the Thebe and Jupiter Joint Ventures, which cover the Thebe and Jupiter gas fields adjacent to the Scarborough and North Scarborough gas fields. BHP Petroleum does not hold an ownership interest in either the existing Pluto LNG processing facility or the proposed Pluto Train 2.

In a separate arrangement to the Proposed Transaction, BHP and Woodside have agreed an option for BHP Petroleum to divest both its 26.5% interest in the Scarborough Joint Venture and its 50% interest in the Thebe and Jupiter Joint Ventures to Woodside in the event the Proposed Transaction is not completed.

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[79] Net resources include volumes consumed in operations (CIO or fuel).
[80] The remaining interest is held by BP (30%).
[81] Net resources include volumes consumed in operations (CIO or fuel).

The option is exercisable by BHP Petroleum in the second half of CY22 and if exercised, consideration of US$1 billion is payable to BHP Petroleum with adjustment from an effective date of 1 July 2021. An additional US$100 million is payable contingent upon a future FID for a Thebe development.

As at 31 December 2021, BHP Petroleum's share of Scarborough's net gas 1P Reserves and 2P Reserves was 1,769.0 Bcf and 2,226.0 Bcf respectively[82]. BHP Petroleum's share of Scarborough's net gas 2C Contingent Resources was 981.0 Bcf[83][84].

Please refer to section 8.4.1 for further detail on the Scarborough asset.

9.4.3 *Shenzi Subsea Multi-Phase Pumping (Shenzi SSMPP)*

The Shenzi SSMPP project was developed to improve oil recovery and increase production rates at the existing wells in the Shenzi field. BHP Petroleum is the operator and the joint venture interests are the same as for the original Shenzi project. The Shenzi SSMPP project is forecast to have potential first production in CY22 and peak production capacity of 6.5 Mbbl/d in CY22.

9.4.4 *Atlantis Phase 3*

The Atlantis Phase 3 project, which was sanctioned in February 2019, was developed to take advantage of the existing infrastructure and production ullage in place at the established Atlantis field. The Atlantis Phase 3 project will include the development of a new subsea production system, comprising an eight-well subsea tieback which will connect to the current Atlantis production facility. The project will expand the Atlantis field and provide cost-efficient, near term volumes. BP operates the project and the joint venture interests are the same as for the original Atlantis project.

BHP Petroleum has stated the Atlantis Phase 3 project achieved first production in July 2020 and has the capacity to produce up to 35 Mbbl/d.

9.4.5 *Mad Dog A Spar*

To increase the production capacity of the existing Mad Dog A Spar field, three to four infill wells will be tied back to the existing Mad Dog A Spar facility. BP operates the project and the joint venture interests are the same as for the original Mad Dog project. Mad Dog A Spar is forecast to have potential first production in CY23 and peak production capacity of 18 Mbbl/d in CY26.

9.4.6 *Mad Dog Phase 2*

Following the successful Mad Dog South appraisal well, the Mad Dog Phase 2 platform will be developed as an extension of the existing Mad Dog field and will be located southwest of the existing Mad Dog platform. BP operates the project and the joint venture interests are the same as for the original Mad Dog project.

The Mad Dog Phase 2 project is comprised of a semi-submersible floating production facility (**Argos**) that has the capacity of 110 thousand barrels per day (**Mbbl/d**) of oil and 140 Mbbl/d water injection.

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[82] Net reserves include volumes consumed in operations (CIO or fuel).
[83] Net resources include volumes consumed in operations (CIO or fuel).
[84] BHP Petroleum's share of Scarborough's net gas 2C Contingent Resources of 981.0 Bcf includes Thebe and Jupiter.

BHP Petroleum is targeting potential first production in CY22. Argos, which arrived in the US from South Korea in April 2021, will have 22 subsea wells, 14 of which will be producing wells and eight water injection wells.

9.4.7 Pyrenees Phase 4

At the time of this report, Pyrenees had no undeveloped reserves. Pyrenees Phase 4 is aimed to develop incremental reserves and optimise value using the existing infrastructure through a well re-entry program comprising infill drilling and water shut off operation.

The project is forecast to have potential first production in CY23 and peak production capacity of 13.5 Mbbl/d in CY23. Resources currently booked for the project will be migrated to undeveloped reserves as the project progresses.

9.4.8 NWS Lambert Deep & GWF-3

Woodside, as operator of the NWS Project, is developing Lambert Deep and GWF-3 in order to support ongoing production from the NWS Project. BHP Petroleum has a 16.7% interest in these projects. Woodside has received approval for the planned activities at GWF-3 and Lambert Deep, which commenced in the first half of 2021 and include the drilling of four new production wells and installation of subsea infrastructure, which will be tied-back to the existing NWS Project infrastructure. First production is expected in CY22 with peak production capacity of 250 MMscfd in CY23.

Please refer to section 8.4.2 for further detail on the Lambert Deep and GWF-3 projects.

9.4.9 Shenzi North

Shenzi North represents the first development phase of the Greater Wildling field, which was discovered north of the established Shenzi field in the deep-water GOM in the Green Canyon area. The project will take advantage of the existing infrastructure and production capacity at the Shenzi facility and is underpinned by a two-well subsea tieback to the Shenzi TLP. BHP Petroleum is the operator and holds a 72% interest in the project[85]. On 5 August 2021, the BHP Petroleum's Board approved funding to develop the Shenzi North project, which BHP Petroleum is targeting first production in CY24 and peak production capacity of 30 Mbbl/d in CY24.

As at 31 December 2021, BHP Petroleum's share of Shenzi North's net oil and condensate 1P Reserves and 2P Reserves was 16.4 MMbbl and 27.6 MMbbl respectively and gas 1P Reserves and 2P Reserves was 11.6 Bcf and 19.5 Bcf respectively[86].

9.5 Unsanctioned assets

BHP Petroleum has a number of unsanctioned projects, which are unexecuted and awaiting FID. These unsanctioned projects are set out below and discussed in more detail in GaffneyCline's ITSR which is attached as Appendix 15 to this report.

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[85] Repsol holds the remaining 28% interest.
[86] Net reserves include volumes consumed in operations (CIO or fuel).

9.5.1 Wildling

In addition to the proposed two-well subsea tieback to Shenzi TLP for the sanctioned Shenzi North project, the unsanctioned Wildling project would incorporate a two-well subsea tieback to Shenzi TLP via Shenzi North. BHP Petroleum operates and has a 100% interest in the project.

As at 31 December 2021, BHP Petroleum's share of Wildling's net oil and condensate 2C Contingent Resources was 57.1 MMbbl and gas 2C Contingent Resources was 40.2 Bcf[87].

9.5.2 Shenzi growth opportunities

Further growth initiatives such as the development of three producing and two water injection wells will seek to enhance the production capabilities of the Shenzi facility. These additional infill opportunities, which will be tied back to the Shenzi TLP, will utilise the existing infrastructure at the Shenzi facility. BHP Petroleum is the operator and the joint venture interests are the same as for the original Shenzi project.

9.5.3 Atlantis growth opportunities

Additional development opportunities are planned for Atlantis to increase the production at the field, including the investment in 12 infill producing wells and six additional water injection wells. Further opportunities for production expansion include SSMPP and the topside modification of above water facilities. BP operates the project and the joint venture interests are the same as for the original Atlantis project.

9.5.4 Mad Dog Phase 2 growth opportunities

Production increases beyond the initial investment scope of the Mad Dog Phase 2 project will be targeted through the development of nine new wells. The wells will be tied back to the existing Mad Dog Phase 2 platform, which is expected to begin production in CY22. BP operates the project and the joint venture interests are the same as for the original Mad Dog project.

9.5.5 Mad Dog WI expansion

The installation of two water injector wells, which will distribute water from the Mad Dog Phase 2 facility to the existing Mad Dog A Spar facility, will seek to expand the production capacity of the Mad Dog A Spar facility. BP operates the project and the joint venture interests are the same as for the original Mad Dog project.

9.5.6 NWS Project growth opportunities

BHP Petroleum has identified a low-risk investment opportunity to maximise the KGP value through processing third party gas, with benefits through tolling fees, cost recovery and life extension. The project is operated by Woodside, whilst BHP Petroleum has a 16.7% interest in the project.

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[87] Net resources include volumes consumed in operations (CIO or fuel).

9.5.7 *Bass Strait growth opportunities*

A portfolio of potential growth options continue to be evaluated across both the GBJV and the KUJV, including Kipper infill drilling (Phase 1B), Turrum near-field opportunities and possible Wirrah, Sweetlips and/or East Pilchard field developments.

9.5.8 *Pyrenees growth opportunities*

A portfolio of potential growth opportunities continue to be evaluated across the fields including Crosby, Moondyne, Ravensworth, Stickle, Tanglehead, Wild Bull and Harrison.

9.5.9 *Macedon growth opportunities*

BHP Petroleum has identified the Macedon FE compression as a mature opportunity and pending development. BHP Petroleum is the operator of this project.

9.5.10 *Trinidad and Tobago growth opportunities*

BHP Petroleum has identified the Deep Water South (Magellan) opportunity, which comprises of two dry gas discoveries in water depth of 1,800 metres. BHP Petroleum is the operator of this project and holds a 65% interest in this opportunity.

As at 31 December 2021, BHP Petroleum's share of Magellan's net gas 2C Contingent Resources was 246.7 Bcf[88].

9.6 Non-producing assets

9.6.1 *Bass Strait*

Several Bass Strait fields have reached the end of their economic life with their facilities now having ceased production. Well work has commenced to permanently plug and abandon wells in depleted fields and planning has commenced for the permanent decommissioning of platforms and other infrastructure.

9.6.2 *Other Australian*

BHP Petroleum has outstanding D&R obligations associated with three Australian fields that have ceased production; Minerva, Griffin and Stybarrow.

The Minerva gas field is located offshore Otway Basin, Victoria, approximately 10 km south west of Port Campbell. Cessation of production from the gas field, occurred in 2019.

The Griffin oil and gas field is located off the coast of Western Australia, approximately 70 km north west of Onslow and 68 km north east of Exmouth. Production ceased in 2009. The 12 subsea production wells have since been permanently plugged and abandoned with decommissioning of the balance of the subsea infrastructure pending completion of stakeholder engagement and regulatory approvals.

The Stybarrow oil field is located in the Exmouth sub basin, approximately 51 km north west of the North West cape of Western Australia. The Stybarrow facility produced crude oil from the Stybarrow and

[88] Net resources include volumes consumed in operations (CIO or fuel).

Eskdale fields via a single standalone FPSO. Production commenced in November 2007. At the cessation of production in 2015, all wells were bull headed and valves pressure tested and closed.

9.6.3 GOM overriding royalty interest (ORRI)

The GOM ORRI consists of undivided royalty interests in several fields, being Boris, Little Burn, Typhoon, Valhalla, Deep Blue, Cascade, Chinook, Tornado and West Delta. BHP Petroleum's royalty interest in the fields ranges from 0.17% to 4.20%, with most of the fields being producing assets.

9.7 Exploration assets

BHP Petroleum's global exploration portfolio consists of assets in Mexico, Trinidad and Tobago, Canada, Australia and USA. These prospects range from near field exploration opportunities in Mexico, Trinidad and Tobago, Australia and USA to standalone exploration projects in the USA and Canada. These exploration assets are detailed further below and discussed in more detail, along with the other exploration assets, in GaffneyCline's ITSR which is attached as Appendix 15 to this report.

9.8 Equity accounted investments

BHP Petroleum has equity accounted investments in three associates: Caesar Oil Pipeline Company LLC, Cleopatra Gas Gathering Company LLC and Marine Well Containment Company LLC. All three associates have a reporting date of 31 December.

9.8.1 Caesar Oil Pipeline Company LLC (COPC)

COPC's principal asset comprises the Caesar oil pipeline located in the GOM, which transports oil from the Atlantis, Mad Dog and Shenzi projects via the Ship Shoal 322 platform to the Cameron Highway Oil Pipeline System, which in turn connects to onshore infrastructure in the US. As at 31 December 2021, BHP Petroleum's membership interest in COPC was 25%.

We consider COPC to be an operating asset, hence have not attributed any separate value to COPC in our valuation of BHP Petroleum.

9.8.2 Cleopatra Gas Gathering Company LLC (CGGC)

CGGC's principal asset comprises the Cleopatra gas pipeline located in the GOM, which transports gas from the Atlantis, Mad Dog and Shenzi projects via the Ship Shoal 322 platform to the Manta Ray Gathering System, which in turn connects to onshore infrastructure in the US. As at 31 December 2021, BHP Petroleum's membership interest in CGGC is 22%.

We consider CGGC to be an operating asset, hence have not attributed any separate value to CGGC in our valuation of BHP Petroleum.

9.8.3 Marine Well Containment Company LLC (MWCC)

MWCC was founded in 2010 and is a not-for-profit entity which provides containment services in the event of an underwater oil spill or leak in the GOM. Membership in MWCC consists of ten oil & gas producers including BHP Petroleum, which all hold an equal 10% stake in the company.

We consider MWCC to be an operating asset, hence have not attributed any separate value to MWCC in our valuation of BHP Petroleum. However, we have made an allowance for BHP Petroleum's share of MWCC's operating expenses in our estimate of BHP Petroleum's G&A expenses.

9.9 Reserves and Resources

BHP Petroleum's share of net 1P and 2P Reserves and net 2C Contingent Resources by project as at 31 December 2021 are summarised in the tables below.

Table 22: BHP Petroleum's net 1P and 2P Reserves as at 31 December 2021[89]

	Oil and Condensate Reserves (MMbbl)		Gas Reserves (Bcf)[3 4]	
	1P	2P	1P	2P
Bass Strait	10.0	18.6	488.5	869.6
NWS Project[1]	17.8	22.2	728.9	913.4
Pyrenees	10.1	18.8	11.2	1.1
Macedon	0.0	0.0	222.7	300.2
Scarborough	0.0	0.0	1,769.0	2,226.0
Shenzi	64.0	92.1	33.3	49.7
Shenzi North	16.4	27.6	11.6	19.5
Atlantis	62.3	144.3	57.4	139.2
Mad Dog	126.8	178.2	48.2	67.2
Angostura	1.6	2.1	165.4	251.5
Ruby[2]	0.8	1.4	16.1	37.1
Reserves	**309.9**	**505.3**	**3,552.2**	**4,874.4**

Source: BHP's estimates from Explanatory Memorandum

Notes:

1. *The 'NWS Project' region includes all oil and gas fields within the North West Shelf Area*
2. *The 'Ruby' region comprises the Ruby and Delaware fields*
3. *Gas Reserves includes NGL*
4. *Gas volumes include gas equivalent NGL volumes, which have been converted to Bcf by multiplying by a conversion factor of 6.0.*
5. *Figures may not add exactly due to rounding.*

Table 23: BHP Petroleum's net 2C Contingent Resources as at 31 December 2021[90][91]

	2C Contingent Resources	
	Oil and Condensate (MMbbl)	Gas (Bcf)[3]
Bass Strait	57.8	906.1
NWS Project[1]	11.9	140.5
Pyrenees	15.8	0.0
Macedon	0.0	107.0
Scarborough	0.0	981.0
Greater Exmouth	3.2	42.1
Shenzi	83.9	59.2

[89] Net reserves include volumes consumed in operations (CIO or fuel).
[90] Net resources include volumes consumed in operations (CIO or fuel).
[91] Net resources in this table are BHP Petroleum's working interest fraction of the gross field resources.

	2C Contingent Resources	
	Oil and Condensate (MMbbl)	Gas (Bcf)[3]
Wildling	57.1	40.2
Atlantis	155.1	405.7
Mad Dog	164.5	52.3
Trion	241.0	204.0
Angostura	0.9	188.1
Ruby[2]	3.2	45.6
Calypso	0.0	2,456.3
Magellan	0.0	246.7
Resources	**794.3**	**5,874.7**

Source: BHP's estimates Explanatory Memorandum

Notes:

1. *The 'NWS Project' region includes all oil and gas fields within the North West Shelf Area*
2. *The 'Ruby' region comprises the Ruby and Delaware fields*
3. *Gas volumes include gas equivalent NGL volumes, which have been converted to Bcf by multiplying by a conversion factor of 6.0*
4. *Figures may not add exactly due to rounding.*

9.10 Historical financial performance

BHP Petroleum's historical unaudited financial performance for the year ended 30 June 2019, the audited financial performance for the years ended 30 June 2020 and 30 June 2021 and the unaudited financial performance for the six months ended 31 December 2021 are summarised below.

Table 24: BHP Petroleum's historical combined[92] financial performance

For the year ended US$ million unless otherwise stated	12 months Unaudited 30-Jun-19	12 months Audited 30-Jun-20	12 months Audited 30-Jun-21	6 months Unaudited 31-Dec-21
Continuing operations				
Crude oil	3,173	2,033	2,013	1,656
Gas	2,399	1,754	1,659	1,334
Natural gas liquids	252	198	212	183
Other	43	12	25	25
Total Revenue	**5,867**	**3,997**	**3,909**	**3,198**
Other income	32	57	130	172
Expenses excluding net finance costs	(3,510)	(3,390)	(3,799)	(1,761)
Loss from equity accounted investments	(2)	(4)	(6)	(1)
Profit from operations	**2,387**	**660**	**234**	**1,608**
Net finance costs	(637)	(356)	(408)	(118)
Profit/(loss) before taxation	**1,750**	**304**	**(174)**	**1,490**

[92] The combined financial statements relate to the financial information that is limited to the legal entities carved out from BHP in connection with the Proposed Transaction and present the combined financial position, combined results of operations and combined cash flows of the carve-out legal entities. The effects of all intragroup balances and transactions have been eliminated in accordance with the consolidation requirements of IFRS 10 'Consolidated Financial Statements'.

For the year ended US$ million unless otherwise stated	12 months Unaudited 30-Jun-19	12 months Audited 30-Jun-20	12 months Audited 30-Jun-21	6 months Unaudited 31-Dec-21
Income tax expense	(925)	(400)	(211)	(870)
Royalty - related taxation (net of income tax benefit)	(164)	(82)	24	(37)
Total taxation expense	(1,089)	(482)	(187)	(907)
Profit/(loss) after taxation from Continuing operations	**661**	**(178)**	**(361)**	**583**
Discontinued operations				
Loss after taxation from Discontinued operations	(335)	-	-	-
Profit/(loss) after taxation from Continuing and Discontinued operations	**326**	**(178)**	**(361)**	**583**
Attributable to non-controlling interests	7	-	-	-
Attributable to BHP shareholders	319	(178)	(361)	-
Total other comprehensive income/(loss)	**(7)**	**(10)**	**1**	**1**
Total comprehensive income/(loss)	**319**	**(188)**	**(360)**	**584**
Attributable to non-controlling interests	7	-	-	-
Attributable to BHP shareholders	312	(188)	(360)	n/a[2]
Statistics				
Total Revenue growth	*n/a*	*-31.9%*	*-2.2%*	*n/a*
Expenses excluding net finance costs growth	*n/a*	*-3.4%*	*12.1%*	*n/a*
Net finance costs growth	*n/a*	*-44.1%*	*14.6%*	*n/a*

Source: BHP Petroleum General Purpose Financial Report for the years ended 30 June 2019, 30 June 2020, 30 June 2021 and half year ended 31 December 2021

Notes:

1. *Figures may not add exactly due to rounding*
2. *Not available.*

We note the following in relation to BHP Petroleum's recent financial performance:

9.10.1 *Year ended 30 June 2019*

BHP Petroleum's results for the year ended 30 June 2019 reflect revenue from contracts with customers of US$5,817 million and other revenue of US$50 million, for a combined total revenue from continuing operations of US$5,867 million. Revenue was primarily generated from the production and sale of crude oil, natural gas and natural gas liquids, with an average realised sales price of US$48/boe and total production volumes of 121.3 MMboe. During the year ended 30 June 2019, BHP Petroleum had one major customer, which accounted for 15% of external revenues.

Expenses excluding net finance costs primarily consist of depreciation and amortisation expense of US$1,560 million, wages, salaries and redundancies expense of US$416 million, external services of US$387 million, government royalties paid and payable of US$223 million and exploration and evaluation expenses of US$388 million. Net finance costs consist of a US$1,001 million finance expense offset by US$364 million of finance income. An impairment expense of US$21 million was recognised in relation to property, plant and equipment of US$7 million and intangible assets of US$14 million.

During the year ended 30 June 2019, BHP Petroleum completed the sale of its interest in BHP Billiton Petroleum (Arkansas) Inc. and 100 per cent of the membership interests in BHP Billiton Petroleum (Fayetteville) LLC, which held the Fayetteville assets, for a gross cash consideration of approximately

US$300 million. BHP Petroleum also completed the sale of its interests in the Eagle Ford, Haynesville and Permian Onshore US oil and gas assets for gross cash consideration of US$10.3 billion (net of preliminary customary completion adjustments of US$0.2 billion) (**Onshore US assets**) to BP America Production Company. Results from the Onshore US assets are disclosed as Discontinued operations. BHP Petroleum continued to recognise its share of revenue, expense, net finance costs and associated income tax expense related to the operations of each of the Onshore US assets until the respective completion dates of the sale of each of the assets. The discontinued operations net loss of US$335 million after tax predominately relates to incremental costs arising as a consequence of the divestment, including restructuring costs and provisions for surplus office accommodation and tax expenses largely triggered by the completion of the transactions.

9.10.2 Year ended 30 June 2020

BHP Petroleum's results for the year ended 30 June 2020 reflect a 31.9% decrease in total revenue from the corresponding prior year to US$3,997 million (excluding the Onshore US assets). This was primarily driven by lower petroleum volumes due to natural field decline across the portfolio, weaker market conditions due to excess global supply and a decrease of 24.0% in average realised prices over the year to US$37/boe, which in turn reflected lower global commodity prices during the year. Production volumes decreased from 121.3 MMboe during the year ended 30 June 2019 to 108.8 MMboe during the year ended 30 June 2020. During the year ended 30 June 2020, BHP Petroleum had one major customer which accounted for 13% of external revenues.

Expenses excluding net finance costs reduced by 3.4% to US$3,390 million. Depreciation and amortisation expense decreased by 6.6% to US$1,457 million, in line with lower production volumes. Net finance costs reduced by 44.1% to US$356 million.

Impairment losses of US$11 million were recognised in relation to property, plant and equipment.

9.10.3 Year ended 30 June 2021

BHP Petroleum's results for the year ended 30 June 2021 reflect a 2.2% decrease in total revenue from the corresponding prior year, to US$3,909 million. Higher average realised oil and natural gas prices were offset by lower volumes due to natural field decline across the portfolio. More specifically, BHP Petroleum's results for the year ended 30 June 2021, reflect a 3.5% increase in average realised sales price over the year to US$38/boe. Production volumes decreased from 108,796 MMboe for the year ended 30 June 2020 to 102,809 MMboe for the year ended 30 June 2021. During the year ended 30 June 2021, BHP Petroleum had two major customers which accounted for 18% and 10% of external revenues.

Expenses excluding net finance costs increased by 12.1% to US$3,799 million, which was largely attributable to an increase of 26.3% in depreciation and amortisation expense to US$1,840 million (as a result of a decrease in estimated remaining reserves at Bass Strait due to underperformance of the reservoir in the Turrum field and lower overall condensate and natural gas liquids recovery from the Bass Strait gas fields), net impairment losses of US$127 million (described further below), an increase of 22.8% in external services to US$620 million, partially offset by a decrease of 25.1% in exploration and evaluation expenditure during the period of US$296 million.

Net finance costs increased by 14.6% to US$408 million largely due a decrease in finance income to US$56 million.

Impairment losses totalling US$127 million were recognised in relation to both property, plant and equipment and intangibles. For the property, plant and equipment impairment losses, US$66 million of the impairment loss was recognised in relation to previously capitalised exploration and evaluation costs and US$42 million was recognised as a write-off of leasehold fit out and fittings following a restructure. For the intangible assets impairment loss, US$19 million was written off for abandoned and relinquished exploration leases.

9.10.4 *Half year ended 31 December 2021*

BHP Petroleum's results for the half year period ended 31 December 2021 reflect total revenue of US$3,198 million. Profit from operations of US$1,608 million was driven by an 89% increase in average realised sales price for the six month period to US$60/boe compared to the corresponding prior half year period ending 31 December 2020. Production volumes increased from 50.5 MMboe for the six month period ended 31 December 2020 to 53.2 MMboe for the six month period ended 31 December 2021.

Expenses excluding net finance costs were US$1,761 million, which included depreciation and amortisation expense of US$1,047 million. Net finance costs were US$118 million during the period.

Impairment losses totalling US$210 million were recognised in relation to a write-down of reserve estimates for the Ruby project.

9.11 Historical financial position

BHP Petroleum's historical unaudited financial position as at 30 June 2019, audited financial position as at 30 June 2020 and 30 June 2021 and unaudited financial position as at 31 December 2021 are summarised below.

Table 25: BHP Petroleum's historical financial position

As at US$ million unless otherwise stated	Unaudited 30-Jun-19	Audited 30-Jun-20	Audited 30-Jun-21	Unaudited 31-Dec-21
Cash and cash equivalents	1,398	325	776	992
Trade and other receivables	835	673	908	1,230
Receivables from BHP Group	15,871	12,424	5,526	10,852
Other financial assets	3	7	-	-
Inventories	251	250	307	278
Current tax assets	6	210	130	69
Other assets	23	34	9	14
Total Current Assets	**18,387**	**13,923**	**7,656**	**13,435**
Trade and other receivables	38	112	157	201
Other financial assets	67	86	52	37
Property, plant and equipment[1]	10,628	11,787	11,854	11,226
Intangible assets	104	110	78	63
Net investments and funding of equity accounted investments	239	245	253	246
Deferred tax assets	2,040	2,041	2,182	1,947
Other financial assets	1	5	3	3
Total Non-Current Assets	**13,117**	**14,386**	**14,579**	**13,723**
Total Assets	**31,504**	**28,309**	**22,235**	**27,158**
Trade and other payables	929	771	919	952
Payables to BHP Group	6,520	6,533	2,001	12,552

As at US$ million unless otherwise stated	Unaudited 30-Jun-19	Audited 30-Jun-20	Audited 30-Jun-21	Unaudited 31-Dec-21
Interest bearing liabilities[2]	17	61	35	38
Other financial liabilities	1	6	9	60
Current tax payable	465	292	280	312
Closure and rehabilitation provisions	205	162	141	144
Other provisions	277	274	315	216
Deferred income	21	25	14	16
Total Current Liabilities	**8,435**	**8,124**	**3,714**	**14,290**
Non-current tax payable	-	-	14	69
Payables to BHP Group	14,340	10,347	10,347	-
Interest bearing liabilities	-	322	234	219
Closure and rehabilitation provisions	2,095	3,433	3,816	3,760
Deferred tax liabilities	1,244	1,028	610	465
Other provisions	368	276	344	341
Deferred income	85	55	44	40
Total Non-Current Liabilities	**18,132**	**15,461**	**15,409**	**4,894**
Total Liabilities	**26,567**	**23,585**	**19,123**	**19,184**
Net Assets	**4,937**	**4,724**	**3,112**	**7,974**
Statistics				
Gearing - %[3]	73%	87%	194%	9%
Gearing inc lease liabilities - %[4]	73%	96%	203%	12%
Current Ratio - %[5]	2.2	1.7	2.1	0.9

Source: BHP Petroleum General Purpose Financial Report for the years ended 30 June 2019, 30 June 2020, 30 June 2021 and half year ended 31 December 2021

Notes:

1. *Property, plant and equipment as at 31 December 2021 includes leased assets of US$124 million*
2. *The US$17 million interest bearing liabilities as at 30 June 2019 relate to bank overdrafts*
3. *Gearing represents net debt divided by net assets, where net debt is total external borrowings less cash and cash equivalents. BHP Group payables have been included as external borrowings and Receivables from BHP Group have been included as cash and cash equivalents*
4. *Gearing represents net debt divided by net assets, where net debt is total external borrowings, plus lease liabilities less cash and cash equivalents. BHP Group payables have been included as external borrowings and Receivables from BHP Group have been included as cash and cash equivalents*
5. *Current ratio represents current assets divided by current liabilities*
6. *Figures may not add exactly due to rounding.*

We note the following in relation BHP Petroleum's historical financial position as at 31 December 2021:

9.11.1 *Cash and cash equivalents*

BHP Petroleum held US$992 million of cash and cash equivalents as at 31 December 2021. The movement in cash and cash equivalents from 30 June 2021 to 31 December 2021, represents an approximate 28% increase.

The increase in cash and cash equivalents from 31 December 2020 to 31 December 2021 of US$216 million is largely due to an increase in net operating cash flows of US$1,388 million due to the underlying cash flows generated from operations of US$1,980 million in the half year ended 31 December 2021, a decrease in net investing cash flows of US$543 million due to a reduction in investment in subsidiaries, operations and joint operations and an increase in net financing cash flows due to US$633 million of net other financing from BHP Group.

9.11.2 *Financing arrangements*

BHP Petroleum has financing arrangements with BHP for short term cash management. Under these financing arrangements, BHP Petroleum had a US$10,852 million current receivable from BHP and US$12,552 million current payable to BHP as at 31 December 2021.

BHP Petroleum entered into debt arrangements with BHP Group to finance its projects. As at 31 December 2021, the outstanding balance relating to these arrangements was US$12,552 million. This balance was reclassified as a current liability in Payables to BHP Group during the six months ended 31 December 2021 as a result of its scheduled repayment date falling within the next 12 months. The debt agreements were entered at the 3-month USD LIBOR plus a margin, with a maturity date between November 2022 and December 2022.

9.11.3 *Derivative financial instruments*

Embedded derivatives resulting from a physical commodity purchase and sale contract in Trinidad and Tobago are included in other financial assets and other financial liabilities. As at 31 December 2021, the carrying value of the embedded derivative was a net liability of US$23 million.

9.11.4 *Net investments and funding of equity accounted investments*

As at 31 December 2021, BHP Petroleum's net investments and funding of equity accounted investments was US$246 million. This balance compromised of ownership interests in Caesar Oil Pipeline Company LLC (25%), Cleopatra Gas Gathering Company LLC (22%) and Marine Well Containment Company LLC (10%).

9.11.5 *Property, plant and equipment*

The carrying value of BHP Petroleum's property, plant and equipment as at 31 December 2021 was US$11,226 million. This balance is comprised of land and buildings, plant and equipment, other mineral assets, assets under construction and exploration and evaluation assets.

9.11.6 *Deferred tax assets/(liabilities)*

As at 31 December 2021, BHP Petroleum had deferred tax assets of US$1,947 million and deferred tax liabilities of US$465 million. The deferred tax assets balance is primarily comprised of tax losses, whilst the deferred tax liabilities balance relates to a resource rent tax balance.

9.11.7 *Closure and rehabilitation provisions*

BHP Petroleum, as specified in licence agreements is required to rehabilitate sites and associated facilities at the end of, or in some cases, during production, to a condition acceptable to the relevant authorities. BHP Petroleum had a current closure and rehabilitation provision of US$144 million and a non-current amount of US$3,760 million as at 31 December 2021.

9.12 Statement of cash flows

BHP Petroleum's historical unaudited statement of cash flows for the year ended 30 June 2019, audited statement of cash flows for the year ended 30 June 2020 and the year ended 30 June 2021 and unaudited statement of cash flows for the six months ended 31 December 2021 are summarised below.

Table 26: BHP Petroleum's historical combined statement of cash flows

For the year ended US$ million unless otherwise stated	12 months Unaudited 30-Jun-19	12 months Audited 30-Jun-20	12 months Audited 30-Jun-21	6 months Unaudited 31-Dec-21
Cash Flows from Operating Activities				
Profit/(loss) before taxation	1,750	304	(174)	1,490
Adjustments for:				
Depreciation and amortisation expense	1,560	1,457	1,840	1,047
Impairments of property, plant and equipment and intangible assets	21	11	127	210
Net finance costs	637	356	408	118
Share of operating loss of equity investments	2	4	6	1
Other	(223)	(141)	(187)	(215)
Changes in assets and liabilities:				
Trade and other receivables	142	253	(298)	(630)
Inventories	(1)	(1)	(42)	29
Trade and other payables	17	(166)	52	74
Provisions and other assets and liabilities	(212)	(152)	11	(144)
Cash generated from operations	*3,693*	*1,925*	*1,743*	*1,980*
Dividends received	17	20	25	8
Net interest paid	(553)	(395)	(257)	(104)
Income taxes paid (including royalty taxes)	(810)	(965)	(451)	(496)
Net Cash Inflow Related to Operating Activities from Continuing operations	**2,347**	**585**	**1,060**	**1,388**
Net Cash Inflow Related to Operating Activities from Discontinued operations	**474**	**-**	**-**	**-**
Net Cash Inflow Related to Operating Activities	**2,821**	**585**	**1,060**	**1,388**
Cash Flows from Investing Activities				
Purchases of property, plant and equipment	(645)	(909)	(994)	(556)
Exploration expenditure	(297)	(169)	(26)	(131)
Investment in subsidiaries, operations and joint operations, net of cash	-	-	(480)	-
Net investment and funding of equity accounted investments	(6)	(22)	(25)	(2)
Other investing	(4)	(11)	(34)	-
Proceeds from sale of assets	8	78	39	146
Net Cash Outflow Related to Investing Activities from Continuing operations	**(944)**	**(1,033)**	**(1,520)**	**(543)**
Net investing cash flows from Discontinued operations	**(443)**	**-**	**-**	**-**
Net Cash Outflow Related to Investing Activities	**(1,387)**	**(1,033)**	**(1,520)**	**(543)**
Cash Flows from Financing Activities				
Lease payments	-	(39)	(38)	(18)
Repayments of long-term borrowings to BHP Group	-	(3,000)	(3,993)	-

For the year ended US$ million unless otherwise stated	12 months Unaudited 30-Jun-19	12 months Audited 30-Jun-20	12 months Audited 30-Jun-21	6 months Unaudited 31-Dec-21
Net other financing with BHP Group	(12,544)	2,432	4,941	(633)
Proceeds from issuance of shares to BHP Group	2,000	-	-	
Currency valuation change	-	-	-	23
Net Cash Outflow Related to Financing Activities from Continuing operations	**(10,544)**	**(607)**	**910**	**(628)**
Net Cash Outflow Related to Financing Activities from Discontinued operations	**(13)**	**-**	**-**	**-**
Net Cash Outflow Related to Financing Activities	**(10,557)**	**(607)**	**910**	**(628)**
Net (Decrease)/Increase in Cash and Cash Equivalents from Continuing operations	**(9,141)**	**(1,055)**	**450**	**217**
Net (Decrease)/Increase in Cash and Cash Equivalents from Discontinued operations	**18**	**-**	**-**	**-**
Proceeds from divestment of Onshore US, net of its cash	10,427	-	-	
Cash and cash equivalents, net of overdrafts at the beginning of the financial year	77	1,381	325	776
Foreign currency exchange rate changes on cash and cash equivalents	-	(1)	1	(1)
Cash and Cash Equivalents at end of the year[1]	**1,381**	**325**	**776**	**992**

Source: BHP Petroleum General Purpose Financial Report for the years ended 30 June 2019, 30 June 2020, 30 June 2021 and half year ended 31 December 2021

Notes:

1. *The US$1,381 million includes US$1,398 million of cash and cash equivalents less bank overdrafts of US$17 million*
2. *Figures may not add exactly due to rounding.*

We note the following in relation to BHP Petroleum's reported cash flows:

- On 6 November 2020, BHP Petroleum finalised a membership interest purchase and sale agreement to acquire an additional 28% working interest in the Shenzi asset for US$480 million. BHP Petroleum's total working interest in Shenzi post the acquisition is 72%
- BHP Petroleum's net cash flows from operating activities for the half year ended 31 December 2021 were US$1,388 million, an increase from the prior corresponding period of 1,209% (US$106 million), which was largely driven by an increase in the average realised sales prices of crude oil, natural gas and LNG, in addition to an increase in volumes
- BHP Petroleum's net cash flows from financing activities for the half year ended 31 December 2021 were (US$628 million). This net cash outflow is largely attributable to the net financing arrangements with BHP.

9.13 Taxation

Under the Australian tax consolidation regime, BHP Petroleum is part of the income tax consolidated group parented by BHP. As such, the benefit of tax losses generated by BHP Petroleum entities are not recognised in BHP Petroleum's profit and loss, as these losses were transferred to BHP in the years in which they were generated.

BHP Petroleum's tax losses totalled US$83 million in the year ended 30 June 2021, US$143 million in the year ended 30 June 2020 and US$205 million in the year ended 30 June 2019.

BHP Petroleum is also subject to PRRT when they are imposed under government authority.

9.14 Contingent liabilities

BHP Petroleum's contingent liabilities include possible obligations for litigation, uncertain tax and royalty matters, open regulatory audits and various other claims, for which the timing of resolution and potential economic outflow is uncertain.

BHP Petroleum's contingent liabilities totalled US$774 million as at 31 December 2021, US$759 million as at 30 June 2021, US$687 million as at 30 June 2020 and US$713 million as at 30 June 2019.

9.15 Commitments

As at 31 December 2021, BHP Petroleum had commitments for capital expenditure of US$2,150 million. The majority of BHP Petroleum's capital expenditure incurred during the half year ended 31 December 2021 was in relation to its Australian, GOM and T&T assets.

BHP Petroleum announced on the 22 November 2021, the approval of US$1.5 billion in capital expenditure for the development of the Scarborough upstream project.

10 Profile of the Merged Group

10.1 Overview

If Woodside is successful in acquiring BHP Petroleum, Woodside Shareholders will initially own approximately 52% of the Merged Group, which will remain headquartered in Perth, Western Australia. Woodside Shareholders will gain exposure and benefit from the improved investment characteristics of the Merged Group, including:

- a substantially larger company with a broader shareholder base and a pro forma market capitalisation in the order of A$63,038 million (based on Woodside's closing share price of A$33.20 on 24 March 2022), making it the largest listed oil and gas company on the ASX
- a significantly greater scale of operations, with greater geographical diversification and a more balanced product mix
- a stronger balance sheet with reduced gearing and increased operational cash flow
- the potential to realise benefits from cost savings and operational synergies
- the potential for increased share trading liquidity and market re-rating
- immediate access to a suite of development and growth opportunities not available to Woodside as a standalone entity within the same timeframe.

However, the final extent to which long-term benefits will be realised by Woodside Shareholders following completion of the Proposed Transaction remains uncertain, in that:

- global oil and gas markets are currently experiencing significant volatility as a result of the ongoing conflict between Russia and Ukraine, which has the potential to result in long term systemic change to the markets for the Merged Group's products, the impact of which may not be known with any certainty for an extended period of time

- the Proposed Transaction is being completed at a time when there is intense global focus on the reduction in carbon emissions, including the pursuit of replacements for fossil fuels as an energy source. Whilst there are differing views as the likely speed and extent of the future global transition towards and the availability of alternative energy sources such as renewables, there is no doubt this change has the potential to significantly impact upon the Merged Group's long term outcomes, particularly as the Proposed Transaction significantly increases Woodside's investment in developed and undeveloped oil and gas assets
- the Merged Group's success and profitability could be adversely affected if BHP Petroleum's business and assets are not effectively integrated with Woodside. There is also always the risk that the cost savings and operational synergies expected to be realised may not emerge to the extent anticipated, may be realised over a time-frame that is longer than anticipated and/or that realisation costs are higher than anticipated
- at the date of this report, completion of the Proposed Transaction remains subject to the satisfaction of certain conditions precedent, including obtaining the approval of various domestic and overseas authorities. In the event required approvals are received but are provided subject to various conditions, this could impact on the ultimate value of the Merged Group
- Woodside has also set out various additional risks relating to the Merged Group at section 8 of the Explanatory Memorandum which Woodside Shareholders should also consider in deciding whether to vote in favour of the merger.

Woodside's stated goal for the Merged Group is to leverage its base business profitability to build a low-cost, lower carbon, profitable, resilient and diversified portfolio of growth opportunities to achieve its strategic objectives. This strategy sees Woodside continuing to develop hydrocarbons while gradually building optionality in new energy products and lower-carbon services such as ammonia, liquid hydrogen and the development of carbon capture. Further details in relation to Woodside's strategy for the Merged Group are set out in section 6 of the Explanatory Memorandum.

Summarised below are various investment characteristics of the Merged Group that would be relevant to Woodside shareholders in the event that Woodside is successful in acquiring BHP Petroleum.

10.2 Financial impact[93]

Section 7 of the Explanatory Memorandum sets out solely for illustrative purposes Woodside's calculation of the pro forma financial position of the Merged Group as at 31 December 2021 (including a description of the assumptions and adjustments made), along with the pro forma financial performance and cash flows statements of the Merged Group for the 12 months ended 31 December 2021.

[93] KPMG Corporate Finance has not had any involvement in the preparation of the pro forma financial information prepared by Woodside and has assumed that it has been prepared appropriately. The pro forma financial information is provided solely for illustrative purposes and the final financial information is expected to differ, potentially materially, from that presented following the completion of acquisition accounting.

We make the following observations in relation to Woodside's pro forma financial information generally:

- the pro forma financial information has been prepared on the basis of Woodside's audited financial report for FY21 and BHP Petroleum's independently reviewed financial report for 1HY22 and FY21
- no adjustments have been made by Woodside for anticipated synergies and costs of realisation from combining Woodside and BHP Petroleum, nor in relation to the finalisation of purchase price accounting, including the identification and measurement of all required purchase price allocations, tax cost base resets or treatment of the transaction costs associated with the Proposed Transaction.

10.2.1 Pro forma financial position

Set out below is the pro forma financial position of the Merged Group as at 31 December 2021, prepared by Woodside along with various metrics calculated by KPMG Corporate Finance.

Table 27: The Merged Group pro forma financial position as at 31 December 2021

Pro forma unaudited statement of financial position - US$ million	Woodside	BHP Petroleum	Pro Forma Adjustments	Merged Group pro forma
	As at 31 December 2021			
Cash and cash equivalents	3,025	992	-	4,017
Receivables	368	1,230	(572)	1,026
Inventories	202	278	-	480
Intercompany	-	10,852	(10,852)	-
Current tax assets	-	69	-	69
Other financial assets	320	-	-	320
Other assets	109	14	537	660
Non-current assets held for sale	254	-	-	254
Total Current Assets	**4,278**	**13,435**	**(10,887)**	**6,826**
Receivables	686	201	-	887
Inventories	19	-	-	19
Other financial assets	107	37	(37)	107
Other assets	34	3	-	37
Exploration and evaluation assets	614	-	2,905	3,519
Oil and gas properties	18,434	11,102	8,658	38,194
Other plant and equipment	215	-	-	215
Intangible assets	-	63	(63)	-
Deferred tax assets	1,007	1,947	(849)	2,105
Lease assets	1,080	124	68	1,272
Investments accounted for using the equity method	-	246	-	246
Goodwill	-	-	7,126	7,126
Total Non-Current Assets	**22,196**	**13,723**	**17,808**	**53,727**
Total Assets	**26,474**	**27,158**	**6,921**	**60,553**
Payables	639	952	1,319	2,910
Interest-bearing liabilities	277	38	(38)	277
Lease liabilities	191	-	38	229
Other financial liabilities	411	60	(60)	411
Other liabilities	86	16	-	102

Pro forma unaudited statement of financial position - US$ million	Woodside	BHP Petroleum	Pro Forma Adjustments	Merged Group pro forma
	As at 31 December 2021			
Provisions	605	360	(16)	949
Tax payable	413	312	-	725
Intercompany payables	-	12,552	(12,552)	-
Total Current Liabilities	**2,622**	**14,290**	**(11,309)**	**5,603**
Interest-bearing liabilities	5,153	219	(219)	5,153
Lease liabilities	1,176	-	219	1,395
Deferred tax liabilities	878	465	1,933	3,276
Other financial liabilities	161	-	-	161
Other liabilities	36	40	1,144	1,220
Provisions	2,219	4,101	841	7,161
Tax payable	-	69	-	69
Total Non-Current Liabilities	**9,623**	**4,894**	**3,918**	**18,435**
Total Liabilities	**12,245**	**19,184**	**(7,391)**	**24,038**
Net Assets	**14,229**	**7,974**	**14,312**	**36,515**
Ordinary shares on issue (million) (undiluted)	**969.6**	**nmf**	**901.5**	**1,871.2**
Net assets per ordinary share on issue (US$)[1]	**14.67**	**nmf**		**19.51**
Net tangible assets per ordinary share on issue (US$)[2]	**14.67**	**nmf**		**15.71**
Current ratio (times)	**1.6**	**0.9**		**1.2**
Gearing[3]	**15.2%**	**n/a**		**3.8%**
Gearing incl lease liabilities[4]	**21.9%**	**n/a**		**7.8%**
Underlying EBITDA / Net borrowings (excl lease liabilities)	**1.7**	**nmf**		**6.5**

Source: Woodside management and KPMG Corporate Finance analysis

Notes:

1. *Net assets per share is calculated as net assets divided by the number of shares at period end*
2. *Net tangible assets per share is calculated as net assets, less intangible assets, divided by the number of shares at period end*
3. *Gearing represents net borrowings excluding lease liabilities, divided by net assets plus net borrowings*
4. *Gearing represents net borrowings including lease liabilities, divided by net assets plus net borrowings including lease liabilities*
5. *Underlying EBITDA for Woodside has been calculated as profit before tax add net finance costs, depreciation and amortisation and net impairment costs. Underlying EBITDA for BHP Petroleum has been calculated as profit before tax add net finance costs, depreciation and amortization and one-off costs primarily comprised of net impairment costs, onerous lease costs and exploration leases. Underlying EBITDA for the Merged Group has been calculated as the underlying EBITDA for Woodside added to that of BHP Petroleum add pro forma adjustments to; fair value of embedded derivatives and decrease in depreciation and amortisation, less pro forma adjustment to gain on sale of Scarborough interest*
6. *"nmf" means not meaningful*
7. *"n/a" means not applicable as BHP Petroleum is being acquired on a cash free debt free basis*
8. *May not add exactly due to rounding.*

Adjustments have been made by Woodside to BHP Petroleum's historical statement of financial position to realign BHP Petroleum's basis of presentation with that of Woodside, and to account for the Proposed

Transaction as a business combination using the acquisition method of accounting, with Woodside identified as the acquirer, including:

- the reclassification of intangible assets of (US$63) million and oil and gas properties of (US$878) million to exploration and evaluation assets
- the reclassification of current interest-bearing liabilities of (US$38) million and non-current interest-bearing liabilities of (US$219) million as 'lease liabilities'
- recognition of an accrual in respect of the estimated cash adjustment to be paid to BHP on completion of US$947 million, comprising the estimated Woodside dividend payment of US$830 million and estimated net locked box payment of US$117 million
- an adjustment to accruals for estimated non-recurring transaction costs of US$410 million, comprising advisory, legal, regulatory, accounting, valuation and other professional fees not capitalised as part of the Transaction
- adjustments to receivables of (US$572) million and payables of (US$38) million to reflect the difference in accounting policies for overlift and underlift
- adjustments to intercompany balances to reflect the Proposed Transaction is being completed on a cash-free debt-free basis, where BHP Petroleum will settle all intercompany loan balances with a net impact of US$1,700 million prior to implementation of the merger
- fair value adjustments to:
  - other financial assets of (US$37) million and other financial liabilities of (US$60) million relate to embedded derivatives
  - right-of-use asset of (US$68) million to align with the related lease liability and to reflect off-market terms
  - non-current other liabilities for additional liabilities assumed of (US$56) million and unfavourable contracts of (US$1,088) million
  - other assets of US$537 million in respect of entitlement to additional LNG volumes
- other preliminary purchase price allocation adjustments:
  - to Oil and gas properties and Exploration and evaluation assets resulting in an increase of US$9,536 million and US$1,964 million respectively
  - to deferred income taxes to record the estimated tax effect accounting. The deferred tax adjustment assumes a forecast blended BHP Petroleum statutory tax rate of 25%
  - to provisions of US$825 million primarily to record the estimated fair value of the assumed BHP Petroleum asset retirement obligations. As a result of the adjustment, the current provision decreased by US$16 million, and the non-current provision increased by US$841 million
  - recognition of goodwill arising from the preliminary purchase price adjustment totalling US$7,126 million.

Impact relative to Woodside standalone

- relative to Woodside standalone, the Merged Group's:
  - proforma net asset backing per share increases from US$14.67 to US$19.51
  - pro forma net tangible asset backing per share increases from US$14.67 to US$15.71
  - the proforma current ratio falls from 1.6 times to 1.2 times
  - pro forma gearing inclusive of lease liabilities is 7.8%, compared to 21.9% prior to the Proposed Transaction
  - pro forma gearing (excluding lease liabilities) falls from 15.2% prior to the Proposed Transaction to 3.8%
  - EBITDA / net borrowings (excluding lease liabilities) increases from 1.7 to 6.5 times.

A more detailed discussion of the assumptions and adjustments incorporated in the pro forma financial statements of the Merged Group is set out in section 7 of the Explanatory Memorandum.

10.2.2 Pro forma financial performance

Set out below is a summary of the pro forma financial performance of the Merged Group prepared by Woodside for the 12 months ended 31 December 2021, along with various metrics calculated by KPMG Corporate Finance based on the pro forma financial performance.

Table 28: The Merged Group pro forma financial performance for the 12 months ended 31 December 2021

	12 months ended 31 December 2021			
Pro forma unaudited statement of profit or loss – US$ million	**Woodside**	**BHP Petroleum**	**Pro Forma Adjustments**	**Merged Group pro forma**
Operating revenue	6,962	5,505	-	12,467
Cost of sales	(3,845)	-	(2,548)	(6,393)
Gross profit	**3,117**	**5,505**	**(2,548)**	**6,074**
Other income	139	282	(104)	317
Other expenses	(811)	(3,744)	2,348	(2,207)
Impairment losses	(10)	-	(276)	(286)
Impairment reversals	1,058	-	-	1,058
Loss from equity accounted investments	-	(2)	-	(2)
EBIT[1]	**3,493**	**2,041**	**(580)**	**4,954**
Finance income	27	23	-	50
Finance costs	(230)	(311)	-	(541)
Profit/(loss) before tax	**3,290**	**1,753**	**(580)**	**4,463**
Petroleum resource rent tax (expense)/benefit	(297)	-	-	(297)
Income tax benefit/(expense)	(957)	(1,115)	166	(1,906)
Royalty—related taxation (net of income tax benefit)	-	(29)	-	(29)
Profit/(loss) after tax	**2,036**	**609**	**(414)**	**2,231**

Pro forma unaudited statement of profit or loss – US$ million	12 months ended 31 December 2021			
	Woodside	BHP Petroleum	Pro Forma Adjustments	Merged Group pro forma
Profit/(loss) attributable to:				
Equity holders of the parent	1,983	609	(414)	2,178
Non-controlling interest	53	-	-	53
Profit/(loss) for the period	**2,036**	**609**	**(414)**	**2,231**
Statistics				
Weighted average ordinary shares on issue (million)	962.6			1,877.4
Basic earnings per share ($)[2]	2.06			1.16
Interest cover (times)[3]	18.0	14.0		16.9

Source: Woodside management and KPMG Corporate Finance analysis

Notes:

1. *EBIT is earnings before interest, tax and equity accounted investments*
2. *Basic earnings per share is calculated by dividing net profit attributable to the members of the parent entity by the weighted average number of ordinary shares outstanding during the year*
3. *Interest cover is calculated as underlying EBITDA divided by finance costs. Underlying EBITDA for Woodside has been calculated as profit before tax add net finance costs, depreciation and amortisation and net impairment costs. Underlying EBITDA for BHP Petroleum has been calculated as profit before tax add net finance costs, depreciation and amortization and one-off costs primarily comprised of net impairment costs, onerous lease costs and exploration leases. Underlying EBITDA for the Merged Group has been calculated as the underlying EBITDA for Woodside added to that of BHP Petroleum add pro forma adjustments to; fair value of embedded derivatives and decrease in depreciation and amortisation, less pro forma adjustment to gain on sale of Scarborough interest*
4. *Profit and loss has not been adjusted for synergies expected to be achieved as a result of the Proposed Transaction*
5. *May not add exactly due to rounding.*

The Merged Group's pro-forma financial performance for the year ended 31 December 2021, includes:

- net adjustments to costs of sales and other expenses of (US$2,482) million to reflect the reclassification of other expenses to cost of sales relating to changes in inventory, freight and transportation, government royalties, depreciation and amortisation recognition and the reclassification of impairment losses of (US$276) million
- adjustments to cost of sales of (US$156) million to reflect:
  - the transition of BHP Petroleum's accounting policy to Woodside's accounting policy in relation to reserves bases being used in the respective units of production calculations, resulting in a decrease of US$316 million in depreciation, depletion and amortisation expense
  - a net adjustment of US$472 million relating to underlift and overlift impacts on receivables and payables, respectively, between December 2020 and December 2021.
- an allowance for estimated non-recurring transaction costs of approximately US$410 million related to the Proposed Transaction

- the reversal of BHP Petroleum's gain of (US$104) million attributable to its previous divestment of Scarborough to Woodside
- adjustment to cost of sales of (US$90) million reflecting a fair value adjustment in respect of embedded derivatives recorded by BHP Petroleum
- net adjustments to income tax benefit of US$166 million to reflect the tax effect of the transaction accounting adjustments and other accounting policy differences.

Impact relative to Woodside standalone

Relative to Woodside standalone:

- shares on issue in the Merged Group increase from 969.6 million to 1,871.2 million
- the Merged Group's pro forma EBITDA interest cover decreases from 18.0 times to 16.9 times. However, we note that as the asset portfolio of BHP Petroleum is being acquired on a cash free debt free basis, the finance costs recorded in relation to BHP Petroleum will no longer be incurred. In the event these charges are excluded, EBITDA interest cover increases to 39.7 times
- the Merged Group's prima facie pro forma earnings per share (**EPS**) decreases to US$1.16 per share from US$2.06 per share. In the event that finance costs in relation to BHP Petroleum are excluded, the pro forma EPS increases to US$1.28 per share.

10.3 Relative contributions

The relative contributions of each of Woodside and BHP Petroleum to the Merged Group under various other parameters are set out in the table below.

Table 29: Relative contributions to the Merged Group as at 31 December 2021

Relative Contributions	Woodside	BHP Petroleum	Contribution % Woodside	Contribution % BHP Petroleum
Reserves and Resources as at 31 December 2021[1,2]				
2P (liquids[4]) (MMbbl)	247.0	560.4	30.6%	69.4%
2P (gas) (MMboe)[3]	2,157.4	916.7	70.2%	29.8%
Total 2P (MMboe)	**2,404.3**	**1,477.1**	**61.9%**	**38.1%**
2C (liquids[4]) (MMbbl)	590.0	558.8	51.4%	48.6%
2C (gas) (MMboe)	3,961.0	823.8	82.8%	17.2%
Total 2C (MMboe)[5]	**4,551.0**	**1,382.6**	**76.7%**	**23.3%**
Production (MMboe)				
CY21 (actual)[6]	91.1	102.3	47.1%	52.9%
CY22 (projected)[7]	93.2	114.5	44.9%	55.1%
Earnings ($ millions)				
CY21 Underlying EBITDA[8,9]	4,135	4,349	48.7%	51.3%
CY21 Underlying NPAT[10,11]	1,620	885	64.7%	35.3%

Source: GaffneyCline's ITSR, Woodside 2021 Annual Report, BHP Petroleum 2HY21, FY21 and 2HY20 financial reports and KPMG Corporate Finance analysis

Notes:

1. *Reserves and Resources included in the table above may differ from those reported by Woodside and BHP Petroleum (including those reported in Tables 7, 8, 9, 22 and 23 above) as the above figures reflect GaffneyCline's assessment of Reserves and Resources as set out in the ITSR*
2. *Gas Reserves in the table above are inclusive of volumes consumed in operations (CIO or fuel) per GaffneyCline's ITSR*
3. *BHP Petroleum's net gas Reserves and Resources have been converted from Bcf to MMBoe by dividing by a conversion factor of 6.0 for all assets except the NWS Project, NWS Oil and Scarborough (including Thebe and Jupiter), where a conversion factor of 5.8 has been adopted (consistent with the factor adopted by KPMG Corporate Finance for the Woodside interest in those projects)*
4. *Liquids reserves and resources includes oil, condensate, natural gas liquids and LPG*
5. *2C Contingent Resources in this table are BHP Petroleum's working interest fraction of the gross field resources*
6. *Production from Algeria and Neptune is excluded from BHP Petroleum production*
7. *Projected CY22 production has been based on the aggregate of the production profiles prepared by GaffneyCline for each of the individual assets*
8. *Underlying EBITDA for Woodside has been calculated as profit before tax add net finance costs, depreciation and amortisation and net impairment costs*
9. *Underlying EBITDA for BHP Petroleum has been calculated as profit before tax add net finance costs, depreciation and amortization and one-off costs primarily comprised of net impairment costs, onerous lease costs and exploration leases*
10. *Underlying NPAT for Woodside excludes amounts relating to cost write-offs, impairment losses, impairment reversals and prior period impacts*
11. *Underlying NPAT for BHP Petroleum has been calculated as profit before tax add net finance costs, net impairment costs, office onerous lease costs, exploration lease costs and other costs.*

In considering the above contribution analysis, we would caution Woodside Shareholders that it is required to be treated with a degree of caution, given that:

- reserves, resources and production contributions do not take into consideration:
  - different levels of profitability between products, field locations and jurisdictions
  - stages of development, forecast capital expenditure and timing of future production profiles
  - different quantum and profiles of capital and abandonment expenditures.
- point in time earnings figures may not adequately capture various factors including:
  - stage of development and forecast production profiles as well as forecast capital and abandonment expenditure
  - the volatility of hydrocarbon commodity prices and the varied impact of this to each product.

10.4 Dividend policy

Woodside has indicated that the Merged Group's dividend policy is expected to be unchanged compared to the Woodside current policy, which aims to maintain a minimum dividend of 50% of NPAT excluding non-recurring items (expressed in USD), with a target payout ratio of between 50% and 80%. In addition, Woodside has indicated that in periods of excess cash generation, additional opportunities to provide returns to the shareholders of the Merged Group through special dividends and share buy-backs will be considered.

10.5 Potential cost savings and operational synergies

Prior to the announcement of the Proposed Transaction, both Woodside and BHP Petroleum had separately commenced programs to improve operational efficiency in their businesses. As part of the transaction process, Woodside undertook a review of the costs of the Merged Group, with the support of an external advisor, and identified a range of synergy opportunities which following implementation, will build on the programs underway to further consolidate operations and execute efficient practices across the Merged Group.

Woodside's review established the Merged Group's spend of approximately US$10,000 million as a baseline[94] and focussed initially on spend in operations and corporate (internal spend of approximately US$1,800 million and external spend of US$1,500 million) and exploration, before also considering capital expenditure and D&R. A structured evaluation of synergy opportunities yielded an initial target of over US$400 million in annual pre-tax cost savings, which was assessed as being reasonable after being benchmarked against the synergy expectations set in comparable transactions within the industry.

The identified synergy opportunities include:

- the reduction in corporate costs across a range of functions as a result of the rationalisation of applications, licenses and subscriptions, and the optimisation of organisational design for the merged business
- the reduction in operating and maintenance costs through the sharing of systems and digital solutions across all assets
- improved procurement outcomes by leveraging long-term supplier relationships and improving purchasing power through economies of scale
- the reduction in marketing and trading costs with the Merged Group's increased scale helping to improve shipping utilisation
- improved asset productivity of the Merged Group's upstream assets as a result of sharing experience and technology solutions to improve uptime and lower unit-production costs
- the reduction in exploration expenditure in the combined exploration portfolio by focusing on high-quality prospects that have a clear path to commercialisation
- the reduction in capital spend across the Merged Group's portfolio of development projects by consolidating project teams and leveraging relationships with key contractors to secure better service and pricing.

The identified synergy opportunities will be realised progressively, with full implementation expected by early 2024. As the integration process is undertaken, Woodside expects to identify further synergies and value creation opportunities over and above the identified synergy opportunities.

The achievement of synergies in any business combination is uncertain and not without risk in terms of the quantum of the benefit achieved and the timing realised. However, of the US$400 million in identified

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[94] Year commencing 1 July 2021

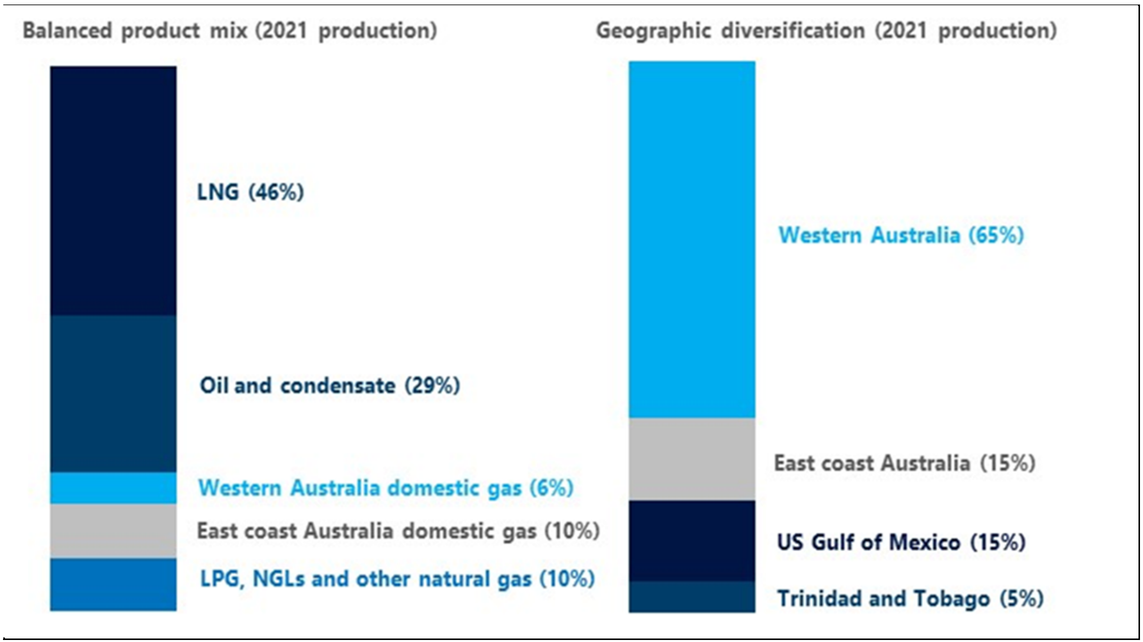
synergy opportunities targeted, in excess of US$250 million relates to operating and corporate cost savings, which are typically easier to identify and realise, with the remaining US$150 million relating to exploration expenditure.

Woodside estimates that the implementation of the identified synergy opportunities would require one-off costs in the order of US$500 million to US$600 million to be incurred in the first two years following completion of the Proposed Transaction.

10.6 Geographical and production diversification

Figure 13 below sets out Woodside estimate[95] of geographic and production mix of the Merged Group's combined producing asset portfolio, based on Woodside's and BHP Petroleum's production for the 12 months ended 31 December 2021.

Figure 13 – Geographic and production mix of the Merged Group

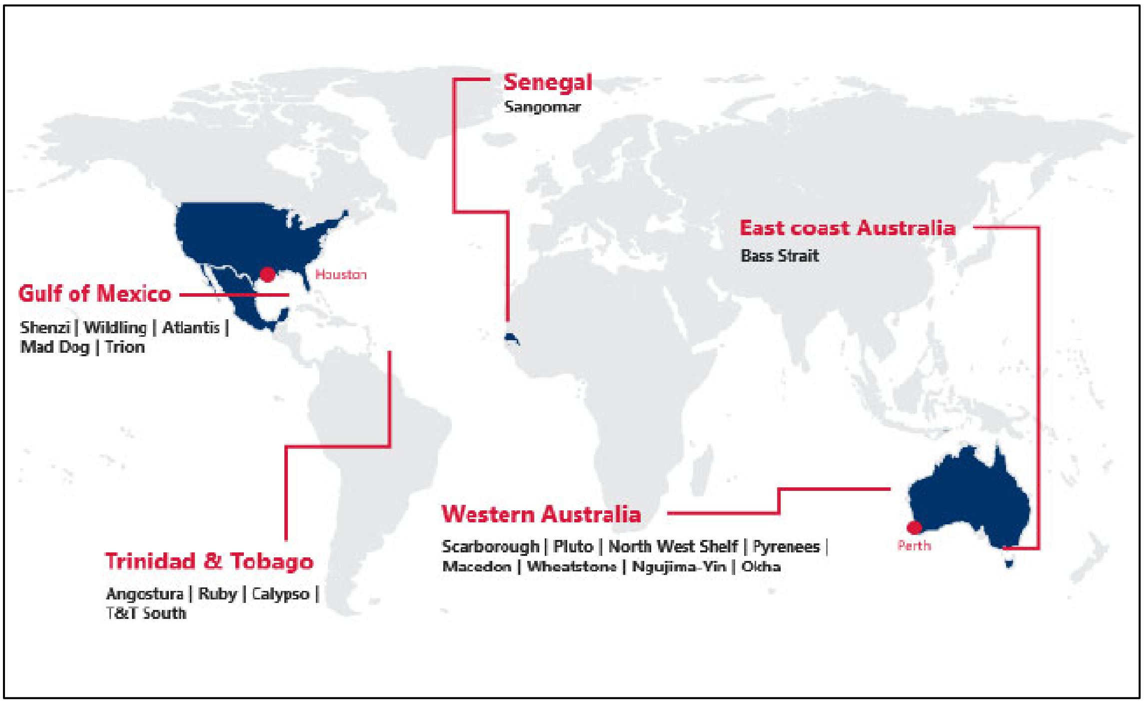


Source: Explanatory Memorandum

Figure 14 sets out the geographical combined location of the Merged Group's major asset portfolio.

[95] Woodside and BHP Petroleum Merger Investor Presentation, 17 August 2021. Combined Woodside and BHP for the 12 months to 30 June 2021, not giving effect to any pro forma adjustments. Other natural gas volumes includes T&T and US GOM. Other includes Algeria production of 3 MMboe. Neptune production volume is included in GOM but divested in May 2021.

Figure 14 – International locations of Merged Group's major assets



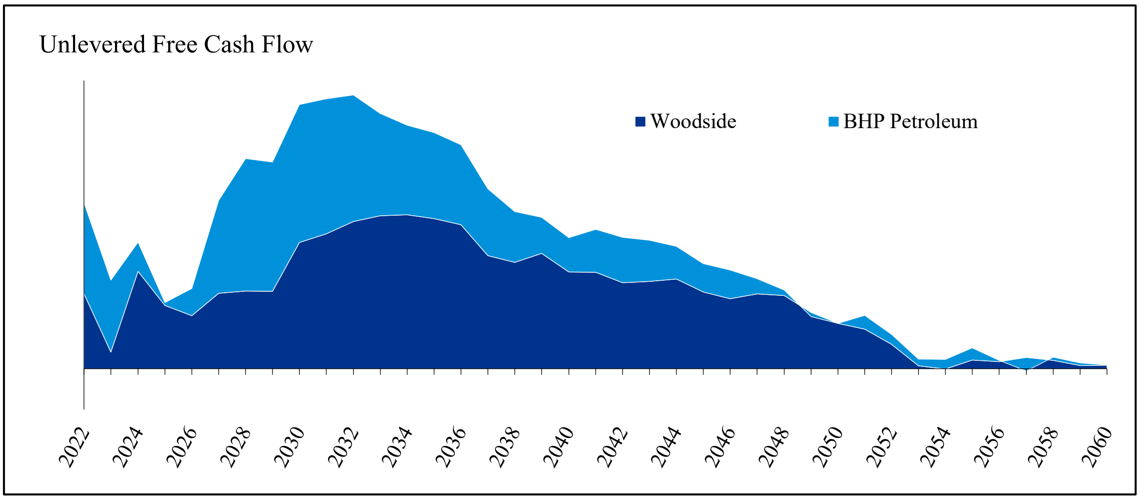
Source: Explanatory Memorandum

As indicated by the above charts, 100% of Woodside's and BHP Petroleum's FY21 production was from conventional oil and gas projects, with the significant majority of projects located in OECD countries, which is expected to remain the case for the foreseeable future.

10.7 Net free cash flow

As illustrated in the figure below, based our forecast cash flows developed in conjunction with GaffneyCline, the combination of Woodside's and BHP Petroleum's assets is expected to significantly improve the level of net free cash flows available to the Merged Group, crucially, in the initial years when Woodside is looking to bring Scarborough/Pluto Train 2 and Sangomar into production, whilst also continuing to advance other growth opportunities, including its New Energy ambitions.

Figure 15 – Profile of net free cash flows over the period to 2060



Source: KPMG Corporate Finance analysis
Note 1: Net free cash flows are based on the production; operational, capital and D&R expenditure profiles assessed by GaffneyCline and the macroeconomic assumptions determined by KPMG Corporate Finance but are before exploration expenditure and the realisation of any operational and other cost savings and synergies.

10.8 Potential market re-rating and increase in share trading

Woodside had approximately 984.0 million ordinary shares on issue as at 24 March 2022. Immediately following completion of the Proposed Transaction, the number of shares on issue in the Merged Group will total approximately 1,898.7 million, as summarised in the table below.

Table 30: Woodside Shareholders' interest in the Merged Group

	millions	Relevant interest
Current shares on issue – Woodside shareholders	984.0	52%
New shares to be issued – BHP shareholders	914.8	48%
Shares in the Merged Group	**1,898.7**	**100%**

Source: Explanatory Memorandum, ASX Announcements and KPMG Corporate Finance Analysis
Note 1: Figures may not add exactly due to rounding.

Based on the closing price for a Woodside share on 24 March 2022 of A$33.20 and the number of shares expected to be on issue in the Merged Group would have a notional market capitalisation in the order of A$63,038 million, which compares to Woodside's market capitalisation of A$32,668 million as at that date.

The significantly larger market capitalisation of the Merged Group, coupled with a larger shareholder base and secondary listings on the NYSE and LSE could result in an increased daily trading volumes compared to Woodside as a standalone entity and an increased level of investor interest.

10.9 Merger and integration risks

Woodside has identified various risks associated with the business and operations of the Merged Group, which are discussed at section 8 of the Explanatory Memorandum. We recommend Woodside Shareholders consider these risks in deciding whether or not to support the Proposed Transaction.

10.10 Directors and management

Following completion of the Proposed Transaction it is the current intention to invite a current director of BHP to join the Board of Directors of Woodside. Accordingly, Woodside Directors are expected to hold the significant majority of Board positions following completion of the Proposed Transaction. Further details in relation to the qualifications and experience of the Directors of Woodside are set out in section 6 of the Explanatory Memorandum.

10.11 Transaction costs

Woodside will incur transaction costs in relation to the Proposed Transaction estimated at US$410 million pre-tax (excluding integration costs). The non-recurring transaction costs expected to be incurred by Woodside, include stamp duty, advisory, legal, regulatory, accounting, valuation and other fees that will not be capitalised as part of the Proposed Transaction.

Woodside estimates that it will incur transaction and integration costs in connection with the Proposed Transaction regardless of whether or not the Proposed Transaction is completed, which are estimated at US$100 million pre-tax.

11 Valuation Assessment

11.1 Valuation methodology

The appropriate test in assessing whether the Proposed Transaction is fair to Woodside Shareholders is whether the value of a share in the Merged Group is greater than or equal to the value of a Woodside share prior to the Proposed Transaction.

As the value of the Merged Group will be driven by the value of the combined businesses of Woodside and BHP Petroleum, it is necessary to assess the value of both Woodside and BHP Petroleum prior to completion of the Proposed Transaction as a starting point.

The principal assets of each of Woodside and BHP Petroleum comprise interests in oil, natural gas and/or natural gas liquids assets at various stages of development, from early-stage exploration through to project development and operational assets. Such assets have lives and future profitability that depend upon factors that are inherently unpredictable.

In our experience, the most appropriate method for determining the value of companies similar to Woodside and BHP Petroleum is on the basis of the value of the sum of the parts of the underlying net assets, with their principal development and operational assets being valued using the discounted cash flow (**DCF**) approach.

The DCF methodology has a strong theoretical basis, valuing a business on the net present value (**NPV**) of its future cash flows. It requires an analysis of future cash flows, the capital structure adopted and the costs of the capital deployed. This technique is particularly appropriate for companies with a limited asset life, which is often the case with companies dependent upon depleting oil and gas reserves. In addition, a sensitivity analysis for variations in key assumptions adopted should be performed.

Those production and development assets of Woodside and BHP Petroleum where DCF has been adopted as the primary valuation methodology are set out in the table below.

Table 31: Woodside/BHP Petroleum assets valued by DCF

Woodside		BHP Petroleum	
Project	**Project interest**	**Project**	**Project interest**
NWS Project[1]	16.7%	NWS Project[1]	16.7%
Pluto LNG	90%	NWS Oil	16.7%
Wheatstone LNG[2]	65% U / 13% D	Bass Strait	50% GBJV / 32.5% KUJV
Australia Oil	60%	Macedon	71.4%
NWS Oil	33.3%	Pyrenees[3]	71.43% / 39.999%
Scarborough Upstream	73.5%	Scarborough	26.5%
Pluto Train 2	51%	Australian Non-Producing	71.2%
Browse	30.6%	Atlantis	44%
Sangomar	82%	Mad Dog	23.9%
		Shenzi[4]	72%
		GOM ORRI	100%
		Angostura	45%
		Ruby	68.5%
		Calypso	70%
		Trion	60%

Source: KPMG Corporate Finance analysis

Notes:

1. *NWS Project ownership interest shown. Woodside has separate production share interests*
2. *U = Upstream, D = Downstream*
3. *BHP Petroleum holds a 71.43% interest in the WA-42-L permit and a 39.999% interest in the WA-43-L permit*
4. *BHP Petroleum holds a 72% interest in the Shenzi and Shenzi North projects and a 100% interest in the Wildling Project*

ASIC Regulatory Guides envisage the use by an independent expert of specialists when valuing specific assets. To assist KPMG Corporate Finance in the valuation of Woodside's and BHP Petroleum's project interests, GaffneyCline was engaged by Woodside, and instructed by us, to prepare an ITSR in relation to a reasonable production scenario, including appropriate oil and/or gas production inventory, operational cost, sustaining and growth capital expenditure and abandonment expenditure profiles to be adopted by us in the preparation of forecast cash flows for Woodside's and BHP Petroleum's separate interests in their production and development assets as at 31 December 2021. In addition, GaffneyCline has assessed the value of Woodside's and BHP Petroleum's interests in other petroleum assets not captured in the DCF valuations. A copy of GaffneyCline's ITSR, which was prepared in accordance with the VALMIN Code, is attached to this report as Appendix 15.

The production and development assumptions recommended by GaffneyCline have been adopted in the cash flow projections prepared by us in assessing the values of Woodside's and BHP Petroleum's separate interests in their production and development assets. KPMG Corporate Finance was responsible for the determination of certain macroeconomic and other assumptions such as commodity prices, exchange rates, discount rates, inflation and taxation assumptions. GaffneyCline has also estimated a range of values within which it considers the value of each of the relevant interests in other petroleum assets to lie. The valuations ascribed by GaffneyCline to Woodside's and BHP Petroleum's interests in other petroleum assets as at 31 December 2021 have been adopted in our report.

Other assets and liabilities of Woodside and BHP Petroleum have been incorporated in our valuation based on book values as at 31 December 2021, as reasonable estimates of market value unless specifically noted otherwise.

In order to ensure a consistent approach in our assessment of the relative values, our valuations of each of Woodside, BHP Petroleum and the Merged Group has been undertaken on a 100% basis.

In assessing the value of a share in the Merged Group, we have also considered those synergies and cost savings expected to be available to Woodside in combining its existing portfolio of oil and gas assets with those held by BHP Petroleum.

However, given:

- there is no change of control of Woodside, either from a shareholder voting or Board perspective, as a result of completion of the Proposed Transaction
- Woodside Shareholders will continue to hold the same number of shares in Woodside both prior to and following completion of the Proposed Transaction[96]
- the primary purpose of undertaking the valuation is to determine whether the Proposed Transaction is fair to Woodside Shareholders, that is, whether the value of a share held by Woodside Shareholders in the Merged Group is greater than or equal to the value of a Woodside share held by Woodside Shareholders prior to the Proposed Transaction,

we have not incorporated any allowance for additional cost savings and/or synergies that might be available to an unrelated third-party purchaser of Woodside standalone or for the Merged Group itself at some future point in time after completion of the Proposed Transaction.

Whilst the Proposed Transaction has an Effective Date of 1 July 2021, KPMG Corporate Finance and GaffneyCline have adopted a valuation date of 31 December 2021 for each entity, reflecting that a balance sheet for both Woodside and BHP Petroleum is available as at that date and that the acquisition balance sheet of BHP Petroleum as at 31 December 2021 reflects the outcome of the 6 months trading between the Effective Date and 31 December 2021.

In order to cross-check the outcomes of our valuation assessments, we have compared the Reserve and Resource multiples implied by our range of values for Woodside and BHP Petroleum against comparable listed companies and transactions. Whilst as discussed later, these multiples are subject to a number of limitations, they do provide a useful secondary measure to assess the reasonableness of the valuation outcomes under our primary valuation methodology.

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[96] excluding the impact of new Woodside shares that might be issued to existing Woodside shareholders in their capacity as shareholders in BHP

11.2 Macroeconomic and other financial assumptions

Set out below is a summary of the macroeconomic assumptions adopted by us in the DCF analysis. In selecting our macroeconomic assumptions, we have adopted what we consider to be reasonable inputs that a purchaser of Woodside's and BHP Petroleum's long-term assets would adopt[97].

11.2.1 Denominations of cash flows

The NPV of the Woodside's and BHP Petroleum's interests in each project has been calculated in USD terms. Project inputs denominated in currencies other than USD have been converted to USD terms based on the inflation and foreign exchange rate assumptions set out below.

11.2.2 Inflation

Inflation rate assumptions adopted by us in the DCFs are set out in the table below.

Table 32: Summary of inflation assumptions

%	2022	2023	2024	2025	2026
Australia	3.2%	2.5%	2.5%	2.4%	2.4%
United States	5.2%	2.5%	2.2%	2.2%	2.2%
Canada	3.8%	2.2%	2.2%	2.1%	2.0%
Mexico	5.3%	3.8%	3.6%	3.5%	3.5%

Source: Capital IQ, brokers' notes, various economic commentators and KPMG Corporate Finance analysis

Inflation rates have been determined having regard to the forecasts of a range of brokers and economic commentators. Subsequent to 2026, the rate has been assumed to be constant at 2.5% per annum for Australia, 2.0% per annum for the United States, 2.0% per annum for Canada and 3.0% for Mexico.

11.2.3 Forecast currency exchange

Nominal foreign exchange rate assumptions adopted by us in the DCFs are set out in the table below.

Table 33: Summary of nominal foreign currency exchange assumptions

	2022	2023	2024	2025	2026
AUD:USD	0.74	0.75	0.75	0.75	0.76
CAD:USD	0.79	0.79	0.79	0.78	0.78
MXN:USD	0.048	0.046	0.044	0.042	0.041

Source: Capital IQ, brokers' notes, various economic commentators and KPMG Corporate Finance analysis

Exchange rates have been determined having regard to the forecasts of brokers and economic commentators and also the relevant forward curve, where available.

Subsequent to 2026, we have adopted exchange rates such that the nominal exchange rate is assumed to be driven by the long-term inflation differential between the relevant county and the United States, such that the relative purchasing power parity between both currencies is maintained. That is, the exchange rates stay constant in real terms.

[97] Based on information available as at 8 March 2022

11.2.4 Commodity prices

Contracted revenues

A proportion of Woodside's and BHP Petroleum's revenue streams are underpinned by medium to long term supply agreements. The terms of these contracts are commercial in confidence and are not disclosed to the market. The volumes and sales prices set out in these contracts have been incorporated in KPMG Corporate Finance's valuation models. Management has advised that as these contracts roll-off, it has been assumed for internal business planning purposes that sales volumes will be rebased having regard to prevailing commodity prices at the relevant time. We have adopted the same approach for the purpose of our valuations.

Brent Oil

Forecast Brent oil prices adopted by us over the period to 2026 are set out in the table below.

Table 34: Summary of Brent oil assumptions

US$/bbl	2022	2023	2024	2025	2026
Brent oil price	100	90	80	75	70

Source: Capital IQ, brokers' notes, various economic commentators and KPMG Corporate Finance analysis

In determining our forecast Brent oil price assumptions, we have had regard to Brent oil forecast prices published by various economic commentators and broking houses as well as the prevailing Intercontinental Exchange (**ICE**) Brent futures curve.

Subsequent to 2026, we have assumed that Brent oil prices will increase by the long-term inflation rate for the United States. In effect, the Brent oil price is assumed to remain constant in real USD terms post 2026.

LNG

Forecast uncontracted LNG price assumptions adopted by us over the period to 2026 are set out in the table below.

Table 35: Summary LNG price assumptions

US$/MMbtu	2022	2023	2024	2025	2026
Uncontracted spot price	21.0	17.1	13.6	14.3	11.9

Source: Bloomberg, Consensus Economics and KPMG Corporate Finance Analysis

In determining our forecast uncontracted LNG price assumptions, we have had regard to:

- the historical relationship between the Japanese Korea Marker (**JKM**) benchmark Asian spot price for LNG and Brent oil prices, which, as set out in Appendix 3, has until recently typically traded at a discount to the Brent oil price on an energy equivalent basis
- the year-to-year price slope implied by recent forecast Brent oil prices and forecast JKM benchmark Asian spot prices published by various economic commentators and broking houses.

After 2026, we have adopted a constant price slope compared to our adopted Brent oil prices of 12.5%.

Domestic gas – Uncontracted East Coast spot prices

As discussed in Appendix 3, spot gas prices on the east coast of Australia have exhibited a significant level of volatility in recent years. Having largely traded in the range of A$8 - A$10 per GJ over the period between mid-2016 through until late 2019, the impact of Covid-19 on economic activity, coupled with a surplus supply of LNG in 2020, resulted in a significant and rapid fall in East Coast gas prices to A$4 - A$5 per GJ by mid-2020. Since then, tightening market conditions for LNG coupled with various temporary supply issues have resulted in a strong increase in East Coast gas prices, with prices trading above the A$13 per GJ in late 2021. For the purpose of our valuations, we have assumed, consistent with our forecast trend in LNG prices and as a result the implied net back price for LNG producers, that East Coast spot gas prices will retreat to long term trend of A$9 per GJ by 2025.

Subsequent to 2025, we have assumed that East Coast spot gas prices will increase by the long-term inflation rate for Australia. In effect, the East Coast spot gas price is assumed to remain constant in real AUD terms post 2025.

Domestic gas – Uncontracted West Coast spot prices

Reflecting the impact of Western Australia's gas reservation policy and recent Western Australian domgas prices, we have assumed that West Coast spot gas prices will continue to trade around current levels of A$5 per GJ, being an increase over recent historical levels but below prices on the East Coast.

Subsequent to 2025, we have assumed that West Coast spot gas prices will increase by the long-term inflation rate for Australia. In effect, the West Coast spot gas price is assumed to remain constant in real AUD terms post 2025.

Henry Hub

Forecast Henry Hub prices adopted by us over the period to 2026 are set out in the table below.

Table 36: Summary of Henry Hub price assumptions

US$/MMbtu	2022	2023	2024	2025	2026
Henry Hub price	4.6	3.7	3.3	3.3	3.3

Source: Capital IQ, brokers' notes, various economic commentators and KPMG Corporate Finance analysis

In determining our forecast Henry Hub price assumptions, we have had regard to Henry Hub forecast prices published by various economic commentators and broking houses as well as futures curve.

Subsequent to 2026, we have assumed that Henry Hub prices will increase by the long-term inflation rate for the United States. In effect, the Henry Hub price is assumed to remain constant in real USD terms post 2026.

WTI

Forecast WTI prices adopted by us over the period to 2026 are set out in the table below.

Table 37: Summary of WTI price assumptions

US$/bbl	2022	2023	2024	2025	2026
WTI price	96	86	76	72	67

Source: Capital IQ, brokers' notes, various economic commentators and KPMG Corporate Finance analysis

In determining our forecast WTI price assumptions, we have had regard to WTI forecast prices published by various economic commentators and broking houses as well as futures curve.

Subsequent to 2026, we have assumed that WTI prices will increase by the long-term inflation rate for the United States. In effect, the WTI price is assumed to remain constant in real USD terms post 2026.

11.2.5 Carbon costs

We have included an allowance for cash outflows in respect of carbon costs where abatement is expected to be required under current government regulations, based on forecast operations. Further details in relation to the assessment of carbon costs are set out in section 3 of the ITSR.

11.2.6 Discount rates

Where DCF has been employed as the primary valuation approach, projected ungeared, post tax cash flows for each asset have been discounted using the USD nominal ungeared, post tax weighted average cost of capital (**WACC**) estimates which we consider as a reasonable estimation of the rate of return required by investors in relevant segments of the oil and gas assets sector. Further details in relation to our assessment of appropriate discount rates to apply to each asset are set out in Appendix 5.

Where appropriate, this range of discount rates has then been adjusted to respect the specific characteristics and risks of each asset not captured in the cash flows themselves, including for such matters as project location, stage of development and nature and risk of the underlying cash flows i.e. sanctioned versus unsanctioned, upstream versus downstream, infrastructure related revenues versus end market sale revenues, etc. Individual project discount rates adopted are summarised in the table below.

Table 38: Summary of USD post-tax nominal WACCs

Woodside		BHP Petroleum	
Project	**WACC %**	**Project**	**WACC %**
NWS	7.5% - 8.5%	NWS	7.5% - 8.5%
NWS Growth[1]	8.0% - 9.0%	NWS Growth[1]	8.0% - 9.0%
Pluto LNG	8.0% - 9.0%	NWS Oil	7.5% - 8.5%
Wheatstone LNG	7.5% - 8.5%	Scarborough	8.5% - 9.5%
Australia Oil	7.5% - 8.5%	Bass Strait	8.5% - 9.5%
Scarborough	8.5% - 9.5%	Macedon	8.0% - 9.0%
Pluto Train 2	7.0% - 8.0%	Pyrenees	9.0% - 10.0%
Browse	10.0% - 11.0%	Other Australian (D&R only)	1.5% - 2.0%
Sangomar	13.5% - 14.5%	Atlantis	9.0% - 10.0%
Stybarrow (D&R only)	1.5%	Mad Dog	9.0% - 10.0%
Balnaves (D&R only)	1.5%	Shenzi	9.0% - 10.0%
		GOM ORRI	4.5% - 5.5%
		Trion	10.0% - 11.0%
		Angostura & Ruby	9.0% - 10.0%
		Calypso	10.5% - 11.5%

Source: KPMG Corporate Finance analysis

11.2.7 Taxation

Key tax and royalty assumptions adopted by us include:

- corporate income tax rates of:
  - Australia - 30%
  - Mexico – 30%
  - Senegal – 33%
  - Trinidad and Tobago – 30%
  - United States GOM – 21%
- utilisation of the accumulated tax losses as at 31 December 2021 where applicable
- state and private royalty charges calculated at the applicable rates after adjustments for allowable deductions
- a PRRT rate of 40%
- PSC arrangements where applicable.

Other operational and specific assumptions adopted by us in the DCF models for Woodside, BHP Petroleum and the Merged Group assets are set out in the valuation section for each entity below.

11.3 Valuation of Woodside

We have assessed the value of 100% of Woodside to be in the range of US$16,978 million to US$19,424 million, which equates to between A$22,719 million to A$25,992 million[98], or between A$23.09 and A$26.42 per current diluted Woodside share.

The market value of Woodside was determined after aggregating the estimated market value of Woodside's interests in its oil and gas assets, adding the assessed value of other assets and, if appropriate, deducting any external borrowings and non-trading liabilities.

As the Proposed Transaction does not involve a change of control, the principal purpose of our valuation is to compare the value of a Woodside share held by Woodside Shareholders prior to the Proposed Transaction against the value of a share in the Merged Group held by Woodside Shareholders following completion to the Proposed Transaction. As such, our range of market values for Woodside does not include any adjustment for cost savings or potential operational synergies to a purchaser of Woodside as these are only available to Woodside Shareholders in the event of an offer to acquire Woodside itself, which is not the case in the current circumstances.

[98] Based on an USD:AUD exchange rate of approximately 0.747.

Our range of assessed values reflects that a number of Woodside's assets are yet to be developed, in particular, Scarborough, Pluto Train 2, Sangomar and Browse, and therefore incorporates a greater degree of subjectivity than projects with established and well-known operating profiles.

Table 39: Summary of Woodside assessed values

	Assessed Values	
All figures in US$ million (unless otherwise stated)	**Low**	**High**
Market values of Woodside's interests in petroleum assets		
NWS Project (incl. expansion projects)	2,673	2,771
Pluto LNG (incl. expansion projects)	11,537	12,050
Pluto Train 2	1,678	2,078
Wheatstone LNG	3,013	3,139
Australia Oil (incl. Okha)	852	859
Scarborough	1,175	1,640
Browse	224	571
Sangomar	1,824	2,033
Greater Sunrise & Thebe	256	486
Stybarrow	(88)	(88)
Balnaves	(43)	(43)
Surplus exploration petroleum interests	78	118
Total Petroleum Assets	**23,180**	**25,615**
Less: Net (debt) / cash	(3,101)	(3,101)
Less: Net financial liabilities and other assets	(171)	(171)
Less: Put option for Scarborough (payable to BHP)	(593)	(419)
Less: Regret costs	(70)	(70)
Less: NPV of NWC movements	(687)	(703)
Less: NPV of future corporate overheads	(1,581)	(1,727)
Total equity value	**16,978**	**19,424**
Number of ordinary shares[2,3] (millions)	984.0	984.0
Value per share - US$	**17.25**	**19.74**
Value per share - A$[4]	**23.09**	**26.42**

Source: GaffneyCline's ITSR and KPMG Corporate Finance analysis
Notes:
1. *May not add due to rounding*
2. *No adjustment has been made for the 7.5 million shares reserved for executives and employees under share plans as allowance for associated expenses has been included in forecast corporate overheads and project costs. We note Woodside has advised it typically purchases shares on market to meet obligations under the share plans rather than issue new Woodside shares*
3. *Current ordinary shares on issue reflecting the dividend reinvestment plan shares issued in March 2022*
4. *Based on an exchange rate of approximately AUD:USD 0.747.*

An overview of the key operating parameters adopted by us in relation to individual assets are set out below.

11.3.1 Valuation of NWS Project[99]

We have assessed the value of Woodside's interest in the projected ungeared, post tax cash flows from the NWS Project to be in the range of US$2,673 million to US$2,771 million. Our valuation takes into account Woodside's participation interest in the existing NWS oil and gas fields and the KGP, along with tariff revenue from processing 3rd party gas and gas supplied via the KGP-Pluto Interconnector currently being constructed. The valuation also includes an allowance for the potential upside of Woodside's intention to process gas from the currently unsanctioned Browse project through the KGP.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Due to issues of commercial sensitivity and the commercial-in-confidence nature of various trading arrangements we have been requested by Woodside not to disclose details in relation to:

- Contracted and uncontracted revenues or profiles
- D&R costs.

Aggregate annual production, operating costs and capital expenditure (Woodside interest) are summarised at Appendix 4.

Table 40: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
LNG	MMboe	18	17	16	11	10	54	127
Domgas	MMboe	1	1	1	4	3	8	16
Condensate	MMbbl	3	3	3	2	2	9	21
LPG	MMboe	0.4	0.3	0.3	0.3	0.3	2	3
Total Production	**MMboe**	**22**	**21**	**20**	**17**	**15**	**72**	**167**
Operating costs	**US$m**	**169**	**174**	**173**	**141**	**145**	**4,251**	**5,054**
Capital expenditure	**US$m**	**128**	**90**	**100**	**126**	**157**	**2,307**	**2,908**
Operating costs	US$/boe	8	8	9	8	10	59	30
Capital expenditure	US$/boe	6	4	5	7	10	32	17

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not add due to rounding.*

LNG is by far the largest contributor to production revenues, comprising a mix of contracted volumes which progressively roll off over the period to 2032, and uncontracted volumes. LNG is produced over

[99] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

the period 2022 to 2036, with the rate of production declining steadily year-on-year as gas reserves deplete.

The next largest contributor to production revenue is condensate (21 MMbbl), which follows a similar pattern to LNG in terms of steady decline in year-on-year production volumes over the remaining life of the NWS fields.

Annual production of domgas ramps up over the period to 2025 before falling sharply over the next few years through to 2030, after which production volumes stabilise for the remaining project life, with a total of 16 MMboe produced over the life of the project.

The NWS Project is also forecast to receive infrastructure access and tariff revenues from the processing of Pluto gas at the KGP between 2022 and 2025 and 3rd party gas between 2022 and 2036.

In addition, we have included Woodside's interest in the net benefit from processing 2,462 MMboe of gas (100%) through the KGP from the currently unsanctioned Browse project over the period 2030 through to 2060. However, reflecting that this project is yet to take FID, and the final terms for any future transport and processing costs are yet to be agreed between the parties, we have, as discussed below, included an additional risking to the incremental net cash flows from this upside opportunity to reflect timing, development and commercial uncertainty.

The estimated obligation in relation to D&R totals US$819 million. Upstream and downstream D&R expenditure is incurred on an annual basis over the life of the NWS Project and continues through to 2046 (before the impact of processing Browse gas at the KGP, which results in an extension of the effective life of certain upstream infrastructure and at the KGP resulting, in turn, in a deferral of a portion of D&R to later years. Consistent with the treatment of Browse tariff revenues we have applied a risk adjustment to the benefit of this deferral).

Inclusion of the processing activities associated with the unsanctioned Browse project results in a modest uplift in our assessed NPV for the NWS Project of between US$25 million to US$57 million, largely reflecting the tolling of this revenue stream, that Browse is currently expected to be developed as a backfill to the NWS Project, with production not commencing until 2030 and our effective risking of this revenue stream as discussed below. The increase in operating cost and capital expenditure unit costs for the period beyond 2026 reflects the shift in operations after 2030 to be primarily tolling of third party gas.

In calculating our range of assessed values we have adopted a discount rate of 7.5% to 8.5% per annum in relation to the existing NSW Project (i.e. before the impact of Browse processing) taking into account:

- the established and vertically integrated nature of the NSW Project
- whilst the final realised price of exported LNG is still impacted by movements in the oil price, a portion of forecast export LNG revenues are underpinned by long term sales contracts
- a portion of NWS Project revenues is derived for processing gas on behalf of 3rd parties on a contracted "tolling" basis, eliminating end market risk from this revenue stream.

Conversely, whilst construction is well underway, the Pluto-KGP Interconnector is not yet complete. Accordingly, these is a small degree of residual timing risk inherent in the revenue stream assumed to be realised from the processing of Pluto gas and in the final costs to complete, noting however that this represents only a small portion of forecast revenues.

In relation to the incremental value added by the inclusion of cash flows from the processing of Browse gas, we note that, whilst once in place the nature of the tolling revenue stream removes a significant element of pricing and end market risk, there is no certainty at this time that the project will proceed and the final terms of any future processing arrangements have not been agreed between all required stakeholders. Accordingly, we have applied a higher range of discount rates of 8.0% to 9.0% per annum to the incremental net cashflows relating to the forecast operations associated with the processing of Browse gas.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the NWS Project based on a range of key assumptions, the outcome of which is set out in the table below.

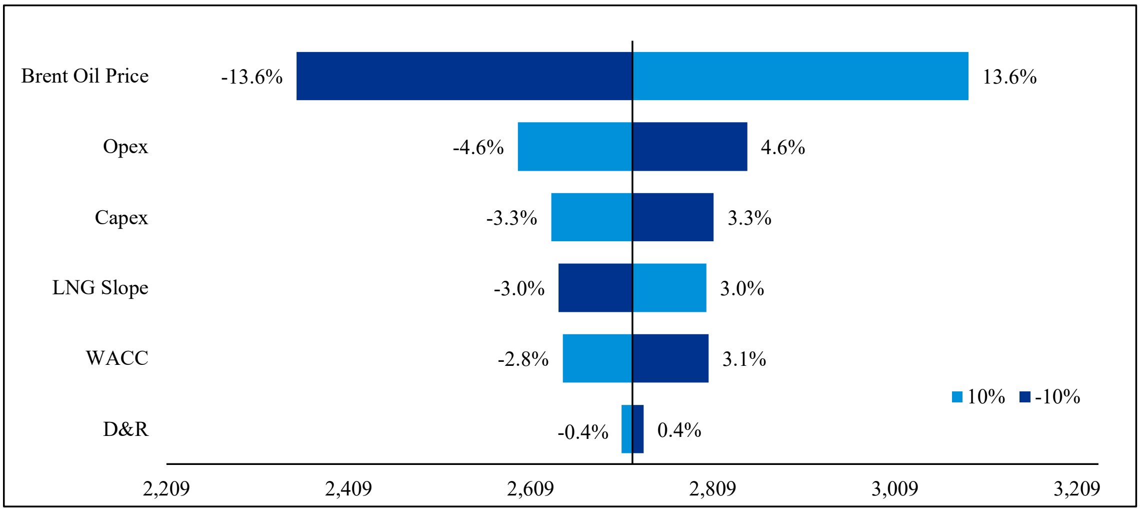
Table 41: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	2,352	2,536	2,721	2,905	3,089
Opex	2,847	2,784	2,721	2,658	2,595
Capex	2,810	2,765	2,721	2,676	2,631
LNG Slope	2,640	2,680	2,721	2,761	2,802
WACC	2,804	2,761	2,721	2,682	2,644
D&R	2,733	2,727	2,721	2,715	2,708

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the NWS Project is most sensitive to assumptions made in relation to future Brent oil prices given the interrelationship and various linked commodities, as set out in the tornado chart below, which is based on a 10% variance to each key input. This reflects that the sales price realised on LNG is a function of the brent oil price and the LNG Slope that has been assumed (for uncontracted volumes). We note the NWS Project's limited sensitivity to spot LNG slope reflects the level of contracted LNG arrangements held.

Figure 16: NWS Project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.2 Valuation of Pluto LNG[100]

We have assessed the value of Woodside's 90% interest in the projected ungeared, post tax cash flows from Pluto LNG to be in the range of US$11,537 million to US$12,050 million. Our valuation takes into account Woodside's participation interest in the existing Pluto fields, along with infrastructure and tariff revenues associated with processing gas from the recently sanctioned Scarborough project.

GaffneyCline generated production profiles and associated cost profiles as discussed in earlier sections for KPMG Corporate Finance valuation scenario inputs.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GCA's ITSR which is attached at Appendix 15.

Table 42: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
LNG	MMboe	45	45	49	44	30	84	297
Domgas	MMboe	2	1	2	2	1	5	14
Condensate	MMbbl	4	4	4	4	2	7	24
Total Production	**MMboe**	**50**	**50**	**55**	**49**	**34**	**97**	**335**
Operating costs	**US$m**	**464**	**522**	**511**	**499**	**375**	**8,484**	**10,854**
Capital expenditure	**US$m**	**203**	**250**	**210**	**181**	**206**	**1,584**	**2,633**

[100] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Operating costs	US$/boe	9	11	9	10	11	88	32
Capital expenditure	US$/boe	4	5	4	4	6	16	8

Source: GCA, KPMG Corporate Finance analysis
Notes:
1. _US$ amounts are stated in nominal terms_
2. _May not sum due to rounding_

Production of LNG comprises a mix of contracted volumes and uncontracted volumes.

Production of LNG is maintained in the range of approximately 44 MMboe to 49 MMboe over the period to 2025, before gradually stepping down over the remaining life of the project. Condensate and domgas are produced over the project life for total production of 24 MMbbl and 14 MMboe respectively.

Tariffs charged to Pluto Train 2 for processing Scarborough gas through Pluto Train 1 commence in 2026 and continue through to 2052, which consist of a mixture of infrastructure access and processing charges and the pass through of various other operating costs.

The estimated obligation in relation to upstream D&R associated with the Pluto gas fields is incurred over the period 2026 to 2034, and 2048 to 2060, totalling US$593 million. Downstream D&R commences in 2048 and continues through to 2060, totalling US$443 million.

Inclusion of the processing activities associated with the sanctioned Scarborough/Pluto Train 2 projects results in an uplift in our assessed NPV for Pluto LNG, largely reflecting the tolling nature this revenue stream, production is not forecast to commence until 2026 and our effective risking of this revenue stream as discussed below.

In calculating our range of assessed values we have adopted a discount rate of 8.0% to 9.0% per annum in respect of the foundation Pluto LNG project, reflecting the vertically integrated and established nature of the operations and that, whilst the final realised price of exported LNG is still linked to movements in the oil price, a significant portion of forecast export volumes are underpinned by long term sales contracts.

Conversely, a significant portion of Pluto LNG's revenue subsequent to 2026, comprises infrastructure access and gas processing charges and operating cost pass through to Pluto Train 2 for processing gas from Scarborough, which, although sanctioned and pre-production capital works have commenced, neither Pluto Train 2 or Scarborough are constructed and therefore the flow through cash flows to Pluto LNG carry an inherent level of increased risk.

Accordingly, we consider a risk adjustment to our range of base discount rates of 7.5% to 8.5% per annum is appropriate to apply to the incremental cash flows associated with processing gas from Scarborough, resulting in a final range of discount rates of 8.0% to 9.0% per annum.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for Pluto LNG based on a range of key assumptions, the outcome of which is set out in the table below.

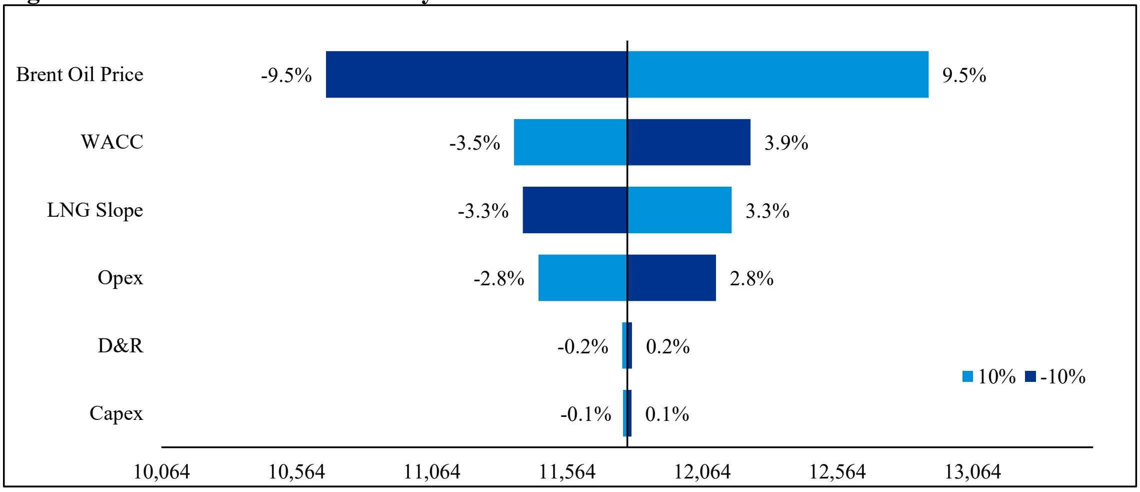
Table 43: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	10,673	11,230	11,787	12,344	12,902
WACC	12,243	12,010	11,787	11,574	11,369
LNG Slope	11,401	11,594	11,787	11,980	12,174
Opex	12,115	11,951	11,787	11,623	11,459
D&R	11,805	11,796	11,787	11,778	11,769
Capex	11,803	11,795	11,787	11,779	11,772

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of Pluto LNG is most sensitive to assumptions made in relation to future Brent oil prices given the interrelationship and various linked commodities, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 17: Pluto LNG DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.3 *Valuation of Wheatstone LNG*[101]

We have assessed the value of Woodside's interests in the projected ungeared, post tax cash flows from the Wheatstone LNG to be in the range of US$3,013 million to US$3,139 million. Our valuation takes into account Woodside's:

- 13% interest in the Wheatstone Project, which includes the offshore platform, the pipeline to shore and the onshore plant, but excludes the Wheatstone and Iago fields and subsea infrastructure
- 65% interest in the Julimar Development Project, which comprises the Woodside operated offshore Julimar and Brunello gas fields which tie back to the central processing platform.

[101] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (Woodside interest) are summarised at Appendix 4.

Table 44: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
LNG	MMboe	9	10	11	10	10	70	120
Domgas	MMboe	1	2	2	2	1	10	18
Condensate	MMbbl	1	1	2	1	1	10	17
Total Production	**MMboe**	**12**	**13**	**14**	**13**	**12**	**90**	**155**
Operating costs	**US$m**	**134**	**119**	**126**	**142**	**150**	**1,773**	**2,444**
Capital expenditure	**US$m**	**29**	**52**	**134**	**210**	**101**	**455**	**981**
Operating costs	US$/boe	11	9	9	11	12	20	16
Capital expenditure	US$/boe	2	4	10	16	8	5	6

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not add due to rounding.*

Forecast LNG volumes at the Julimar Development Project total approximately 120 MMboe, over the period 2022 to 2039.

Annual LNG production volumes are largely consistent over the period to 2030 before stepping down to 6 MMboe in 2031, which is then maintained until 2036 when the production goes into further annual decline through to the end of the project in 2039.

Condensate production totals approximately 17 MMbbl over the life of the project, with annual production ranging between 1.0 MMbbl and 1.5 MMbbl between 2022 and 2030, falling to between 0.6 MMbbl and 0.8 MMbbl over the period 2031 to 2036 before stepping down thereafter until cessation of production in 2037.

Julimar Development Project D&R commences in 2039 and ceases in 2045, totalling US$451 million. D&R incurred in respect of the Wheatstone Project topside infrastructure is incurred over the period 2038 to 2048, totalling US$89 million.

Whilst Woodside holds different participation interests in Wheatstone LNG and the Julimar Development Project, we consider that the nature of the combined operation is such that it should be considered more akin to a vertically integrated project. Accordingly, we have adopted a discount rate of 7.5% to 8.5% per annum in relation to the separate cash flows of Wheatstone LNG and the Julimar Development Project.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for Wheatstone LNG based on a range of key assumptions, the outcome of which is set out in the table below.

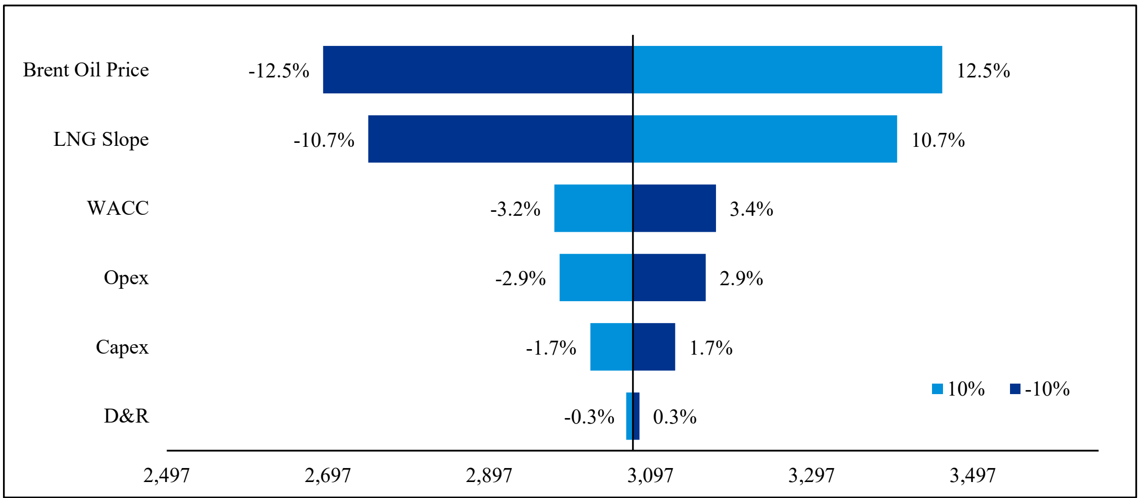
Table 45: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	2,691	2,883	3,075	3,267	3,459
LNG Slope	2,747	2,911	3,075	3,239	3,403
WACC	3,178	3,126	3,075	3,025	2,978
Opex	3,165	3,120	3,075	3,029	2,984
Capex	3,127	3,101	3,075	3,048	3,022
D&R	3,083	3,079	3,075	3,071	3,066

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of Wheatstone LNG is most sensitive to assumptions made in relation to future Brent oil prices given the interrelationship and various linked commodities, as set out in the tornado chart below, which is based on a 10% variance to each key input. We note the sensitivity to spot LNG slope reflects that revenue is predominantly comprised of LNG sales.

Figure 18: Wheatstone LNG DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.4 *Valuation of Australia Oil*

We have assessed the value of Woodside's 60% and 33% interest in the projected ungeared, post tax cash flows from the Ngujima-Yin FPSO and the Okha FPSO respectively to be in the range of US$852 million to US$859 million.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (Woodside interest) are summarised at Appendix 4.

Table 46: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil	MMbbl	8	6	6	4	3	14	41
Total Production	**MMbbl**	**8**	**6**	**6**	**4**	**3**	**14**	**41**
Operating costs	**US$m**	**134**	**145**	**150**	**127**	**133**	**680**	**1,369**
Capital expenditure	**US$m**	**31**	**62**	**4**	**8**	**14**	**3**	**122**
Operating costs	US$/boe	17	26	27	31	39	49	34
Capital expenditure	US$/boe	4	11	1	2	4	0.2	3

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not add due to rounding.*

30 MMbbl of oil is produced via the Ngujima-Yin FPSO over the period to 2022 to 2032, with annual production progressively declining from 7 MMbbl to 1 MMbbl in the final year of production. Year-on-year D&R is incurred over the life of the project, totalling US$808 million.

Oil is produced via the Okha FPSO over the period 2022 to 2031, with annual production gradually declining from 1.4 MMbbl to 0.6 MMbbl in the year prior to production ceasing. Year-on-year D&R is incurred over the life of the project, totalling US$307 million.

Reflecting the relatively short term remaining project life and that production is established, we have adopted a discount rate range of 7.5% to 8.5% per annum.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for Australia Oil based on a range of key assumptions, the outcome of which is set out in the table below.

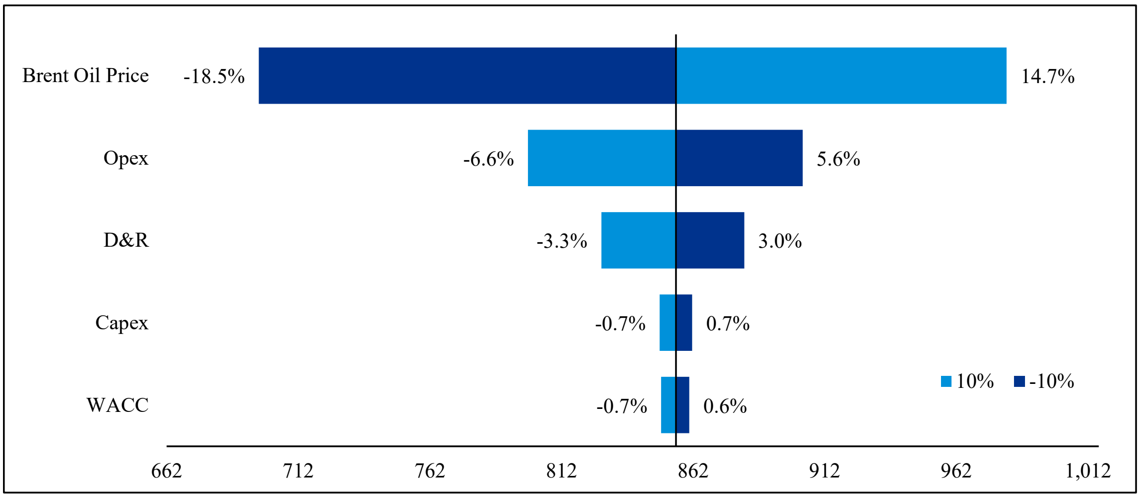
Table 47: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	697	784	856	919	981
Opex	904	880	856	832	800
D&R	882	869	856	843	827
Capex	862	859	856	853	850
WACC	861	858	856	853	850

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of Australia Oil is most sensitive to assumptions made in relation to future Brent oil prices given the interrelationship and various linked commodities, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 19: Australia Oil DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.5 Valuation of Scarborough[102]

We have assessed the value of Woodside's 73.5% interest in the projected ungeared, post tax cash flows from development of the Scarborough project to be in the range of US$1,175 million to US$1,640 million.

GaffneyCline generated production profiles and associated cost profiles as discussed in earlier sections for KPMG Corporate Finance valuation scenario inputs.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GCA's ITSR which is attached at Appendix 15.

Table 48: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022-25	2026	2027	2028	2029	Balance	Total
Production								
LNG	MMboe	-	18	46	46	47	961	1,118
Domgas	MMboe	-	4	7	7	7	143	168
Total Production	**MMboe**	**-**	**22**	**53**	**53**	**54**	**1,104**	**1,286**
Operating costs	**US$m**	**50**	**735**	**1,567**	**1,554**	**1,624**	**43,217**	**48,747**
Capital expenditure	**US$m**	**4,015**	**26**	**51**	**128**	**297**	**648**	**5,165**
Operating costs	US$/boe	-	34	30	29	30	39	38
Capital expenditure	US$/boe	-	1	1	2	5	1	4

Source: GCA, KPMG Corporate Finance analysis

[102] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not sum due to rounding.*

Production at Scarborough commences in 2026, with total life of project production of 1,286 MMboe over 27 years, comprising a mix of LNG (1,118 MMboe) and domgas (168 MMboe). Production of LNG ramps up over time to 55 MMboe per annum, with production maintained at or around this level until around 2040 before entering into a period of year-on-year decline through to the end of the project in 2052.

Of Scarborough's total life of project operating costs of US$48,747 million approximately 77% comprises tariffs charged by Pluto Train 2 for access to up to 8 Mtpa of processing services and capacity. These tariffs comprise a fixed rate per unit of volume processed, along with a variable pass through of operating costs incurred by Pluto Train 1 and Pluto Train 2 in processing Scarborough gas.

The estimated obligation in relation to D&R is incurred over the period 2051 to 2054, totalling US$1,236 million.

Development capex from 2022 through to production commencing in 2026 is forecast to total approximately US$4,123 million.

In calculating our range of assessed values for Scarborough we have adopted a discount rate of 8.5% to 9.5% per annum, reflecting that, whilst the project has been sanctioned and the assumptions adopted by us are considered reasonable, the project is at a pre-development upstream project, as such, there is a degree of inherent risk in the development, construction and commissioning of any new operation which can be considered to add to the risk of the underlying cash flows emerging as projected in comparison to an established production project with known operating parameters.

In a separate arrangement to the Proposed Transaction, BHP and Woodside have agreed an option for BHP Petroleum to divest both its 26.5% interest in the Scarborough Joint Venture and its 50% interest in the Thebe and Jupiter Joint Ventures to Woodside in the event the Proposed Transaction is not completed. We have separately assessed the value of the Scarborough put option at section 11.3.12 below.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for Scarborough based on a range of key assumptions, the outcome of which is set out in the table below.

Table 49: Sensitivity analysis

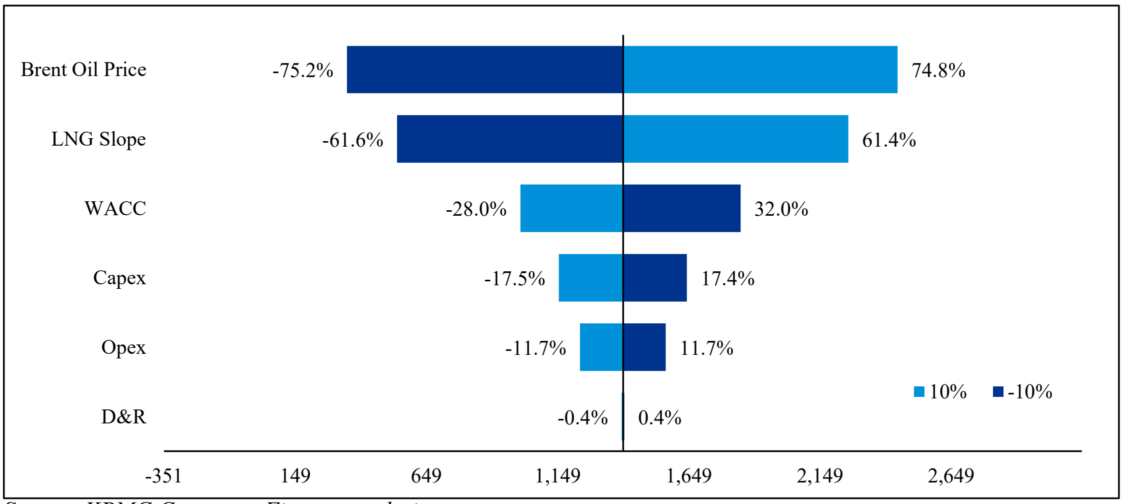
Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	347	874	1,398	1,922	2,445
LNG Slope	537	968	1,398	1,828	2,257
WACC	1,846	1,615	1,398	1,196	1,007
Capex	1,642	1,520	1,398	1,276	1,154
Opex	1,562	1,480	1,398	1,316	1,234
D&R	1,403	1,401	1,398	1,396	1,393

Source: KPMG Corporate Finance analysis

Note 1: Opex assumption excludes tariff opex charges

This analysis indicates that our range of assessed values of Scarborough is most sensitive to assumptions made in relation to future Brent oil prices given the interrelationship and various linked commodities, as set out in the tornado chart below based on a 10% variance to each key input. We note the sensitivity to spot LNG slope reflects that revenue is predominantly comprised of LNG sales and the NPV of Scarborough is very sensitive to changes in key assumptions reflecting its early stage of development.

Figure 20: Scarborough DCF sensitivity



Source: KPMG Corporate Finance analysis

Note 1: Opex assumption excludes tariff opex charges

11.3.6 *Pluto Train 2*[103]

We have assessed the value of Woodside's 51% interest in the projected ungeared, post tax cash flows from development of the Pluto Train 2 to be in the range of US$1,678 million to US$2,078 million.

GaffneyCline generated production profiles and associated cost profiles as discussed in earlier sections for KPMG Corporate Finance valuation scenario inputs.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GCA's ITSR which is attached at Appendix 15.

[103] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

Table 50: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022-25	2026	2027	2028	2029	Balance	Total
Operating costs	US$m	-	167	395	407	393	10,782	12,144
Capital expenditure	US$m	2,614	156	2	2	2	150	2,927

Source: GCA, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not sum due to rounding.*

Pluto Train 2's sole source of revenue is the tariffs charged to Scarborough, which were discussed at 8.4.1 above, whilst its operating costs largely comprise tariffs charged by Pluto LNG for access to onshore infrastructure, including Pluto Train 1, utilities, storage and loading and site infrastructure capacity, and the pass through of various operating costs.

On 15 November 2021, Woodside announced that it had entered into a sale and purchase agreement with GIP for the sale of a 49% non-operating participating interest in the Pluto Train 2 in consideration for an initial capital contribution by GIP of approximately US$822 million (**Initial Capital Contribution**)[104], plus GIP funding 49% of future development capital from the transaction's effective date of 1 October 2021. The transaction was completed on 17 January 2022.

Payment of the Initial Capital Contribution will be achieved by GIP meeting Woodside's obligation in respect of future cash calls up to this amount. If the total capital expenditure incurred is less than US$5.6 billion, GIP will pay Woodside an additional amount equal to 49% of the under-spend. In the event of a cost overrun, Woodside will fund up to US$822 million in respect of a 49% share of any overrun. Delays to the expected start-up of production will result in payments by Woodside to GIP in certain circumstances.

We have adjusted Woodside's interest in cash flows for Pluto Train 2 to reflect the recovery of GIPs 49% share of capex spent from 1 October 2021 to 31 December 2021, the Initial Capital Contribution reducing Woodside's capex contributions going forward, and the estimated payment of compensation to GIP of US$28 million in 2026 for overs-spend having regard to GaffneyCline's forecast capital expenditure for the project.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for Pluto Train 2 based on a range of key assumptions, the outcome of which is set out in the table below.

[104] The 15 November 2021 ASX announcement referred to an amount of up to US$835 million but noted that the final amount was dependent on interest rate swaps and foreign exchanges rates on the date of the FID for Scarborough and Pluto Train 2, which was taken on 22 November 2021

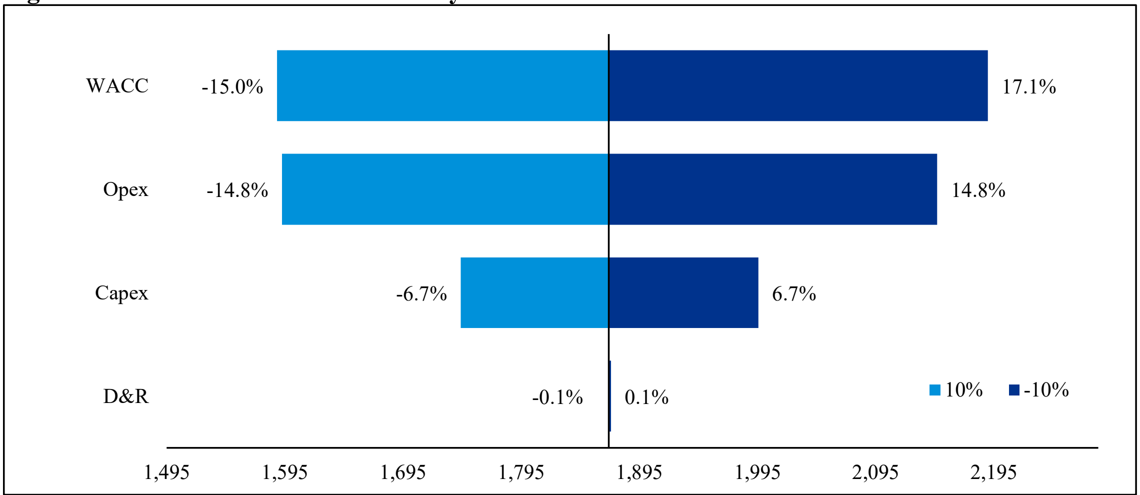
Table 51: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
WACC	2,190	2,025	1,870	1,725	1,588
Opex	2,147	2,008	1,870	1,731	1,593
Capex	1,996	1,933	1,870	1,807	1,744
D&R	1,871	1,870	1,870	1,869	1,870

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of Pluto Train 2 is most sensitive to the WACC and Opex assumptions, as set out in the tornado chart below, which is based on a 10% variance to each key input. We note Pluto Train 2 revenue is comprised of tariff's received from Scarborough, with fixed and variable components linked to volumes. As such, Pluto Train 2 cash flows are not sensitive to commodity prices.

Figure 21: Pluto Train 2 DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.7 Valuation of Browse[105]

We have assessed the value of Woodside's 30.6% interest in the projected ungeared, post tax cash flows from Browse to be in the range of US$224 million to US$571 million.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (Woodside interest) are summarised at Appendix 4.

[105] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

Table 52: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022-28	2029	2030	2031	2032	Balance	Total
Production								
LNG	MMboe	-	-	12	23	28	560	623
Domgas	MMboe	-	-	2	3	4	82	91
Condensate	MMbbl	-	-	3	6	7	113	129
LPG	MMboe	-	-	0.2	0.3	0.4	7	8
Total Production	**MMboe**	**-**	**-**	**17**	**32**	**39**	**762**	**850**
Operating costs	**US$m**	**-**	**-**	**330**	**601**	**726**	**19,888**	**21,544**
Capital expenditure	**US$m**	**4,298**	**828**	**168**	**65**	**142**	**2,669**	**8,169**
Operating costs	US$/MMbbl	-	-	20	19	19	26	25
Capital expenditure	US$/MMbbl	-	-	10	2	4	4	10

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not add due to rounding.*

As noted in section 8.4.3 above, it is currently contemplated that Browse will be developed to backfill the current NWS Project, with production commencing in 2029.

LNG is by far the largest contributor to production revenues, with production of 623 MMboe over the life of the project. LNG production gradually ramps up over the period to 2033 following which a production rate around 29 MMboe is maintained for the next 12 years, following which production steadily declines year-on-year as gas reserves deplete, until cessation in 2060.

The next largest contributor to production revenue is condensate (129 MMbbl), which follows a similar timeframe to LNG in terms of ramp up, however unlike LNG, condensate production commences a steady year-on-year decline almost immediately thereafter through to the end of the project.

Annual production of domgas and LPG both ramp up over the period to 2032, maintaining a production level around 4 MMboe and 0.4 MMboe respectively through to 2044, before both entering into a period of steady year-on-year decline for the remaining project life, with a total of 91 MMboe and 8 MMboe produced over the life of the project respectively.

Of Browse's total life of project operating costs of US$21,544 million, approximately 61% comprises processing tariffs charged by the NWS Project.

Development capex from 2022 through to production commencing in 2029 is forecast to total approximately US$5,109 million.

The estimated obligation in relation to D&R totals US$913 million, the majority of which is incurred over the period 2059 to 2063.

In calculating our range of assessed values for Browse we have adopted a discount rate of 10.0% to 11.0% per annum, reflecting that, whilst the assumptions adopted by us are considered reasonable, the project is at an unsanctioned pre-development upstream stage, with production some time away.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for Browse based on a range of key assumptions, the outcome of which is set out in the table below.

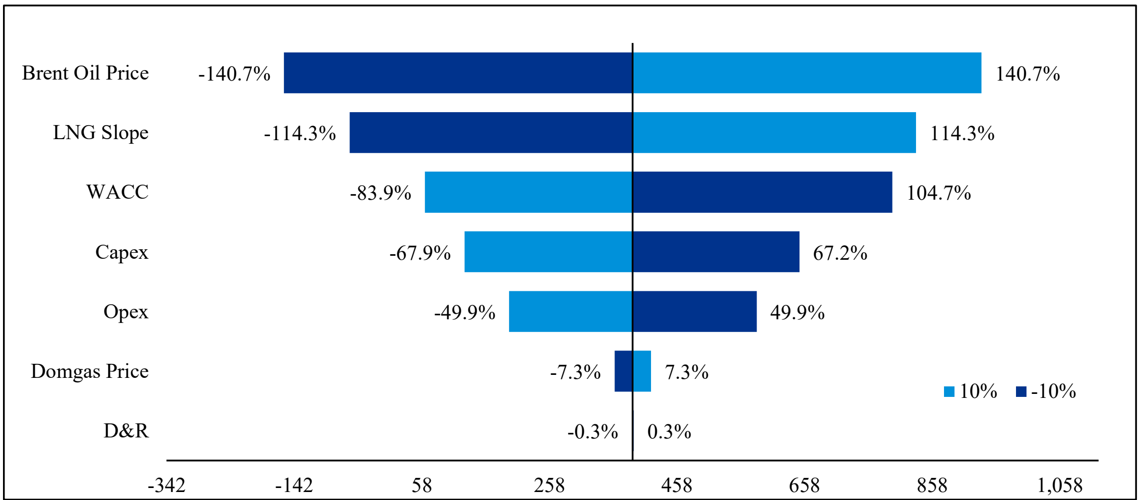
Table 53: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	(158)	115	388	662	935
LNG Slope	(55)	167	388	610	832
WACC	795	581	388	216	63
Capex	649	519	388	257	125
Opex	582	485	388	291	195
Domgas Price	360	374	388	403	417
D&R	390	389	388	388	387

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of Browse is sensitive to assumptions made in relation to future Brent oil prices given the interrelationship and various linked commodities, as set out in the tornado chart below, which is based on a 10% variance to each key input. We note the sensitivity to spot LNG slope reflects that revenue is predominantly comprised of LNG sales and the NPV of Browse is very sensitive to changes in key assumptions reflecting its early stage of development.

Figure 22: Browse DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.8 *Valuation of Sangomar*[106]

We have assessed the value of Woodside's 82% interest in the projected ungeared, post tax cash flows from Sangomar to be in the range of US$1,824 million to US$2,033 million.

[106] All references to forecast revenues, production volumes, operating costs and capital expenditure are based on Woodside's interest.

A summary of project outputs (Woodside interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (Woodside interest) are summarised at Appendix 4.

Table 54: Summary of cash flow parameters - Woodside interest

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil	MMboe	-	7	25	23	18	325	397
Total Production	**MMboe**	**-**	**7**	**25**	**23**	**18**	**325**	**397**
Operating costs	**US$m**	**0.3**	**60**	**123**	**140**	**193**	**5,731**	**6,249**
Capital expenditure	**US$m**	**1,217**	**907**	**142**	**89**	**141**	**3,386**	**5,882**
Operating costs	US$/boe	-	9	5	6	11	18	16
Capital expenditure	US$/boe	-	137	6	4	8	10	15

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts are stated in nominal terms*
2. *May not add due to rounding.*

Sangomar is in development phase, with first oil targeted for 2023, with forecast total life of project oil production of 397 MMboe. Production peaks in 2024, is maintained at reduced production levels from 2026 to 2032 before entering into a period of year-on-year decline through to the end of production in 2048.

Development capex from 2022 through to production commencing in 2023 is forecast to total approximately US$2,124 million.

The estimated obligation in relation to D&R totals US$1,519 million.

In calculating our range of assessed values for Sangomar we have adopted a discount rate of 13.5% to 14.5% per annum. Our selected range of discount rates takes into account that, whilst the assumptions adopted by us are considered reasonable, the project is still in the development phase, albeit with production expected to commence in the relatively short term, with project revenue comprising solely of uncontracted sales of oil. In addition, an element of the production has been forecast by GaffneyCline to come from 2C Contingent Resources, with an associated chance of development risk, as well as sovereign risk for Senegal.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Sangomar project based on a range of key assumptions, the outcome of which is set out in the table below.

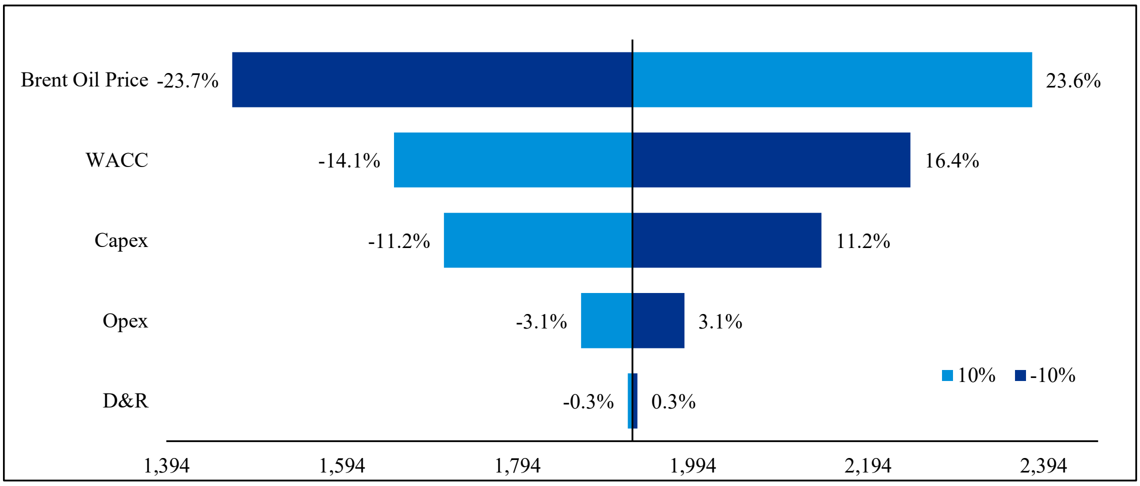
Table 55: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	1,470	1,698	1,926	2,154	2,381
WACC	2,243	2,078	1,926	1,785	1,654
Capex	2,141	2,034	1,926	1,818	1,711
Opex	1,985	1,955	1,926	1,897	1,867
D&R	1,931	1,929	1,926	1,923	1,920

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the Sangomar project is most sensitive to Brent oil, discount rates and capex assumptions, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 23: Sangomar DCF sensitivity



Source: KPMG Corporate Finance analysis

11.3.9 Valuation of Stybarrow

We have assessed the value of Woodside's interest in the projected ungeared, post tax cash flows from the Stybarrow project to be a negative value in the order of US$88 million.

Forecast operations for the project comprise post-tax D&R expenditure. Further detail in relation to the project assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15.

In calculating the NPV of Woodside's interest we have adopted a discount rate of 1.5% per annum, which has been estimated having regard to yields on short term US Treasury bonds and reflects that these forecast cash outflows are unavoidable.

11.3.10 Valuation of Balnaves

We have assessed the value of Woodside's interest in the projected ungeared, post tax cash flows from the Balnaves project to be a negative value in the order of US$43 million.

Forecast operations for the project comprise post-tax D&R expenditure. Further detail in relation to the project assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15.

In calculating the NPV of Woodside's interest we have adopted a discount rate of 1.5% per annum, which has been estimated having regard to yields on short term US Treasury bonds and reflects that these forecast cash outflows are unavoidable.

11.3.11 Valuation of Woodside's interest in other petroleum assets

GaffneyCline has assessed a value range for Woodside's interest in other petroleum assets not included in the above sections to be in the order of US$334 million to US$604 million as summarised in the table below.

Table 56: Summary of valuations of other petroleum assets - Woodside interest

	Assessed Values	
	Low US$m	High US$m
Sunrise LNG	204	387
Thebe and Jupiter fields	52	99
Kitimat LNG	Nil	Nil
Myanmar A-6 Development	Nil	Nil
Exploration assets	78	118
Total other petroleum assets	**334**	**604**

Source: GaffneyCline's ITSR

In its assessment of the value of the other petroleum assets, GaffneyCline has adopted generally accepted methods for valuing early stage petroleum assets including expected monetary value approach, comparable transactions and sunk costs. Further details in relation to each of these assets and the valuation methodology adopted are set out in GaffneyCline's ITSR which is included at Appendix 15. It should be noted that the valuation of early stage/exploration assets is highly subjective and involves subjective assessments based on professional judgements made by GaffneyCline.

11.3.12 Valuation of other assets and liabilities

Net assets not valued as part of Woodside's petroleum assets comprise cash and other sundry assets and liabilities held by Woodside. Except as specifically noted below, having regard to their nature and quantum, these assets and liabilities have been incorporated in our valuation at net book values as at 31 December 2021.

Net debt

Woodside's net debt position as at 31 December 2021 has been adjusted to reflect the US$696 million cash component of Woodside's final dividend paid to Woodside Shareholders in March 2022 in respect of the year ended 31 December 2021. The component of the final dividend which was reinvested under Woodside's dividend reinvestment plan has been reflected in Woodside's current ordinary shares on issue.

Net working capital

We have estimated Woodside's interest in net working capital movements over the project lives at a project portfolio level based on GaffneyCline's operational forecasts, incorporating estimated sustainable debtor, inventory and creditor days having regard to historical net working capital days for the selected comparable listed upstream and midstream LNG production and processing companies set out in Appendix 6. Trade and other debtors, inventory and trade and other creditors as at 31 December 2021 have been reflected in the opening balances of our net working capital movements calculation.

In calculating the NPV of the forecast net working capital movements we have adopted a blended discount rate of 8.0% to 9.0% per annum at the corporate level, which has been estimated based on weighted average blending of the discount rates applied in the valuation of each of Woodside's assets, having regard to the NPV of Woodside's interest in each project.

The NPV of the forecast net working capital movements over the total life of Woodside's existing asset portfolio has been estimated to have a negative NPV in order of US$687 million to US$703 million.

Regret costs

We have adopted Woodside's estimate of pre-tax transactions costs expected to be incurred irrespective of whether the Proposed Transaction proceeds or not, along with amounts payable to senior management in the event of a change of control transaction in the order of US$100 million (US$70 million post-tax) in our valuation of other net assets.

Scarborough Put Option

In a separate arrangement to the Proposed Transaction, BHP and Woodside have agreed an option for BHP Petroleum to divest both its 26.5% interest in the Scarborough project and its 50% interest in the Thebe and Jupiter Joint Ventures to Woodside in the event the Proposed Transaction is not completed. The option is exercisable by BHP Petroleum in the second half of CY22 and if exercised, the following consideration will be payable to BHP Petroleum:

- US$1 billion, with an adjustment for expenditure incurred by BHP Petroleum in relation to Scarborough over the period 1 Jul 2021 to the date of exercise (the expenditure adjustment is also subject to interest costs at a rate of 3.5% per annum, compounded monthly)
- US$100 million contingent amount (nominal) payable FID of Thebe.

Based on these terms and information provided by Woodside and GaffneyCline in relation to estimated joint venture costs for the 12 months to 30 June 2022, we have calculated the potential cash payment required to be made by Woodside as at 1 July 2022 (being the earliest date the put option can be exercised).

We have not included the contingent amount given the uncertainty regarding the timing of Thebe FID, if at all, consistent with GaffneyCline's approach to its valuation of Thebe.

As discussed below at section 11.5.16, we have separately assessed the estimated value of BHP Petroleum's 26.5% interest in the Scarborough Joint Venture as at 1 July 2022 as being in the range of US$562 million to US$736 million (determined by rolling forward the 31 December 2021 valuation of BHP Petroleum's interest in the Scarborough project, as discussed below).

Accordingly, the net diminution in Woodside's value as a standalone entity as a result of the put option is between US$419 million to US$593 million (with an offsetting value accretion to BHP Petroleum as a standalone entity). Exercise of the put option may result in a portion of the exercise price paid being allocated to tax depreciable assets for Woodside, which would increase our range of assessed values of Woodside on a standalone basis. As the potential value impact of such an allocation is not able to be quantified with certainty at this time, we have not adjusted our values in relation to same. Based on the quantum of the put option exercise price, the value impact of any potential allocation would not change our opinion.

Future corporate overheads

Woodside incurs corporate overheads in relation to managing its business. These costs have not been incorporated in the valuation of Woodside's interest in the assets set out above, and therefore it is necessary to deduct the present value of the anticipated future management and administrative costs in relation to Woodside's assets from the overall value of Woodside.

We have been provided with a schedule prepared by Woodside that sets out the expected future corporate costs. In assessing the quantum of these costs for the purpose of our valuation we have considered, general and administrative expenses, insurance costs, compliance costs and Northern Oil & Gas Australia (**NOGA**) levy. We have assumed total corporate costs will decline in line with aggregate production levels over the forecast period.

As noted early in this section, we have not incorporated any allowance for cost savings and/or synergies that might be available to an unrelated third-party purchaser of Woodside standalone.

In calculating the NPV of estimated corporate costs we have adopted a blended discount rate of 8.0% to 9.0% per annum at the corporate level, which has been estimated based on weighted average blending of the discount rates applied in the valuation of each of Woodside's assets.

The NPV of the forecast after-tax corporate costs, having regard to the various projects and respective cessation of production, has been estimated to be in the order of US$1,581 million to US$1,727 million.

New Energy opportunities

We have been advised by Woodside that whilst these opportunities are considered to be highly prospective, they are currently pre-FID, are largely at a conceptual stage without any binding off-take agreements in place and no forecast cash flows or trading budgets have been prepared. Accordingly we do not consider there to be a reasonable basis to ascribe separate value to these projects at this time.

11.4 Other Valuation Parameters – Woodside

Having regard to our assessed values in respect of Woodside's assets and liabilities, the implied enterprise value for Woodside is between approximately A$30,604 million and A$33,754 million, which, based on GaffneyCline's assessed 1P and 2P Reserves of Woodside as at 31 December 2021 implies a value per boe as summarised in the table below.

Table 57: Summary of 1P and 2P boe multiples implied by our assessed value of Woodside

Parameter	Low A$/boe	High A$/boe
1P	19	21
2P	13	14

Source: KPMG Corporate Finance analysis

Note 1: The implied enterprise value of Woodside has been calculated as the aggregate of assessed equity values, net borrowings, the put option for Scarborough (payable to BHP), regret costs and lease liabilities

Comparison to contained 1P and 2P multiples implied by listed comparable companies

The implied value per 1P and 2P boe Reserves for a selection of companies involving companies predominantly focused on upstream and midstream LNG production and processing are summarised in the table below.

Table 58: Summary of 1P and 2P boe multiples for comparable upstream and midstream LNG production and processing companies

	1P Reserves A$/boe	2P Reserves A$/boe
Low	10	6
Mean	28	16
Median	32	18
High	44	22

Source: KPMG Corporate Finance analysis

This analysis indicates a wide range of outcomes, however we note that the range of 1P and 2P multiples implied by our range of assessed market values for Woodside lies comfortably within the range of equivalent observed listed company multiples. We note:

- approximately 75% of Woodside's 2P Reserves are undeveloped, which would be expected to result in a lower implied multiple relative to companies with a high proportion of developed resources
- there were only 4 companies (including Woodside) that have published details in relation to 2P Reserves, this likely reflects the different reporting regulations in overseas jurisdictions. This lack of relevant data significantly reduces the utility of the findings in relation to 2P multiples.

Whilst in our view the outcome of this analysis provides broad support for our range of values, due to the limitations of this form of analysis as highlighted above and in Appendix 8, it should only be considered as a high-level cross-check of the outcomes of other valuation methodologies and not as a determinant of value.

Further details of our analysis are set out in Appendix 8 to this report.

Comparison to contained boe 1P and 2P multiples implied by comparable transactions

The implied value per 1P and 2P boe Reserves for a selection of recent corporate transactions involving companies/projects predominantly focused on upstream and midstream LNG production and processing are summarised in the table below.

Table 59: Summary of 1P and 2P multiples for comparable upstream and midstream LNG production and processing transactions

	1P Reserves A$/boe	2P Reserves A$/boe
Low	23	13
Mean	28	19
Median	28	18
High	33	29

Source: KPMG Corporate Finance analysis

Whilst in our view the outcome of this analysis provides broad support for our range of values, due to the limited transaction data available (4 transactions), limitations of this form of analysis highlighted in Appendix 12, it should only be considered as a high-level cross-check of the outcomes of other valuation methodologies and not as a determinant of value.

Further details of our analysis is set out in Appendix 12 to this report.

11.5 Valuation of BHP Petroleum

We have assessed the market value of a 100% interest in BHP Petroleum to be in the range of US$19,064 million to US$20,443 million, which equates to an AUD equivalent value range of A$25,511 million to A$27,356 million[107].

The market value of BHP Petroleum was determined after aggregating the estimated market value of BHP Petroleum's interests in its oil and gas assets, adding the assessed value of other assets and including corporate and other adjustments.

The value of BHP Petroleum has been assessed on the basis of the value that should be agreed in a hypothetical transaction between a knowledgeable, willing, but not anxious buyer and a knowledgeable, willing, but not anxious seller, acting at arm's length.

Our range of assessed values reflects that a number of BHP Petroleum's assets are yet to be developed, in particular, Scarborough, Trion, Calypso, Mad Dog Phase 2, and Shenzi North. The forecasts for these projects incorporate a greater degree of subjectivity than the forecasts for projects with established operating profiles.

Table 60: Summary of BHP Petroleum assessed values

	Assessed Values	
	Low $USm	High $USm
Market values of BHP Petroleum's interests in petroleum assets		
NWS Project	3,197	3,329
NWS oil	79	80
Scarborough	446	615
Bass Strait	2,214	2,260

[107] Based on an USD:AUD exchange rate of approximately 0.747.

	Assessed Values	
	Low $USm	**High $USm**
Macedon	308	315
Pyrenees	321	323
Other Australian	(223)	(226)
Total Australian	**6,341**	**6,695**
Atlantis	3,985	4,170
Mad Dog	3,667	3,954
Shenzi	3,857	4,031
GOM ORRI	86	87
Total GOM	**11,594**	**12,243**
Project Ruby & Angostura	544	555
Calypso	47	189
Trion	501	783
Total rest of world	**1,092**	**1,528**
Surplus exploration petroleum interests	190	436
Total Petroleum Assets	**19,217**	**20,902**
Add: Cash and cash equivalents	992	992
Add: Put option for Scarborough (receivable from Woodside)	593	419
Less: Other net liabilities	(150)	(150)
Less/Add: NPV of NWC movements	(20)	2
Less: NPV of future corporate overheads	(1,568)	(1,722)
Total Equity Value	**19,064**	**20,443**

Source: GaffneyCline, KPMG Corporate Finance analysis
Note 1: May not add due to rounding

11.5.1 Valuation of NWS Project[108]

We have assessed the value of BHP Petroleum's 16.7% interest in the projected ungeared, post tax cash flows from development of the NWS Project to be in the range of US$3,197 million to US$3,329 million[109]. Our valuation takes into account BHP Petroleum's participation interest in existing NWS gas fields, along with tariff revenue from processing third party gas and gas supplied via the Pluto-KGP Interconnector (currently being constructed). The valuation also includes an allowance for the potential upside of the intention to process gas from the currently unsanctioned Browse project through the KGP facilities.

A summary of project outputs (BHP Petroleum interest) is set out in the table below for the NWS Project (excluding NWS Oil). Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

[108] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.
[109] The assessed value range is higher than Woodside's interest primarily due to differing volume exposure to uncontracted LNG and the resulting tax positions.

Table 61: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
LNG	MMboe	18	17	16	11	10	54	126
LPG	MMboe	0	0	0	0	0	2	3
Domgas	MMboe	1	1	1	4	3	8	16
Condensate	MMbbl	3	3	3	2	2	9	21
Total Production	**MMboe**	**22**	**21**	**20**	**17**	**15**	**72**	**167**
Operating costs	**US$m**	**168**	**172**	**171**	**138**	**140**	**4,194**	**4,984**
Capital expenditure	**US$m**	**128**	**90**	**100**	**126**	**157**	**2,307**	**2,908**
Operating costs	US$/boe	8	8	9	8	9	59	30
Capital expenditure	US$/boe	6	4	5	7	10	32	17

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

LNG is by far the largest contributor to production revenues, with aggregate forecast sales of 126 MMboe, comprising a mix of contracted volumes, which progressively roll off over the period to 2032, and uncontracted volumes. LNG is produced over the period 2022 to 2036, with the rate of production declining steadily year-on-year.

The next largest contributor to production revenue is condensate (21 MMbbl), which follows a similar pattern to LNG in terms of steady decline in year-on-year production volumes over the remaining life of the NWS fields.

Annual production of domgas ramps up over the period to 2025 before declining over the next few years through to 2029. At that point, production volumes stabilise for the remaining project life, with a total of 16 MMboe produced over the life of the project.

A variable working interest for BHP Petroleum has been applied to the production revenues, ranging between 11.9% to 15.8% over the period 2022 to 2036, which reflects BHP Petroleum's entitlement under the joint venture arrangement.

The NWS Project is forecast to receive tariff revenues from the processing of gas from the currently unsanctioned Browse project over the period 2030 through to 2060. However, reflecting that this project is yet to take FID, and the final terms for any future transport and processing costs are yet to be agreed between the parties, we have been consistent with the approach adopted for Woodside's interest in the NWS Project (refer section 11.3.1 above), and included an additional risking to the incremental net cash flows from this upside opportunity to reflect timing, development and commercial uncertainty.

Additionally, the NWS Project is forecast to receive tariff revenues from the processing of 3rd party gas between 2023 and 2038 (inclusive of the Pluto-KGP Interconnector, CNOOC and onshore Waitsia development).

Capex for the NWS Project totals US$2,908 million, comprising of upstream Capex (US$572 million) and downstream Capex (US$2,336 million). Upstream Capex is incurred between 2022 and 2036 with downstream Capex peaking in 2037 before a steady year-on-year decline to 2059.

The NWS Project's total life of project Opex is US$4,984 million, which is incurred between 2022 and 2059. A variable working interest for BHP Petroleum has been applied to the Opex, ranging between 15.0% to 15.8% over the period 2022 to 2036.

The estimated D&R obligation for the NWS Project totals US$819 million, comprising of upstream (US$69 million) and downstream (US$750 million) D&R expenses. D&R is incurred on an annual basis over the life of the project, through to 2067.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the NWS Project (excluding NWS Oil), based on a range of key assumptions, the outcomes of which are set out in the table below.

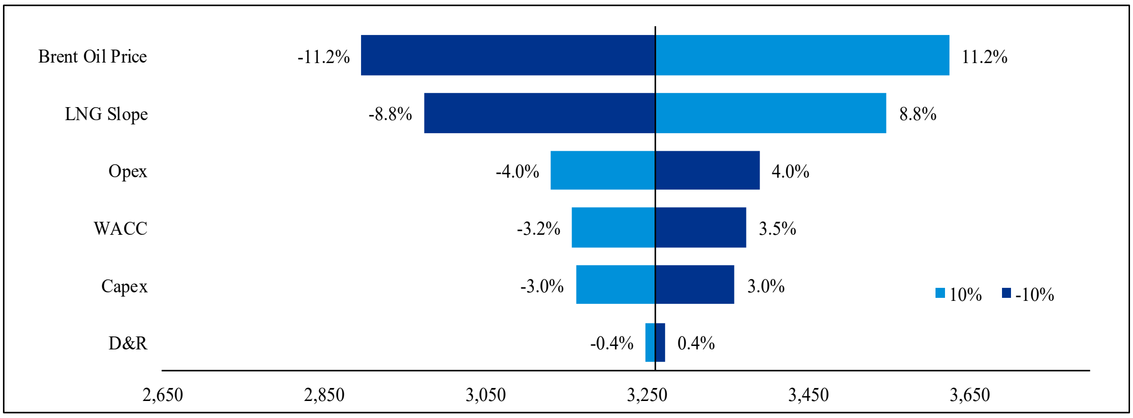
Table 62: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	2,868	3,064	3,261	3,458	3,654
LNG Slope	2,974	3,118	3,261	3,404	3,548
Opex	3,390	3,326	3,261	3,196	3,132
WACC	3,374	3,316	3,261	3,208	3,158
Capex	3,360	3,310	3,261	3,212	3,162
D&R	3,273	3,267	3,261	3,255	3,249

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the NWS Project (excluding NWS Oil) is most sensitive to the forecast brent oil price as set out in the tornado chart below, which is based on a 10% variance to each key input. This reflects that the sales price realised on LNG is a function of the brent oil price and the LNG Slope that has been assumed (for uncontracted volumes).

Figure 24 – NWS Project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.2 *Valuation of NWS Oil*[110]

We have assessed the value of BHP Petroleum's 16.7% interest in the projected ungeared, post tax cash flows from development of the NWS Oil project to be in the range of US$79 million to US$80 million. The valuation of the NWS Oil project also includes the forecast cash flows associated with the Okha FPSO oil production facility related to the offshore oil fields.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 63: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil	MMbbl	1	1	1	1	0	2	5
Total Production	**MMboe**	**1**	**1**	**1**	**1**	**0**	**2**	**5**
Operating costs	**US$m**	**17**	**17**	**21**	**16**	**22**	**70**	**162**
Capital expenditure	**US$m**	**3**	**1**	**1**	**3**	**6**	**1**	**15**
Operating costs	US$/boe	24	25	34	28	47	34	32
Capital expenditure	US$/boe	4	2	1	5	12	1	3

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

[110] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

Production of oil takes place over the period 2022 to 2031, with aggregate forecast sales of 5 MMbbl. Over the remaining life the NWS Oil project, annual production follows a steady decline in year-on-year annual production volumes.

NWS Oil's total life of project Opex is US$162 million, which remain relatively stable over the period 2022 and 2031.

Capex for the NWS Oil project totals US$15 million, the majority of which is incurred between 2022 and 2026.

The estimated D&R obligation totals US$154 million, the majority of which is incurred between 2032 and 2034 at the end of field life.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the NWS Oil Project based on a range of key assumptions, the outcomes of which is set out in the table below.

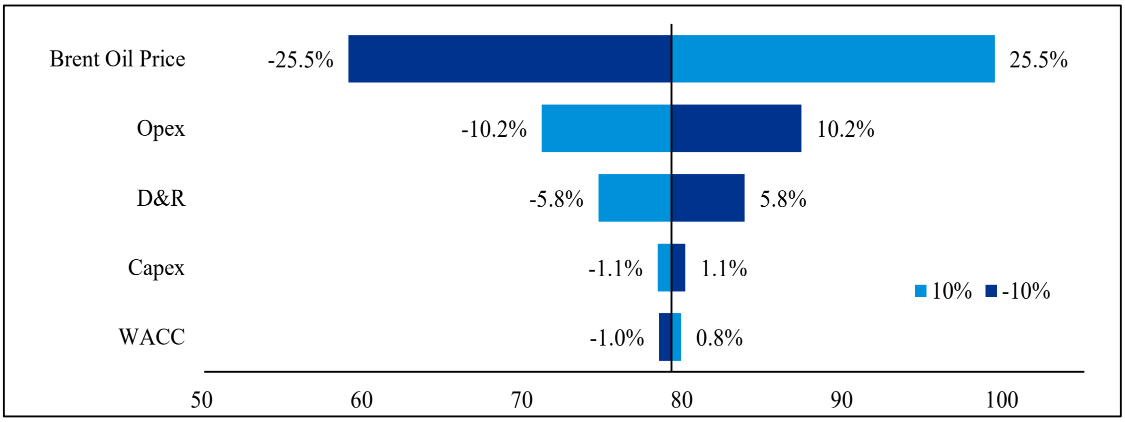
Table 64: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	59	69	79	89	99
Opex	87	83	79	75	71
D&R	84	81	79	77	75
Capex	80	80	79	79	78
WACC	78	79	79	80	80

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the NWS Oil project is most sensitive to the forecast brent oil price, forecast Opex and forecast D&R, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 25 – NWS Oil project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.3 *Valuation of Scarborough*[111]

We have assessed the value of BHP Petroleum's 26.5% interest in the projected ungeared, post tax cash flows from the development of the Scarborough project to be in the range of US$446 million to US$615 million.

GaffneyCline generated production profiles and associated cost profiles as discussed in earlier sections for KPMG Corporate Finance valuation scenario inputs.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15.

Table 65: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022-25	2026	2027	2028	2029	Balance	Total
Production								
LNG	MMboe	-	6	17	17	17	347	403
Domgas	MMboe	-	2	3	3	3	52	61
Total Production	**MMboe**	**-**	**8**	**19**	**19**	**20**	**398**	**464**
Operating costs	**US$m**	**18**	**265**	**565**	**560**	**586**	**15,582**	**17,575**
Capital expenditure	**US$m**	**1,448**	**9**	**18**	**46**	**107**	**234**	**1,862**
Operating costs	US$/boe	n/a	34	30	29	30	39	38
Capital expenditure	US$/boe	n/a	1	1	2	5	1	4

Source: GaffneyCline, KPMG Corporate Finance analysis

[111] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

Notes:
1. *US$ amounts stated in nominal terms*
2. *May not sum due to rounding*

Production at Scarborough commences in 2026, with a total life of project production over 27 years. LNG is by far the largest contributor to production revenues, with aggregate uncontracted forecast sales of 403 MMboe over the life of the project. Production of LNG ramps up over time to 20 MMboe per annum, with production maintained at or around this level until around 2040 before entering into a period of year-on-year decline through to the end of the project in 2052. Domgas production remains steady over the period from 2026 to 2046, with aggregate uncontracted production of 61 MMboe.

Of Scarborough's total life of project Opex of US$17,575 million, the large majority comprises tariffs charged. These tariffs comprise a fixed rate per unit of volume processed[112], along with a variable pass through of Opex incurred by Pluto Train 1 and Pluto Train 2 in processing Scarborough project gas.

Capex for the Scarborough project totals US$1,862 million, the majority of which is incurred between 2022 and 2024, associated with the development of the project.

The estimated obligation in relation to D&R totals US$446 million, which is assumed to be incurred over the period 2051 to 2054.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Scarborough project, based on a range of key assumptions, the outcomes of which are set out in the table below.

Table 66: Sensitivity analysis

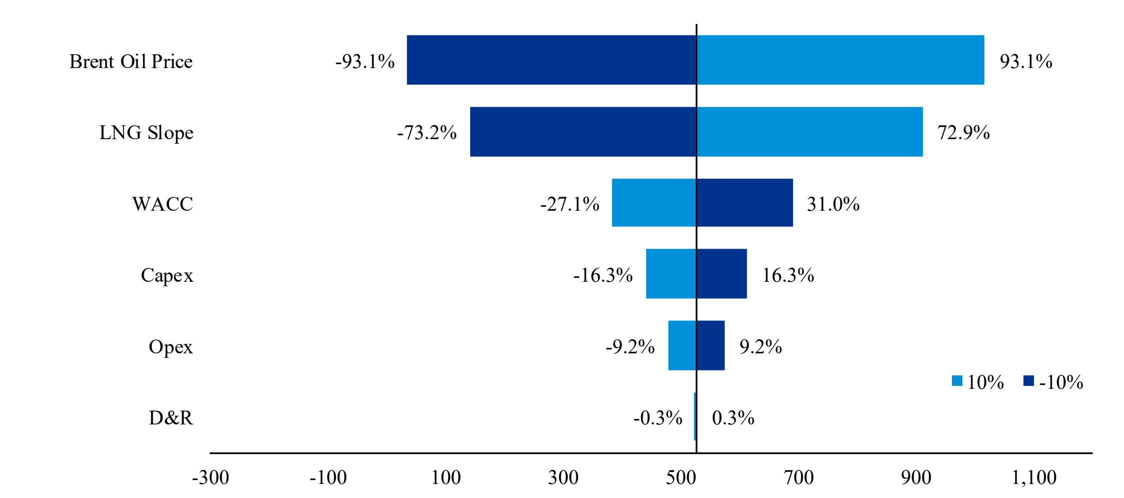
Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	36	282	527	773	1,018
LNG Slope	141	335	527	719	912
WACC	691	606	527	453	385
Capex	613	570	527	484	441
Opex	576	552	527	503	479
D&R	529	528	527	526	526

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the Scarborough project is most sensitive to the forecast brent oil price (which underpins the LNG price) and the forecast LNG slope, as set out in the tornado chart below, which is based on a 10% variance to each key input. The NPV of Scarborough is very sensitive to changes in key assumptions reflecting it's early stage of development.

[112] in real January 2019 terms

Figure 26 – Scarborough project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.4 *Valuation of Bass Strait*[113]

We have assessed the value of BHP Petroleum's interest in the projected ungeared, post tax cash flows from the Bass Strait project to be in the range of US$2,214 million to US$2,260 million. Our valuation takes into account BHP Petroleum's interest in the seven gas fields, four gas cap fields and 13 oil gas fields which are producing, along with the 2C Contingent Resources.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 67: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Domgas	MMboe	21	17	16	14	13	42	123
Oil	MMbbl	2	1	-	-	-	-	3
Condensate	MMbbl	3	3	2	2	2	14	27
Ethane	MMboe	3	2	2	2	2	6	17
Propane	MMboe	3	2	2	2	2	5	16
Butane	MMboe	2	1	1	1	1	2	8
Total Production	**MMboe**	**33**	**27**	**24**	**21**	**19**	**71**	**193**

113 All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Operating costs	**US$m**	**348**	**317**	**273**	**248**	**224**	**1,079**	**2,488**
Capital expenditure	**US$m**	**85**	**136**	**206**	**171**	**47**	**54**	**700**
Operating costs	US$/boe	10	12	11	12	12	16	13
Capital expenditure	US$/boe	3	5	9	8	2	1	4

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Domgas is the largest contributor to production revenues, with aggregate forecast sales of 123 MMboe, comprising a mix of contracted volumes and uncontracted volumes over the life of the project. The next largest contributor to production revenues is condensate, with a total of 27 MMboe produced. Annual production shows a steady declining rate over the forecast period. The Bass Strait projects also generates tariff revenue from GBJV and third party processing revenue.

Capex is incurred over the production life of the Bass Strait project, totalling US$700 million. Capex peaks in 2024 at US$206 million and rapidly declines over the remaining period to 2032.

Total project Opex, over the period 2022 to 2032, for Bass Strait is US$2,488 million, comprising of tariff costs and offshore, onshore and overhead Opex and follows a steady year-on-year decline over the life of the project (consistent with the production trend).

D&R is incurred on an annual basis over the remaining life of the Bass Strait Project and continues through to 2039, totalling US$2,563 million. D&R is currently targeted at the legacy oil fields which have ceased production.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Bass Strait project, based on a range of key assumptions, the outcomes of which are set out in the table below.

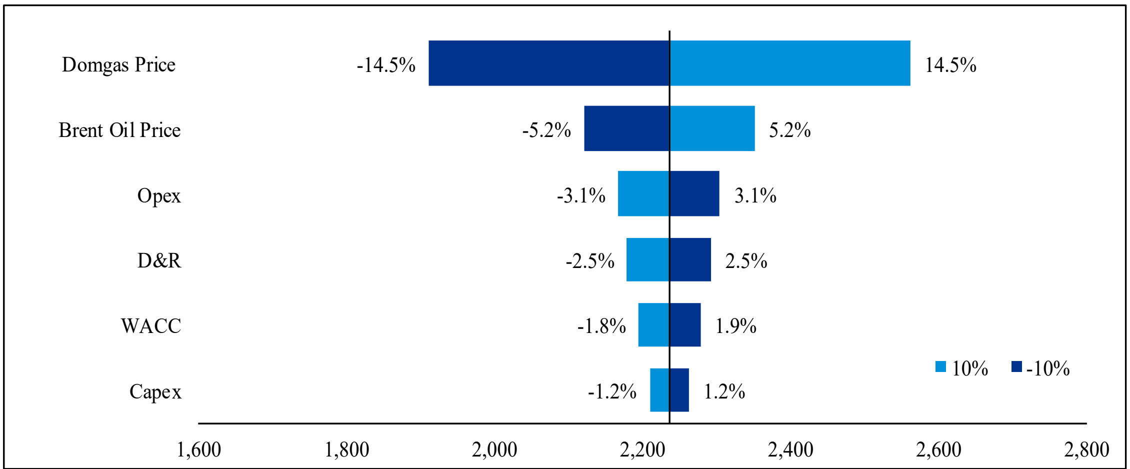
Table 68: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Domgas Price	1,911	2,074	2,236	2,399	2,562
Brent Oil Price	2,121	2,179	2,236	2,294	2,352
Opex	2,305	2,271	2,236	2,202	2,168
D&R	2,293	2,265	2,236	2,208	2,180
WACC	2,279	2,257	2,236	2,216	2,196
Capex	2,263	2,250	2,236	2,223	2,210

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the Bass Strait project is most sensitive to the forecast domgas price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 27 – Bass Strait project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.5 *Valuation of Macedon*[114]

We have assessed the value of BHP Petroleum's 71.4% interest in the projected ungeared, post tax cash flows from the Macedon project to be in the range of US$308 million to US$315 million. Our valuation takes into account BHP Petroleum's participation interest in the existing gas fields. The valuation also includes an allowance for the potential production upside from BHP Petroleum's 2C Contingent Resources resulting from the front end compression project and unapproved programs.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 69: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Domgas	MMboe	8	7	7	7	6	19	53
Oil	MMbbl	0	0	0	0	0	0	0
Total Production	**MMboe**	**8**	**7**	**7**	**7**	**6**	**19**	**53**
Operating costs	**US$m**	**22**	**23**	**20**	**21**	**21**	**117**	**223**

[114] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Capital expenditure	**US$m**	**16**	**23**	**16**	**3**	**1**	**3**	**61**
Operating costs	US$/boe	3	3	3	3	4	6	4
Capital expenditure	US$/boe	2	3	2	1	0	0	1

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Production of domgas takes place over the period 2022 to 2032, with aggregate forecast sales of 53 MMboe, comprising a mix of contracted volumes and uncontracted volumes. Annual production of domgas follows a steady decline in year-on-year production volumes over the remaining life of the Macedon fields. Production of oil takes place over the period 2022 to 2032, with annual production steadily declining over the period.

Macedon's total life of project operating cost is US$223 million and is incurred between 2022 and 2032. Capex for the Macedon project totals US$61 million, the majority of which is incurred between 2022 and 2024, associated with the development of the fields.

The estimated obligation in relation to D&R totals US$377 million, the majority of which is incurred between 2033 and 2035.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Macedon project based on a range of key assumptions, the outcomes of which are set out in the table below.

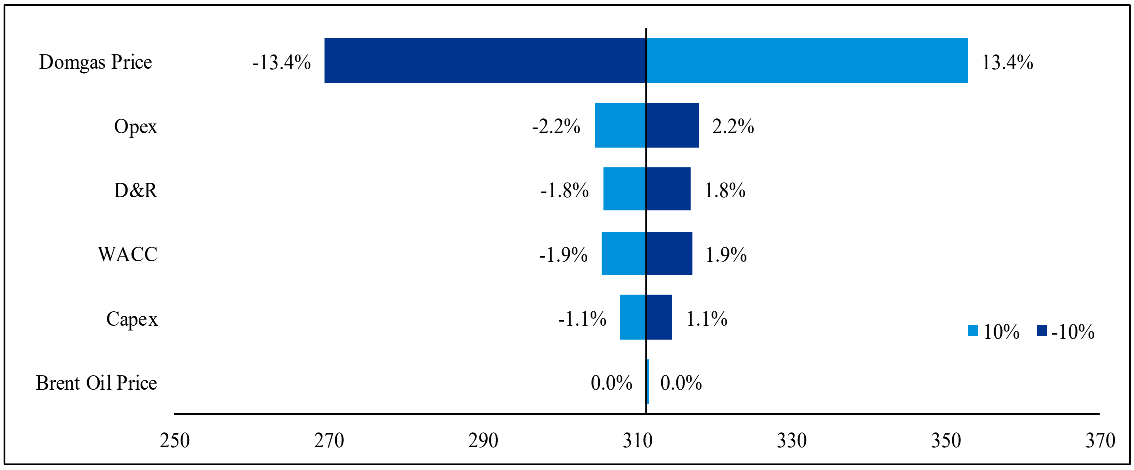
Table 70: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Domgas Price	270	290	311	332	353
Opex	318	315	311	308	304
D&R	317	314	311	308	306
WACC	317	314	311	308	305
Capex	315	313	311	310	308

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the Macedon project is most sensitive to the forecast domgas price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 28 – Macedon project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.6 *Valuation of Pyrenees*[115]

We have assessed the value of BHP Petroleum's interest in the projected ungeared, post tax cash flows from development of the Pyrenees project to be in the range of US$321 million to US$323 million. Our valuation takes into account BHP Petroleum's participation interest in the remaining recoverable volumes of the producing fields up to and including Phase 4. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 71: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil	MMbbl	3	3	2	2	2	10	22
Total Production	**MMboe**	**3**	**3**	**2**	**2**	**2**	**10**	**22**
Operating costs	**US$m**	**56**	**57**	**52**	**43**	**40**	**337**	**584**
Capital expenditure	**US$m**	**31**	**21**	**4**	**1**	**0**	**5**	**63**

[115] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Operating costs	US$/boe	20	21	22	20	22	32	26
Capital expenditure	US$/boe	11	8	2	1	0	1	3

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Production of oil takes place over the period 2022 to 2036, with aggregate forecast sales of 22 MMbbl. Over the remaining life the Pyrenees project, annual production peaks in 2022 before a steady decline in year-on-year annual production volumes.

Pyrenees' total life of project Opex is US$584 million, which is incurred between 2022 and 2036. Opex peaks in 2023, before a steady decline in year-on-year Opex over the remaining life of the project.

Capex for the Pyrenees project totals US$63 million, the majority of which is incurred between 2022 and 2023, associated with the expansion of the field.

The estimated D&R obligation totals US$820 million. D&R is incurred between 2034 and 2047 and peaks in 2039 and 2040. D&R activities are planned to commence two years prior to the end of field life.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Pyrenees project, based on a range of key assumptions, the outcomes of which is set out in the table below.

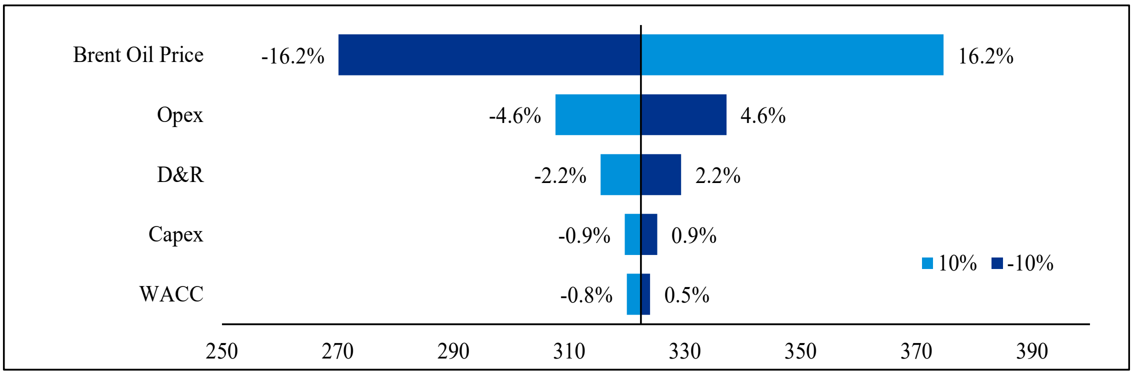
Table 72: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	270	296	322	349	375
Opex	337	330	322	315	308
D&R	329	326	322	319	315
Capex	325	324	322	321	320
WACC	324	323	322	321	320

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the Pyrenees project is most sensitive to the forecast brent oil price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 29 – Pyrenees project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.7 *Valuation of Other Australian*[116]

We have assessed the value of BHP Petroleum's 71.2% interest in the projected ungeared, post tax cash flows, relating to the D&R activities of the Minerva, Griffin and Stybarrow fields, to be a negative value in the range of US$223 million to US$226 million.

Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate operating costs (BHP Petroleum interest) are summarised at Appendix 4.

Production has ceased at the three fields. The estimated obligation in relation to D&R associated with the Minerva, Griffin and Stybarrow fields is incurred over the period 2022 to 2030, totalling US$555 million (pre-tax and excluding PRRT refunds).

In calculating our range of assessed values we have adopted discount rate of 1.5% to 2.0% per annum, which has been estimated having regard to yields on short term US Treasury bonds aligning to the forecast period and reflects that these forecast cash outflows are unavoidable.

11.5.8 *Valuation of Atlantis*[117]

We have assessed the value of BHP Petroleum's 44.0% interest in the projected ungeared, post tax cash flows from development of the Atlantis project to be in the range of US$3,985 million to US$4,170 million. Our valuation takes into account BHP Petroleum's participation interest in the field, along with an allowance for the approved outstanding Phase 3 wells and 2C Contingent Resources.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

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[116] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.
[117] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

Table 73: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil	MMbbl	17	16	14	13	14	153	227
Natural gas liquids	MMboe	1	1	1	1	1	5	9
Henry Hub	MMboe	1	1	1	1	1	8	13
Total Production	**MMboe**	**18**	**18**	**16**	**15**	**16**	**166**	**249**
Operating costs	**US$m**	**165**	**185**	**199**	**215**	**238**	**4,664**	**5,664**
Capital expenditure	**US$m**	**213**	**277**	**400**	**405**	**425**	**984**	**2,705**
Operating costs	US$/boe	9	10	13	15	15	28	23
Capital expenditure	US$/boe	12	16	26	28	27	6	11

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Oil is by far the largest contributor to production revenues, with aggregate forecast sales of 227 MMbbl over the life of the project. Annual production of oil steadily declines year-on-year over the life of the project. Production of both gas and natural gas liquids follow a similar pattern to oil, in terms of a steady decline in year-on-year production volumes over the remaining life of the project.

Atlantis' total life of project Opex is US$5,664 million, which is incurred between 2022 and 2047. Total Opex ramps up from 2022 to 2028, before a steady decline in year-on-year Opex over the remaining life of the project.

Capex for the Atlantis project totals US$2,705 million, comprising of sustaining Capex (US$445 million) and growth Capex (US$2,260 million). The majority of the growth Capex is incurred between 2022 and 2029.

The estimated D&R obligation totals US$1,604 million, the majority of which is incurred between 2047 and 2050.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Atlantis project, based on a range of key assumptions, the outcomes of which are set out in the table below.

Table 74: Sensitivity analysis

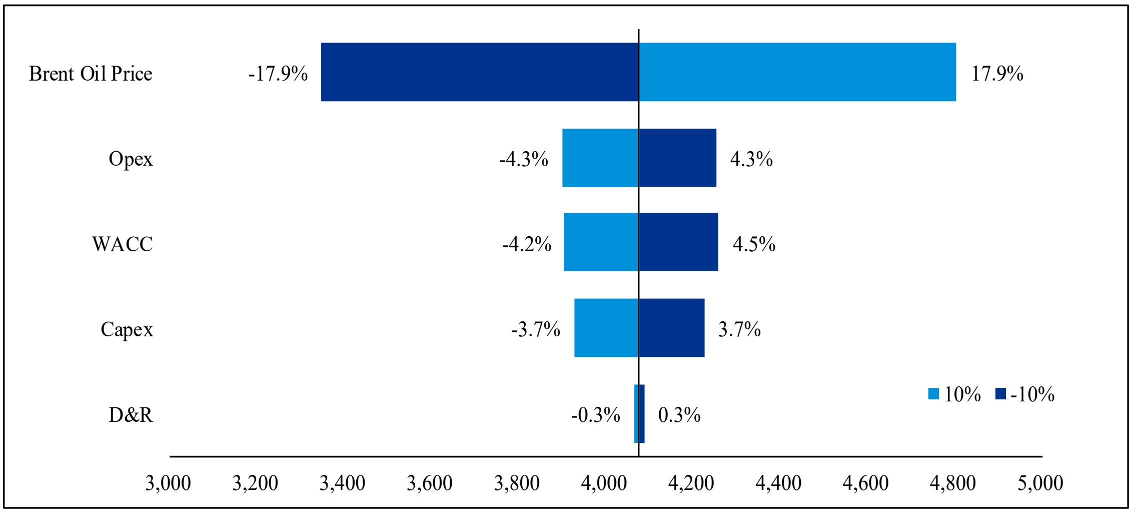
Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price[1]	3,348	3,712	4,076	4,440	4,804
Opex	4,253	4,164	4,076	3,987	3,899

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
WACC	4,259	4,166	4,076	3,989	3,906
Capex	4,225	4,150	4,076	4,001	3,927
D&R	4,087	4,082	4,076	4,070	4,064

Source: KPMG Corporate Finance analysis
Note 1: The forecast WTI price is sensitive to assumptions in relation to the future brent oil price given the interrelationship

This analysis indicates that our range of assessed values of the Atlantis project is most sensitive to the forecast brent oil price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 30 – Atlantis project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.9 Valuation of Mad Dog[118]

We have assessed the value of BHP Petroleum's 23.9% interest in the projected ungeared, post tax cash flows from development of the Mad Dog projects to be in the range of US$3,667 million to US$3,954 million. Our valuation takes into account BHP Petroleum's participation interest in the existing gas field, being Mad Dog A Spar. The valuation also includes the potential production upside from BHP Petroleum's 2P Reserves and 2C Contingent Resources production from Mad Dog Phase 2, and multiple unapproved and unsanctioned projects.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is

[118] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 75: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil (Crude Oil)	MMbbl	8	12	12	11	11	186	240
Oil 2 (Condensate)	MMbbl	0	0	0	0	0	0	0
Natural gas liquids	MMboe	0	0	0	0	0	1	1
Henry Hub	MMboe	0	0	0	0	0	2	4
Total Production	**MMboe**	**9**	**13**	**12**	**11**	**11**	**189**	**245**
Operating costs	**US$m**	**74**	**106**	**107**	**111**	**122**	**3,374**	**3,894**
Capital expenditure	**US$m**	**297**	**237**	**277**	**324**	**261**	**547**	**1,942**
Operating costs	US$/boe	9	8	9	10	11	18	16
Capital expenditure	US$/boe	34	19	23	28	24	3	8

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Production of oil across all Mad Dog projects takes place over the period 2022 to 2057 and makes up the majority of production at Mad Dog, with forecast sales of uncontracted volumes totalling approximately 240 MMboe (includes both crude oil and condensate).

Annual production of all commodities peaks in 2023, before a steady decline in year-on-year production volumes over the remaining life of the Mad Dog fields.

Opex is incurred over the production life of the Mad Dog projects, totalling US$3,894 million. Opex ramps up from 2022 to 2027 primarily due to the development of Mad Dog Phase 2.

Capex for all Mad Dog projects totals US$1,942 million, the majority of which is incurred between 2022 and 2029 due to the development of Mad Dog Phase 2.

The estimated D&R obligation totals US$910 million, the majority of which is incurred between 2042 and 2047 and 2056 to 2058, associated with the abandonment of Mad Dog A Spar and Mad Dog Phase 2, respectively.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Mad Dog project, based on a range of key assumptions, the outcomes of which are set out in the table below.

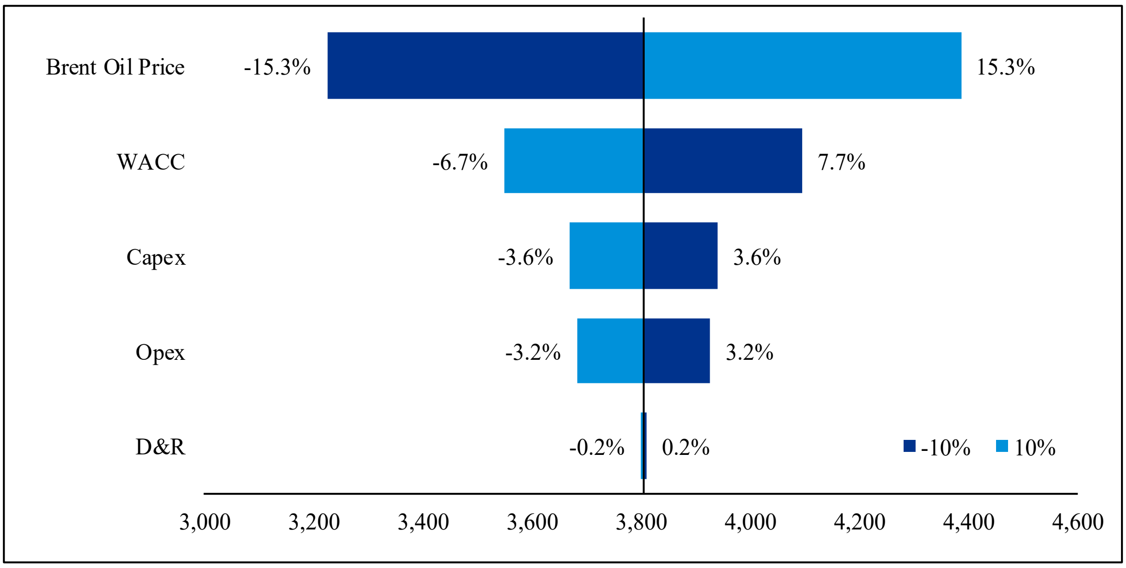
Table 76: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price[1]	3,225	3,515	3,806	4,096	4,387
WACC	4,097	3,946	3,806	3,673	3,549
Capex	3,942	3,874	3,806	3,737	3,669
Opex	3,928	3,867	3,806	3,744	3,683
D&R	3,811	3,808	3,806	3,803	3,800

Source: KPMG Corporate Finance analysis
Note 1: The forecast WTI price is sensitive to assumptions in relation to the future brent oil price given the interrelationship

This analysis indicates that our range of assessed values of the Mad Dog project is most sensitive to the forecast brent oil price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 31 – Mad Dog project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.10 *Valuation of Shenzi*[119]

We have assessed the value of BHP Petroleum's interest in the projected ungeared, post tax cash flows from development of the Shenzi project to be in the range of US$3,857 million to US$4,031 million. Our valuation takes into account BHP Petroleum's participation interest in the existing Shenzi fields. The valuation also includes the potential for production upside from BHP Petroleum's 2P Reserves and 2C Contingent Resources at Shenzi North and Wildling, and multiple unapproved and unsanctioned projects.

[119] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

BHP Petroleum holds a 72% interest in the Shenzi and Shenzi North projects and a 100% interest in the Wildling project.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 77: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production								
Oil	MMbbl	11	12	16	20	18	91	168
Natural gas liquids	MMboe	1	1	1	1	1	4	8
Henry Hub	MMboe	0	0	1	1	1	3	6
Total Production	**MMboe**	**12**	**13**	**18**	**22**	**20**	**98**	**182**
Operating costs	**US$m**	**58**	**118**	**142**	**159**	**164**	**1,324**	**1,966**
Capital expenditure	**US$m**	**393**	**380**	**443**	**349**	**68**	**1**	**1,634**
Operating costs	US$/boe	5	9	8	7	8	14	11
Capital expenditure	US$/boe	33	29	25	16	3	0	9

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Production of oil takes place over the period 2022 to 2038 and makes up the majority of production for the Shenzi fields, with aggregate forecast sales of uncontracted volumes totalling 168 MMbbl. Annual production of natural gas liquids and gas ramps up over the period to 2025 before a steady decline in year-on-year production volumes over the remaining life of the Shenzi fields.

Opex, which peaks in 2026 and continues through to 2038, is incurred over the production life of the Shenzi project, and totals US$1,966 million.

Capex from 2022 through to 2028 is forecast to total approximately US$1,634 million. The estimated obligation in relation to D&R totals US$1,516 million, the majority of which is incurred from 2038 to 2041.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Shenzi project, based on a range of key assumptions, the outcomes of which are set out in the table below.

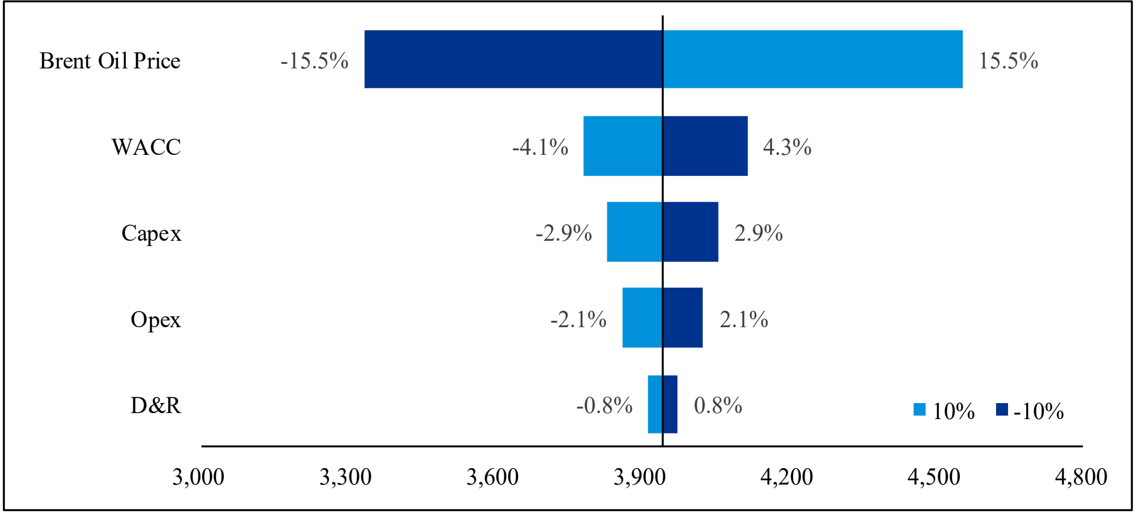
Table 78: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price[1]	3,333	3,638	3,943	4,247	4,552
WACC	4,114	4,027	3,943	3,861	3,781
Capex	4,056	3,999	3,943	3,886	3,829
Opex	4,026	3,984	3,943	3,901	3,859
D&R	3,973	3,958	3,943	3,927	3,912

Source: KPMG Corporate Finance analysis
Note 1: The forecast WTI price is sensitive to assumptions in relation to the future brent oil price given the interrelationship

This analysis indicates that our range of assessed values of the Shenzi project is most sensitive to the forecast brent oil price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 32 – Shenzi project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.11 Valuation of GOM ORRI[120]

We have assessed the value of BHP Petroleum's 100% interest in the projected ungeared, post tax cash flows from the GOM ORRI to be in the range of US$86 million to US$87 million.

Further detail in relation to project technical and operational assumptions (where relevant) are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production (BHP Petroleum interest) is summarised at Appendix 4, noting forecast operating costs and capital expenditure are US$nil.

[120] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

Oil production is forecast to be 1.1 MMbbl from 2022 to 2025. There is no Opex, Capex or D&R incurred by BHP Petroleum over the life of the GOM ORRI.

In calculating our range of assessed values we have adopted a discount rate of 4.5% to 5.5% per annum, reflecting the relatively short term remaining in the project life and that there is no profit risk in the cash flows, as the GOM ORRI is effectively a royalty revenue stream.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the GOM ORRI based on certain key assumptions, the outcomes of which are set out in the table below.

Table 79: Sensitivity analysis

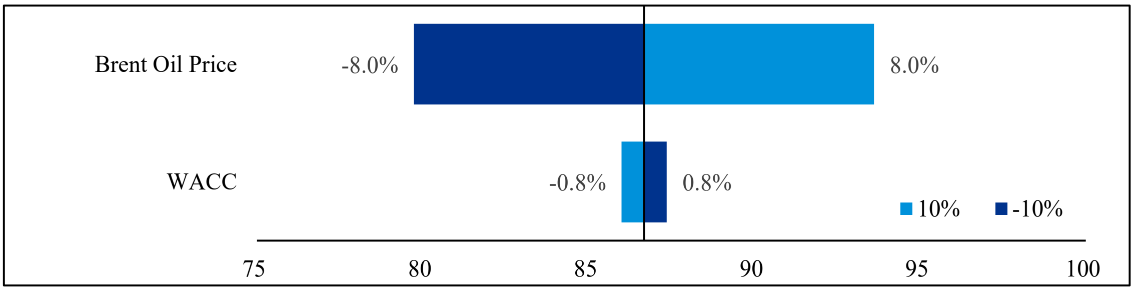
Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price[1]	80	83	87	90	94
WACC	87	87	87	86	86

Source: KPMG Corporate Finance analysis

Note 1: The forecast WTI price is sensitive to assumptions in relation to the future brent oil price given the interrelationship

This analysis indicates that our range of assessed values of the GOM ORRI is most sensitive to the forecast brent oil price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 33 – GOM ORRI DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.12 *Valuation of Greater Angostura Complex*[121]

We have assessed the value of BHP Petroleum's interests in the projected ungeared, post tax cash flows from development of both the Angostura and Ruby projects (Greater Angostura Project) to be in the range of US$544 million to US$555 million. Our valuation takes into account BHP Petroleum's 45% participation interest in Angostura and 68.5% participation interest in Ruby.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is

[121] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 80: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022	2023	2024	2025	2026	Balance	Total
Production[2]								
Oil	MMbbl	1	1	0	0	0	0	2
Gas	MMboe	5	5	5	5	5	5	29
Total Production	**MMboe**	**6**	**5**	**5**	**5**	**5**	**5**	**32**
Operating costs	**US$m**	**43**	**39**	**38**	**36**	**40**	**54**	**251**
Capital expenditure	**US$m**	**5**	**8**	**7**	**4**	**4**	**2**	**30**
Operating costs	US$/boe	8	7	7	7	8	11	8
Capital expenditure	US$/boe	1	2	1	1	1	0	1

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *Production forecasts are net of entitlement volumes*
3. *May not add due to rounding.*

Production of oil and gas at the Greater Angostura Complex takes place over the period 2022 to 2028, with gas making up the majority of production, and aggregate forecast sales of 29 MMboe.

Annual total production is relatively constant between 2022 and 2026, before year-on-year production volumes decline as both the Angostura and Ruby fields reach the end of their remaining lives in 2028 and 2027 respectively.

Opex is incurred over the production life of the Greater Angostura Complex, totalling US$251 million. Opex is relatively constant between 2022 to 2027, before declining in 2028 after Ruby reaches the end of its production life.

Capex is incurred over the production life of the Greater Angostura Complex projects, totalling US$30 million. Capex peaks in 2022 and declines over the remaining production life.

The estimated D&R obligation totals US$165 million. D&R peaks across 2024 to 2026 and is incurred over the remaining production life of the Greater Angostura Complex.

In calculating our range of assessed values, we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Greater Angostura Complex, based on a range of key assumptions, the outcomes of which are set out in the table below.

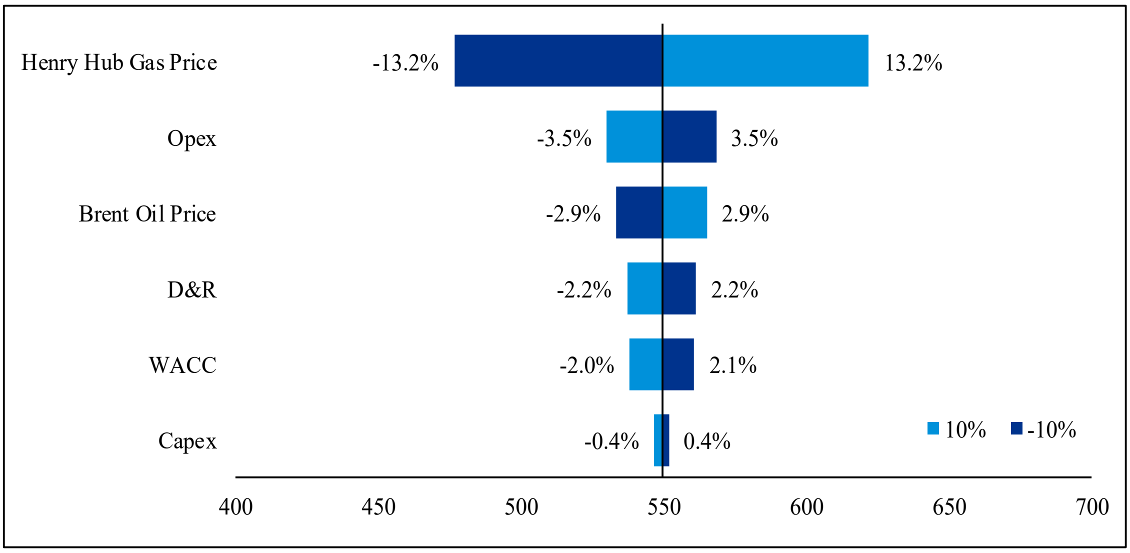
Table 81: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Henry Hub Gas Price	477	513	549	586	622
Opex	569	559	549	540	530
Brent Oil Price[1]	534	542	549	557	565
D&R	562	555	549	543	537
WACC	561	555	549	544	538
Capex	552	551	549	548	547

Source: KPMG Corporate Finance analysis
Note 1: The forecast WTI price is sensitive to assumptions in relation to the future brent oil price given the interrelationship

This analysis indicates that our range of assessed values of the Greater Angostura Complex is most sensitive to the forecast Henry Hub gas price, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 34 – Greater Angostura Complex DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.13 Valuation of Calypso[122]

We have assessed the value of BHP Petroleum's interest in the projected ungeared, post tax cash flows from the development of the Calypso project to be in the range of US$47 million to US$189 million. Our valuation takes into account the potential upside from BHP Petroleum's 70% participation interest in 2C production from Calypso, which has development options under appraisal.

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[122] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 82: Summary of cash flow parameters – BHP Petroleum interest

	Unit[1]	2022-2025	2026	2027	2028	2029	Balance	Total
Production[2]								
Oil	MMbbl	-	-	0	0	0	3	3
Gas	MMbbl	-	-	3	7	8	104	121
LNG	MMboe	-	-	6	16	19	242	283
Total Production	**MMboe**	**-**	**-**	**9**	**23**	**28**	**348**	**408**
Operating costs	**US$m**	**101**	**-**	**22**	**57**	**71**	**1,504**	**1,753**
Capital expenditure	**US$m**	**1,032**	**894**	**720**	**206**	**-**	**676**	**3,528**
Operating costs	US$/boe	n/a	-	2	2	3	4	4
Capital expenditure	US$/boe	n/a	n/a	78	9	n/a	2	9

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *Production forecasts are net of entitlement volumes*
3. *May not add due to rounding.*

Production at the Calypso project is forecast to commence in 2027 and to continue to 2048, with aggregate forecast sales of approximately 283 MMboe of LNG, 121 MMboe of gas and 3 MMbbl of oil.

Annual production ramps up from 2027 to 2031 and peaks from 2032 to 2039, before a steady decline in year-on-year production volumes over the remaining life of the Calypso fields.

Opex totals US$1,753 million and is incurred between 2022 and 2024 and over the production life of the Calypso project. Opex ramps up from 2027 to 2039, before declining in 2047 and 2048 in line with the end of production life.

Capex totals US$3,528 million, the majority of which is incurred between 2024 and 2028, associated with the development of the Calypso project.

The estimated D&R obligation totals US$686 million, incurred across the production life of the project from 2027 to 2048.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Calypso project based on a range of key assumptions, the outcomes of which are set out in the table below.

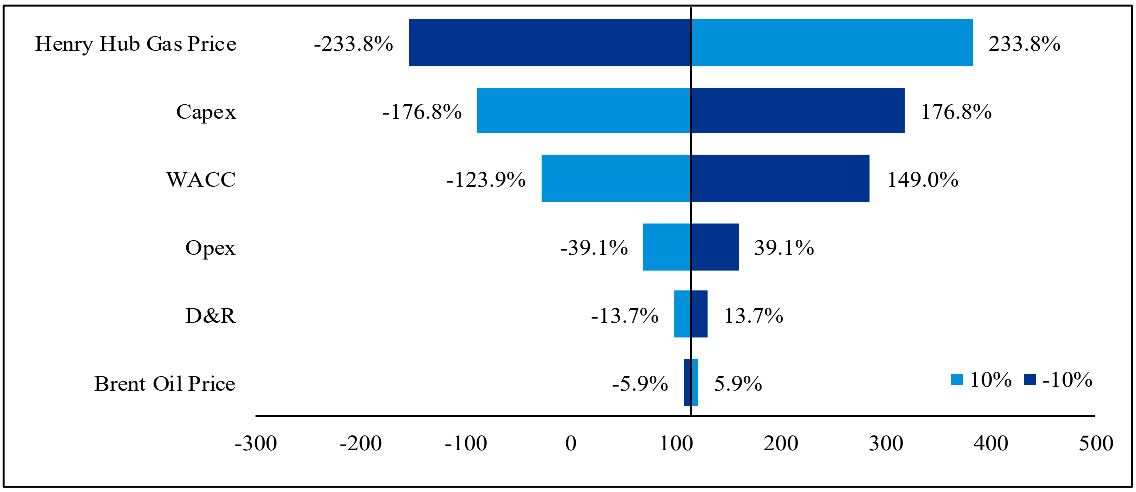
Table 83: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Henry Hub Gas Price	-154	-19	115	249	383
Capex	318	216	115	13	-88
WACC	286	196	115	40	-27
Opex	160	137	115	92	70
D&R	131	123	115	107	99
Brent Oil Price[1]	108	111	115	118	122

Source: KPMG Corporate Finance analysis
Note 1: The forecast WTI price is sensitive to assumptions in relation to the future brent oil price given the interrelationship

This analysis indicates that our range of assessed values of the Calypso project is most sensitive to forecast Henry Hub gas price, forecast Capex and the WACC, as set out in the tornado chart below, which is based on a 10% variance to each key input. The NPV of the Calypso project is very sensitive to changes in key assumptions reflecting it's early stage of development.

Figure 35 – Calypso project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.14 Valuation of Trion[123]

We have assessed the value of BHP Petroleum's 60%[124] interest in the projected ungeared, post tax cash flows from the development of the Trion project to be in the range of US$501 million to US$783 million.

A summary of project outputs (BHP Petroleum interest) is set out in the table below. Further detail in relation to project technical and operational assumptions are discussed in GaffneyCline's ITSR which is

[123] All references to production volumes, operating costs and capital expenditure are based on BHP Petroleum's interest.
[124] BHP Petroleum's working interest in the operating costs and capital expenditure falls from 100% to 60% over 2022 to 2025, as per the fiscal contracts and carry arrangements.

attached at Appendix 15. Aggregate annual production, operating costs and capital expenditure (BHP Petroleum interest) are summarised at Appendix 4.

Table 84: Summary of cash flow parameters (BHP Petroleum interest)

	Unit[1]	2022-2025	2026	2027	2028	2029	Balance	Total
Production								
Oil	MMbbl	-	5	15	21	21	198	259
Gas	MMboe	-	0	0	0	0	2	3
Total Production	**MMboe**	**-**	**5**	**15**	**21**	**21**	**201**	**262**
Operating costs	**US$m**	**1**	**28**	**67**	**79**	**76**	**3,163**	**3,414**
Capital expenditure	**US$m**	**3,178**	**733**	**299**	**255**	**393**	**392**	**5,249**
Operating costs	US$/boe	n/a	6	4	4	4	16	13
Capital expenditure	US$/boe	n/a	156	20	12	19	2	20

Source: GaffneyCline, KPMG Corporate Finance analysis
Notes:
1. *US$ amounts stated in nominal terms*
2. *May not add due to rounding.*

Production at Trion is forecast to commence in 2026 and is expected to continue until 2066. Total life of project production of 262 MMboe is predominately comprised of oil, with 259 MMbbl of uncontracted volumes forecast to be sold from 2026 to 2066, and gas, with 3 MMboe of uncontracted volumes forecast to be sold from 2026 to 2039. Oil production is estimated to peak in 2028 and Gas production in 2033.

Opex, which is forecast to peak in 2060, is incurred over the production life of the Trion project and is forecast to total US$3,414 million. Capex is front loaded from 2022 to 2026 in the lead up to first production and is forecast to total approximately US$5,249 million from 2022 to 2035. Whilst D&R, which is estimated to total US$734 million over the production life, is forecast to be incurred from 2033 to 2066.

In calculating our range of assessed values we have adopted discount rate ranges as set out in Appendix 5.

Sensitivity Analysis

We have undertaken a sensitivity analysis around the mid-point of our DCF valuation range for the Trion project, based on a range of key assumptions, the outcomes of which are set out in the table below.

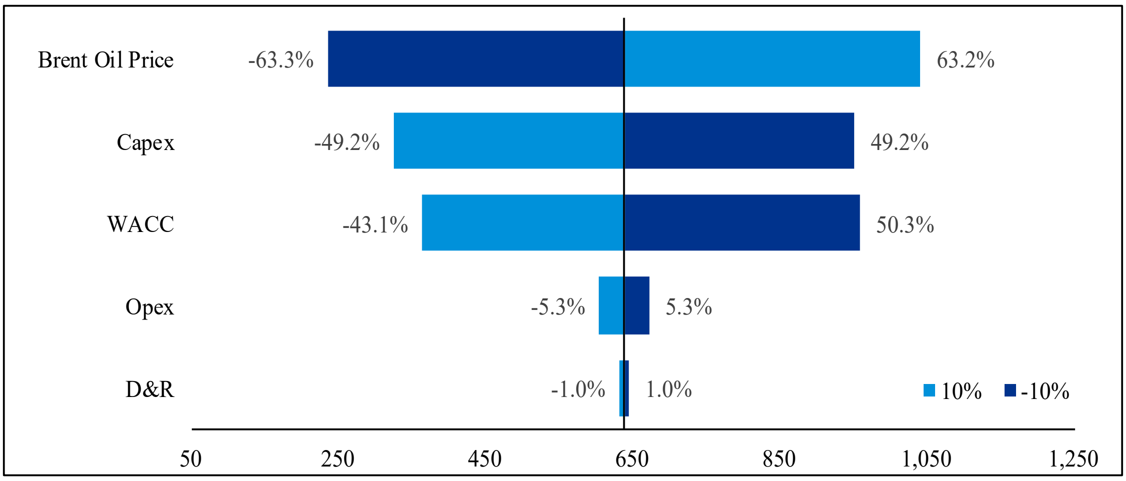
Table 85: Sensitivity analysis

Sensitivity (US$m)	-10%	-5%	0%	5%	10%
Brent Oil Price	234	436	637	839	1,040
Capex	950	794	637	481	324
WACC	958	791	637	495	362
Opex	671	654	637	620	603
D&R	644	640	637	634	631

Source: KPMG Corporate Finance analysis

This analysis indicates that our range of assessed values of the Trion project is most sensitive to the forecast brent oil price, forecast Capex and the WACC, as set out in the tornado chart below, which is based on a 10% variance to each key input.

Figure 36 – Trion project DCF sensitivity



Source: KPMG Corporate Finance analysis

11.5.15 Valuation of BHP Petroleum's interest in other petroleum assets

GaffneyCline has assessed a value range for BHP Petroleum's interest in other petroleum assets not included in the above sections to be in the order of US$190 million to US$436 million as summarised in the table below.

Table 86: Summary of valuations of other petroleum assets – BHP Petroleum interest[1]

	Assessed Values	
	Low US$m	High US$m
GOM Prospect 1	83	215
GOM Prospect 2	Nil	106
Australia Prospect 1	48	51
Australia Prospect 2	60	64
Total other petroleum assets	**190**	**436**

Source: GaffneyCline
Notes:
1. BHP have requested that we remove the prospect names given they are commercially sensitive

In its assessment of the value of the other petroleum assets, GaffneyCline has adopted generally accepted methods for valuing early stage petroleum assets including expected monetary value approach, comparable transactions and sunk costs. Further details in relation to each of these assets and the valuation methodology adopted are set out in GaffneyCline's ITSR which is included at Appendix 15. It should be noted that the valuation of early stage/exploration assets is highly subjective and involves subjective assessments, based on professional judgements made by GaffneyCline.

11.5.16 Valuation of other assets and liabilities

Net assets not valued as part of BHP Petroleum's assets comprise cash and other sundry assets and liabilities held by BHP Petroleum. Except as specifically noted below, having regard to their nature and quantum, these assets and liabilities have been incorporated in our valuation at net book values as at 31 December 2021.

Scarborough Put Option

In a separate arrangement to the Proposed Transaction, BHP and Woodside have agreed an option for BHP Petroleum to divest both its 26.5% interest in the Scarborough project and its 50% interest in the Thebe and Jupiter Joint Ventures to Woodside in the event the Proposed Transaction is not completed. The option is exercisable by BHP Petroleum in the second half of CY22 and if exercised, the following consideration will be payable to BHP Petroleum:

- US$1 billion, with an adjustment for expenditure incurred by BHP Petroleum in relation to Scarborough over the period 1 Jul 2021 to the date of exercise (the expenditure adjustment is also subject to interest costs at a rate of 3.5% per annum, compounded monthly)
- US$100 million contingent amount (nominal) payable FID of Thebe.

Based on these terms and information provided by Woodside and GaffneyCline in relation to estimated joint venture costs for the 12 months to 30 June 2022, we have calculated the potential cash payment required to be made by Woodside as at 1 July 2022 (being the earliest date the put option can be exercised).

We have not included the contingent amount given the uncertainty regarding the timing of Thebe FID, if at all, consistent with GaffneyCline's approach to its valuation of Thebe.

As discussed above at section 11.3.12, we have separately assessed the estimated value of BHP Petroleum's 26.5% interest in the Scarborough project as at 1 July 2022 as being in the range of US$562 million to US$736 million (determined by rolling forward the 31 December 2021 valuation of BHP Petroleum's interest in the Scarborough project, as discussed below).

We have compared this value range to the estimated consideration described above under the option and determined the difference to be the implied value of the option, being in the range of US$419 million to US$593 million. We have adopted this difference as a surplus asset in the overall value of BHP Petroleum. Exercise of the put option may have upfront tax implications which could reduce the value to BHP Petroleum. As the potential value impact of any future tax liability is not able to be quantified with certainty at this time, we have not adjusted the valuation in relation to same. Based on the quantum of the put option exercise price, the value impact of any potential tax liability would not change our opinion.

Net working capital

In assessing the value of BHP Petroleum we have included a value for the movement in working capital over the forecast period, incorporating the 31 December 2021 BHP Petroleum opening working capital balances (including the current overlift and underlift positions). We have adopted the closing BHP Petroleum balances as at 31 December 2021 for accounts receivable, accounts payable and inventory as the opening balances in our analysis.

Our value is based on an analysis of the 31 December 2021 balance sheet for BHP Petroleum and consideration of working capital metrics of comparable companies operating in the predominantly upstream conventional sector as set out in Appendix 6. We have adopted debtor days, creditor days and inventory days calculation to estimate forecast working capital balances based on our comparable company benchmarking.

In calculating our value range of assessed working capital movements, we have adopted a blended discount rate of 8.5% to 9.5% per annum at the corporate level, which has been estimated based on a weighted average blend of the discount rates applied in the valuation of each of BHP Petroleum's assets, having regard to the NPV of BHP Petroleum's interest in each project.

The NPV of the forecast working capital movements spend has been estimated to be in the order of US$20 million (negative) and US$2 million.

Future corporate overheads

BHP Petroleum incurs corporate overheads in relation to managing its business on a standalone basis. These costs have not been incorporated in the valuation of BHP Petroleum's interest in the assets set out above, and therefore it is necessary to deduct the present value of the anticipated future management and administrative costs in relation to BHP Petroleum's assets from the overall value of BHP Petroleum.

We have been provided with a schedule prepared by Woodside that sets out the expected future corporate costs for BHP Petroleum on a standalone basis. These costs include general and administrative expenses, insurance costs, Sarbanes-Oxley compliance costs, NOGA levy, ongoing costs related to MWCC, assumed severance liabilities and costs of compensating BHP Petroleum staff for exiting the BHP incentive plan. Total corporate costs incurred have been assumed to decline in line with production over the forecast period.

As noted early in this section, we have not incorporated any allowance for cost savings and/or synergies that might be available to an unrelated third-party purchaser of BHP Petroleum.

In assessing the value of the future corporate overheads we have included the expected tax benefit that should arise as a result of the utilisation of net operating losses (**NOLs**) available in the United States and tax losses in Mexico that are assumed to be available to BHP Petroleum on a standalone basis on the assumption that the relevant loss recoupment tests will be satisfied (as required by the relevant tax legislation) at the relevant time.

In calculating the NPV of estimated corporate costs, we have adopted a blended discount rate of 8.5% to 9.5% per annum at the corporate level, which has been estimated based on a weighted average blend of the discount rates applied in the valuation of each of BHP Petroleum's assets.

The NPV of the forecast after-tax corporate costs, having regard to the various projects and respective cessation of production, has been estimated to be in the order of US$1,568 million to US$1,722 million.

11.6 Other Valuation Parameters – BHP Petroleum

Having regard to our assessed values in respect of BHP Petroleum's assets and liabilities, the implied enterprise value for BHP Petroleum is between approximately A$23,733 million and A$25,812 million, which, based on GaffneyCline's assessed 1P and 2P Reserves of BHP Petroleum as at 31 December 2021 implies a value per boe as summarised in the table below.

Table 87: Summary of 1P and 2P boe multiples implied by our assessed value of BHP Petroleum

Parameter	Low A$/boe	High A$/boe
1P	25	27
2P	16	17

Source: KPMG Corporate Finance analysis

Note 1: The assessed enterprise value of BHP Petroleum has been calculated as the aggregate of assessed equity values, adjusted for lease liabilities, net cash and put option for Scarborough (receivable from Woodside)

Comparison to contained boe 1P and 2P multiples implied by listed comparable companies

The implied value per 1P and 2P boe Reserves for a selection of companies involving companies predominantly focused on conventional upstream hydrocarbon production are summarised in the table below.

Table 88: Summary of 1P and 2P multiples for comparable predominantly conventional upstream hydrocarbon production companies

	1P Reserves A$/boe	2P Reserves A$/boe
Low	9	7
Mean	30	21
Median	25	19
High	58	44

Source: KPMG Corporate Finance analysis

This analysis indicates a wide range of outcomes, however we note that the range of 1P and 2P multiples implied by our range of assessed values for BHP Petroleum lies within the range of equivalent observed listed company multiples and is relatively aligned with the mean and median multiples.

Whilst in our view the outcome of this analysis provides broad support for our range of values, due to the limitations of this form of analysis highlighted in Appendix 10, it should only be considered as a high-level cross-check of the outcomes of other valuation methodologies and not as a determinant of value.

Further details of our analysis are set out in Appendix 10 to this report.

Comparison to contained boe 1P and 2P multiples implied by comparable transactions

The implied value per 1P and 2P boe Reserves and resources for a selection of recent corporate transactions involving companies/projects predominantly focused on conventional upstream hydrocarbon production are summarised in the table below.

Table 89: Summary of 1P and 2P multiples for comparable predominantly conventional upstream hydrocarbon production transactions

	1P Reserves A$/boe	2P Reserves A$/boe
Low	13	2
Mean	25	13
Median	23	12
High	40	35

Source: KPMG Corporate Finance analysis

This analysis indicates a wide range of outcomes, however we note that the range of 1P and 2P multiples implied by our range of assessed market values for BHP Petroleum lies within the range of equivalent observed corporate transaction multiples for 1P and 2P multiples, and is relatively aligned with the mean and median multiples.

Whilst in our view the outcome of this analysis provides broad support for our range of values, due to the limitations of this form of analysis highlighted in Appendix 14, it should only be considered as a high-level cross-check of the outcomes of other valuation methodologies and not as a determinant of value.

Further details of our analysis are set out in Appendix 14 to this report.

11.7 Valuation of the Merged Group

We have assessed the full underlying value of the Merged Group immediately after completion of the Proposed Transaction to be in the range of US$37,242 million to US$42,302 million, which equates to between A$49,836 million to A$56,607 million[125], or between A$26.25 and A$29.81 per diluted Merged Group share.

However, for the reasons stated previously at section 11.1 above, we have not incorporated any allowance for additional cost savings and/or synergies that might be available to an unrelated third-party purchaser of the Merged Group itself at some future point in time after completion of the Proposed Transaction. Accordingly, whilst our assessment of value of the Merged Group has been completed on a 100% equity basis, it does not include a full premium of control.

Table 90: Assessed value of the Merged Group

	Assessed Values	
All figures in US$ million (unless otherwise stated)	**Low**	**High**
Woodside equity value	16,978	19,424
BHP Petroleum equity value	19,064	20,443
Add: Synergies expected to be achieved, post-tax	2,364	3,599
Add: Woodside regret costs, post-tax	70	70
Less: Transaction costs, post-tax	(287)	(287)
Less: Dividend payment	(830)	(830)
Less: Locked box payment	(117)	(117)

[125] Based on an USD:AUD exchange rate of approximately 0.747.

All figures in US$ million (unless otherwise stated)	Assessed Values Low	High
Merged Group equity value	**37,242**	**42,302**
Woodside ordinary shares	984.0	984.0
Add: New Woodside shares to be issued	914.8	914.8
Merged Group shares (diluted)	**1,898.7**	**1,898.7**
Merged Group value per share (US$/share)	**19.61**	**22.28**
Merged Group value per share (A$/share)	**26.25**	**29.81**

Source: KPMG Corporate Finance analysis

The market value of a share in the Merged Group on a 100% basis has been determined by:

- aggregating the value of each of Woodside's and BHP Petroleum's standalone equity values
- adjusting for:
  - our assessed NPV range for the post-tax synergies and cost savings (net of one-off costs) expected to be available to Woodside in combining its existing portfolio of oil and gas assets with those held by BHP Petroleum, which is discussed further below
  - adding back of Woodside's regret costs included in our assessment of Woodside's equity value as a standalone entity, reflecting that these costs will be replaced by estimated transaction costs of US$410 million (pre-tax)
  - deduction of Woodside's estimate of the dividend payment to BHP representing the cash dividend that BHP would have received (from 1 July 2021) had the Proposed Transaction completed on the Effective Date
  - deduction of the estimated locked box payment as at 31 December 2021, representing the pre-tax net cash flow generated by BHP Petroleum, adjusted for permitted adjustments, between 1 July 2021 and implementation of the Proposed Transaction, which is net of cash held in bank accounts beneficially controlled by BHP Petroleum and assumed by Woodside
- adjusting the Merged Group's issued capital to reflect 914.8 million new Woodside shares to be issued to BHP shareholders.

NPV of estimated synergies that may be available to the Merged Group

As set out in section 10.5, Woodside has undertaken a review of the costs of the Merged Group, with the support of external advisors, and identified a range of synergy opportunities in relation to the Merged Group.

The identified synergy opportunities, estimated at US$400 million per annum, will be realised progressively, with full implementation expected by early 2024.

Woodside estimates that the implementation of the identified synergy opportunities would require one-off costs in the order of US$500 million to US$600 million to be incurred in the first two years following completion of the Proposed Transaction.

In calculating the NPV of estimated synergies we have adopted a blended discount rate of 8.0% to 9.0% per annum at the corporate level, which has been estimated based on weighted average blending of the discount rates applied in the valuation of each of the Merged Group's assets, having regard to the NPV of the Merged Group's interest in each project.

The NPV of the forecast after-tax synergies for the Merged Group, having regard to the various projects and respective cessation of production, has been estimated to be in the order of US$2,364 million to US$3,599 million.

Comparison to traded share price

Our assessed values for a Merged Group share of between A$26.25 and A$29.81 lies below Woodside's closing price of A$33.20 per share on 24 March 2022. This may reflect:

- whilst our valuation of the Merged Group incorporates an uplift for the benefits of the Proposed Transaction, including for the potential of up to US$400 million in annual pre-tax synergies and other costs savings expected by Woodside to be realised progressively over the period to 2024, it does not include any uplift for Woodside's expectation that the final quantum of costs savings and synergies could potentially exceed this amount
- the market is more bullish in relation to the value of the Merged Group's asset portfolio, either in relation to the technical and operational assumptions estimated by GaffneyCline, including GaffneyCline's assessment of the chance of development of various pre-production assets, or in relation to the macroeconomic assumptions adopted by us, including future commodity prices and discount rates. As noted, previously, given the current volatility in commodity markets, a range of macroeconomic assumptions could credibly be adopted, which has the potential to be accretive or dilutive to value. To assist readers in this regard we have included sensitivity analysis around key value drivers for each project in sections 11.3 and 11.5 of this report.

Our valuations of each of Woodside and BHP Petroleum and their underlying asset portfolios are set out in greater detail in Sections 11.3 and 11.5 of this report and in GaffneyCline's report is attached as Appendix 15.

We would normally compare the share price implied by our standalone valuation of Woodside to Woodside's share price immediately prior to the Initial Announcement. However given the significant movement in the key commodity prices since the Initial Announcement, which are reflected in our valuation but not the Initial Announcement share price, we do not consider such an analysis would be meaningful.

Appendix 1 – KPMG Corporate Finance Disclosures

Qualifications

The individuals responsible for preparing this report on behalf of KPMG Corporate Finance are Jason Hughes, Bill Allen, Sean Collins and Ben Della-Bosca. Each has a significant number of years of experience in the provision of corporate financial advice, including specific advice on valuations, mergers and acquisitions, as well as preparation of expert reports.

Jason Hughes is an Authorised Representative of KPMG Financial Advisory Services (Australia) Pty Ltd and a Partner in the KPMG Partnership. Jason is a Fellow of Chartered Accountants Australia and New Zealand and holds a Bachelor of Commerce and a Graduate Diploma in Applied Finance.

Bill Allen is an Authorised Representative of KPMG Financial Advisory Services (Australia) Pty Ltd and a Partner in the KPMG Partnership. Bill is an Associate of Chartered Accountants Australia and New Zealand and holds a Bachelor of Commerce degree and a Graduate Diploma in Applied Finance.

Sean Collins is an Authorised Representative of KPMG Financial Advisory Services (Australia) Pty Ltd and a Partner in the KPMG Partnership. Sean is a Fellow of Chartered Accountants Australia and New Zealand, a Fellow of the Chartered Institute of Securities and Investments in the United Kingdom and holds a Bachelor of Commerce.

Ben Della-Bosca is an Authorised Representative of KPMG Financial Advisory Services (Australia) Pty Ltd. Ben is an Associate of Chartered Accountants Australia and New Zealand, a Fellow of the Financial Services Institute of Australasia and holds a Masters of Applied Finance, a Bachelor of Commerce and a Graduate Diploma in Applied Finance.

Disclaimers

It is not intended that this report should be used or relied upon for any purpose other than KPMG Corporate Finance's opinion as to whether the Proposed Transaction is in the best interests of Woodside Shareholders. KPMG Corporate Finance expressly disclaims any liability to any Woodside 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.

Other than this report, neither KPMG Corporate Finance nor the KPMG Partnership has been involved in the preparation of the Explanatory Memorandum or any other document prepared in respect of the Proposed Transaction. Accordingly, we take no responsibility for the content of the Explanatory Memorandum as a whole or other documents prepared in respect of the Proposed Transaction.

We note that the forward-looking financial information prepared by Woodside does not include estimates as to the potential impact of any future changes in taxation legislation in Australia or other jurisdictions. Future taxation changes are unable to be reliably determined at this time.

Independence

KPMG Corporate Finance and the individuals responsible for preparing this report have acted independently. In addition to the disclosures in our Financial Services Guide, it is relevant to a consideration of our independence that, during the course of this engagement, KPMG Corporate Finance provided draft copies of this report to management of Woodside for comment as to factual accuracy, as opposed to opinions which are the responsibility of KPMG Corporate Finance alone. Changes made to this report as a result of those reviews have not altered the opinion of KPMG Corporate Finance as stated in this report.

Consent

KPMG Corporate Finance consents to the inclusion of this report in the form and context in which it is included with the Explanatory Memorandum to be issued to the shareholders of Woodside. Neither the whole nor the any part of this report nor any reference thereto may be included in any other document without the prior written consent of KPMG Corporate Finance as to the form and context in which it appears.

Our report has been prepared in accordance with professional standard APES 225 "Valuation Services" issued by the Accounting Professional & Ethical Standards Board. KPMG Corporate Finance and the individuals responsible for preparing this report have acted independently.

Appendix 2 – Sources of information

In preparing this report we have been provided with and considered the following sources of information:

Publicly available information:

- company presentations and announcements of Woodside and BHP
- Woodside annual reports for the periods ended 31 December 2019, 31 December 2020 and 31 December 2021
- annual reports, company presentations and news releases of comparable companies
- data providers including S&P Capital IQ Pty Ltd, Bloomberg, MergerMarket, Thompson One, Consensus Economics, Connect 4, IBISWorld Pty Ltd, Economic Intelligence Unit, Oxford Economics and the Department of Industry Innovation and Science.
- various ASX company announcements
- various broker and analyst reports
- various press and media articles
- the Explanatory Memorandum
- GaffneyCline's ITSR.

Non-public information

- life of field forecast production and costing projections prepared by GaffneyCline
- other confidential agreements, documents, presentations and industry papers provided by Woodside and BHP Petroleum.

In addition, we have held discussions with, and obtained information from, the senior management of Woodside and BHP.

Appendix 3 – Overview of the oil and gas industry

The oil and gas industry consists of the upstream and midstream segments, which extract, produce and process crude oil, natural gas liquids and natural gas, and the downstream segment which refines these outputs into fuels, lubricants and other petroleum-based products and the ultimate sale of these products.

Woodside's and BHP Petroleum's principal assets comprise interests in upstream/midstream projects[126]. Accordingly, in order to provide a context for assessing the prospects of Woodside and BHP Petroleum, we have set out below an overview of recent trends and outlook in international oil and gas markets, including LNG and Australian domgas markets.

Oil industry

We would highlight however that this industry overview was prepared just prior to the breakout of hostilities between Russia and the Ukraine and the consequent trade and other economic sanctions imposed on Russia by various countries. Given the short period of time that has elapsed since Russia's invasion on 24 February, the continuing evolving nature of the situation and uncertainty as to the impact of these events over the medium to longer term, it is not practicable to update our analysis to reflect these circumstances.

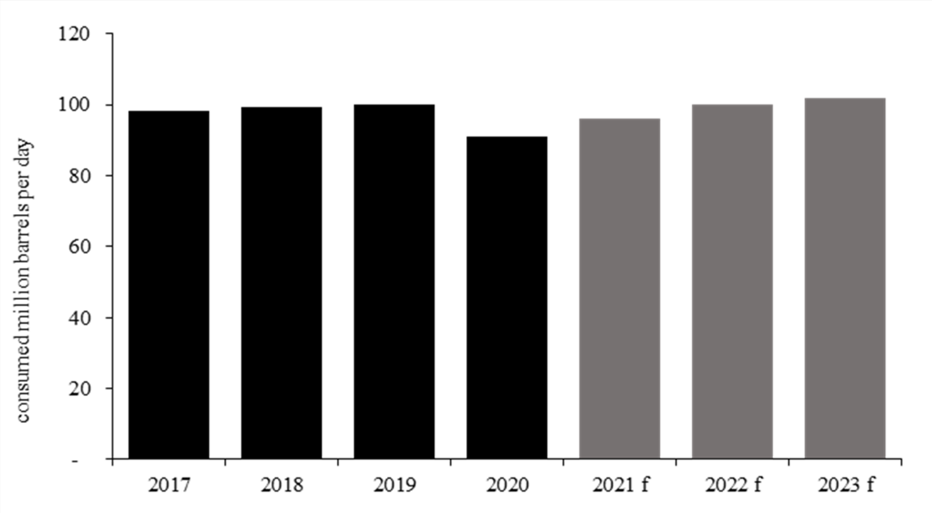
Demand

Recent trends and medium-term outlook

Global oil consumption was significantly impacted by the Covid-19 pandemic in 2020, and whilst the impacts of the pandemic are likely to linger for an extended period, global consumption of oil increased over 2021 on the back of a recovery in world economic activity. Overall global oil consumption is forecast by the Department of Industry, Science, Energy and Resources (**DISER**) to increase by 3.5% year-on-year to 100 MMbbl a day in 2022, and then rise above pre-pandemic levels in 2023 to 102 MMbbl a day.

[126] Although Woodside's and BHP Petroleum's downstream sales function do not have significant tangible assets, the intangible assets e.g. customer relationships, knowledge of markets/pricing, shipping scheduling etc. also assist in driving the value of each entity's projects.

Figure 37 – Historical and projected global oil consumption



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

Note 1: 2021 consumption onwards are forecasts

Oil consumption in Organisation for Economic Co-operation and Development (**OECD**)[127] countries increased over 2021, boosted by a significant increase in travel in both the US and Europe; OECD growth was however somewhat dampened as a result of a fall in OECD Asia Pacific consumption, where the Covid-19 Delta variant forced Australia, Japan and Korea to re-impose containment measures.

DISER expects the continued roll-out of vaccines across the OECD to support further positive growth in 2022, but notes that OECD consumption may never surpass 2019 levels, driven by improved fuel efficiency in passenger cars and increasing penetration of electric vehicles (**EVs**).

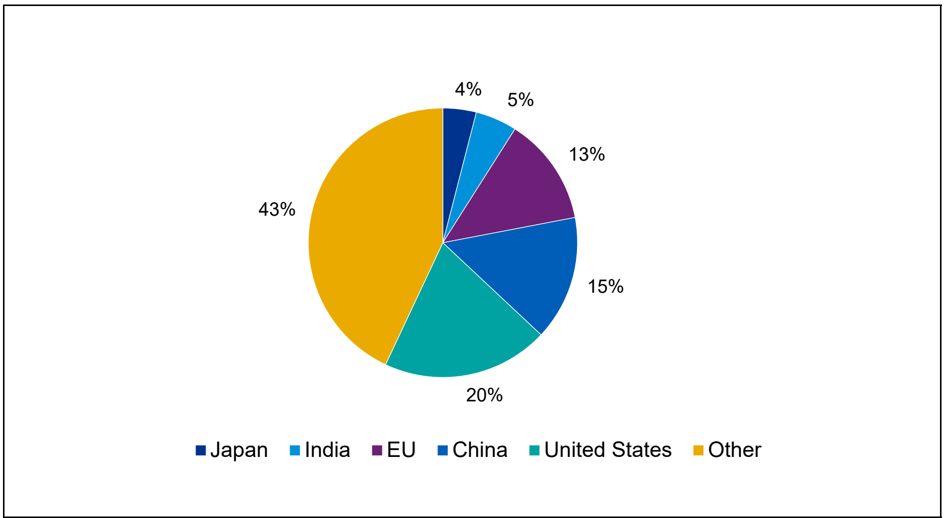
Non-OECD consumption is estimated to have increased by approximately 17% year-on-year to December 2021, largely driven by higher demand in China and India for gasoline, fuel oil and petrochemicals. Non-OECD growth is however being restricted somewhat by South East Asian nations, including Indonesia, Malaysia, Vietnam and Myanmar, which are experiencing a slower recovery from Covid-19, reducing the speed of regional economic re-opening.

In 2022, DISER is forecasting a further increase in non-OECD consumption – surpassing 2019 pre-pandemic levels, with power generators switching away from gas and coal due to global shortages impacting those markets.

127 The OECD is a group of 37 member countries that discuss and develop economic and social policy. Members of the OECD are typically democratic countries that support free-market economies.

Figure 38 below details the top five global oil consumers in 2020.

Figure 38 – Global oil consumers 2020



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

Long-term outlook

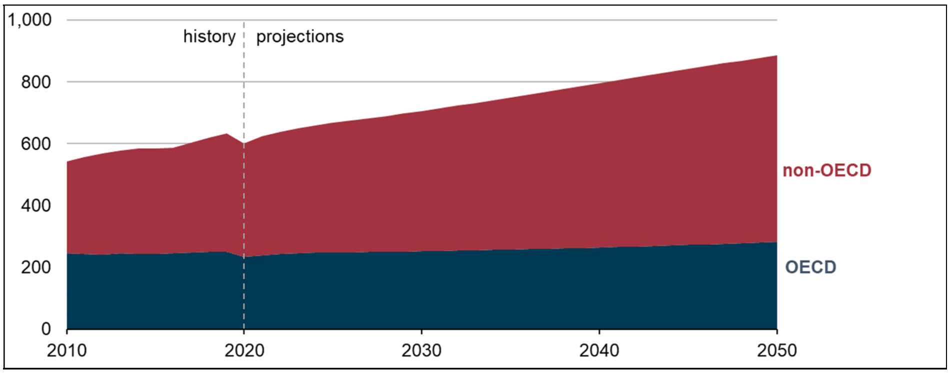
Whilst is generally accepted that over the period to 2050, there is likely, based on current policy settings, to be a significant increase in the level of global consumption of energy, market opinion in relation to the role oil will play in meeting that demand is unsettled, with the final outcome heavily influenced by the speed, extent and success at which the global community transitions to clean energy alternatives.

*US Energy Information Administration (**EIA**)*

The EIA forecasts[128] global energy consumption to increase by almost 50% over the period to 2050, driven largely by growth in both population and gross domestic production in non-OECD countries, particularly in Asia.

[128] References to the views of the EIA are sourced from its "Reference case", which was prepared on the basis of existing laws and regulations and reflects legislated energy sector policies that can be reasonably be modelled, set out in its "International Energy Outlook 2021" published in October 2021. It does not include allowances for technological breakthroughs or policy changes

Figure 39 – Historical and projected global energy consumption - quadrillion BTUs



Source: EIA, International Energy Outlook 2021

The EIA expects global consumption of renewable energy to more than double over the period to 2050, and its relative share of global primary energy consumption to increase to 27%, however, absent future technology breakthroughs or significant policy changes, it does not expect renewables to replace the consumption of petroleum and other liquid fuels[129]; reflecting:

- while plug-in EVs are expected to make up almost a third of global light-duty vehicle stock by 2050, the majority of light-duty vehicles are still expected to continue to be powered by internal combustion engines
- total energy consumption for passenger travel in OECD countries remains below 2019 levels through to 2050, energy consumed in non-OECD passenger travel exceeds OECD countries by 2025
- Industrial sector use in non-OECD countries more than doubling that of OECD countries by 2050.

BP

BP projects[130] a more muted growth in global energy demand[131] under its Business-as-usual (**BAU**) scenario[132], with growth in the order of 25% over the period to 2050, driven principally by increasing levels of prosperity and urbanisation in emerging economies. BP also modelled two additional scenarios: a Rapid Transition Scenario[133] (**Rapid**) and a Net Zero Scenario[134] (**Net Zero**), both of which project growth in global demand of just 10% over the forecast period.

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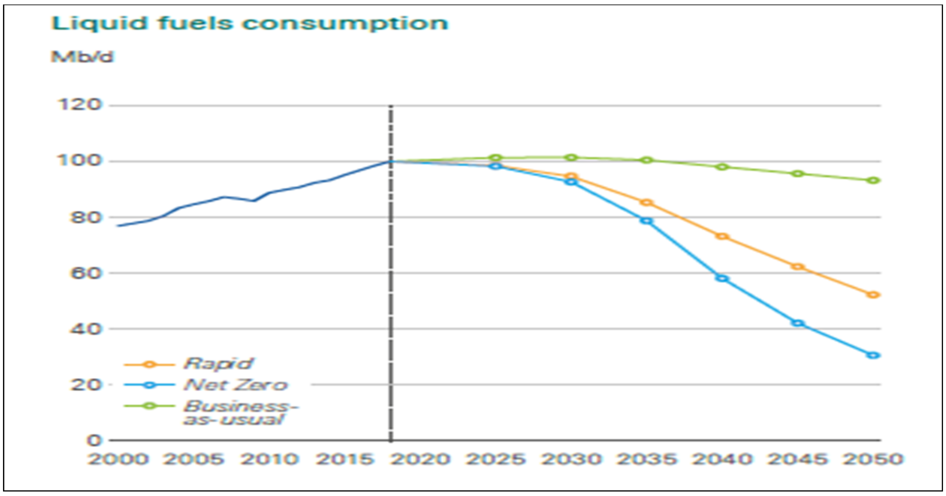
[129] defined by the EIA to include biofuels
[130] References to the views of BP are sourced from its "bp Energy Outlook 2020 edition"
[131] In exajoules
[132] assumes that government policies, technologies and social preferences continue to evolve in a manner and speed seen over the recent past
[133] Assumes a series of policy measures are implemented, led by a significant increase in carbon prices and supported by more-targeted sector specific measures, which cause carbon emissions from energy use to fall by around 70% by 2050
[134] Assumes that the policy measures embodied in Rapid are both added to and reinforced by significant shifts in societal behaviour and preferences, which further accelerate the reduction in carbon emissions. Global carbon emissions from energy use fall by over 95% by 2050

Under its BAU scenario, BP expects that demand for liquid fuels[135] will continue to grow in India, Other Asia and Africa, but will be offset by a decline in consumption in developed economies, such that demand for liquid fuels will remain broadly flat at around 100 MMbbl a day for the next 20 years, before declining slowly to around 95 MMbbl a day by 2050.

Under its Rapid and Net Zero scenarios, both the extent and rate of decline in global demand for liquid fuels is more pronounced, falling to less than 55 MMbbl a day and to around 30 MMbbl a day by 2050 respectively. The falling demand is concentrated in the developed world and China, with consumption in India, Other Asia and Africa broadly flat over the outlook as a whole.

Figure 40 – Recent historical and projected annual liquid fuels consumption



Source: bp Energy Outlook 2020 edition

*The International Energy Agency (**IEA**)*

The IEA expects[136] global energy demand to increase strongly from current levels under its "Stated Policies Scenario" [137] (**STEPS**), with this increased demand met by a changing energy mix as countries move towards clean energy. Global oil demand is projected to exceed 2019 levels by 2023, before reaching peak demand in the mid-2030s, with a marginal year-on-year decline thereafter to 103 MMbbl a day by 2050.

The IEA has also modelled two additional scenarios: an "Announced Pledges Scenario" (**APS**)[138] and a "Net Zero Emissions by 2050 Scenario" (**NZE**)[139]. Under APS, fuel efficiency gains result in global

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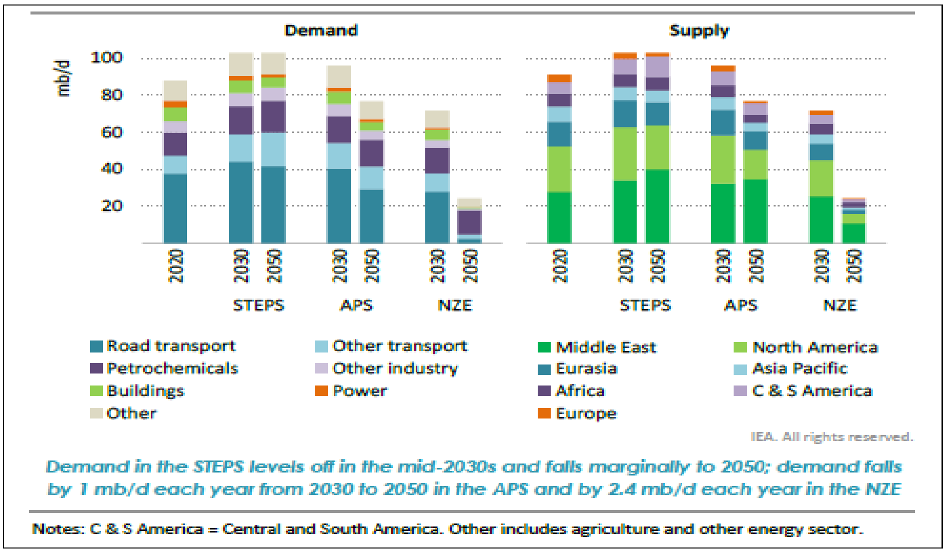
[135] Defined by BP to include crude oil (including shale oil and oil sands); natural gas liquids; gas-to-liquids; coal-to-liquids; condensates; and refinery gains and biofuels
[136] References to the views of the IEA are sourced from its "World Energy Outlook 2021" published in October 2021
[137] STEPS reflects what climate change measures governments have in place, as well as specific clean energy policy initiatives that are under development
[138] APS assumes that those climate change commitments announced by countries in the period prior to the publication of IEA's report are implemented in full
[139] NZE which reflects IEA's assumptions as to what is required to achieve Net Zero by 2050

demand for oil peaking soon after 2025, before declining year-on-year to 77 MMbbl a day in 2050, reflecting:

- that consumption of hydrogen-based fuel cells reaches material levels in the 2030s
- almost 50% of passenger cars EVs and nearly 25% of heavy trucks are either electric or fuel cell powered.

Under the IEA's NZE, more rapid action to address climate change sees demand for oil falling sharply to 72 MMbbl a day by 2030 and continuing to fall to 24 MMbbl a day by 2050.

Figure 41 – Oil supply and demand in 2030 and 2050



Source: IEA World Energy Outlook 2021

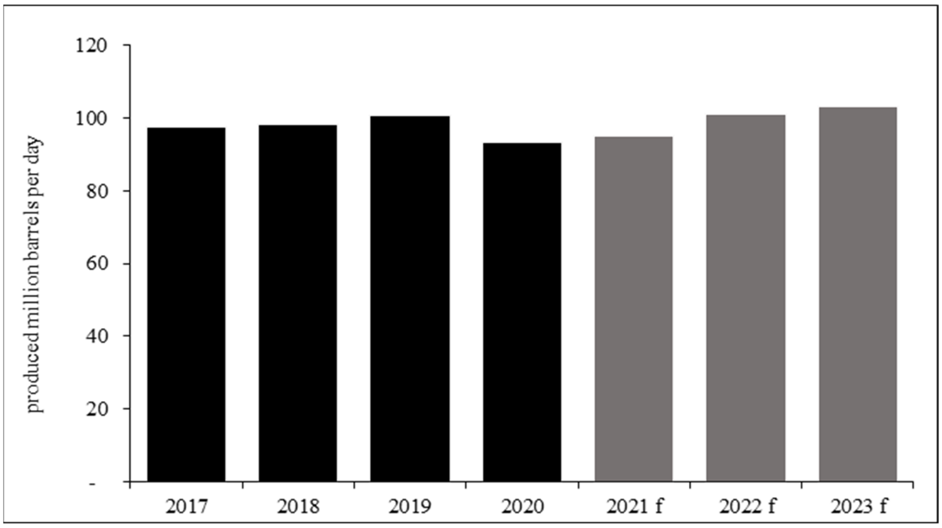
Supply

Recent trends and medium-term outlook

Global oil production is estimated by DISER to have risen 2.1% over 2021 to 95 MMbbl a day, principally due to increasing OPEC+[140] production in the second half of 2021, and is forecast to rise further to 101 MMbbl a day in 2022 on further production increases from OPEC+ and a ramp up in US shale output, and to 103MMbbl in 2023.

[140] Organisation of the Petroleum Exporting Countries (**OPEC**) is a permanent intergovernmental organisation of 13 oil-exporting developing nations that coordinates and unifies the petroleum policies of its Member Countries, comprising Algeria, Angola, Congo, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates and Venezuela. OPEC+ comprises OPEC members, plus Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan and Sudan.

Figure 42 – Historical and projected global oil production



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

In response to a fall in demand due to the outbreak of Covid-19, global storage filling quickly and falling oil prices, OPEC+ members agreed in April 2020 to adjust downwards their overall crude oil production by 9.7 MMbbl per day starting on 1 May 2020, for an initial period of two months concluding on 30 June 2020. For the subsequent period of 6 months, from 1 July 2020 to 31 December 2020, the total adjustment agreed was reduced to 7.7 MMbbl per day. Followed by a 5.8 MMbbl per day adjustment for the 16 months, from 1 January 2021 to 30 April 2022. Throughout 2020 and early 2021, OPEC+ compliance with these output cuts was high.

In July 2021, OPEC+ members announced they had agreed to wind back the current levels of cuts of 5.8 MMbbl per day, increasing by 0.4 MMbbl per day each month starting in August 2021 until phasing out the 5.8 MMbbl per day adjustment. OPEC reaffirmed its planned staged production increase at its meeting held on 4 January 2022.

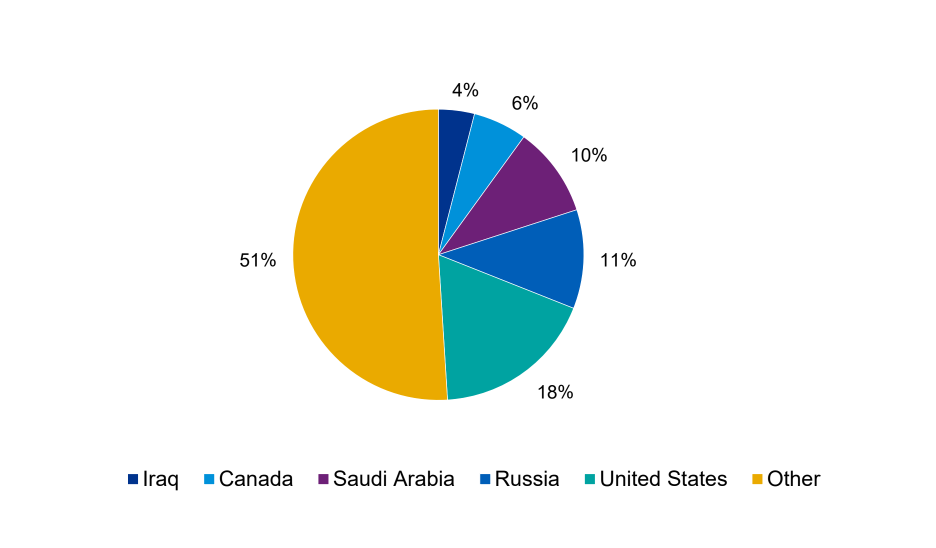
OPEC+ production is estimated by DISER to have averaged 32 MMbbl a day in 2021, an increase of 2.4% over 2020. Assuming that the staged production planned is adhered to, DISER forecasts OPEC+ output to increase by 6% over 2022, averaging 34 MMbbl a day.

Recovery in non-OPEC output dragged in 2021, particularly in the US as operators caught up on maintenance programmes, severe winter temperatures in early 2021 caused disruptions to drilling in Texas and more than 90% of crude oil production in the US Gulf of Mexico was offline in late August 2021, following Hurricane Ida.

In 2022, DISER expects US oil production to increase as US producers accelerate drilling activity in response to higher global oil prices, helping non-OPEC production to surpass pre-Covid-19 levels.

Figure 43 below sets out the top five global oil producers in 2020 but illustrates the fragmented nature of the global oil supply market, with the top five producing countries providing less than 50% of total global supply.

Figure 43 – Global oil producers 2020



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

Long-term outlook

EIA

As the primary raw material in the petroleum refining process, and a necessary precursor for many finished petroleum products, such as petrol, diesel and fuel oil, the EIA projects a steady increase in crude oil and condensate production over the entire period to 2050, reaching approximately 99 MMbbl a day. EIA forecasts both OPEC and non-OPEC oil production to grow over the period to 2050, but OPEC production grows at almost three times the rate of non-OPEC production.

The EIA sees a growing imbalance between oil consumption and production in certain regions, particularly in China and India, with demand outstripping in-country supply. To counter this, the EIA sees non-OECD Asia supplementing local production with increased imports of crude oil or finished products, principally from the Middle East over the longer term given the level of resources available and its proximity to Asia.

BP

Overall global oil production is forecast by BP under its BAU scenario to fall from pre-pandemic levels in 2018 of 98 MMbbl a day to 89 MMbbl a day by 2050.

In contrast to the EIA, BP expects US tight oil[141] production to grow over the period to 2030, largely offsetting declining OPEC production. After the mid-2030s, declines in US tight oil and non-OPEC production are seen as providing scope for OPEC to increase production levels such that OPEC recovers 2018 production levels by 2050.

[141] BP defines US tight oil to include crude, condensate and natural gas liquids from onshore tight formations

Under its Rapid scenario, global oil production is forecast to fall significantly to 47 MMbbl a day in 2050. Whilst non-OPEC production is projected to follow a similar pattern to its BAU scenario, BP forecasts OPEC production to again fall over the period to 2030 and to stabilise at this lower level thereafter rather than recovering 2018 levels as forecast under BAU.

IEA

As illustrated in figure 41 above, under STEPS, global oil supply is projected to increase to 103 MMbbl a day over the period to 2030, with growth in Middle East supply outstripping North American growth as tight oil operators choose to prioritise returns over aggressive production growth.

Post 2030, STEPS oil production is expected to remain largely stable. Non-OPEC production as a proportion of total supply is forecast to decline as resource bases become increasingly mature.

Under APS, global oil supply falls to 96 MMbbl a day by 2030 and continues to fall to 77 MMbbl a day by 2050 as higher costs of production for various producers as a result of their efforts to minimise emissions result in, at best, limited investment in new projects from the mid-2020s.

Under NZE, the sharp fall in oil demand discussed earlier does not justify investment in new fields after 2021. There is still however investment in existing fields to minimise the emissions intensity of production and there are also some low-cost extensions of existing fields to maintain or support production. Production is increasingly concentrated in resource-rich countries due to the large size and slow decline rates of their existing fields, with OPEC and Russia accounting for more than 60% of the global oil market in 2050.

Oil prices

The global energy system is highly interconnected, with huge international flows of traded energy. IEA estimates that in 2018, almost three-quarters of global oil production was traded internationally and around a quarter of natural gas.

Since the 1990s the pricing of crude oils has become increasingly transparent through the use of marker crudes, whereby the pricing of physical crude oil trades is based on a formula where a marker crude is used as the base, with quality/impurities differentials being added or subtracted, as well as demand/supply premiums or discounts being applied, depending on the crude oil being purchased.

Generally, these benchmarks will move in concert with one another, although on occasion demand differentials for the differing types of crude will create a pricing disparity. Arbitrage activity ensures price gaps are closed relatively quickly.

The main criterion of a marker crude is for it to be sold in sufficient volumes to provide liquidity in the physical market as well as having similar physical qualities to alternative crudes. Whilst there are various marker crudes across the globe such as Dubai and Oman in the Middle East and Tapis in Asia, the primary marker crudes referred to globally are:

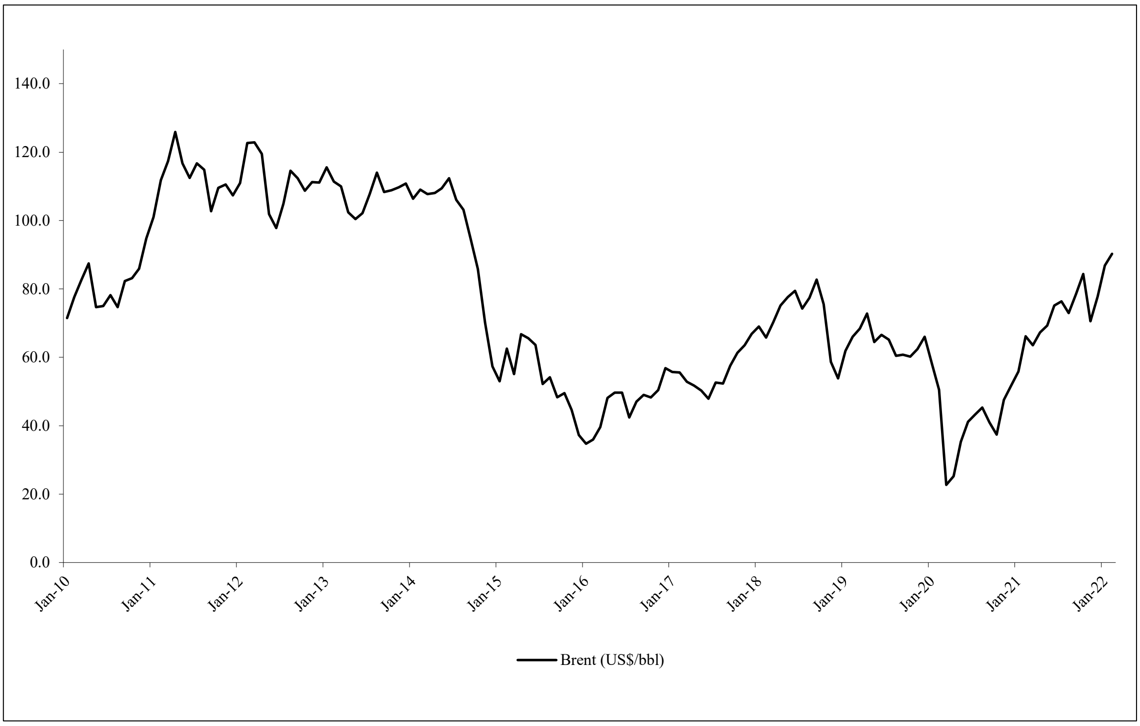
- Brent - a light sweet crude oil, which offers pricing information for Atlantic basin crude oils based on the spot trading and futures contract trading on the Intercontinental Exchange (**ICE**). Brent is a waterborne crude. It is a basket comprised of five different North Sea crudes. As a waterborne crude, it can be put on a vessel and shipped anywhere. Because of this, Brent reflects global oil market fundamentals and the global economy.

- West Texas Intermediate (**WTI**) - a light, sweet crude oil, which provides pricing information through spot transactions and its use on the Chicago Mercantile Exchange (**CME-Nymex**) as the basis of futures contracts. Eligible spot transaction prices at Cushing, Oklahoma, are typically reported as WTI.

With its recent increase in liquidity and trading activity, Brent is now used as the principal benchmark oil price in Europe, West Africa and most Asian countries and is slowly overtaking WTI as the global standard. Brent is adopted by Woodside as the principal benchmark for the purpose of its project and product pricing information.

Set out below is the historical month end Brent trading price since 2010 to 23 February 2022.

Figure 44 – Historical ICE Brent oil price – US$/bbl



Source: Bloomberg

As illustrated above, crude oil prices have exhibited significant volatility over the period since 2010.

Over 2010-2011, oil prices were still recovering from the impact on activity levels of the global financial crisis, with the Brent price reaching US$100/bbl in January 2011, for the first time since October 2008, on concerns that the 2011 Egyptian protests would impact access to the Suez Canal and disrupt oil supplies.

Over the period February 2011 to September 2014, whilst exhibiting a reasonable degree of volatility, the Brent price traded largely in the range US89/bbl to US$126/bbl.

The falling Brent price over 2014–2016 largely reflected excess supply concerns around the significant increase in the production of 'unconventional' oil in the US, where efficiency gains in the sector lowered break-even prices considerably, making US shale oil the de facto marginal cost producer on the international oil market.

Brent oil prices ended 2017 at US$66/bbl, the highest end-of-year price since 2013. Robust global demand and agreement by OPEC members to curtail crude oil production, along with a subsequent decision in November 2017 to extend that agreement through 2018, tightened crude oil supplies supporting crude oil price increases.

Brent oil prices continued to rise through the first three quarters of 2018, reaching to a four-year high of over US$86/bbl in October 2018, reflecting concerns about pressures on global supply, including the expected restoration of US sanctions against Iran (OPEC's third-biggest oil producer). However, as a result of escalating trade tensions between the US and China, various unexpected exemptions to the Iran sanction being granted by the Trump administration and increased supply by Saudi Arabia, concerns of oversupply against a backdrop of falling demand translated into a significant drop in oil prices over the last quarter of 2018 and into 2019.

In 2020, an oil price war between Russia/Saudi Arabia and the Covid-19 pandemic, which lowered demand for oil because of lockdowns around the world, had a significant adverse impact on oil prices.

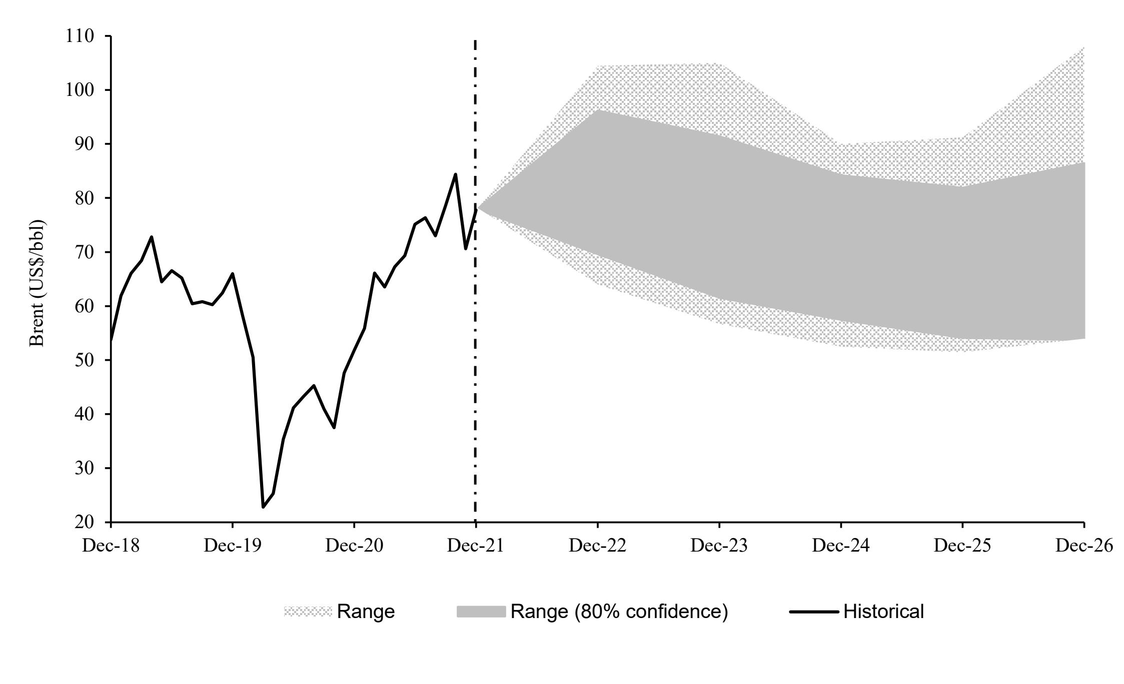
Since closing at a low of US$19/bbl in April 2020, ICE Brent oil prices have recovered strongly reflecting deep cuts in US production levels and continued OPEC supply restraint, coupled with green shoots growth in economic activity as various regions re-emerge from Covid-19 lockdowns.

In more recent times global oil prices have been significantly impacted by the hostilities in the Ukraine which has resulted in a sharp increase in spot prices.

Outlook

Set out in the chart below is a summary of the historical monthly Brent oil price since December 2018 and forecast estimate Brent oil prices published by broking houses and economic commentators considered by us as at 27 January 2022.

Figure 45 – Forecast estimate Brent oil prices by broking houses and market commentators



Source: Consensus Economics, Bloomberg, KPMG Corporate Finance analysis and various market analysts

The above analysis indicates a wide range of views in relation to future Brent oil prices, but on average, and excluding the impact of the hostilities in the Ukraine and associated trade sanctions, the Brent oil price was expected to decrease over the period to 2026. We also note that the majority of these forecasts were prepared subsequent to the Conference of the Parties[142] 26 held in Glasgow, Scotland in November 2021.

Natural Gas

Natural gas is a naturally occurring mixture of gases which are rich in hydrocarbons. Natural gas is colourless and odourless and explosive and is often found near other solid and liquid hydrocarbon beds, such as coal and crude oil deposits.

Natural gas is used as a source of energy for heating, cooking and electricity generation. It is also used as a fuel for vehicles and as a chemical feedstock in the manufacture of plastics and other commercially important organic chemicals.

There are several types of geological formations that trap naturally occurring gas. They are often categorised as being either ‘conventional’ or ‘unconventional’ gas reserves.

[142] In diplomatic parlance, “the parties” refers to the 197 nations that agreed to a new environmental pact, the United Nations Framework Convention on Climate Change, at a meeting in 1992.

Conventional gas is trapped in naturally porous reservoir formations that are capped with impermeable rock strata. When intercepted by a well, gas is able to move to the surface without the need to pump.

Unconventional gas is formed in more complex geological formations, which limit the ability of gas to migrate and therefore different methods are required to extract the gas. There are several types of unconventional gas, including shale gas and tight gas, which occur in reservoirs with very low permeability compared to conventional reservoirs. In these geological formations, horizontal drilling and hydraulic fracturing are often necessary for economic gas extraction. The other form of unconventional gas is coal seam gas, where methane gas is trapped within the coal seam under pressure by overlying formations. To extract the gas, a steel-encased well is drilled vertically into the coal seam at which point the well may also be hydraulically fracture stimulated or drilled horizontally along the coal seam to increase access to the gas reserves.

Before natural gas can be used as a fuel, most, but not all, must be processed to remove impurities, including water, to meet the specifications of marketable natural gas. Some of the substances which contaminate natural gas have economic value and are further processed or sold. An operational natural gas plant delivers pipeline-quality dry natural gas that can be used as fuel by residential, commercial and industrial consumers, or as a feedstock for chemical synthesis.

LNG is natural gas that has been cooled to a liquid state (*liquefied*), at about -162° C (-260° F), for shipping and storage. The volume of natural gas in its liquid state is approximately 600 times smaller than its volume in its gaseous state in a natural gas pipeline. This liquefaction process, developed in the 19th century, makes it possible to transport natural gas from producing regions to markets, such as from Australia to Asian destination countries.

LNG export facilities receive natural gas by pipeline and liquefy the gas for transport on special ocean-going LNG ships or tankers. Most LNG is transported by tankers in large, onboard, super-cooled (cryogenic) tanks. LNG is also transported in smaller International Organization for Standardization (**ISO**)-compliant containers that can be placed on ships and on trucks.

At import terminals, LNG is offloaded from ships and is stored in cryogenic storage tanks before it is returned to its gaseous state or regasified. After regasification, the natural gas is transported by natural gas pipelines to natural gas-fired power plants, industrial facilities and residential and commercial customers. LNG is also emerging as a cost-competitive and cleaner transport fuel, especially for shipping and heavy-duty road transport.

Both Woodside and BHP Petroleum have exposure to the international LNG market and to Australian domgas markets.

Global LNG market

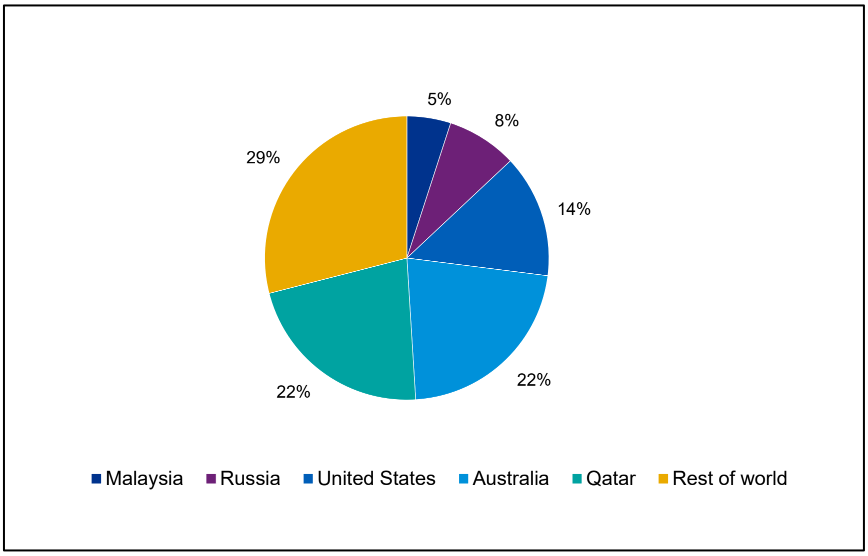
Recent trends and medium-term outlook

The International Gas Union[143] (**IGU**) report states that whilst LNG trade in 2020 was heavily impacted by Covid-19, with both producers and importers affected by lockdowns and significant reductions in levels of economic activity, global LNG trade still recorded a small level of growth, reaching 356.1 Mt, up 1.4 Mt on 2019, which compares to growth achieved in 2019 of 40.9 Mt.

This growth was mostly underpinned by increased exports from the US and Australia, together adding 13.4 Mt of exports. Australia overtook Qatar as the largest LNG exporter in the world, exporting 77.8Mt in 2020 versus 75.4 Mt in 2019, while Qatar exports fell 0.7 Mt in 2020 to 77.1 Mt, with the next largest being the US, exporting 44.8 Mt.

A significant number of markets exported less volumes in 2020 than they did in 2019 as a result of various factors including a mix of technical issues, demand drops due to Covid-19 related restrictions, commercial challenges due to price developments and feed gas challenges.

Figure 46 – 2020 leading exporters - % of total world imports



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

Global liquefaction capacity continued to grow in 2020, adding 20.0 Mtpa of capacity to 452.9 Mtpa notwithstanding several projects with planned start-up of commercial operations in 2020 were delayed to 2021 amid the Covid-19 pandemic.

Together the Asia-Pacific and Asia regions accounted for more than 70% of global LNG imports, adding 9.5 Mt of net LNG imports versus 2019. The Asia-Pacific region was again a key driver of global import

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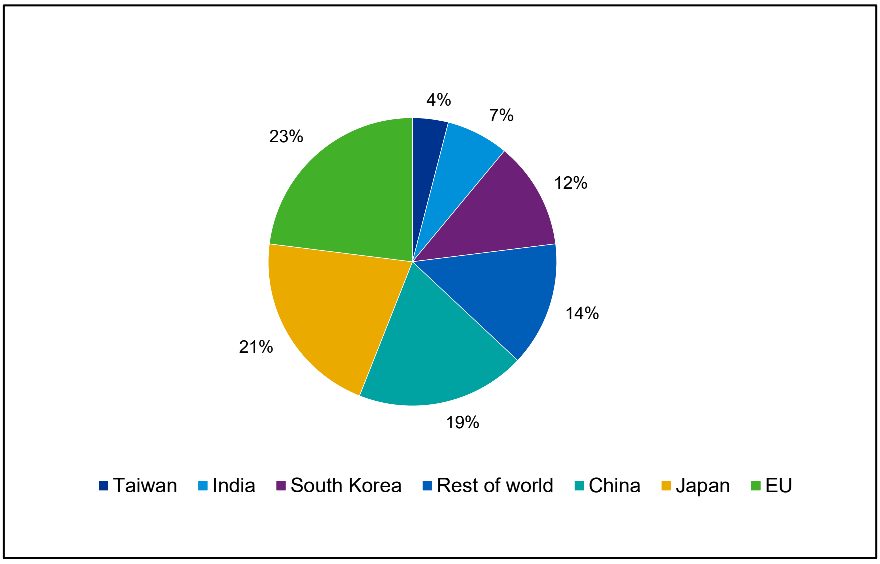
143 References to the IGU are sourced from its "2021 World LNG Report"

growth in early 2021, expanding in the first half of 2021 by 12% over the corresponding prior year period.

Figure 47 – 2020 leading importers - % of total world imports



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

In the first half of 2021, DISER estimates global LNG trade grew by almost 5% year-on-year. This has been attributed to a number of factors:

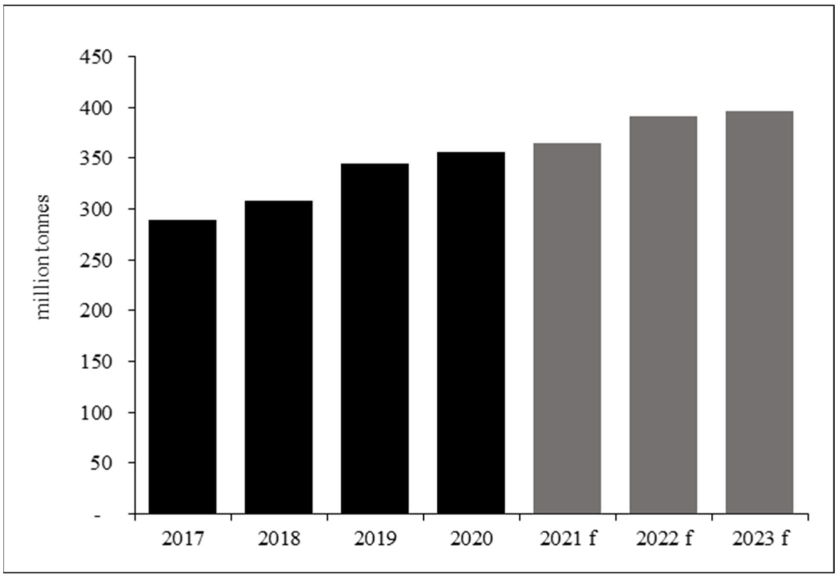
- continued recovery of the global economy from Covid-19, feeding directly through to higher electricity demand
- unusually cold winter/spring conditions in the northern hemisphere, requiring a rebuilding of gas inventories, followed by a hot Asian summer and sustained droughts in South America affecting hydro generation in that region.

High spot prices weighed on demand in some emerging Asian economies, but overall Asian demand remained strong.

Export growth has in recent times been dominated by North America, largely due to a 50% rise in liquefaction capacity since the beginning of 2020. Exports from the Asia-Pacific have largely been flat, and the Middle East has seen only moderate growth.

Global LNG trade was expected by DISER to increase by 2.5% in 2021, largely driven by continued import growth in the Asia-Pacific region and export growth in North America. Trade is then expected to increase by 7.2% in 2022 and 1.4% in 2023, with the rate of demand growth reducing following the recovery from the impact Covid-19 and increasing demand from emerging Asia being partially offset by falls in demand elsewhere.

Figure 48 – Historical and forecast LNG trade by volume



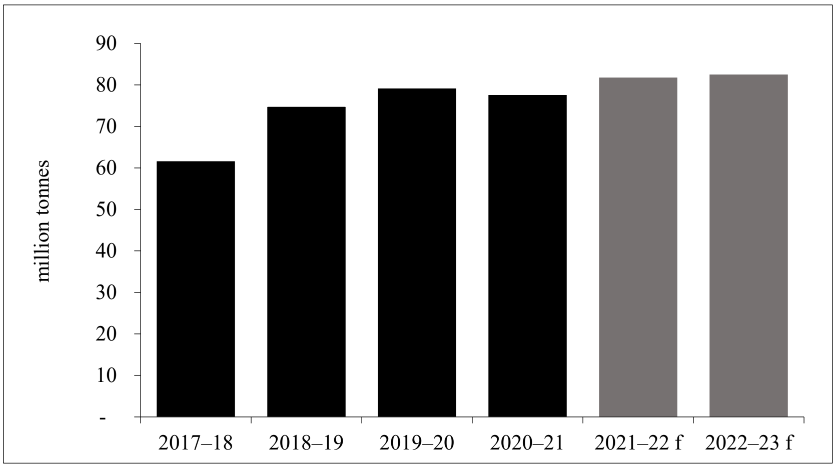
Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

Australia

Australia's LNG export volumes have been relatively stable over the past 2 years despite the Covid-19 pandemic, with fluctuations largely due to technical issues and routine maintenance. DISER estimates that in the September 2021 quarter, Australia's LNG exports were 14.4% up quarter-on-quarter and 16.2% up year-on-year, largely driven by the resolution of production disruptions at the Gorgon, Prelude and Ichthys LNG projects, which had led to a quarter-on-quarter fall in the prior period.

LNG exports are forecast at around 82 Mt in 2021–22, reflecting the resolution of technical issues at various facilities. In 2022–23, Australian exports are expected to remain around 82 Mt. However, further shutdowns at Prelude and Gorgon in the December quarter are seen as representing downside risk to current estimates.

Figure 49 – Historical and forecast Australian LNG export volumes



Source: DISER, Commonwealth of Australia Resources and Energy Quarterly December 2021

DISER notes that with around three-quarters of Australian LNG sold via long-term contracts that link the price of LNG to the price of oil, with a lag of around three to six months, depending on contractual arrangements, the low oil prices that prevailed throughout 2020 had a significant impact on export earnings in the first half of 2021, however, export earnings recovered strongly in the September 2021 quarter supported by both high LNG spot prices and also stronger oil prices.

The outlook for the next wave of investment in Australian LNG projects is considered to be uncertain, with most LNG projects in the investment pipeline being backfill projects, required to support the ongoing operation of existing LNG facilities. Woodside's Scarborough project is the only substantial expansion to Australia's LNG export capacity in the investment pipeline.

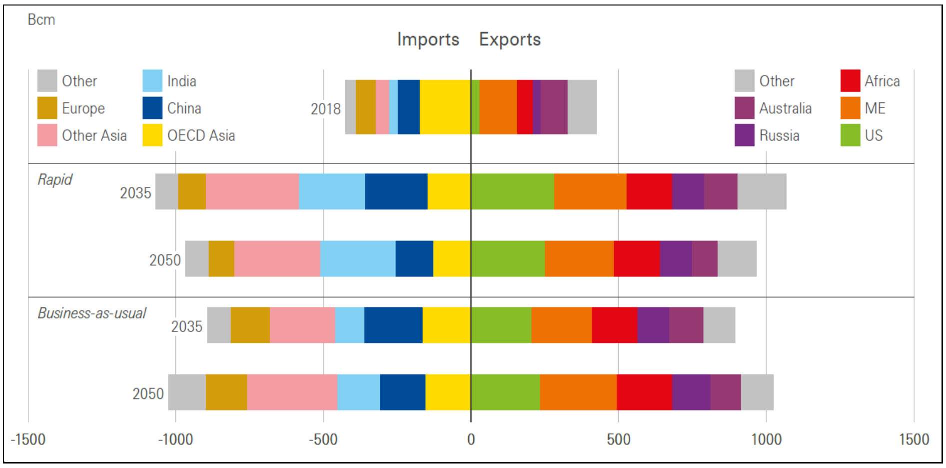
From an Australian LNG import perspective, there are five potential import terminal projects that have been proposed, all concentrated in south eastern Australia, however DISER considers that with construction already commenced on the A$250 million import terminal located in Port Kembla (expected to be ready to receive imports from early 2023), it is likely that only one further import terminal will be constructed and commence importing LNG in the next few years.

Long-term outlook

BP

Figure 50 below illustrates that BP expects both LNG import and export volumes to expand significantly under both its BAU and Rapid scenarios.

Figure 50 – LNG imports and exports



Source: bp Energy Outlook 2020 edition

LNG trade volumes are expected to grow strongly over the next decade in BAU with developing Asia the major destination for these increasing exports and the US, Africa and the Middle East the main sources of incremental supply. Whilst still positive, growth in demand is expected to slow from the 2030s, reaching approximately 1,000 billion cubic metres (**Bcm**) per annum by 2050. This reduction in demand is forecast to be most pronounced in China, as overall demand declines and domestic production (including biomethane) increases.

Under BP's Rapid scenario, LNG trade is expected to grow at a faster rate than BAU over the early part of the forecast period, increasing from 425 Bcm per annum in 2018 to around 1,100 Bcm per annum by the mid-2030s, with growth driven by increasing gas demand in developing Asia (China, India and Other Asia) as gas is used to aid the switch away from coal, with LNG imports the main source of incremental supply.

LNG trade is then forecast to fall after the mid-2030s to around 970 Bcm per annum by 2050. This decline under Rapid is expected to result in some facilities needing to be operated at less than full capacity or shutdown prematurely.

IEA

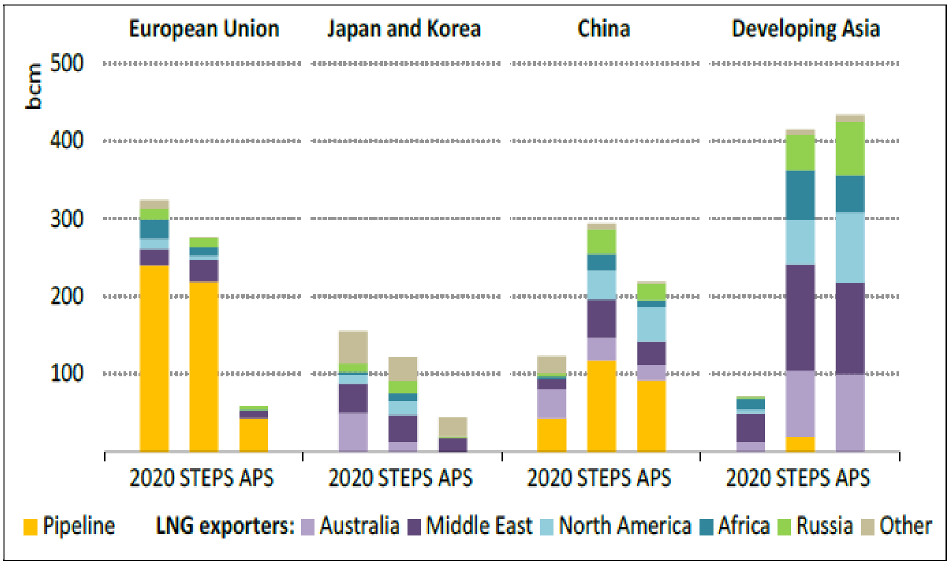
In IEA's STEPS, there is a 430 Bcm increase in natural gas demand to around 4,550 Bcm per annum over the period to 2030, along with a 150 Bcm ramp up in annual LNG export capacity, much of it in Qatar, the US, Russia and East Africa. Demand for natural gas continues to increase after 2030, albeit at a slower pace, with no peak in demand, reaching 5,100 Bcm per annum in 2050, around 30% higher than today. Natural gas demand in industry remains the key driver of growth, but its contribution to overall energy demand growth decreases as emerging market and developing economies transition to more service-oriented economies.

Global LNG trade increasingly takes market share from gas transported by long-distance pipelines, expanding from just over 50% of traded volumes today to 60% in 2050.

Under the APS, countries with net zero pledges experience reductions in domestic demand as the emissions performance of natural gas produced in and/or imported by these countries is subjected to scrutiny. Natural gas demand reaches its maximum level globally soon after 2025 and then declines to around 3,850 Bcm per annum by 2050, however, LNG continues to grow, capturing nearly 70% of traded volumes by 2050.

As illustrated in figure 51 below, reduced gas demand in Europe leads to an 80% drop in pipeline imports, while LNG supplies the majority of the significant increase in gas demand in developing markets in Asia.

Figure 51 – Natural gas imports and exports by source in 2020 and by scenario in 2050



Source: IEA Source: World Energy Outlook 2021

Under IEA's NZE scenario:

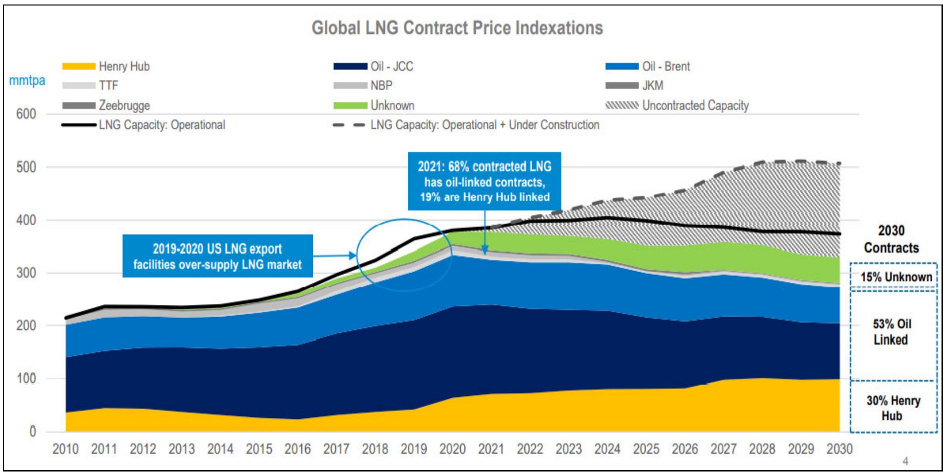
- natural gas use in power generation declines rapidly, accounting for around only 1% of electricity generation worldwide by 2050, compared with almost 25% today. Energy demand in buildings also transitions quickly away from natural gas. In 2050, more than 50% of global gas production is used to produce low-carbon hydrogen
- no new gas fields are developed beyond those that have already been approved for development and LNG trade peaks in the mid-2020s at 475 Bcm per annum before falling to 2020 levels of 390 Bcm by 2030, implying a reduced rate of utilisation of LNG export capacity globally from the mid-2020s compared with historical utilisation rates.

LNG prices

Whilst natural gas and oil share many characteristics and are often produced simultaneously, the way in which they are sold and priced is different. Oil is sold by volume or weight, typically on a barrels or tonnes basis, whereas natural gas is sold by unit of energy, the most common being British thermal unit (**Btu**).

For the majority of natural gas transported by pipeline, prices can be set by negotiation, regulation, or open-market mechanisms similar to those used in oil markets. In contrast, the majority of LNG shipborne cargoes are sold on a contractual basis at prices either indexed to the cost of feed gas, floating price in the destination market, or indexed to oil or other commodities. In its submission in relation to the ACCC 2021 review of LNG Netback Prices, Santos Limited (**Santos**) estimated that 68% of contracted LNG was traded based on oil-index linked prices, and that whilst the proportion of contracts linked to Henry Hub gas prices was likely to increase over the period to 2030, oil-index linked contracts were still expected to represent 53% of contacted LNG.

Figure 52 – Global LNG contract price indexations



Source: Santos submission to ACCC LNG netback review

Because natural gas is difficult to transport, natural gas prices tend to be set locally or regionally, with the basis on which natural gas is sold and priced varying dramatically between regional markets.

The majority of Australian LNG production is sold into the North Asian region, with the principal markets comprising Japan, South Korea, Taiwan and China. Other than China, the North Asia region generally has limited domestic energy resources and does not have the infrastructure to import gas by pipeline. As a result, almost all this region's gas needs are met by imported seaborne LNG.

Whilst China has significant domestic production and pipeline imports of natural gas, there is expected to be an increasing domestic supply deficit, resulting in a growing need for imported LNG, which is increasingly being priced on a similar basis to the pricing model set by Japan and followed by Korea and Taiwan.

This model generally involves medium to long term contracted LNG volumes being priced at a small discount to the energy equivalent of a barrel of Japan Customs Cleared Crude Oil Price (**JCC**), being the average price of customs-cleared crude oil imports into Japan published by the Petroleum Association of Japan, typically based on the following formula:

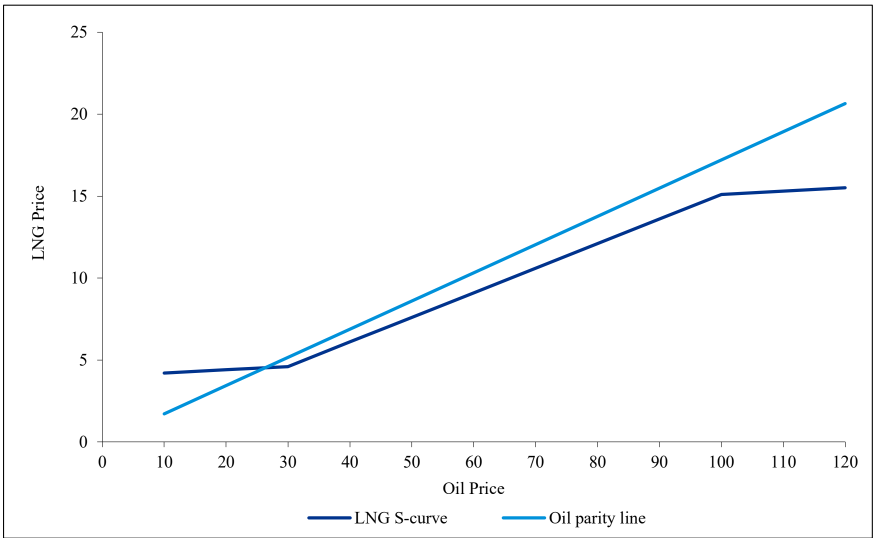
Plng = (A * PCrude Oil) + B

Where:

- A: The 'slope' linking oil and gas prices. This reflects that 1.0 MMbtu has the energy equivalence of approximately 0.1724 boe. A slope of 17.2% indicates energy equivalent parity between oil and gas prices i.e. where the JCC price is US$80/bbl the energy equivalent price of LNG is approximately US$13.80/MMbtu. Slopes less than 17.2% imply that LNG is sold at a discount to oil, and slopes greater than 17.2% imply that LNG will sell at a premium price to oil.
- Typically, LNG will sell on a slope less than the energy equivalent, reflecting supply and demand dynamics and legacy incentives to Japanese power utilities to substitute liquids and solid fuel sources with LNG.
- PCrude Oil: Weighted average JCC over a defined period, a month or more.
- B: A constant added to reflect fixed costs, often related to shipping costs from LNG plant to importing port.

In addition, some contracts can include mechanisms to mitigate the impact of price shocks, resulting in flatter slopes at lower oil prices (to protect the seller) and higher oil prices (to protect the buyer) leading to an "s-curve" pricing curve as illustrated in the chart below.

Figure 53 – LNG S-curve price

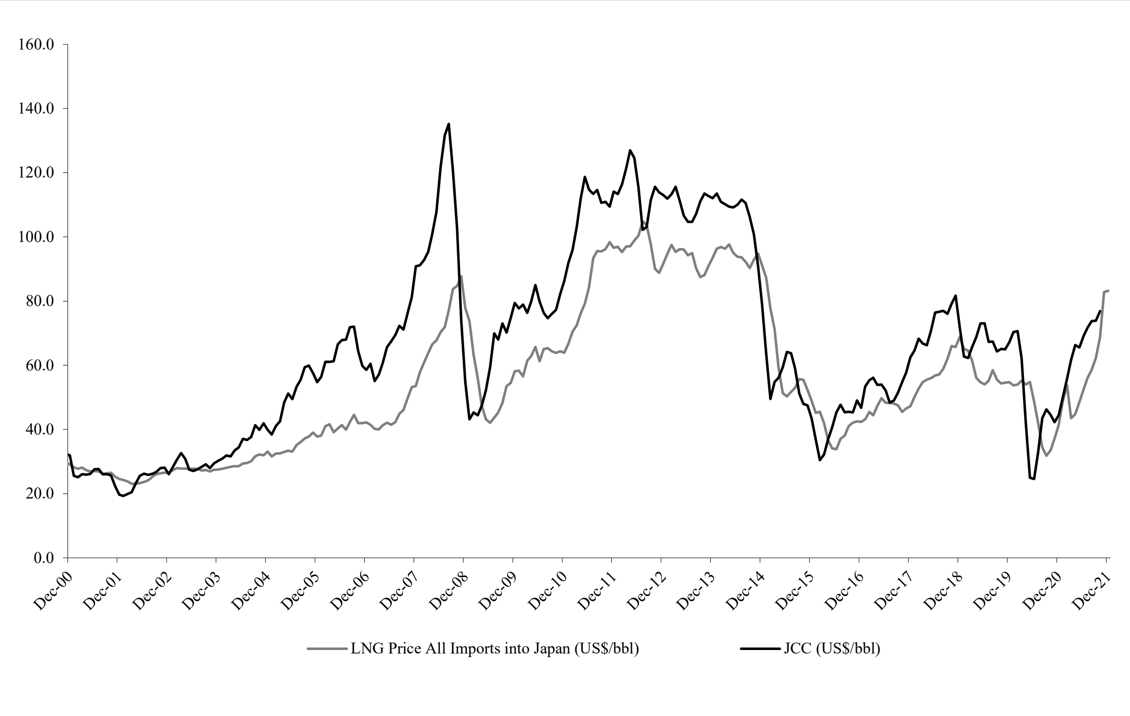


Source: KPMG Corporate Finance analysis

Set out in the chart below is a comparison of historical monthly JCC prices over the 21 years to December 2021 to rebased LNG prices for all imports into Japan (i.e. reflecting both contract and spot sales) [144] over the same period. This comparison indicates a strong correlation between JCC oil prices and LNG import prices into Asia, with LNG prices tending to trade at a slightly delayed discount to JCC prices.

[144] LNG prices have been grossed up based on an energy equivalent factor of 17.24%

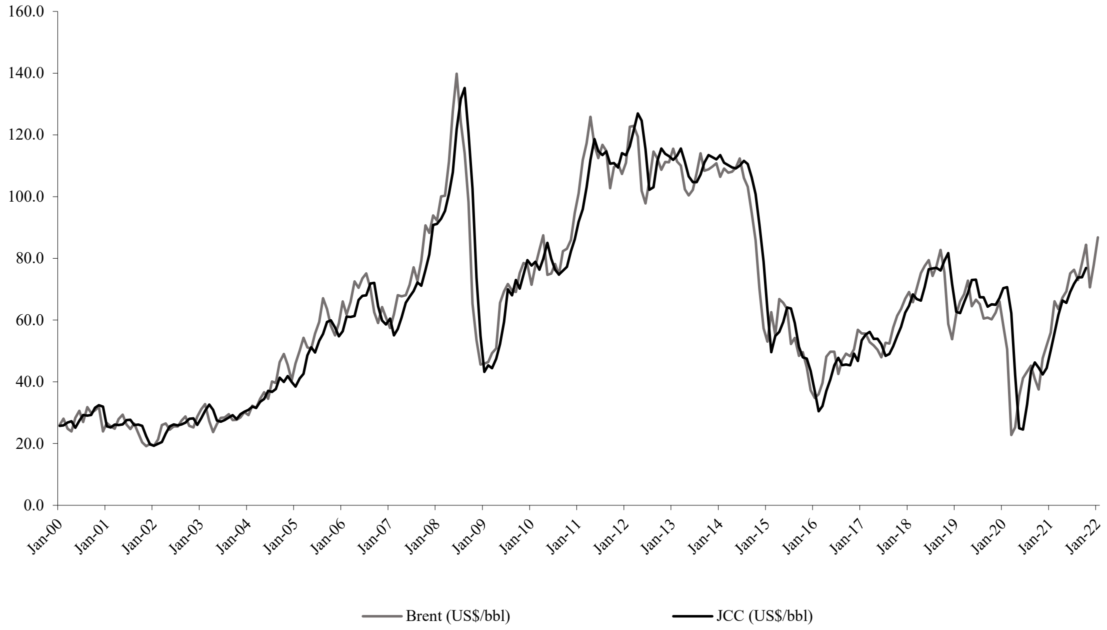
Figure 54 – Comparison of historical JCC price compared to the rebased LNG price for all imports into Japan



Source: Bloomberg

As shown in the chart below, the JCC is also strongly correlated to the Brent price and tends to trade around a centralised level of parity, albeit on a slightly delayed basis.

Figure 55 – Comparison of historical JCC price compared to historical ICE Brent prices



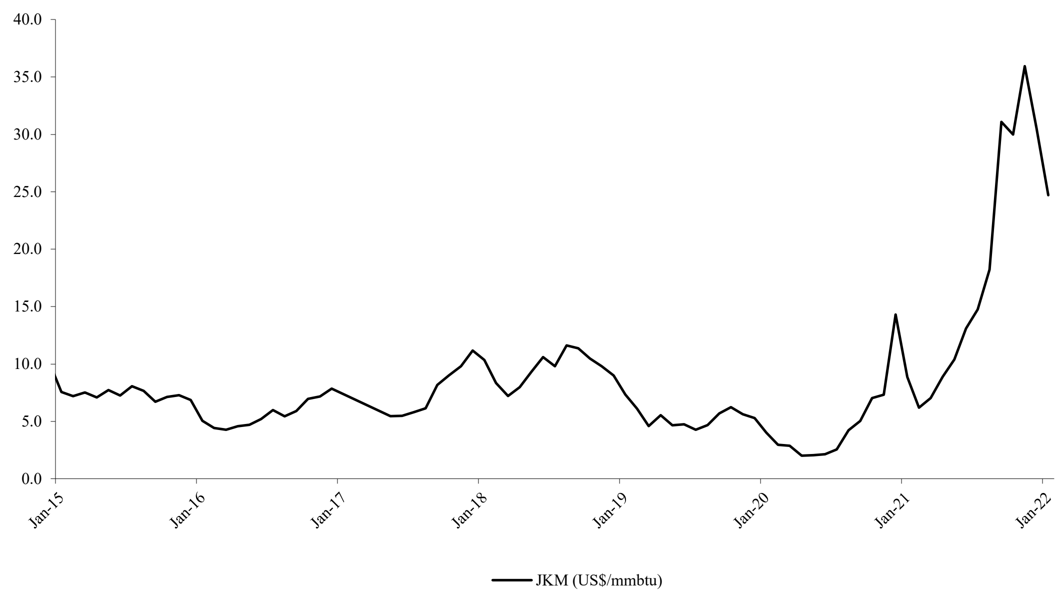
Source: Bloomberg

Taken together, the charts above suggest that typically the average LNG price for all imports into Japan will trade at a discount to the Brent oil price implied by the energy equivalent slope for LNG of 17.24%.

Whilst the significant majority of Australian LNG is sold via medium to long-term contracts, which typically link the price of LNG to the price of oil, an increasingly liquid market for spot LNG trading has emerged, with spot cargoes into the Northeast Asian region generally priced with reference to the Platts Japan-Korea Maker (**JKM**).

Set out in the chart below is the historical month end JKM spot price over the 7 years ended January 2022.

Figure 56 - Historical JKM spot benchmark prices



Source: Bloomberg

The impact of Covid-19 on economic activity exacerbated an already existing oversupplied trade position in early 2020, leading to deferments and cancellations of spot and long-term cargoes by end-users, in turn pressuring spot prices, with the JKM benchmark for cargoes delivered into Northeast Asia falling approximately 65% between the start of 2020 and the end of April 2020.

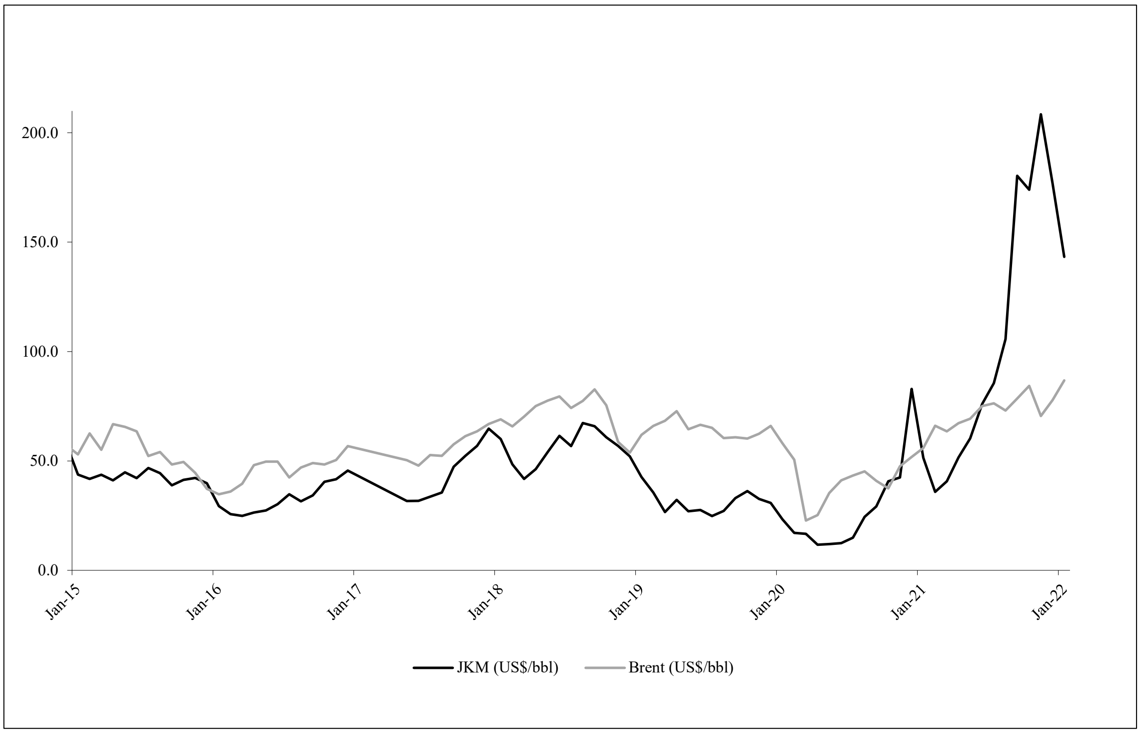
However, these cancellations, coupled with weather related and technical issues impacting production across various global facilities in the second half of 2020, including outages at US and Australian facilities, and an unusually cold winter period across the Northern Hemisphere, resulted in a strong demand-driven price rally in the second half of 2020 and into 2021, with the JKM benchmark reaching a then record level in mid-January 2021.

The end of the Asian cold snap and the arrival of Atlantic shipments into Asia in early 2021 resulted in benchmark JKM spot prices returning toward historical prices levels by March/April 2021, before once again steadily rising across the remainder of 2021, with both European and Asian buyers, particularly China, seeking supply in order to rebuild gas stocks against a background of increasing economic activity following Covid-19 lockdowns, unusual weather patterns in Europe and Asia across the year fuelling demand for power, lower than expected availability or renewable energy and expectations of lower than average temperatures over the forthcoming winter period in China and Korea.

Benchmark JKM spot prices closed 2021 at US$30.5/mmbtu.

Set out in the chart below is comparison of the rebased historical month end JKM spot price[145] over the 7 years ended January 2022 compared to the historical Brent oil price over the same period. This analysis indicates that typically the JKM benchmark spot price will trade at a discount to the energy equivalent Brent price, however, the recent efforts by Europe and China to rebuild gas stocks ahead of the Northern Hemisphere winter period has resulted in a disconnection in this pricing relationship.

Figure 57 – Comparison of rebased JKM LNG to historical ICE Brent oil prices



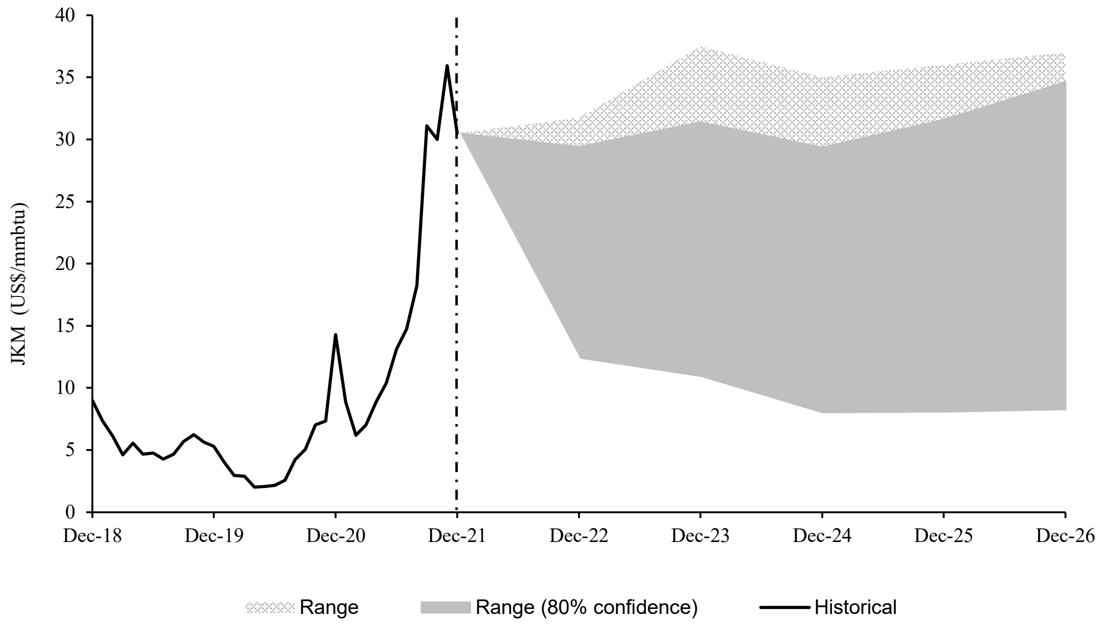
Source: Bloomberg

Outlook

Set out in the chart below is a summary of the historical monthly JKM price since December 2018 and forecast estimate JKM prices published by broking houses and economic commentators considered by us as at 27 January 2022.

[145] JKM spot prices have been grossed up based on an energy equivalent factor of 17.24%

Figure 58 – JKM LNG prices forecast by broking houses and market commentators



Source: Consensus Economics, Bloomberg, KPMG Corporate Finance analysis and various market analysts

The above analysis indicates a wide range of views in relation to future JKM spot prices over the medium term, but in general, the year-on-year the JKM spot price is expected to begin to moderate in 2022 from their current historically high levels.

Asian spot LNG prices are expected to remain high on a relative historical basis over the Northern Hemisphere 21/22 winter period before a general pull back toward the end of the winter season, with the extent and pace of this price retreat heavily influenced by European market dynamics and prevailing weather patterns across the Northern Hemisphere.

The high levels of global LNG FIDs that had been expected to be taken in 2020 but postponed into 2021 and beyond owing to prevailing low oil prices at that time and weaker demand that emerged from the pandemic, coupled with the typical long lead times between FID and first shipments for LNG projects could result in current relatively tight supply conditions until the middle of this decade. Subsequent to this there is also a risk of a supply surplus depending on the full extent of post Covid-19 demand recovery and the rapidity at which the energy sector shifts away from fossil fuels.

As noted previously, whilst long-term contract prices are still expected to be predominantly oil-index linked, there is also an expectation of an increasing use of other index mechanisms, including linking to North American hubs (particularly from US LNG exports) reflecting the scale of US gas reserves and ongoing development of its LNG export market.

It is not unusual for export contracts with US LNG projects to be entered into under tolling agreements, which commit customers to paying a fee for reserving liquefaction capacity, with additional liquefaction fees only charged for LNG volumes processed. The customer is also responsible for acquiring its own input gas in the US market (usually linked to Henry Hub benchmark prices) and also bearing the cost of transportation of the gas to the liquefaction plant and shipping the LNG to its destination. In contrast, most medium/long term contracts between Australian and North Asian countries are based on Delivered Ex Ship, where the Australian supplier assumes supply and cost risk until delivered to the customer's point of offloading.

US oil and gas production is expected to increase over the short to medium term as producers accelerate drilling activity in response to higher global prices, increasing gas availability. Increasing US exports of LNG based on Henry Hub pricing could substantially reduce the costs of LNG for Asian importers and diversify their energy mix, while providing flexibility for customers (via tolling agreements). Offsetting this, shipping costs from the east coast of the US to Asia will be higher than Australian shipping costs and the cost of new US liquefaction capacity could be greater in the future.

Beyond the mid-2030s, one commentator notes that in a long-term equilibrium market, differentials between basins will be set by transportation costs from the marginal supplier and that with flexible destination volumes, US LNG is expected to be the marginal supplier. Differentials between Northwest Europe and Northeast Asia are expected to be set by netback equivalent costs for US Gulf Coast suppliers.

Australian domestic gas markets

The Australian gas industry consists of three distinct regions in the east, west and north of the country, separated by the gas basins and pipelines that supply these three regions. The east coast gas market is currently not connected with the west coast market. It was reported in August 2018 that a study commissioned by the Federal Government in relation to a cross continental pipeline, concluded that this was unviable.

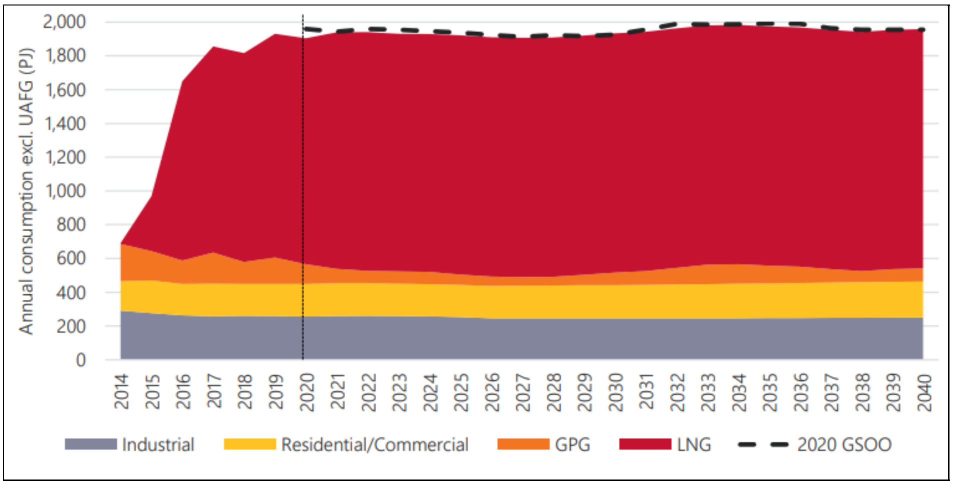
East coast gas market

Demand

Prior to 2014, east coast gas consumption was relatively evenly split between the industrial, residential/commercial and gas-powered electricity generation (**GPG**) sectors. However, the development and construction of three LNG projects in Queensland, starting in late 2010, triggered major structural change and market disruption, with east coast gas demand increasing rapidly as a result of demand from the LNG sector, as shown in figure 59 below, which is expected by Australian Energy Market Operator (**AEMO**)[146] to continue to drive consumption over the long term.

[146] AEMO was established by the Council of Australian Governments on 1 July 2009 to manage the National Electricity Market in the eastern and south-eastern states and Australian gas markets. AEMO became the market and independent power system operator for Western Australia from 2015. References to the views of AEMO in relation to the East Coast gas market are sourced from its "Gas Statement of Opportunities, March 2021, For eastern and south-eastern Australia" (**GSO**)

Figure 59 – Gas consumption actual and forecast, all sectors, Central scenario[147], 2014-40, in Petajoules (PJ)



Source: AEMO GSO

AEMO forecasts, as indicated in figure 59 above, a relatively flat trajectory for east coast gas consumption under its Central outlook, but considers that risk is to the downside in the event of softer economic conditions/a rapid take up of alternative energy sources, including hydrogen.

The only sector forecast to experience a significant consumption decline is the GPG sector, with wind and solar generation (both grid-scale and distributed photovoltaics systems such as residential rooftop systems) expected to continue to grow in capacity and output.

Investment in electricity transmission infrastructure is forecast to drive further reductions in volume in the medium term, although coal generation retirements may drive periodic increases in GPG to support the transition. In the long term, the growing share of renewables, complemented by storage and enabled by major network augmentations, is projected to keep GPG annual consumption low.

AEMO highlights that whilst its forecast industrial demand for natural gas under its Central scenario is relatively stable over the next 20 years, there is downside risk that it could potentially reduce significantly through closure if energy prices rise and as industrial users in the gas sector start to decarbonise.

Growth in residential and commercial gas consumption from new connections is forecast to be mostly offset by increases in energy efficiency in the next five years, but will continue to drive some increase in maximum daily demand in the longer term.

[147] AEMO has considered various scenarios, including a "Central" scenario, which uses AEMO's best (central) view of future uncertainties, a "Slow Change" scenario, which explores reduced gas demand due to slowing economic activity and higher gas prices and a "Hydrogen" scenario, which explores potential gas infrastructure impacts of the development of electrolyser-produced hydrogen under stronger economic conditions, which could provide a potential substitute for gas use in certain applications, but noting that the nature of these impacts would depend on the timing, scale and location of hydrogen facilities, which are highly uncertain

Supply

Gas produced on the east coast of Australia traditionally supplied domestic residential, commercial and industrial users, however, the development of the three Queensland LNG plants opened up alternative international markets for gas producers. In 2021, domestic demand accounted for only approximately 27% of total east coast gas demand, with the balance of gas production exported as LNG[148].

In January 2021, LNG producers signed a new Heads of Agreement with the Australian Government, under which LNG producers committed to not offer uncontracted gas to the international market unless "equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market".

In its July 2021 interim report into gas supply in Australia, the ACCC describes the gas supply outlook for 2022 as being “very finely balanced”, noting that gas production and withdrawals from storage in the southern states are forecast to be less than demand by 6 PJ, with this projected shortfall further exacerbated in the event that current supply from current undeveloped reserves does not eventuate and/or GPG demand is higher than forecast.

In previous years, potential shortfalls in the southern states could largely be met by flows from Queensland (whether through swaps or transportation on key southern haul pipelines). However, Queensland producers are currently forecasting to supply only 3 PJ higher than AEMO's forecast demand for Queensland. As a result, it is expected that LNG producers will be called on under the Heads of Agreement to offer uncontracted gas into the domestic market.

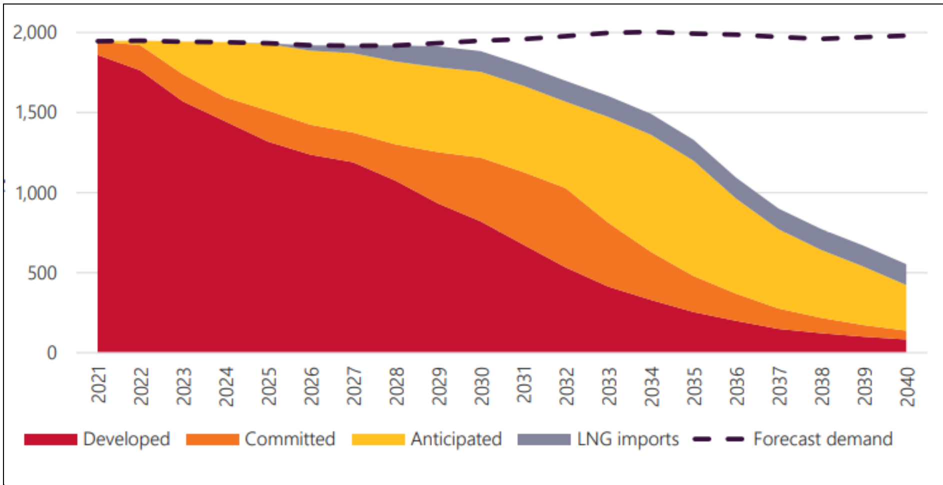
AEMO notes that whilst available annual production in the southern states is generally higher than it previously forecast in 2020, principally due to the conversion of nearly all previously “anticipated” projects to “committed” production[149], the commitment to develop Australia’s first LNG import terminal at Port Kembla, New South Wales, results in annual southern production being forecast to decline over the next five years.

In the north, anticipated projects are forecast to be developed more slowly over the next five years than forecast previously, reflecting the less favourable investment conditions associated with Covid-19. AEMO notes however, that the recent recovery in oil and LNG prices may result in increased northern supply in future years.

As set out in figure 60 below, AEMO considers under its Central scenario that even if all existing, committed and anticipated projects are developed and all associated reserves and resources are commercially recoverable to meet demand, new supply options will be required across eastern and south-eastern Australia towards the end of the decade if domestic and LNG export demand is to be met to the end of the outlook period.

[148] ACCC LNG netback review – Final decision paper September 2021
[149] “Anticipated” is defined by AEMO to comprise projects where regulatory approval and FID is reasonably expected to be achieved. “Committed” comprises gas fields and production facilities that have obtained all necessary approvals, with implementation ready to commence or already underway

Figure 60 –Projected eastern and south-eastern Australia gas production (including export LNG), Central scenario, existing, committed and anticipated developments, 2021-40, in PJ



Source: AEMO GSO 2021

In AEMO's view, a suite of complementary investments in new gas fields, LNG import terminals, pipeline infrastructure and storage may be required to secure adequate gas supply over the long term.

East Coast Gas Prices

For domestic producers and consumers, the majority of gas is traded under bespoke confidential bilateral wholesale Gas Supply Agreements (**GSA**), with prices affected by the prevailing demand and supply conditions at the time of the agreement. Historically these GSAs were predominately long term in nature with single suppliers, however in recent times there has been a shift towards market participants entering into multiple GSAs with different participants, for shorter periods and often with review provisions, to manage their portfolios. In 2019, the ACCC noted that the majority of recent offers for gas supply had durations of just one to two years[150].

Benchmarking of GSA pricing is difficult due to the private nature of the contracts, however in 2018 the ACCC began publishing new data in relation to LNG netback prices[151], which is intended to assist in addressing the information asymmetry for gas consumers when negotiating with gas producers and retailers.

Whilst most gas is traded under GSAs, around 10-20% of gas is traded in spot markets[152], which provides a useful mechanism for participants to manage any imbalances that may emerge in their contract portfolios.

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[150] ACCC, Gas inquiry 2017-2025, July 2021 interim report
[151] An LNG netback price is a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port
[152] References to the Australian Energy Regulator (**AER**), refer to information contained in its publication State of the Energy Market 2021

Three separate spot markets operate on the east coast. These markets however follow different procedures and do not interact, leading the Australian Energy Market Commission (**AEMC**) to find in 2017 that this structure inhibits trading between regions and introduces transaction costs. The AEMC has recommended that over time the markets transition to a single market based on a gas supply hub model.

Contract Gas Prices

Prior to commencement of LNG exports from Queensland in 2015 domestic gas contract prices were historically stable and averaged around A$3–A$4/gigajoule (**GJ**), however after this date domestic gas pricing became linked to more volatile international oil and gas prices, driving prices higher in 2016 and 2017, with domestic prices of A$22/GJ for a one or 2-year contract being quoted in early 2017.

Following the Australian Government's intervention in 2017 requiring LNG producers to offer uncommitted gas back to the domestic market, contract offers eased, aligning them more closely with Asian LNG netback prices, returning to a range of A$8–A$11/GJ by 2018. In late 2019 and 2020, lower Asian prices drove further falls in domestic spot prices, with prices offered by both producers and retailers in 2020 for 2021 supply mostly, in the range of A$6–A$8/GJ.

The ACCC noted[153] that notwithstanding the tightening supply-demand balance referred to previously, prices observed in offers for supply in 2022 remained relatively low up to February 2021 but with international oil and gas price expectations for 2022 rising, this could be changing.

In the period since the issue of the ACCC's interim report, international LNG prices have, as noted previously, surged, resulting in a significant increase in the implied LNG netback price. On 22 November 2021, the Australian Financial Review (**AFR**) reported[154] that Asian benchmark spot LNG prices implied a netback price of more than A$30/GJ. Whilst as discussed previously, the recent increase in LNG prices has seemingly been driven by short term rather than systematic events as North Asian and European countries seek to rebuild gas reserves after unusually long and harsh winter periods, it is too early to see how these increases may have impacted domestic contracts for medium/long term gas supply.

Spot prices

The AER notes that price outcomes in the spot markets do not align with contract prices, although they often move in similar directions. Contract prices reflect expectations of future market conditions, but the spot markets reflect short term shifts in market conditions relating to factors such as the timing of LNG shipments and conditions in the electricity market.

As shown in figure 61 below, spot gas prices have exhibited a significant level of volatility in recent years, increasing in 2015 as Queensland LNG producers entered to market, largely trading in the range of A$8 - A$10/GJ until late 2019.

[153] ACCC, Gas Inquiry 2017 – 2025 – July 2021 interim report
[154] "Gas buyers fear fresh price surge amid Europe crunch", Angela Macdonald-Smith, Australian Financial Review 22 November 2021

In 2020, the surplus supply of LNG, coupled with the impact of Covid-19 on economic activity resulted in a significant fall in domestic gas prices, however, the tight market conditions for LNG in late 2020 and into 2021 resulted in an increase in gas prices.

Figure 61 – Historical east coast spot gas market prices

		AVERAGE SPOT PRICES				
		2017	2018	2019	2020	2021
Price, $/GJ	VIC	8.39	9.12	8.84	5.11	8.24
	ADL	8.50	9.13	9.44	5.70	9.25
	BRI	8.09	8.81	8.02	4.89	9.12
	SYD	9.20	9.40	8.97	5.08	9.07
	WAL	8.52	8.96	7.84	4.83	10.64
	Asian LNG Netback price at Wallumbilla	7.65	10.88	6.83	4.29	16.56

Source: AER Wholesale Markets Quarterly Q4 2021 October – December

The AER noted[155] that the third quarter of 2021 saw the emergence of the largest, most sustained decoupling of domestic spot market prices and LNG spot netback price assessments since LNG exports commenced in 2015. The netback price[156] averaged A$16.56/GJ over 2021 whilst domestic spot market prices averaged between a low of approximately A$8.24/GJ in Victoria and a high of A$10.64/GJ at Wallumbilla.

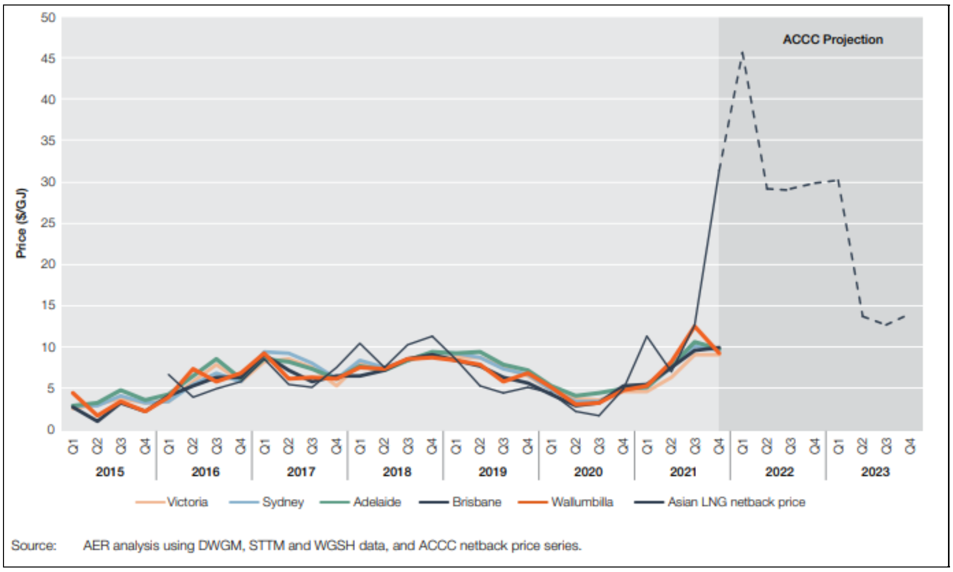
Domestic prices averaged between A$10.00/GJ and A$10.91/GJ in Q4 2021, which compared to Q3 2021 prices which ranged between A$10.10/GJ and A$13.42/GJ.

In contrast, as shown in the figure below, the Asian LNG netback price more than doubled - to A$32.35/GJ - over the same period. The AER attributed this significant decoupling to a range of factors:

- Heavy buying of LNG for heating on expectations of a cold northern hemisphere winter
- Competitive bidding for LNG cargoes between Asian and European customers
- Shipping constraints affecting supply chains
- Outages at production facilities in Malaysia, USA and Australia (NT)
- European supply constraints affecting gas supplies from Russia.

[155] AER "Wholesale markets quarterly – Q3 2021 July – September, 17 November 2021
[156] calculated at Wallumbilla in Queensland

Figure 62 – East coast spot gas prices and Asian LNG spot netback price



Source: AER Wholesale Markets Quarterly Q4 2021 October - December.

Over the medium term, the ACCC is projecting a significant pullback in the netback price, however, this is still expected to be above current east coast spot prices. Future east coast prices will be influenced by a range of uncertain factors, including, inter alia:

- the level of future investment into the development of new gas reserves to supply the domestic market as existing gas reserves deplete
- impact of government policy, both Federal and State, in relation to the transition from fossil fuels to alternative energy sources and in relation to ensuring securing of supply and affordability for consumers
- the successful development of the proposed LNG import terminal at Port Kembla
- the ability to maintain separation between the implied netback price and domestic gas prices,

the outcomes of which are unknown.

Western Australian gas market[157]

As noted above, the west coast gas market is currently not connected with the east coast market. Significant development of the west coast gas market took place during the 1980s with the development of North West Shelf gas fields, supported by positive WA State Government policy and the signing of a large gas supply contract with the NWS Project foundation partners by the State Energy Commission of

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[157] The principal information sources for the overview of the Western Australian (**WA**) domestic gas market include AEMO's: 2021 Western Australia Gas Statement of Opportunities, December 2021, Visual Overview Western Australia's gas market outlook, December 2021 and Appendices to 2021 Western Australia Gas Statement of Opportunities, December 2021

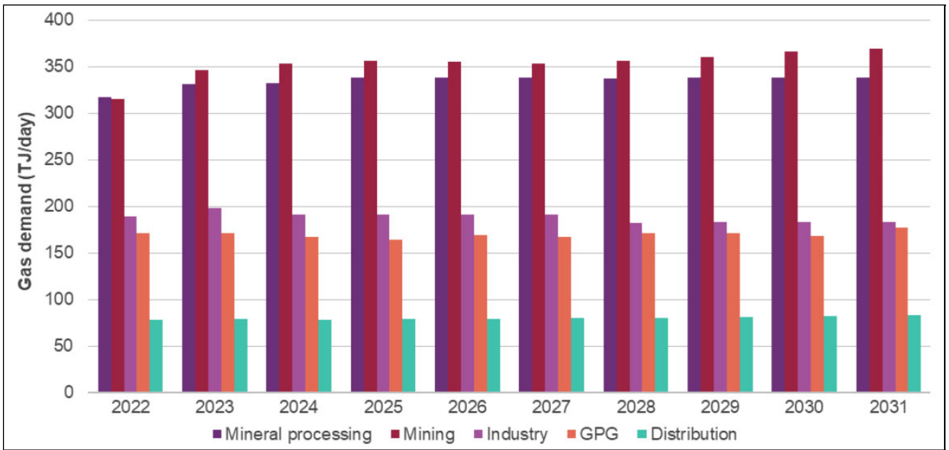
Western Australia (**SECWA**)[158] in 1980. In addition, the State Government, through SECWA, funded and undertook the construction of the Dampier to Bunbury Gas Pipeline (**DBGP**), connecting the gas fields in the State's north with customers in the south-west. At the time, the construction of the DBNGP was the biggest infrastructure project WA had ever seen.

AEMO notes that today, the WA domestic gas market is characterised by a limited number of large suppliers and customers, with approximately 90% of gas produced in WA exported in the form of LNG. Of the 10% of gas produced in WA that is consumed domestically, the majority is consumed by the mining and mineral processing industries. Only 3% of gas produced is consumed in residential use.

Western Australian demand

In its Base scenario, AEMO forecasts WA domestic gas demand to increase from 1,071 TJ/day in 2022 to 1,150 TJ/day in 2031, representing an overall average year-on-year increase of 0.8%, driven largely by the mining sector and committed new resources projects, which are expected to add a combined gas demand of approximately 62 TJ/day by 2031. The breakdown of between the principal users of domestic gas supply over the next 10 years is set out in the figure below.

Figure 63 – AEMO base case demand for WA domestic gas by sector



Source: AEMO Source: 2021 Western Australia Gas Statement of Opportunities, December 2021

Mining sector gas consumption is projected to grow at an average annual rate of 1.7%, compared to average growth of 1.2% per annum (**pa**) in GPG use on the back of the retirement of two units at the coal-fired Muja Power Station by 2024 which is only partially replaced with renewable energy; average annual growth of 0.7% is forecast in the minerals processing sector as new lithium refinery projects increase consumption, with a similar level of average annual growth forecast from residential and small business connections via distribution networks.

[158] SECWA was a government owned managed WA energy provider. Established on 1 January 1975 following the amalgamation of the State Electricity Commission of Western Australia and the Fuel and Power Commission, SECWA was disaggregated on 1 January 1995 into separate gas and electricity utilities, Alinta Gas and Western Power Corporation.

Despite the contribution of new projects, gas demand in the industrial sector is forecast to decline at an average annual rate of 0.3% over the outlook period, primarily due to a decline in gas demand from existing projects.

Western Australian supply

WA has large gas reserve volumes that are generally located offshore and developed mainly to supply the global LNG market. However, WA also has a Domestic Gas Policy which requires LNG export project developers to make gas available to the WA domestic market. The policy seeks to reserve the equivalent of 15% of LNG exports for WA consumers. LNG exporters' domestic gas commitments complement supply from domestic-only projects using the WA gas pipeline network. Gas in the WA pipeline network is not for export.

WA's gas infrastructure includes two multi-user gas storage facilities with a combined capacity of 78 PJ[159], domestic gas transmission pipelines, spot and short-term trading mechanisms and LNG export production facilities. There are nine gas production facilities supplying the WA domestic market, with a total nameplate capacity of about 1,851 TJ/day, with AEMO noting that the KGP currently maintains the largest daily capacity.

The majority of large domestic customers are supplied directly through a transmission network[160] (such as the DBP and the Goldfields Gas Pipeline.

AEMO has forecast that potential total gas supply[161] will decrease at an average annual rate of 1.4% over period 2022 to 2031. This decrease is driven by natural depletion and reserves downgrades at existing gas production facilities, partially offset by new three new project developments, including Scarborough, the offshore Spartan project and the onshore West Erregulla project.

In general, as shown in figure 64 below, AEMO expects the WA domestic market will be adequately supplied until 2024.

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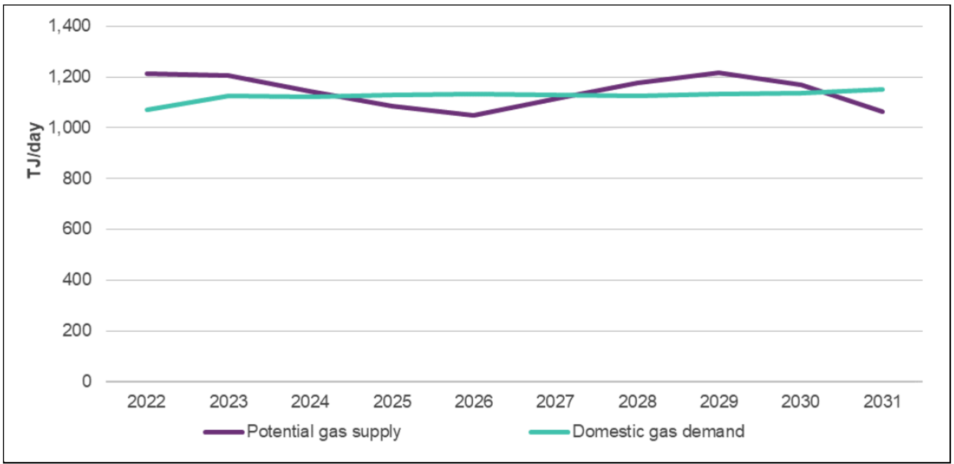
[159] Estimated to have a capacity utilisation rate of 68% in October 2021
[160] High-pressure pipelines used to transport large volumes of gas from the production facilities to customers. Large customers can connect directly to the transmission network, while smaller customers are supplied through the distribution network connected to the transmission network.
161 Instead of forecasting how much gas is expected to be supplied over the outlook period, AEMO's forecasts of potential gas supply reflect how much gas could be produced if there was market demand for it at forecast prices.

Figure 64 – AEMO base case WA gas market balance



Source: AEMO 2021 Western Australia Gas Statement of Opportunities, December 2021

Between 2025 and 2027, domestic demand for gas could exceed supply by 51 PJ in total over those three years, however AEMO considers there are different options that could fill the supply shortfall, including:

- gas being withdrawn from storage
- additional supply from existing facilities with spare production capacity, such as the KGP
- development of backfill and new gas field opportunities that are not currently included in AEMO's potential gas supply forecasts.

From 2027, the incremental gas from the Scarborough project coming on stream is expected to be sufficient to again ensure supply meets demand, although another gap may develop in 2031.

Gas prices

Trade is largely conducted though bilateral, commercial and long-term take-or-pay gas sales contracts, with only small volumes of short-term and spot gas sales, resulting in an opaque market, with limited information about supply available to be contracted, potential buyers, and gas contract pricing.

Short-term gas may be acquired through two independent and non-aligned mechanisms:

- gasTrading Australia Pty Ltd operates a spot market where sellers advise the operator of any surplus gas for the coming month, which is then advised to the market and subsequently allocated depending on the ranking of the purchasers' offers and availability. The exact volumes available are confirmed by the seller one day ahead
- Energy Access Services Pty Ltd operates a real-time energy trading platform where members enter gas trade agreements with a focus on supply durations of up to 90 days. Trades can encompass firm and interruptible gas arrangements, as well as imbalances.

AEMO estimates that approximately 1-2% of total gas consumption in WA is traded on a short-term basis.

The table below indicates that WA domestic gas prices have, on average, trended upwards over the past three years and have recently stabilised at an average price in the order of A$5.25/GJ to A$5.50/GJ.

Figure 65 – Historical WA domestic gas prices

	FEB 2022	JAN 2022	DEC 2021	NOV 2021	OCT 2021	SEPT 2021
Maximum Price	$5.67	$5.50	$5.35	$5.35	$5.29	$5.42
Average Price	$5.50	$5.50	$5.17	$5.23	$5.27	$5.25
Minimum Price	$5.50	$5.50	$5.10	$5.20	$5.27	$5.27

Averages of prices:

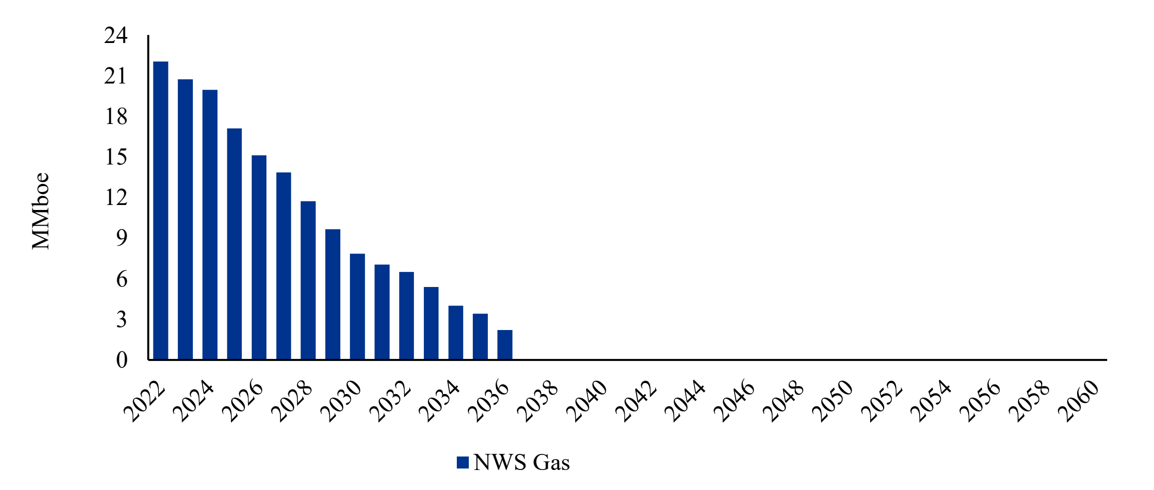
	INCEPTION	3 YEARS	2 YEARS	1 YEAR	9 MONTHS	6 MONTHS
Maximum Price	$6.30	$3.72	$4.12	$5.18	$5.31	$5.43
Average Price	$4.37	$3.61	$4.01	$5.05	$5.21	$5.32
Minimum Price	$3.59	$3.54	$3.98	$5.03	$5.20	$5.31

Source: gasTrading Australia Pty Ltd

Appendix 4 – Production, operating and capital cost profiles

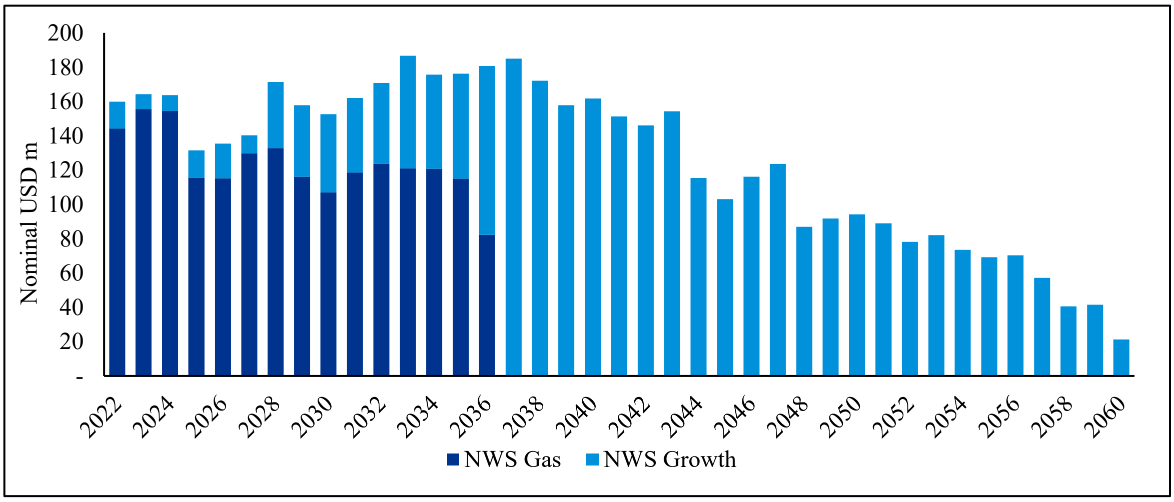
NWS Project (Woodside interest)

Figure 66 – NWS Project forecast production profile



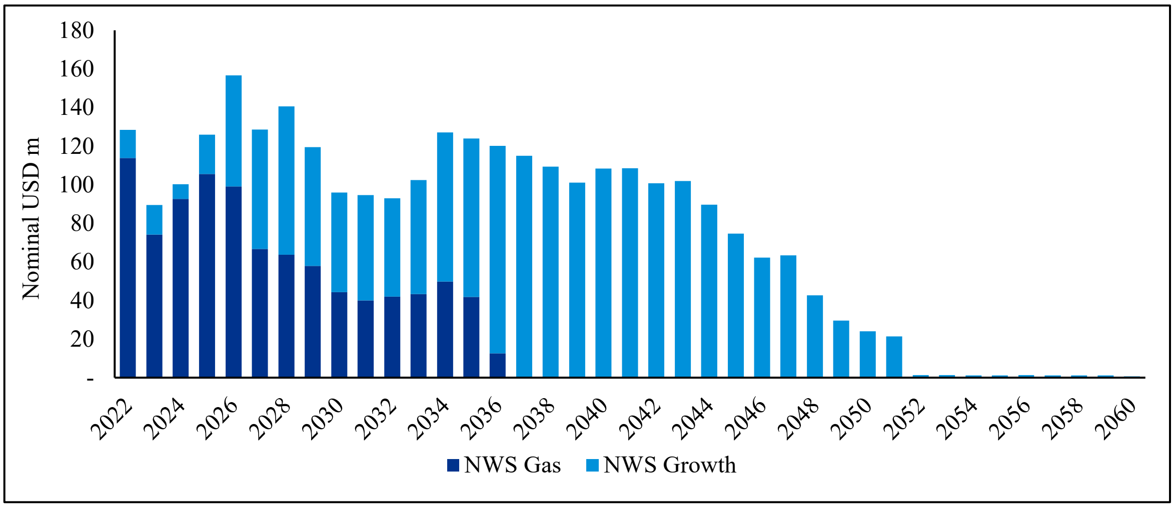
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 67 – NWS Project forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis
Note 1: NWS Growth operating costs relate to Browse tariff arrangements

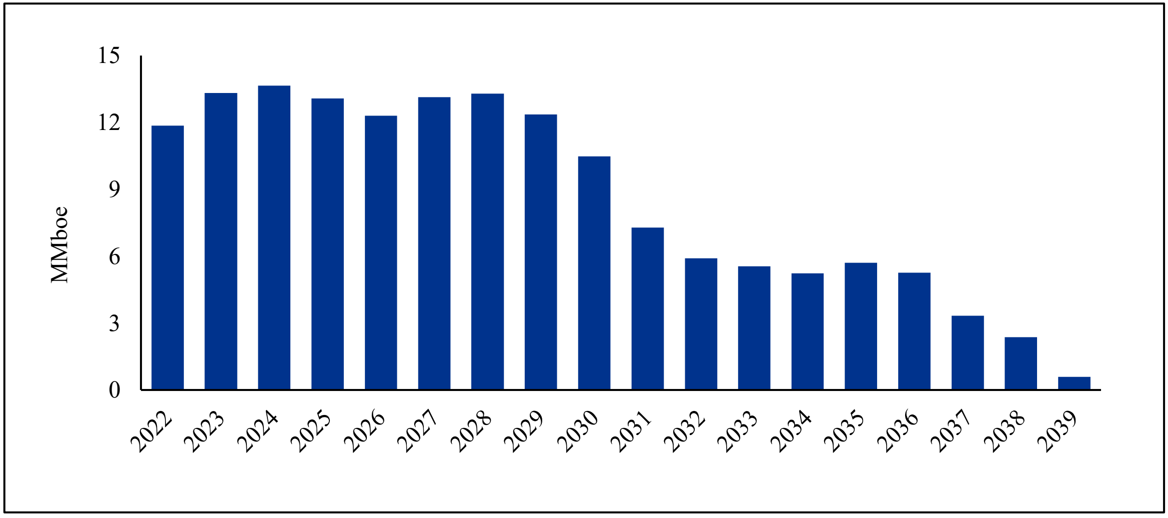
Figure 68 – NWS Project forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis
Note 1: NWS Growth capital expenditure relates to Browse tariff arrangements

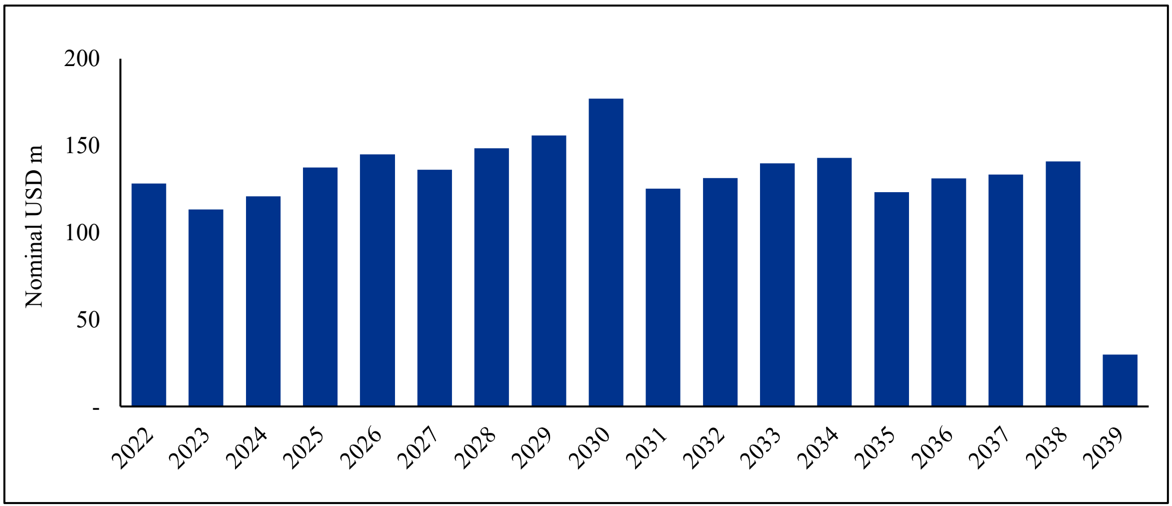
Wheatstone LNG (Woodside interest)

Figure 69 – Wheatstone LNG forecast production profile



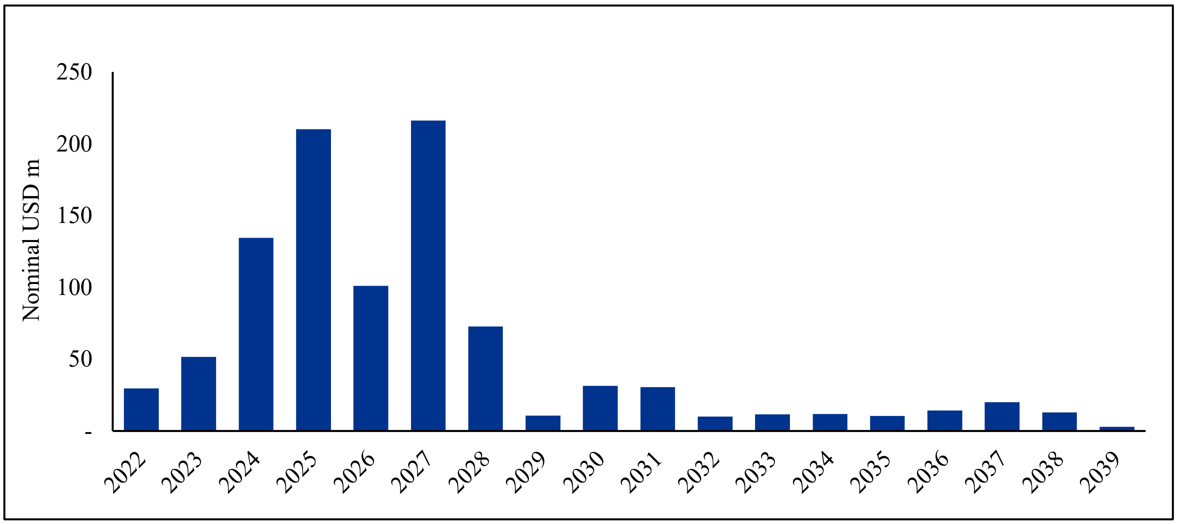
Source: GaffneyCline, KPMG Corporate Finance analysis
Note 1: Wheatstone LNG production relates to the Julimar-Brunello Project

Figure 70 – Wheatstone LNG forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

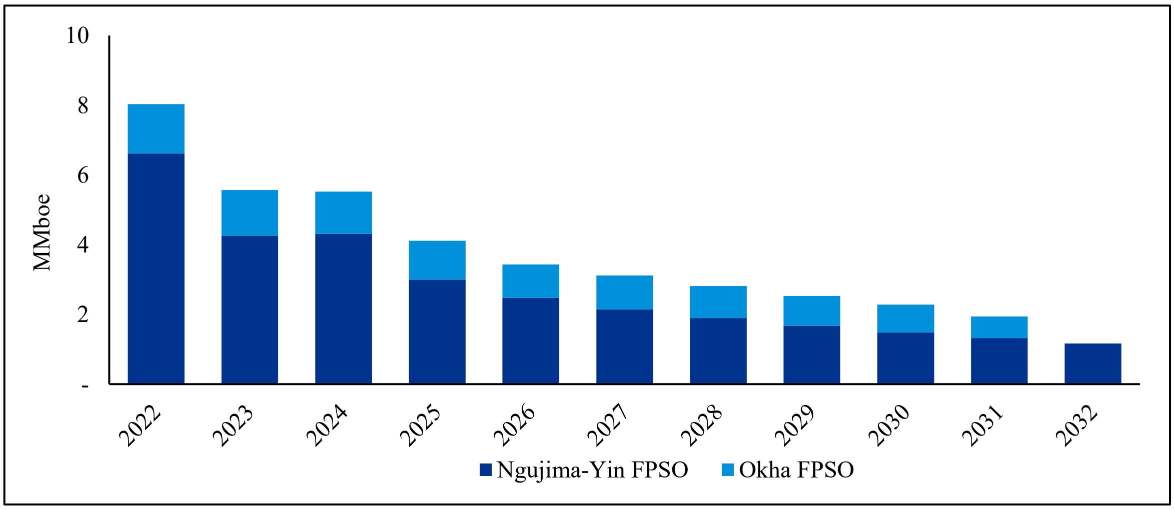
Figure 71 – Wheatstone LNG forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

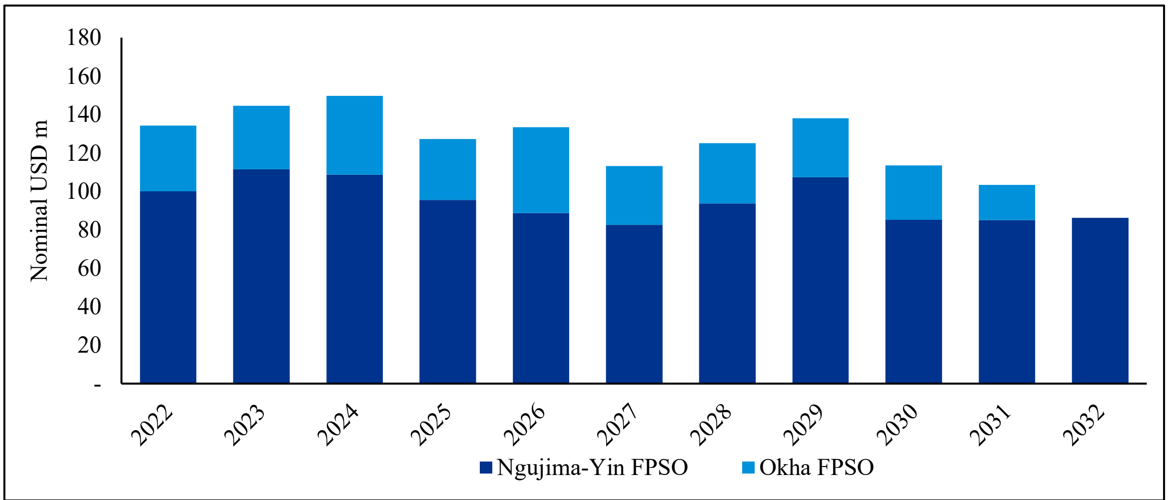
Australia Oil (incl. Okha FPSO) (Woodside interest)

Figure 72 – Australia Oil (incl. Okha FPSO) forecast production profile



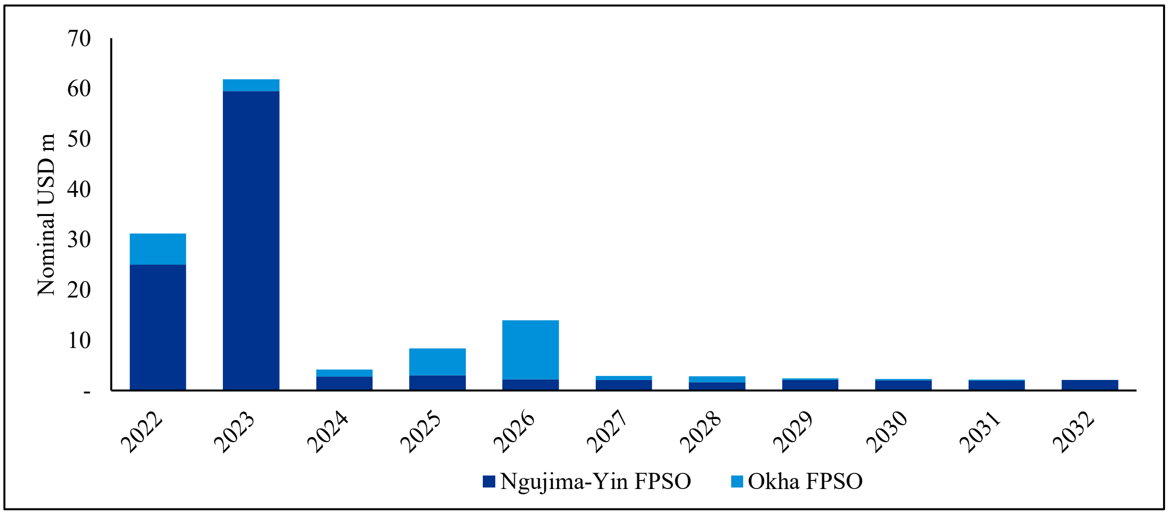
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 73 – Australia Oil (incl. Okha FPSO) forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

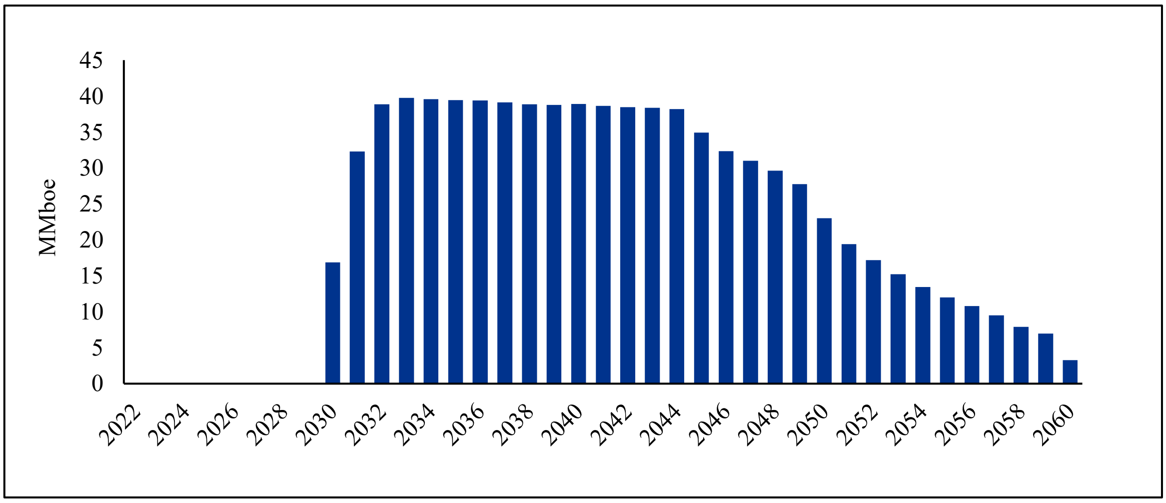
Figure 74 – Australia Oil (incl. Okha FPSO) forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

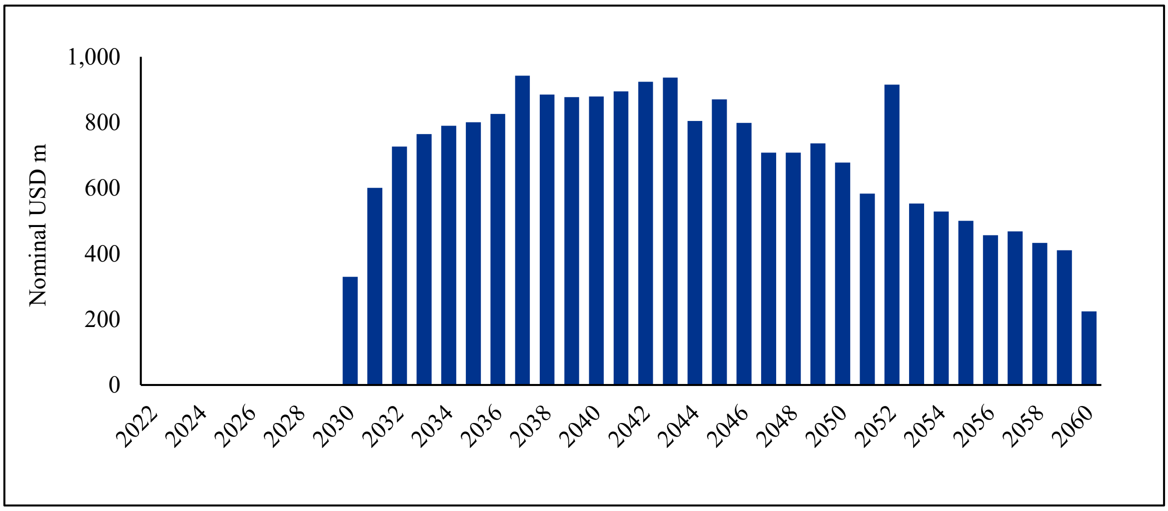
Browse (Woodside interest)

Figure 75 – Browse forecast production profile



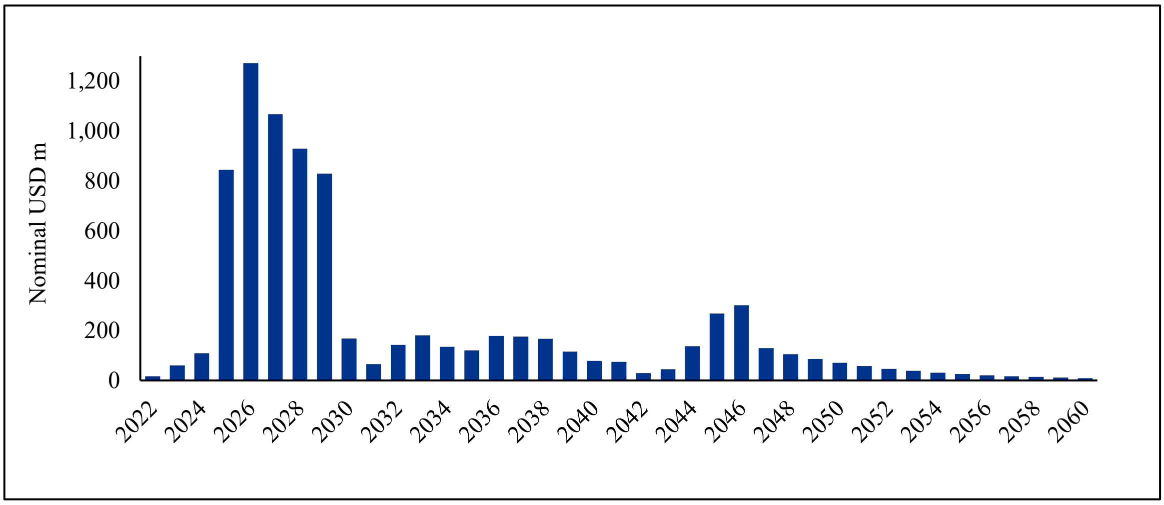
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 76 – Browse forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

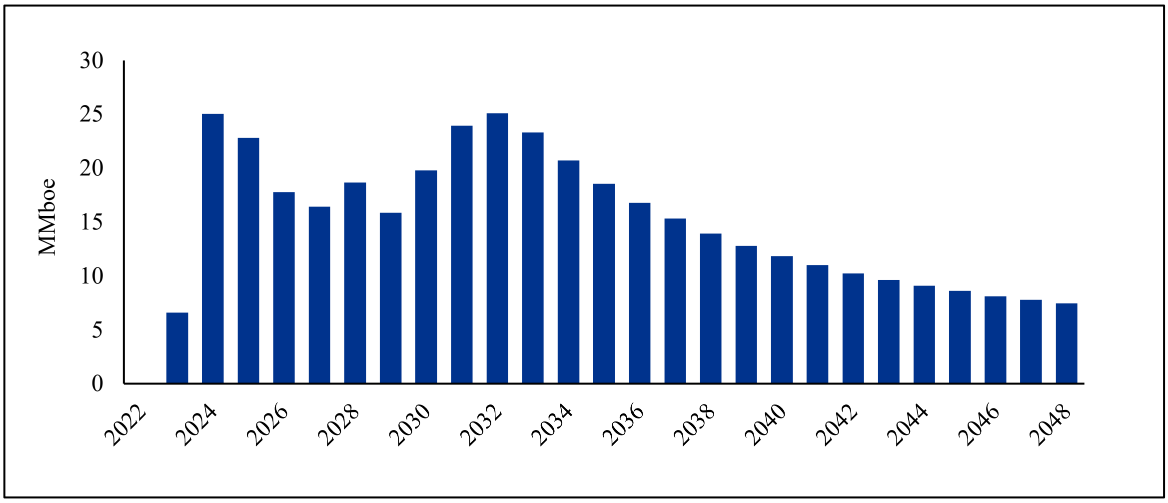
Figure 77 – Browse forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

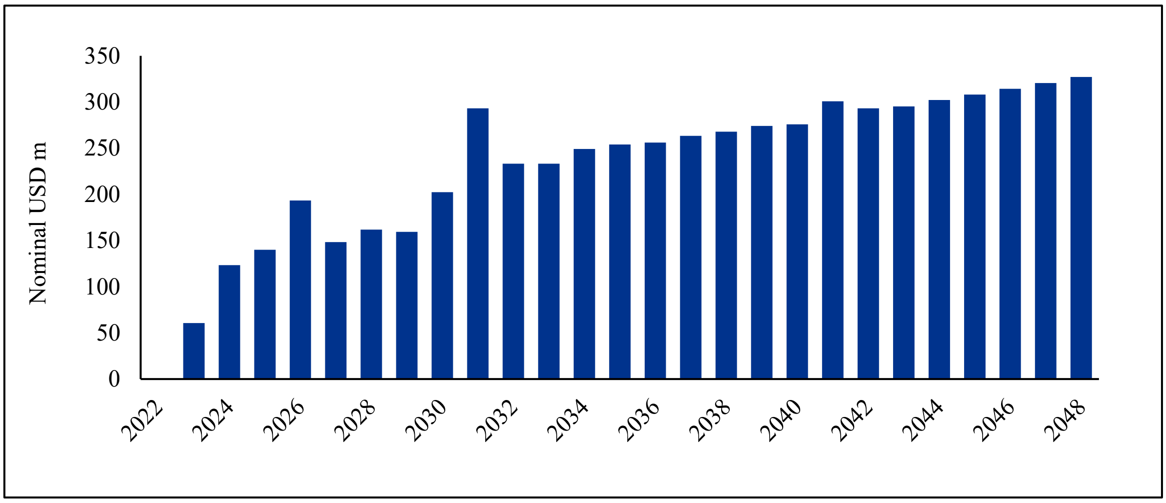
Sangomar (Woodside interest)

Figure 78 – Sangomar forecast production profile



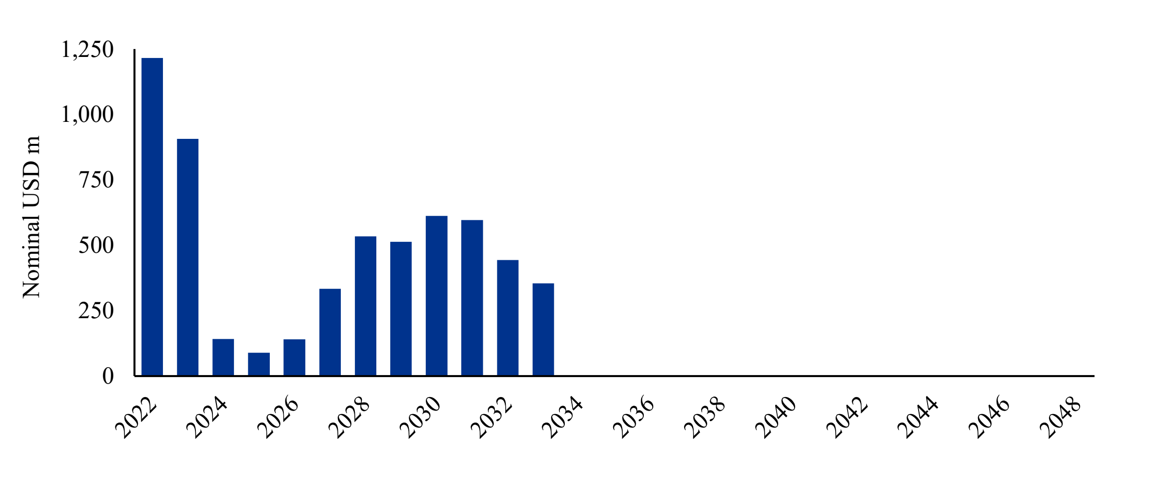
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 79 – Sangomar forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

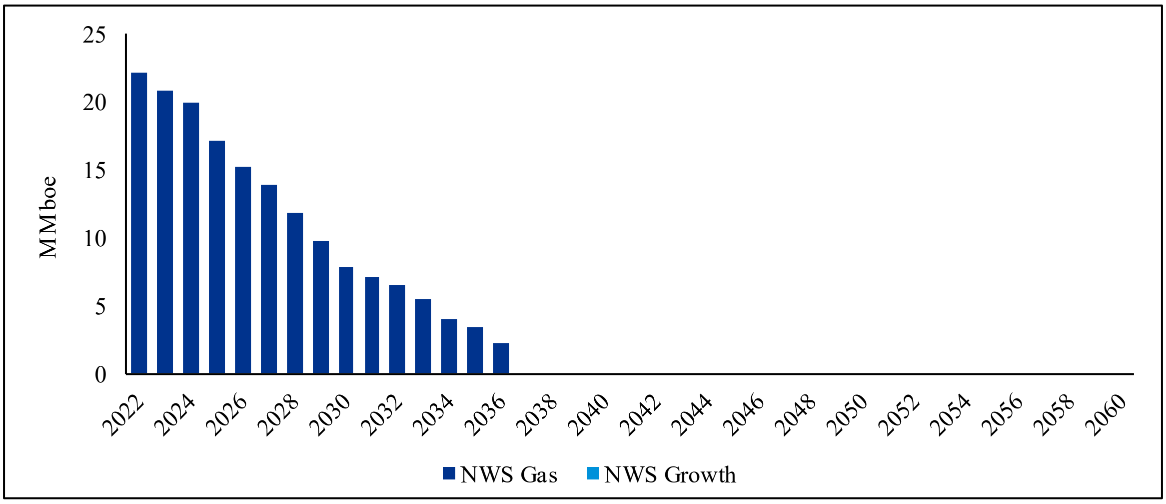
Figure 80 – Sangomar forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

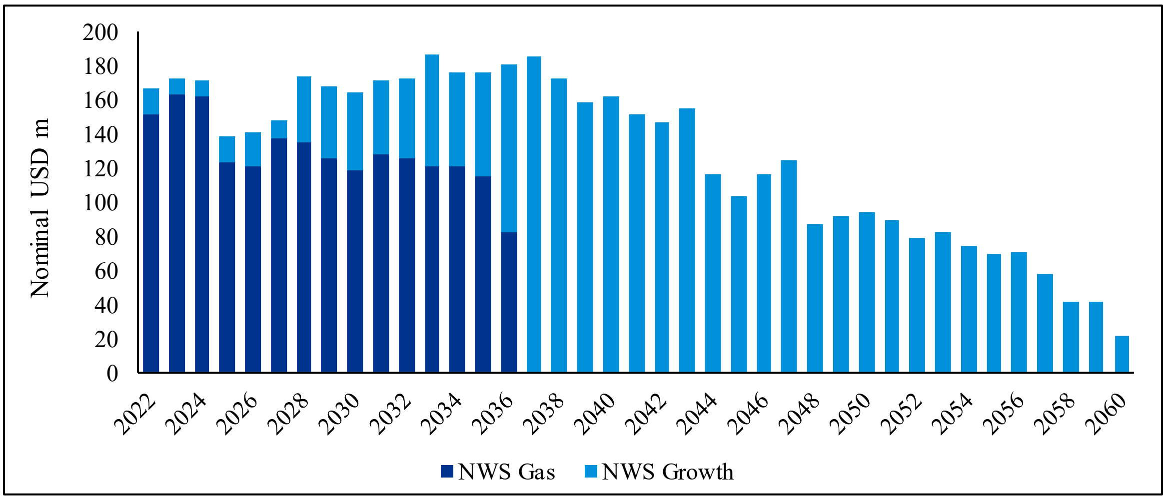
NWS Project (BHP Petroleum interest)

Figure 81 – NWS Project forecast production profile



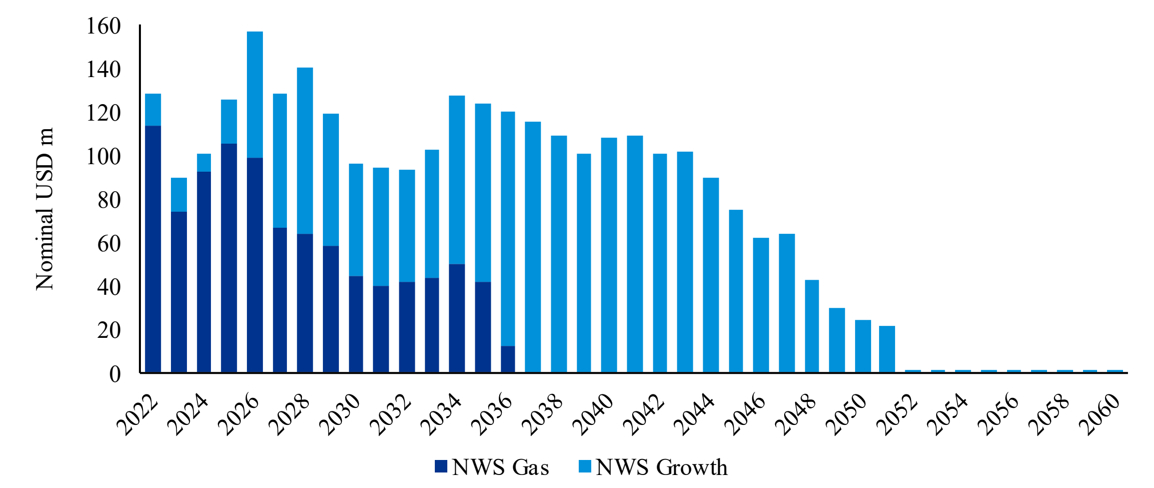
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 82 – NWS Project forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis
Note 1: NWS Growth operating costs relate to Browse tariff arrangements

Figure 83– NWS Project forecast capital expenditure

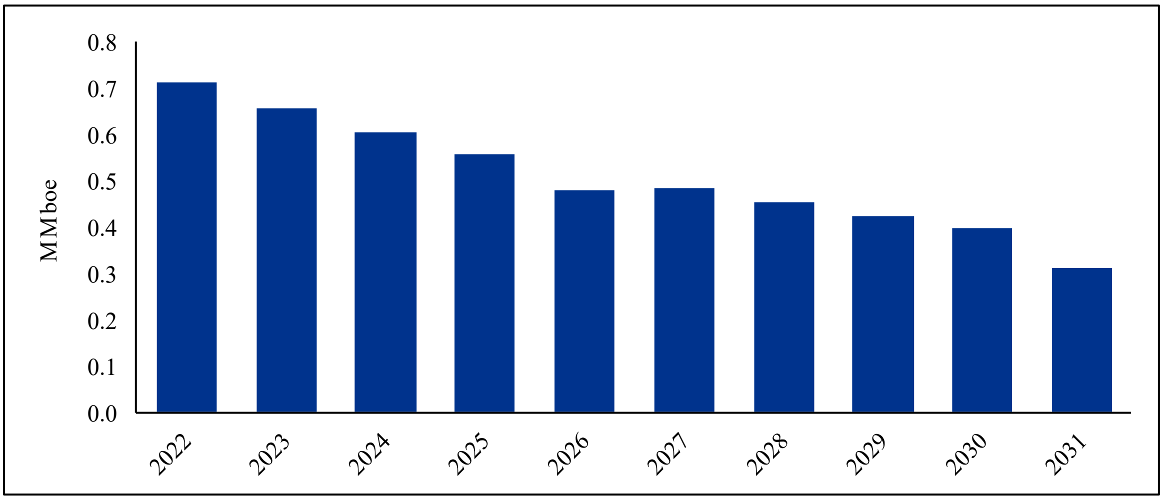


Source: GaffneyCline, KPMG Corporate Finance analysis

Note 1: NWS Growth capital expenditure relates to Browse tariff arrangements

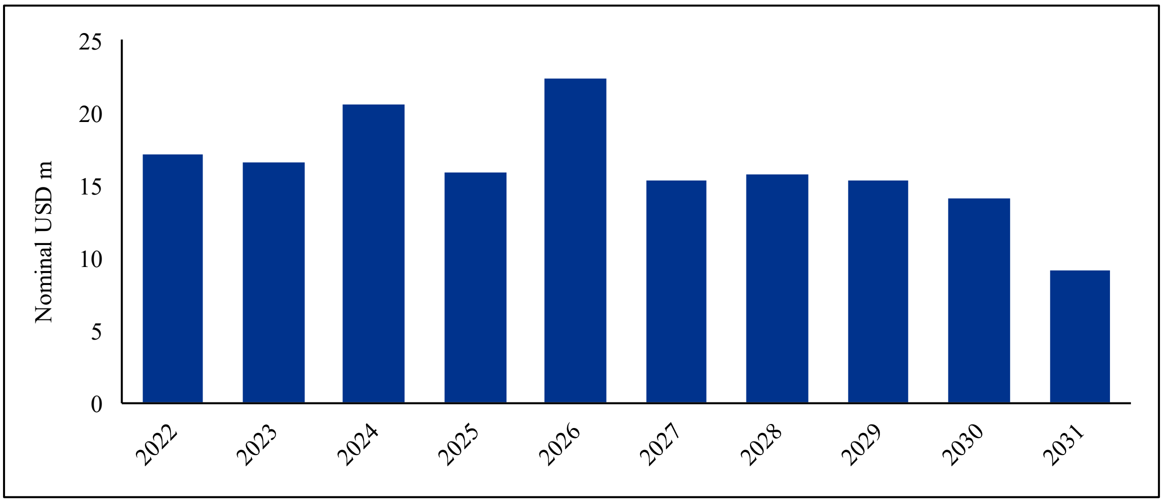
NWS Oil (BHP Petroleum interest)

Figure 84 – NWS Oil forecast production profile



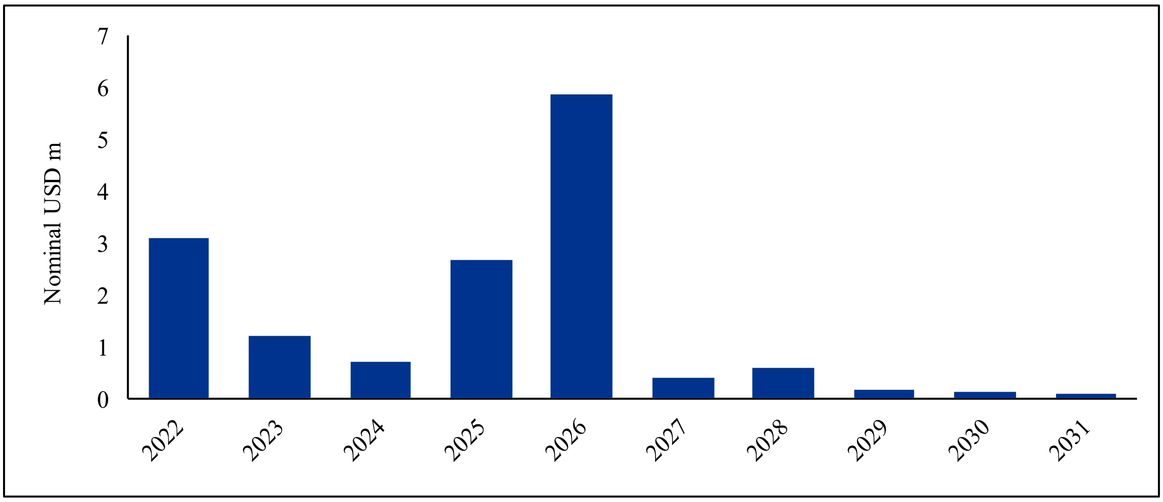
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 85 – NWS Oil forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

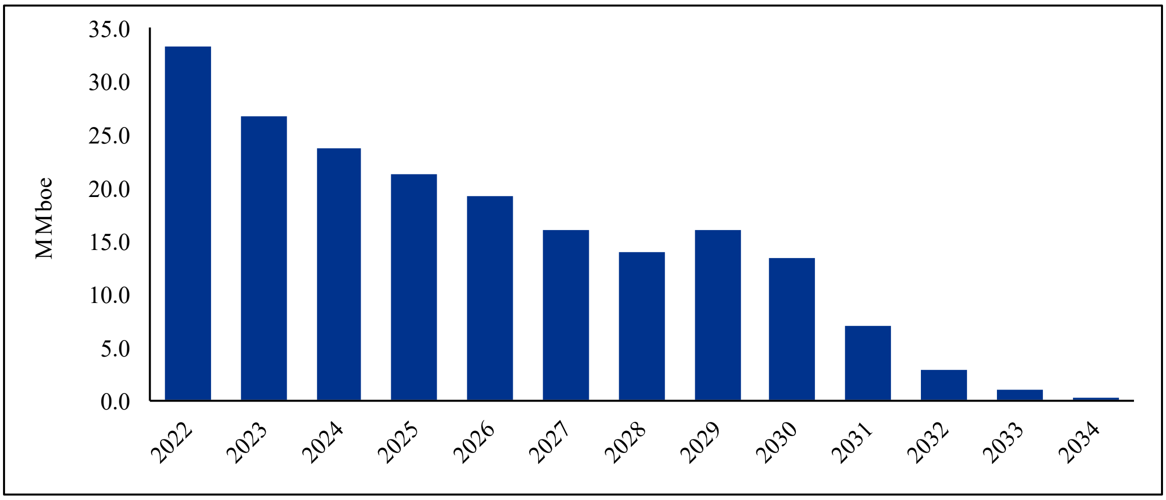
Figure 86 – NWS Oil forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

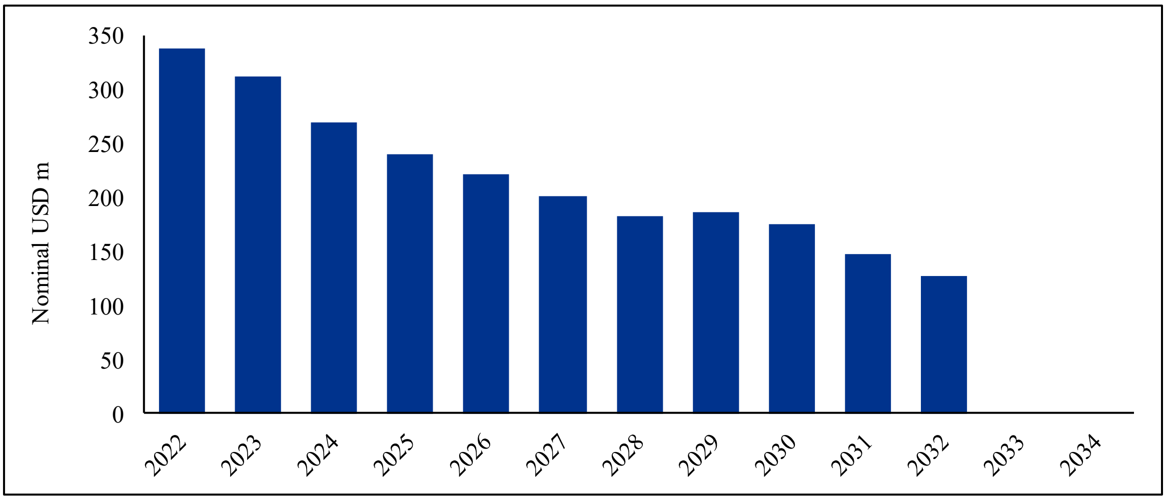
Bass Strait (BHP Petroleum interest)

Figure 87 – Bass Strait forecast production profile



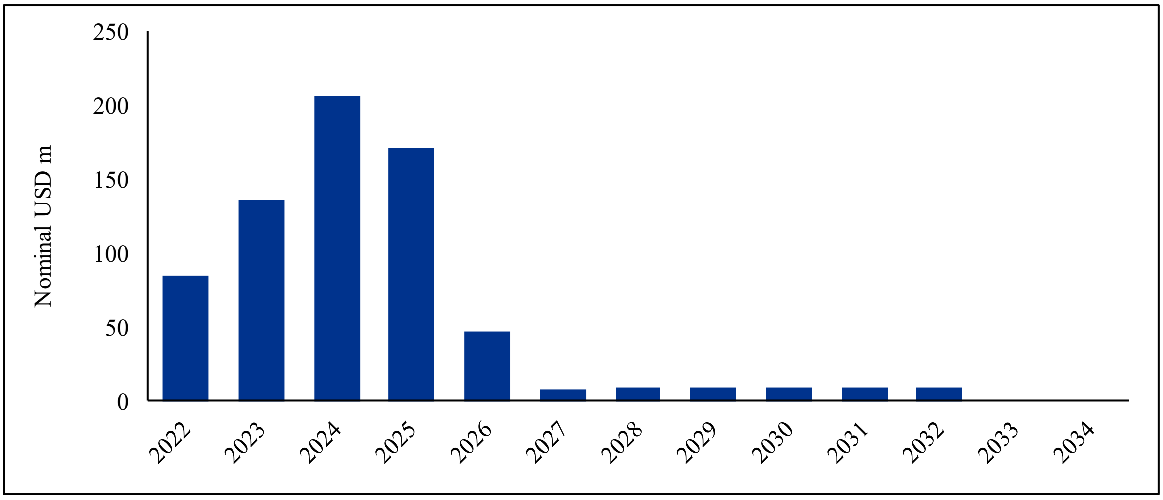
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 88 – Bass Strait forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

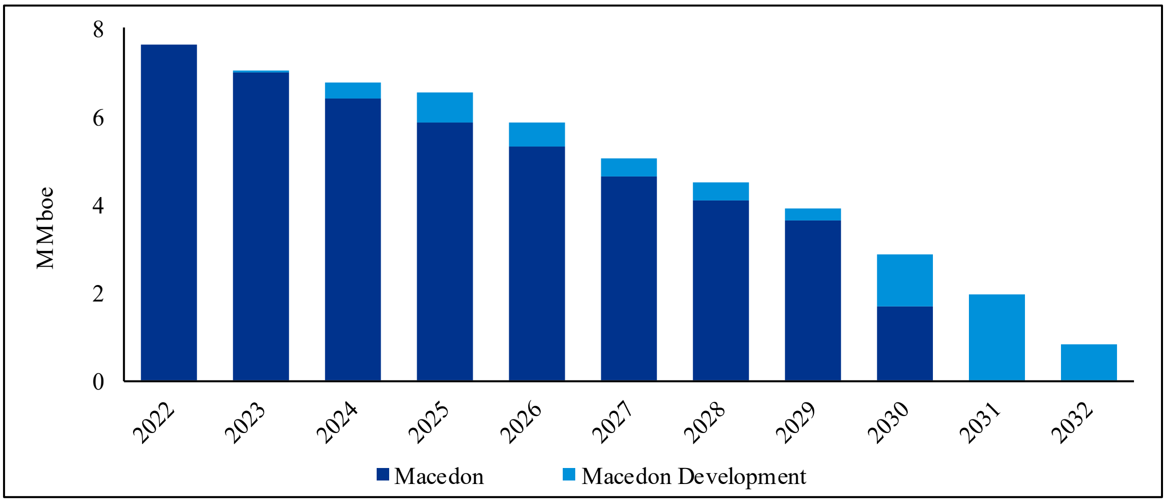
Figure 89 – Bass Strait forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

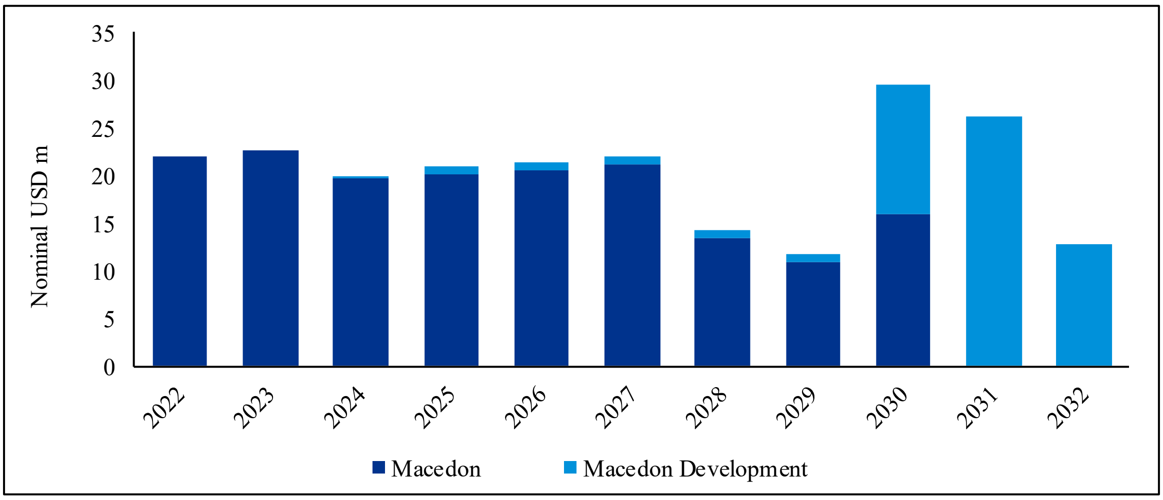
Macedon (BHP Petroleum interest)

Figure 90 – Macedon forecast production profile



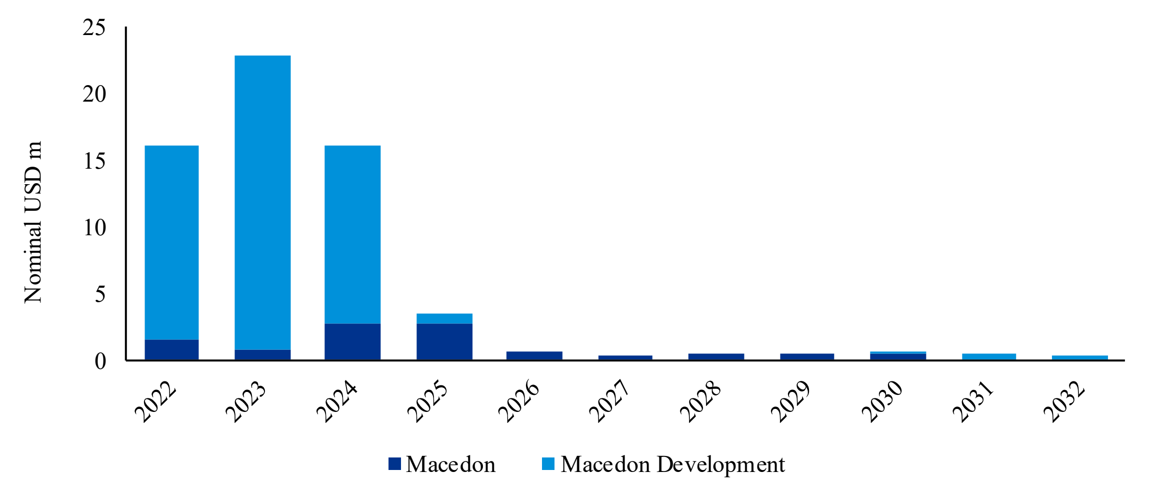
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 91 – Macedon forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

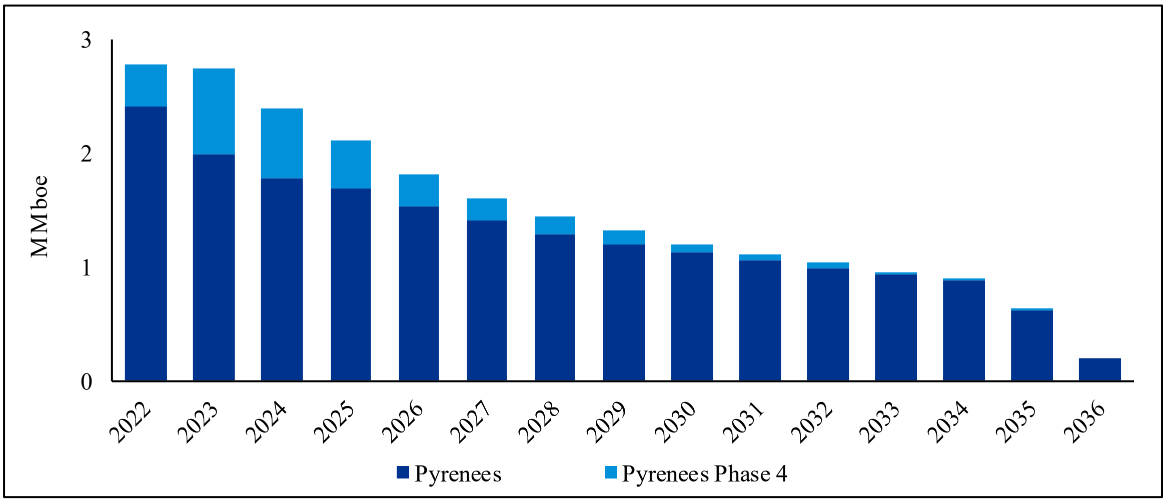
Figure 92 – Macedon forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

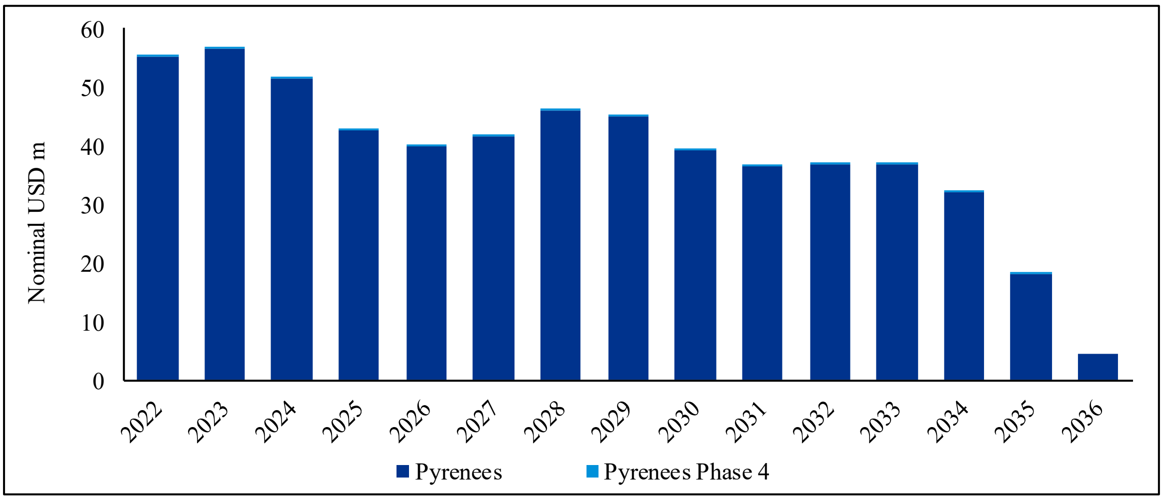
Pyrenees (BHP Petroleum interest)

Figure 93 – Pyrenees forecast production profile



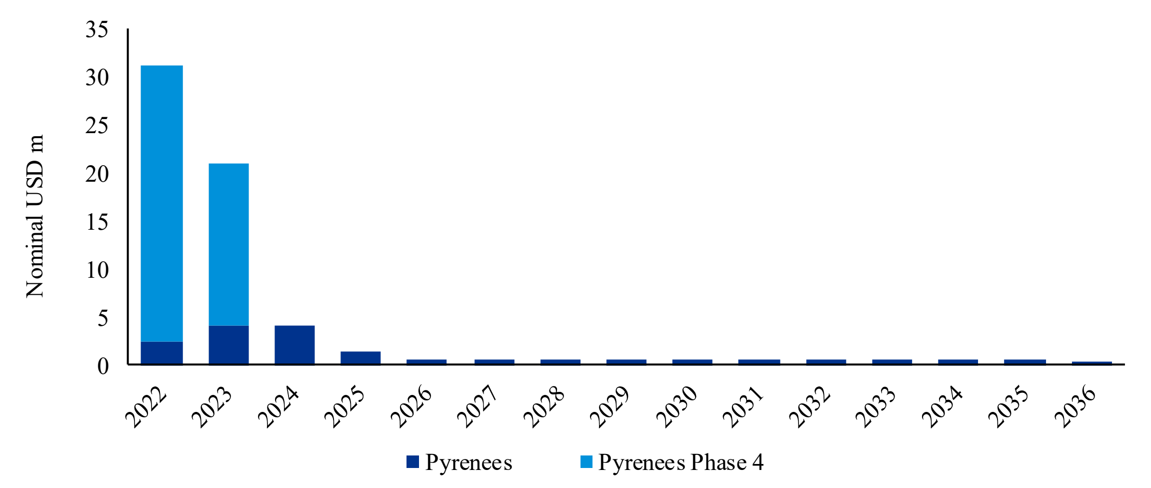
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 94 – Pyrenees forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

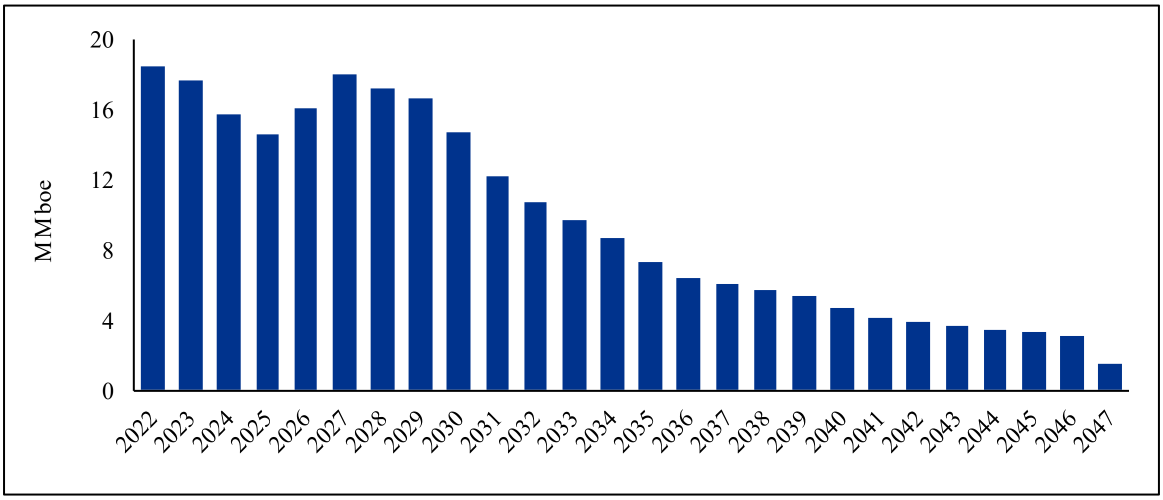
Figure 95 – Pyrenees forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

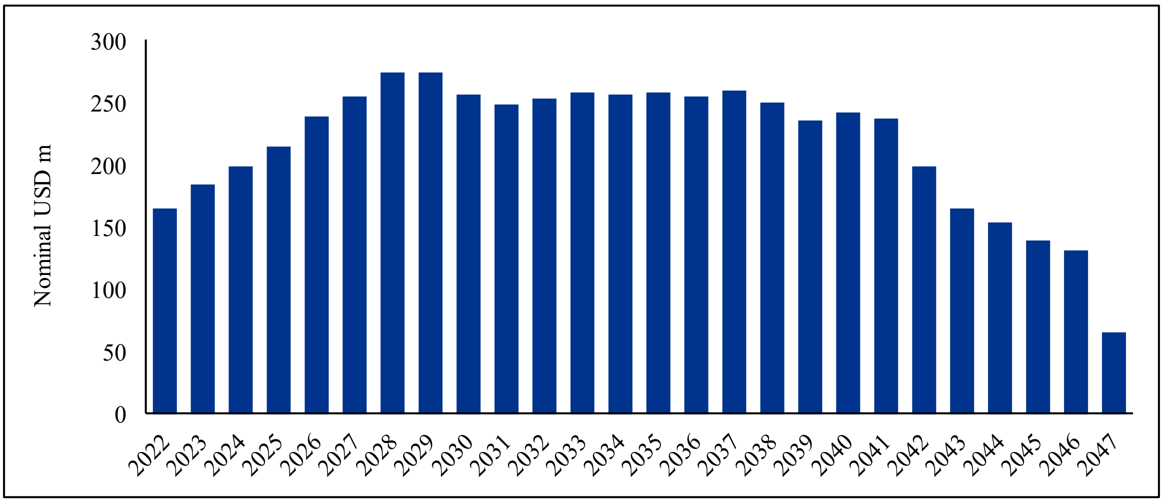
Atlantis (BHP Petroleum interest)

Figure 96 – Atlantis forecast production profile



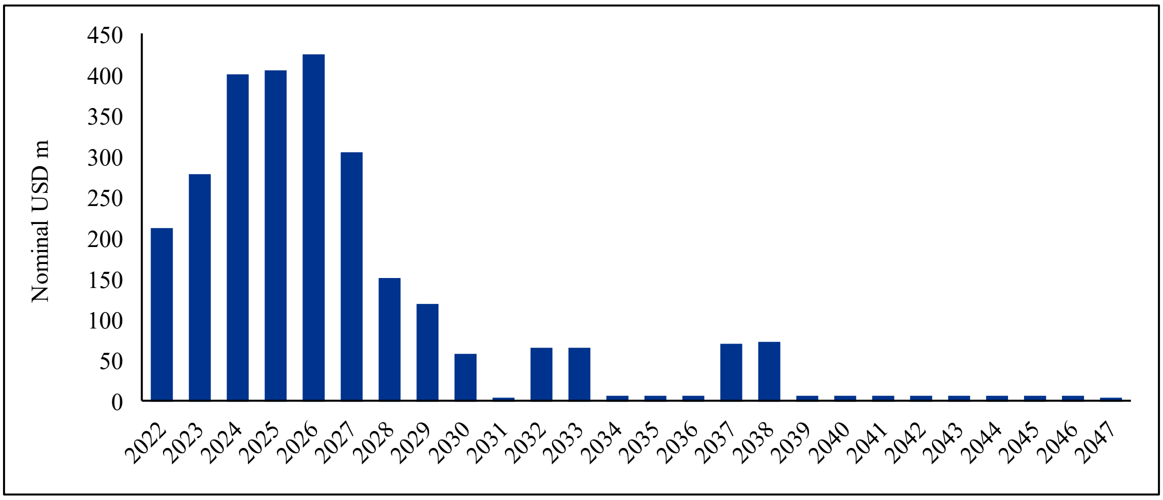
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 97 – Atlantis forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

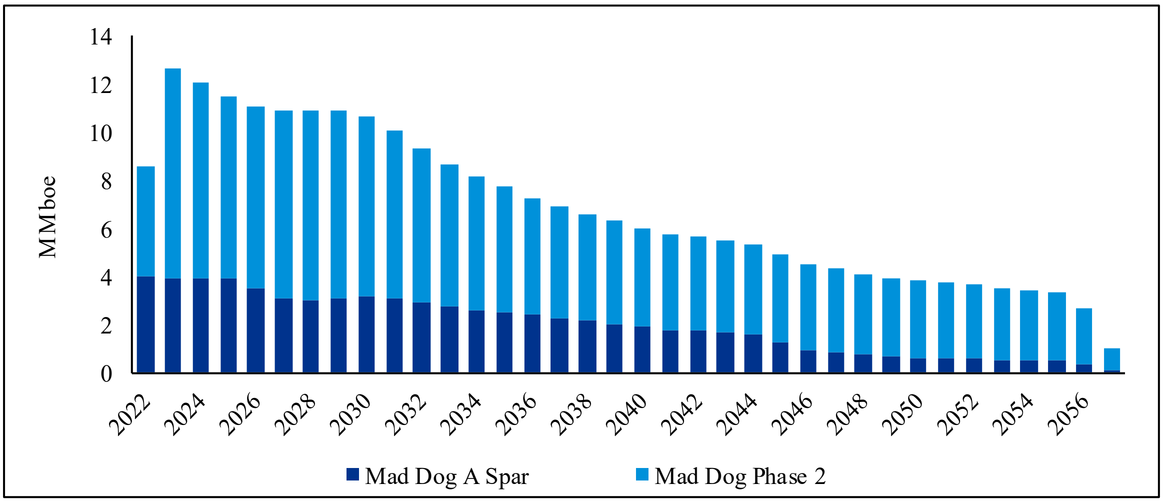
Figure 98 – Atlantis forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

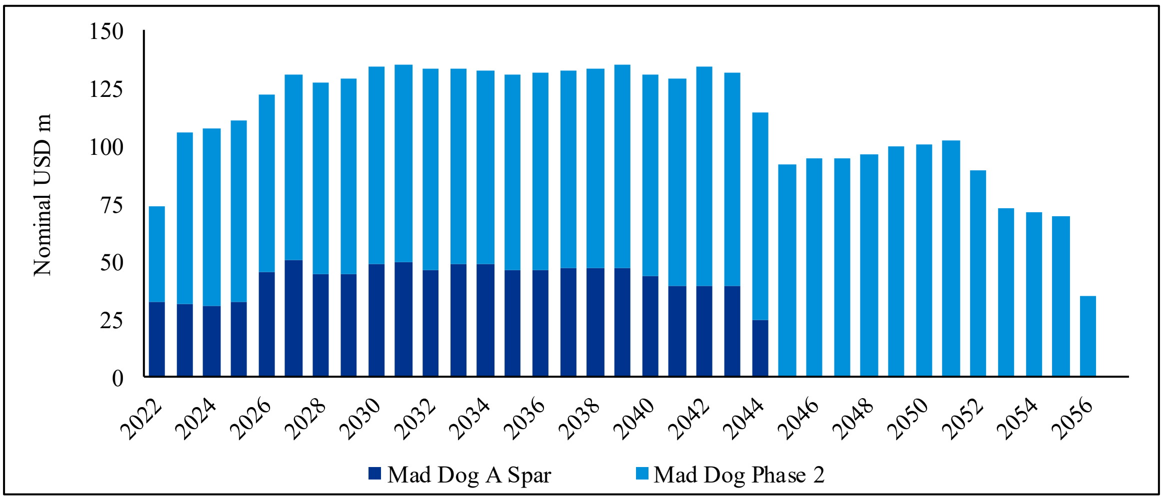
Mad Dog (BHP Petroleum interest)

Figure 99 – Mad Dog forecast production profile



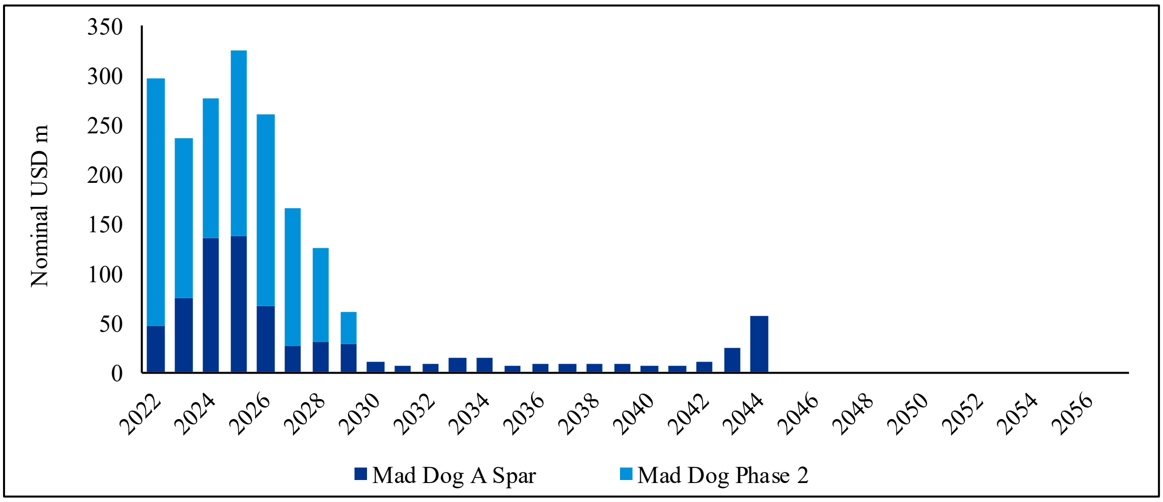
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 100 – Mad Dog forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

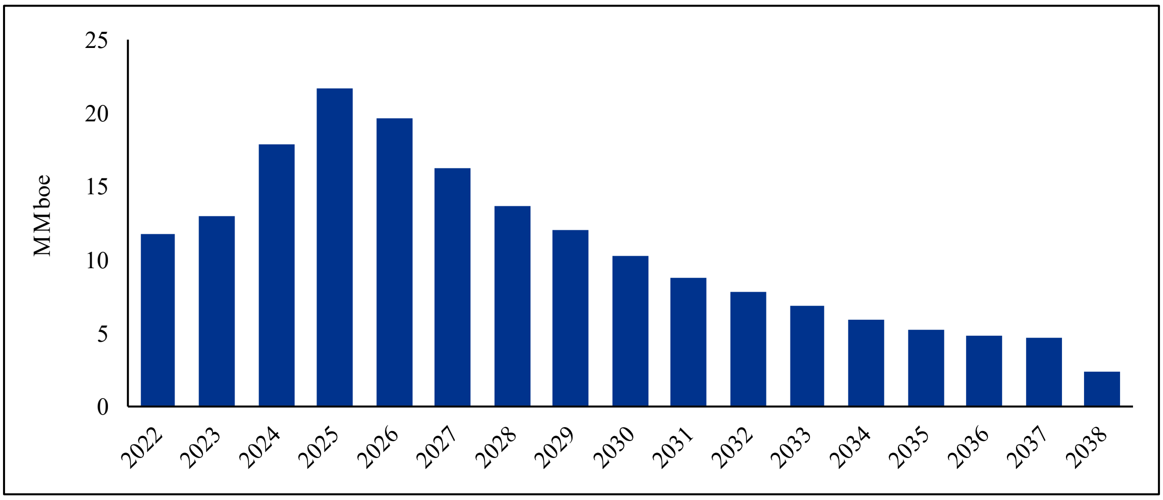
Figure 101 – Mad Dog forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

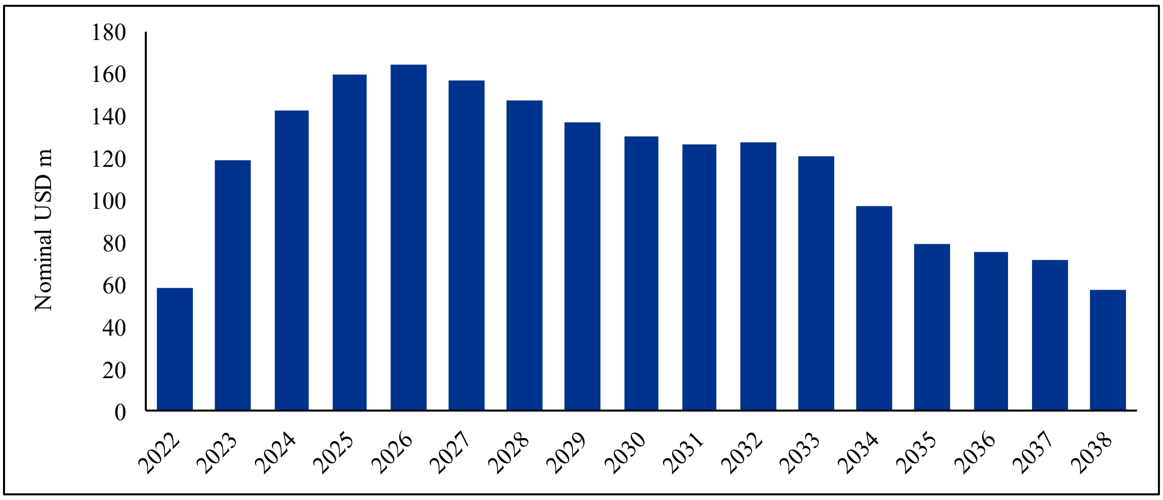
Shenzi (BHP Petroleum interest)

Figure 102 – Shenzi forecast production profile



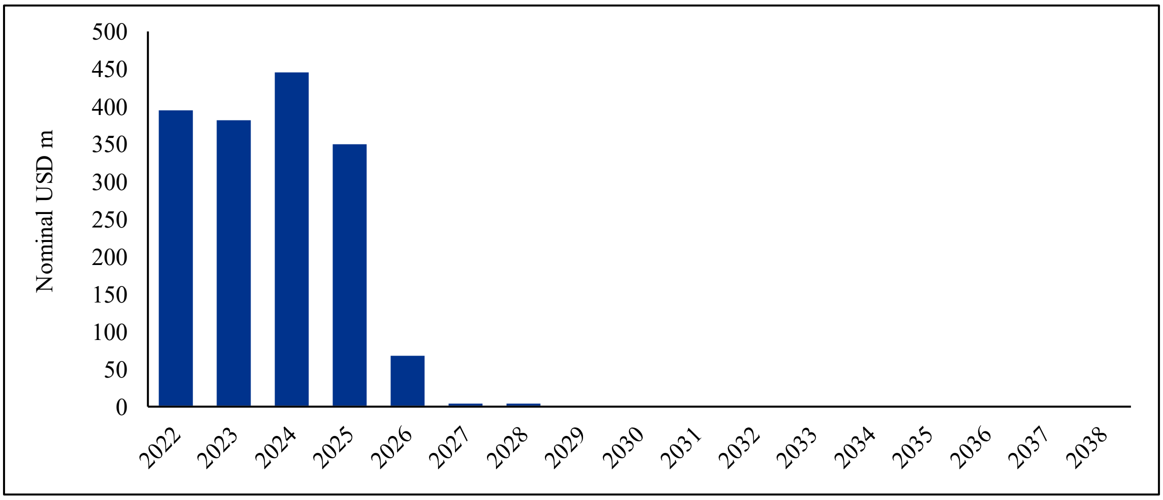
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 103 – Shenzi forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

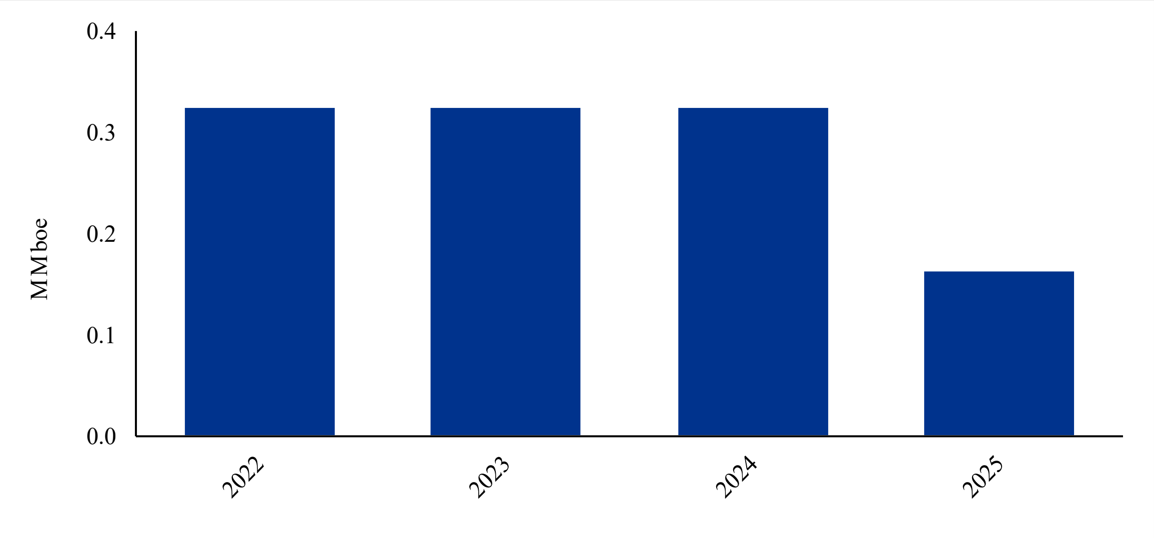
Figure 104 – Shenzi forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

GOM ORRI (BHP Petroleum interest)

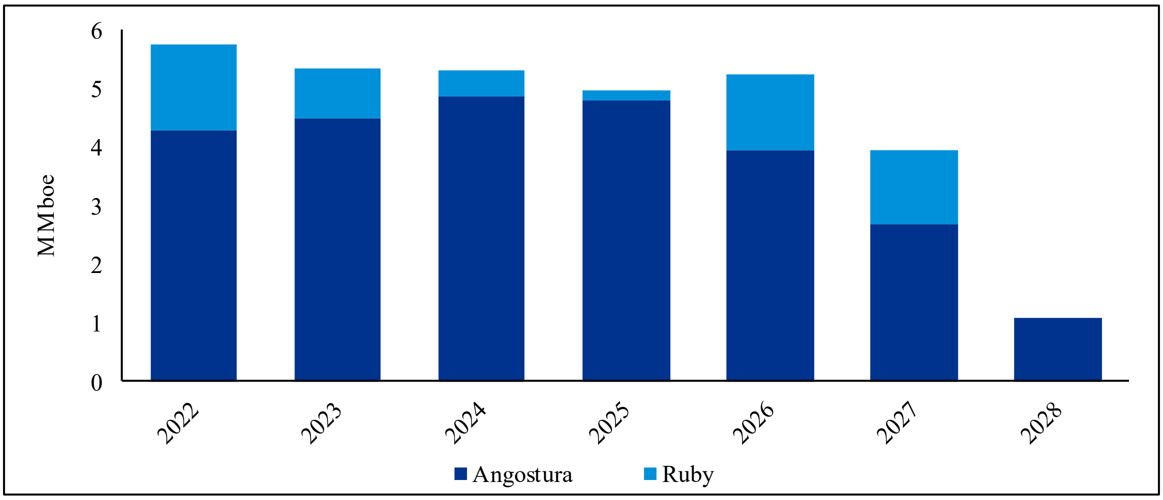
Figure 105 – GOM ORRI forecast production profile



Source: GaffneyCline, KPMG Corporate Finance analysis

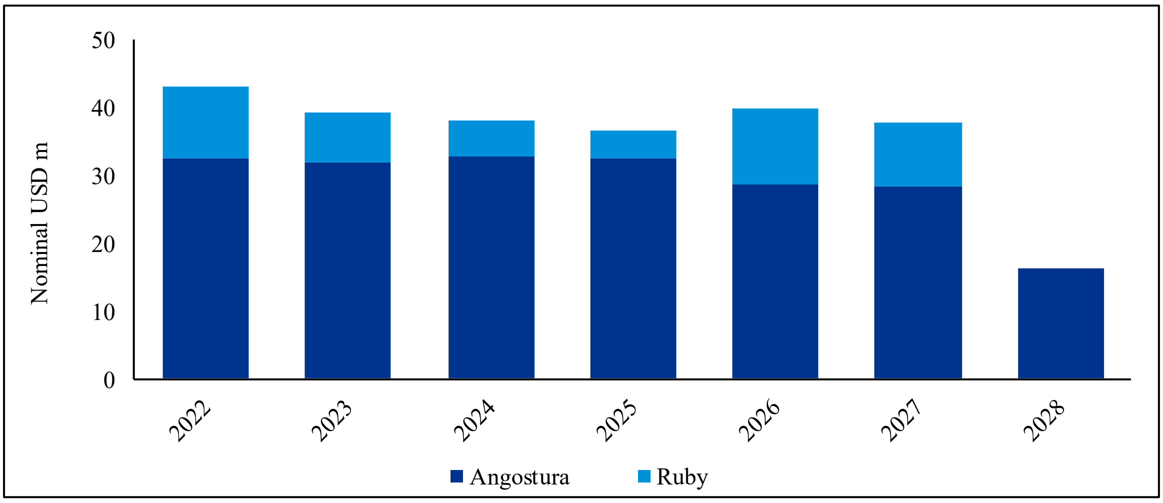
Greater Angostura Complex (BHP Petroleum interest)

Figure 106 – Greater Angostura Complex forecast production profile



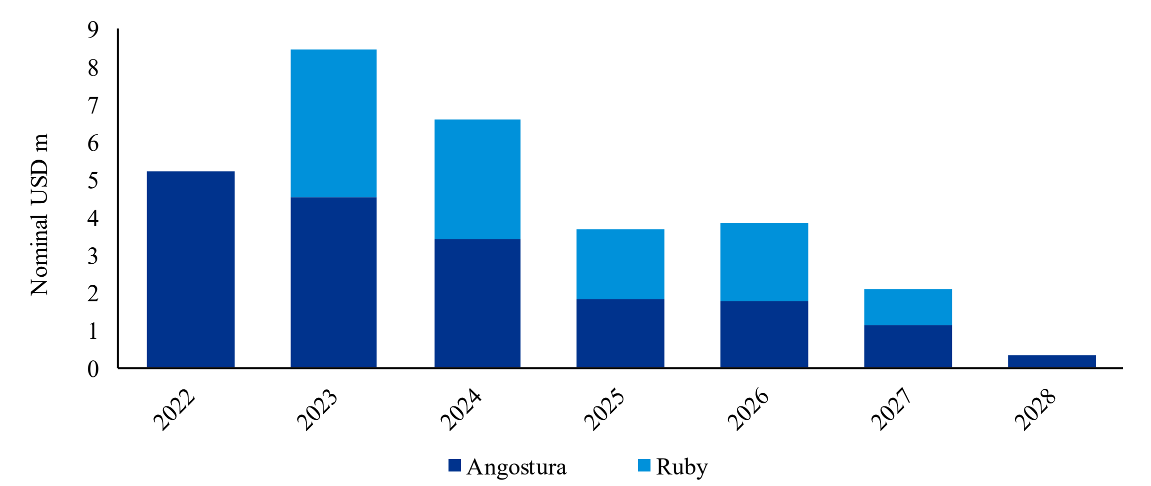
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 107 – Greater Angostura Complex forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

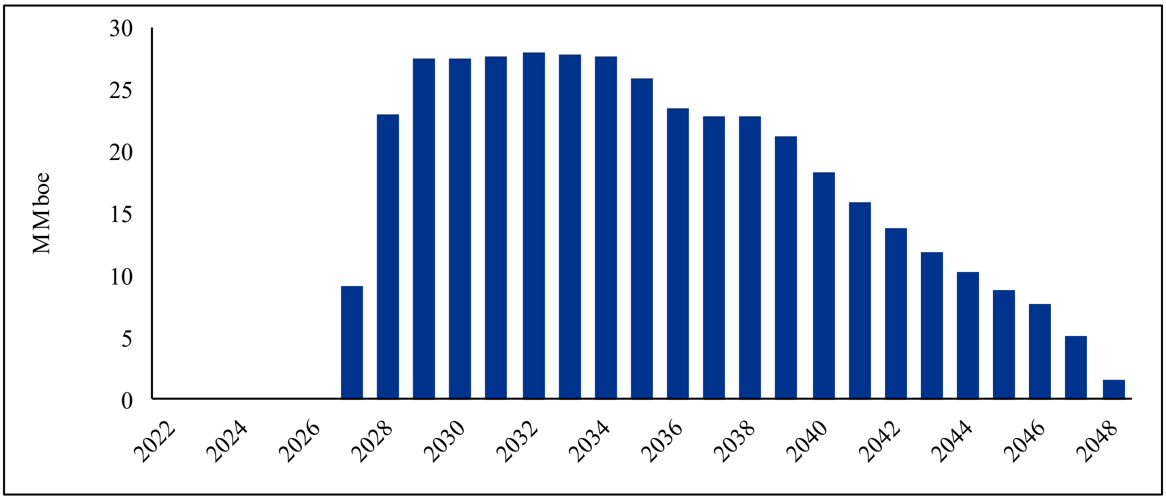
Figure 108 – Greater Angostura Complex forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

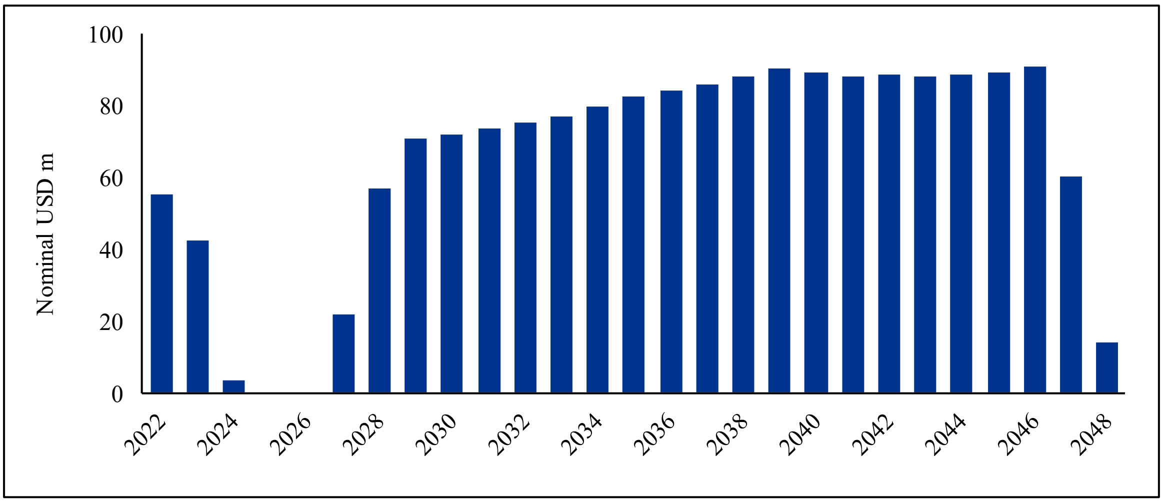
Calypso (BHP Petroleum interest)

Figure 109 – Calypso forecast production profile



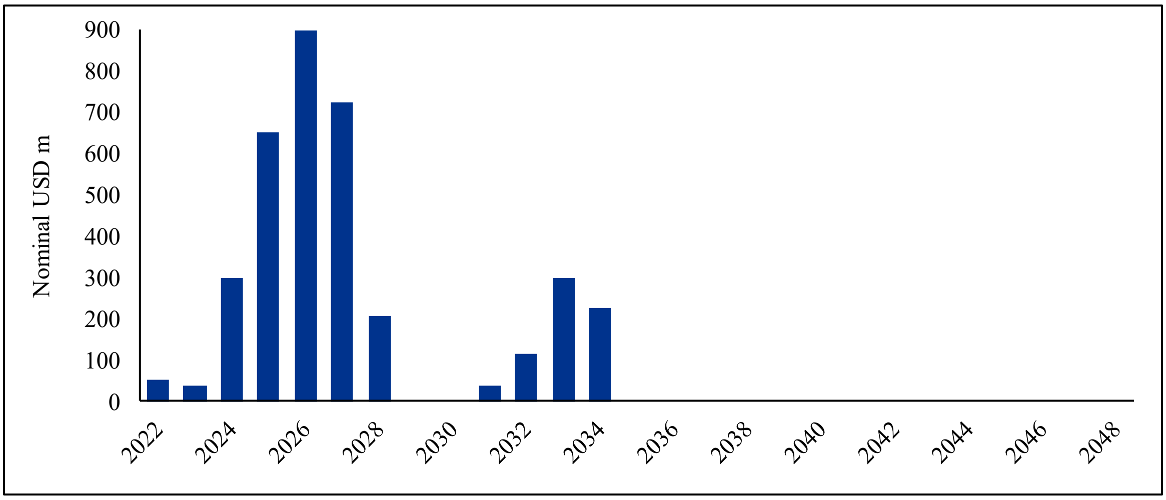
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 110 – Calypso forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

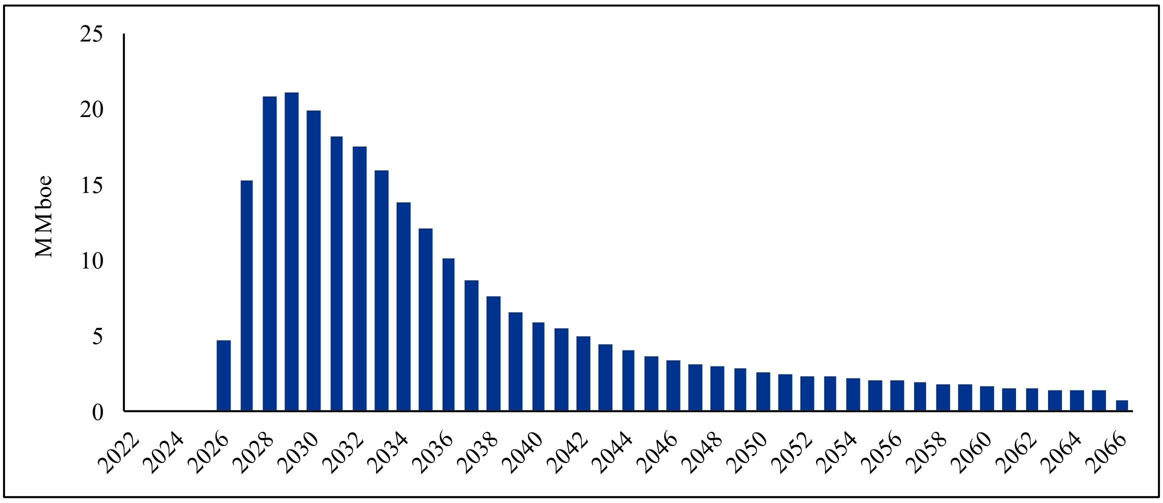
Figure 111 – Calypso forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

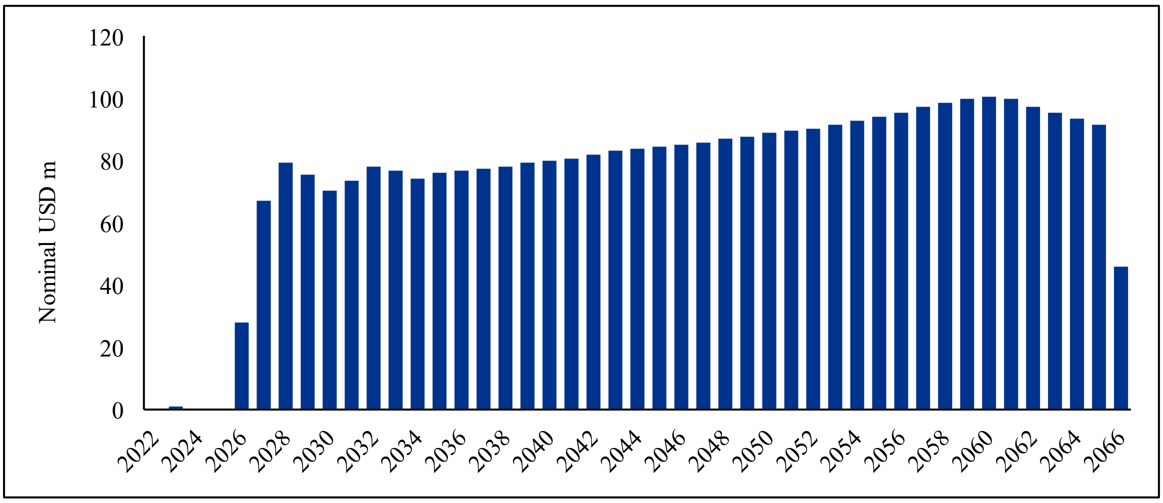
Trion (BHP Petroleum interest)

Figure 112 – Trion project forecast production profile



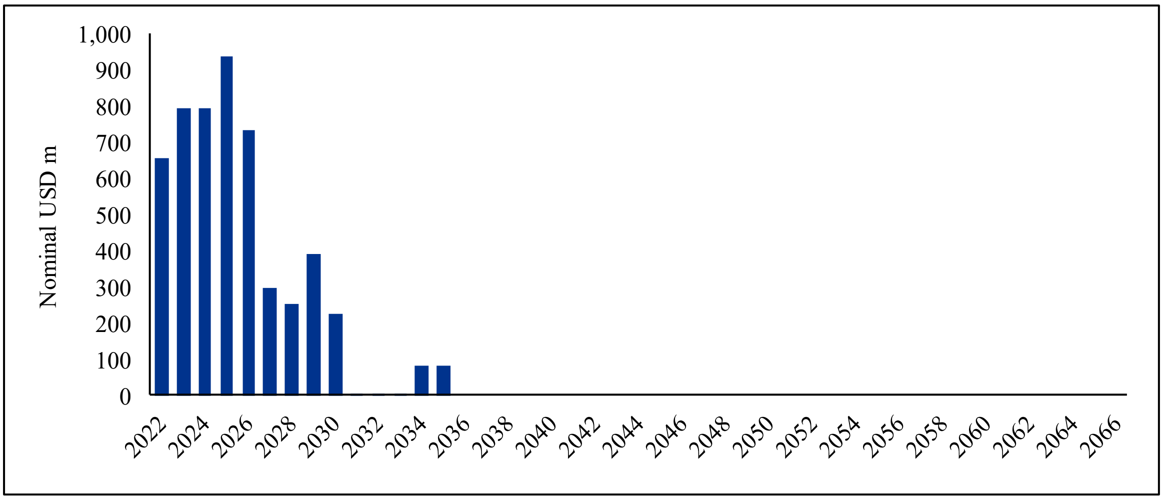
Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 113 – Trion project forecast operating costs



Source: GaffneyCline, KPMG Corporate Finance analysis

Figure 114 – Trion project forecast capital expenditure



Source: GaffneyCline, KPMG Corporate Finance analysis

Appendix 5 – Calculation of discount rates

Selection of the appropriate discount rate to apply to the forecast cash flows of any asset or business operation is fundamentally a matter of judgement. Whilst there is a body of theory that may provide a framework for the derivation on an appropriate discount rate, it is important to recognise that given the level of subjectivity involved in selecting various inputs to the theoretical framework there is no absolute "correct" discount rate.

In bringing the forecast cash flows for each of the projects of Woodside and BHP Petroleum to a present value we have adopted discount rates that we consider arm's length purchasers of each project would use in the current market and that are reflective of the commercial, operational and technical risks of the respective projects. We have had principal regard to an appropriate nominal, post-tax weighted average cost of capital (**WACC**) for each project applicable for the forecast cash flows being valued.

The WACC of a project is the expected cost of the various classes of capital (i.e. its equity and debt) employed in the project, weighted by the proportion of each class of capital to the total capital employed and is represented by the following formula, which calculates an after tax nominal rate:

$$\mathrm{WACC} = \mathrm{K_d} \times (1 - \mathrm{t_c}) \times \left(\frac{\mathrm{D}}{\mathrm{D} + \mathrm{E}}\right) + \mathrm{K_e} \times \left(\frac{\mathrm{E}}{\mathrm{D} + \mathrm{E}}\right)$$

Where the key inputs are defined as follows:

$\mathrm{K_e}$	the after-tax cost of equity, which is the rate of return required by the providers of equity capital
$\mathrm{K_d}$	the pre-tax cost of debt, which is the expected long-term average future borrowing cost of the relevant project and/or business
$\mathrm{t_c}$	the applicable corporate tax rate
D	the market value of debt
E	the market value of equity

The WACC is an opportunity cost of capital in the sense that it reflects the returns that would have been earned in the market with the relevant capital if it was employed in the next best investment of equivalent risk profile. It represents the minimum weighted average rate of return which is required or expected by the providers of capital as compensation for bearing the risks associated with the relevant investment or business operation.

Consistent with the USD denominated nominal cash flow forecasts, we have prepared USD denominated nominal discount rates. In determining our discount rates, we have a calculated a base discount rate for each broad class of project having regard the nature of that project's operations. We have adjusted these base discount rates to reflect the specific characteristics of the project being valued including for such things as where a project is yet to receive FID, GaffneyCline's assessment of the relevant chance of the project proceeding, an allowance for remaining development risk post FID, each project's location and projected operational life, the relative mix of 2P Reserves and 2C Contingent Resources underpinning the forecast cash flows.

A summary of the build-up of our selected base discount rates for each broad project category is set out in the table below.

Table 91: Build-up of selected base discount rates for upstream and midstream LNG production and processing companies

Input	Definition	Low	High
R_f	Risk-free rate of return	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	0.90	1.00
β_e	Equity beta (regeared beta estimate)	1.11	1.23
MRP	Equity market risk premium	6.0%	6.0%
K_e	**Cost of equity (nominal, post-tax)**	**9.0%**	**9.7%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%
K_d	Cost of debt (post-tax)	3.2%	3.5%
D/(D+E)	Proportion of debt in the capital mix	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**7.5%**	**8.2%**

Source: KPMG Corporate Finance analysis
Note 1: amounts may not add exactly due to rounding

Table 92: Build-up of selected base discount rates for conventional upstream hydrocarbon production companies

Input	Definition	Low	High
R_f	Risk-free rate of return	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	1.00	1.10
β_e	Equity beta (regeared beta estimate)	1.23	1.36
MRP	Equity market risk premium	6.0%	6.0%
K_e	**Cost of equity (nominal, post-tax)**	**9.7%**	**10.5%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%
K_d	Cost of debt (post-tax)	3.2%	3.5%
D/(D+E)	Proportion of debt in the capital mix	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**8.1%**	**8.7%**

Source: KPMG Corporate Finance analysis
Note 1: amounts may not add exactly due to rounding

Table 93: Build-up of selected base discount rates for midstream and pipeline companies

Input	Definition	Low	High
R_f	Risk-free rate of return	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	0.80	0.90
β_e	Equity beta (regeared beta estimate)	1.26	1.42
MRP	Equity market risk premium	6.0%	6.0%
K_e	**Cost of equity (nominal, post-tax)**	**9.9%**	**10.8%**
E/(D+E)	Proportion of equity in the capital mix	55%	55%
K_d	Cost of debt (post-tax)	3.2%	3.5%
D/(D+E)	Proportion of debt in the capital mix	45%	45%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**6.9%**	**7.5%**

Source: KPMG Corporate Finance analysis
Note 1: amounts may not add exactly due to rounding

Table 94: Build-up of selected base discount rates for liquefaction and processing companies

Input	Definition	Low	High
R_f	Risk-free rate of return	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	0.50	0.60
β_e	Equity beta (regeared beta estimate)	0.93	1.11
MRP	Equity market risk premium	6.0%	6.0%
K_e	**Cost of equity (nominal, post-tax)**	**7.9%**	**9.0%**
E/(D+E)	Proportion of equity in the capital mix	45%	45%
K_d	Cost of debt (post-tax)	3.2%	3.5%
D/(D+E)	Proportion of debt in the capital mix	55%	55%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**5.3%**	**6.0%**

Source: KPMG Corporate Finance analysis
Note 1: amounts may not add exactly due to rounding

Each of the components of the WACC formula is discussed further below.

Cost of equity (K_e)

The WACC approach represents a merger of the Capital Asset Pricing Model (**CAPM**) with capital structure theory. In the WACC formula discussed earlier, the CAPM provides the means for estimating the cost of equity.

$K_e = R_f + (\beta \times MRP) + \alpha$

Where the key inputs are defined as follows:

R_f	risk free rate of return
β	beta factor of the investment or business operation
MRP	equity market risk premium
α	company/project specific risk factor

A brief overview of each of the inputs adopted in the calculation of our base discount rates is set out below.

Risk free rate (R_f)

The relevant risk-free rate of return is the return on a risk-free security, typically for a long-term period. In practice, long dated government bonds are generally accepted as a benchmark for a risk-free security.

For projects with a forecast operational life longer than 20 years, we have adopted the spot yield on US 20 year Treasury bonds as at 8 March 2022. For projects with a shorter operational we have adopted an interpolated yield based on the spot yield of the closest pre and post dated US Treasury bonds to the project cessation date.

Beta factor (β)

The beta factor is a measure of the risk of an investment or business operation, relative to a well-diversified portfolio of investments. In theory, the only risks that are captured by beta are those risks that cannot be eliminated by the investor through diversification. Such risks are referred to as systematic, undiversifiable or market risk. The concept of beta is central to the CAPM given that beta risk is the only risk that is priced into investor required rates of return.

In assessing appropriate beta factors, we have had regard to the adjusted betas of companies with operations broadly similar to the operational categories adopted by us. The adjusted beta is often used to estimate a security's future beta. It is a historical beta adjusted to reflect the tendency of beta to be mean-reverting – that is, the CAPM's beta value is assumed to move towards the market average, of 1, over time.

The beta factors have been calculated relative to the Morgan Stanley Capital Index – All Countries (**MSCI**), an international equities market index that is widely used as a proxy for the global stock market as a whole. The MSCI is often used as a benchmark in respect of assets where underlying earnings streams are influenced by international markets, the marginal investor is likely to be international and/or the asset is likely to be attractive to international buyers.

A summary of our analysis of adjusted betas is set out at Appendix 6.

Having determined an appropriate ungeared beta, it is necessary to "regear" the beta to a specified level of financial gearing to determine the equivalent beta.

Debt/equity mix

The selection of an appropriate capital structure is a subjective exercise. The tax deductibility of the cost of debt means that the higher the proportion of debt, the lower the WACC for a given cost of equity. However, at significantly higher levels of debt, the marginal cost of borrowing would increase due to the greater risk which debt holders are exposed to. In addition, the cost of equity would also be likely to increase due to equity investors requiring a higher return given the higher degree of financial risk that they have to bear.

In practice, the existing capital structures of comparable businesses is used as a guide to the likely capital structure for a firm/project. Details of the gearing of those comparable companies considered by us in each broad operational category is set out in Appendix 6.

Market risk premium (MRP)

The MRP represents the additional return that investors expect in return for holding risk in the form of a well-diversified portfolio of risky assets (such as a market index) over risk-free assets such as Government bonds. Given that expectations are not observable, a historical premium is generally used as a proxy for the expected risk premium.

Consistent with our approach to the risk-free rate, we adopted a long-term view in setting the market risk premium. A market risk premium of 6.0% per annum is regarded as appropriate by KPMG Corporate Finance for the current long-term investment climate in the United States.

Cost of debt (K_d)

In determining an appropriate cost of debt we have had regard to credit spreads on USD denominated BBB rated bond issues by companies operating in the energy sector as at 8 March 2022 over a duration consistent to the risk-free rate adopted.

Corporate tax rate (t_c)

The following corporate tax rates have been adopted:

- Australian - 30%
- Mexico – 30%
- Senegal – 33%
- Trinidad and Tobago – 30%
- United States GOM – 21%.

Specific risk adjustment

It is assumed that diversified investors require no additional returns to compensate for specific risks because the net effect of specific risks across a diversified portfolio will, on average, be zero i.e. portfolio investors can diversify away all specific risk. In reality, many investors will include an additional risk premium to reflect such factors as project location and stage of development etc. Certainly, it is common for companies to set "hurdle rates" for investments above their own estimates of the cost of capital, to deal with these issues.

In determining our final range of discount rates for each project we have included a specific risk adjustment in relation to each of the projects set out below:

Woodside

- the interdependent NWS Growth and Browse projects, reflecting that:
  - the Browse project (and in turn, the NWS Growth project) is unsanctioned and GaffneyCline has assessed its chance of development, that is it will be commercially developed, at 25%,
  - the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
  - even if commercially developed there remains a degree of inherent risk in the remaining development, construction and commissioning of any new operation (**Development Risk**)
- the Scarborough project, reflecting that whilst FID has been completed, there remains a degree of Development Risk
- the Pluto Train 2 project, reflecting that whilst FID has been completed, there remains a degree of Development Risk, and that the prospects of the Pluto Train 2 project are inherently linked over the longer term to the future success of the Scarborough field operations to supply gas for processing
- the Pluto LNG project, reflecting that a substantial component of the forecast operations for Pluto LNG is underpinned by gas volumes from the Scarborough project which incorporates an associated Development Risk and gas supply risk as noted for Pluto Train 2 above
- the Sangomar project, reflecting that:
  - whilst the early stage of this project covering the 2P Reserves has received FID, GaffneyCline's operational cash flows include an assumption that 2C Contingent Resources will be economically recoverable and are included in its projected production profile. GaffneyCline has assessed the chance of development of the 2C Contingent Resources production at 25%
  - there remains a degree of Development Risk in the project
  - the project is located offshore Senegal and therefore arguably includes an element of country risk, albeit the Senegal government participates via a PSC
- projects with only D&R expenditure remaining, discount rates have been selected having regard to short term US Treasury bond yields consistent with the remaining period of expenditure.

BHP Petroleum

- the NWS Project, reflecting:
  - as described above, GaffneyCline has ascribed a 25% chance of development in relation to the NWS Growth project and there remains a degree of Development Risk

- the Scarborough project, reflecting, as described above, whilst the Scarborough Project has received FID, there remains a degree of Development Risk
- the Bass Strait project, reflecting a component of the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the Macedon project, reflecting:
  - a component of the forecast cash flows relate to the front end compression project and unapproved programs, which are still pending
  - a component of the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the Pyrenees project, reflecting:
  - a component of the forecast cash flows relate to the Phase 4 project, which is a sanctioned project
  - a component of the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the Atlantis project, reflecting:
  - a component of the forecast cash flows relate to the Atlantis Phase 3 project, which is a sanctioned project
  - a component of the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the Mad Dog project, reflecting:
  - a component of the forecast cash flows relate to the Mad Dog Phase 2 project, which is a sanctioned project
  - a component of the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the Shenzi project, reflecting:
  - a component of the forecast cash flows relate to the Shenzi North and Wildling projects. Shenzi North is a sanctioned project whilst Wildling is an unsanctioned project and therefore there remains a degree of Development Risk in relation to these projects
  - a component of the forecast cash flows is underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the Trion project, reflecting that:
  - GaffneyCline has assessed its chance of development at 90%, and that even if commercially developed there remains a degree of Development Risk

- the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
- the project is located offshore Mexico in the GOM and therefore is subject to an element of country risk

- the Angostura and Ruby projects, reflecting these projects are located offshore Trinidad and Tobago and are subject to an element of country risk
- the Calypso project, reflecting that:
  - GaffneyCline has assessed its chance of development at 70%, and that even if commercial developed there remains a degree of Development Risk
  - the forecast cash flows are underpinned by 2C Contingent Resources rather than more mature 2P Reserves
  - the project is located offshore Trinidad and Tobago and is therefore subject to an element of country risk
- For projects with only D&R expenditure remaining, the discount rates have been selected having regard to short term US Treasury bond yields consistent with the remaining period of expenditure.

Having regard to each of the discount rate inputs discussed above, our assessed USD post-tax nominal WACCs for each project is summarised in the tables below.

Table 95: Summary of USD post-tax nominal WACCs

Woodside		BHP Petroleum	
Project	WACC %	Project	WACC %
NWS	7.5% - 8.5%	NWS	7.5% - 8.5%
NWS Growth[1]	8.0% - 9.0%	NWS Growth[1]	8.0% - 9.0%
Pluto LNG	8.0% - 9.0%	NWS oil (Okha)	7.5% - 8.5%
Wheatstone LNG	7.5% - 8.5%	Scarborough	8.5% - 9.5%
Australia Oil (incl. Okha)	7.5% - 8.5%	Bass Strait	8.5% - 9.5%
Scarborough	8.5% - 9.5%	Macedon	8.0% - 9.0%
Pluto Train 2	7.0% - 8.0%	Pyrenees	9.0% - 10.0%
Browse	10.0% - 11.0%	Other Australian (D&R only)	1.5% - 2.0%
Sangomar	13.5% - 14.5%	Atlantis	9.0% - 10.0%
Stybarrow (D&R only)	1.5%	Mad Dog	9.0% - 10.0%
Balnaves (D&R only)	1.5%	Shenzi	9.0% - 10.0%
		GOM ORRI	4.5% - 5.5%
		Trion	10.0% - 11.0%
		Angostura & Ruby	9.0% - 10.0%
		Calypso	10.5% - 11.5%

Source: KPMG Corporate Finance analysis

Table 96: Build-up of selected discount rates for Woodside's assets

		NWS		NWS Growth		Pluto LNG		Wheatstone LNG		Australia Oil	
Input	**Definition**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
R_f	Risk-free rate of return	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.0%	2.0%
β_a	Asset beta (ungeared beta estimate)	0.90	1.00	0.50	0.60	0.90	1.00	0.90	1.00	1.00	1.10
β_e	Equity beta (regeared beta estimate)	1.11	1.23	0.93	1.11	1.11	1.23	1.11	1.23	1.23	1.36
MRP	Equity market risk premium	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
α	Country risk/project specific risk factor	n/a	n/a	6.0%	6.0%	1.0%	1.0%	n/a	n/a	n/a	n/a
K_e	**Cost of equity (nominal, post-tax)**	**9.0%**	**9.7%**	**13.9%**	**15.0%**	**10.0%**	**10.7%**	**9.0%**	**9.7%**	**9.4%**	**10.1%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%	45%	45%	75%	75%	75%	75%	75%	75%
K_d	Cost of debt (post-tax)	3.2%	3.5%	3.2%	3.5%	3.2%	3.5%	3.2%	3.5%	2.8%	3.2%
D/(D+E)	Proportion of debt in the capital mix	25%	25%	55%	55%	25%	25%	25%	25%	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**7.5%**	**8.2%**	**8.0%**	**8.7%**	**8.3%**	**8.9%**	**7.5%**	**8.2%**	**7.8%**	**8.4%**
	Selected range	**7.5%**	**8.5%**	**8.0%**	**9.0%**	**8.0%**	**9.0%**	**7.5%**	**8.5%**	**7.5%**	**8.5%**

Source: KPMG Corporate Finance analysis

Note 1: amounts may not add exactly due to rounding

Table 97: Build-up of selected discount rates for Woodside's assets continued

		Scarborough		Pluto Train 2		Browse		Sangomar	
Input	**Definition**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
R_f	Risk-free rate of return	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	1.00	1.10	0.50	0.60	1.00	1.10	1.00	1.10
β_e	Equity beta (regeared beta estimate)	1.23	1.36	0.93	1.11	1.23	1.36	1.22	1.35
MRP	Equity market risk premium	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
α	Country risk/project specific risk factor	1.0%	1.0%	4.0%	4.0%	3.0%	3.0%	7.0%	7.0%
K_e	**Cost of equity (nominal, post-tax)**	**10.7%**	**11.5%**	**11.9%**	**13.0%**	**12.7%**	**13.5%**	**16.7%**	**17.4%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%	45%	45%	75%	75%	75%	75%
K_d	Cost of debt (post-tax)	3.2%	3.5%	3.2%	3.5%	3.2%	3.5%	5.0%	5.4%
D/(D+E)	Proportion of debt in the capital mix	25%	25%	55%	55%	25%	25%	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**8.8%**	**9.5%**	**7.1%**	**7.8%**	**10.3%**	**11.0%**	**13.8%**	**14.4%**
	Selected range	**8.5%**	**9.5%**	**7.0%**	**8.0%**	**10.0%**	**11.0%**	**13.5%**	**14.5%**

Source: KPMG Corporate Finance analysis

Note 1: amounts may not add exactly due to rounding

Table 98: Build-up of selected discount rates for BHP Petroleum's assets

		NWS		NWS Growth		NWS Oil		Scarborough		Bass Strait	
Input	**Definition**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
R_f	Risk-free rate of return	2.3%	2.3%	2.3%	2.3%	2.0%	2.0%	2.3%	2.3%	2.2%	2.2%
β_a	Asset beta (ungeared beta estimate)	0.90	1.00	0.50	0.60	1.00	1.10	1.00	1.10	1.00	1.10
β_e	Equity beta (regeared beta estimate)	1.11	1.23	0.93	1.11	1.23	1.36	1.23	1.36	1.23	1.36
MRP	Equity market risk premium	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
α	Country risk/project specific risk factor	n/a	n/a	6.0%	6.0%	n/a	n/a	1.0%	1.0%	1.0%	1.0%
K_e	**Cost of equity (nominal, post-tax)**	**9.0%**	**9.7%**	**13.9%**	**15.0%**	**9.4%**	**10.1%**	**10.7%**	**11.5%**	**10.6%**	**11.3%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%	45%	45%	75%	75%	75%	75%	75%	75%
K_d	Cost of debt (post-tax)	3.2%	3.5%	3.2%	3.5%	2.8%	3.1%	3.2%	3.5%	3.1%	3.4%
D/(D+E)	Proportion of debt in the capital mix	25%	25%	55%	55%	25%	25%	25%	25%	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**7.5%**	**8.2%**	**8.0%**	**8.7%**	**7.7%**	**8.4%**	**8.8%**	**9.5%**	**8.7%**	**9.4%**
	Selected range	**7.5%**	**8.5%**	**8.0%**	**9.0%**	**7.5%**	**8.5%**	**8.5%**	**9.5%**	**8.5%**	**9.5%**

Source: KPMG Corporate Finance analysis

Note 1: amounts may not add exactly due to rounding

Table 99: Build-up of selected discount rates for BHP Petroleum's assets continued

		Macedon		Pyrenees		Atlantis		MadDog		Shenzi	
Input	**Definition**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
R_f	Risk-free rate of return	2.0%	2.0%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10
β_e	Equity beta (regeared beta estimate)	1.23	1.36	1.23	1.36	1.26	1.39	1.26	1.39	1.26	1.39
MRP	Equity market risk premium	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
α	Country risk/project specific risk factor	1.0%	1.0%	1.5%	1.5%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
K_e	**Cost of equity (nominal, post-tax)**	**10.4%**	**11.1%**	**11.2%**	**11.9%**	**10.9%**	**11.7%**	**10.9%**	**11.7%**	**10.9%**	**11.6%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
K_d	Cost of debt (post-tax)	2.8%	3.1%	3.1%	3.5%	3.6%	4.0%	3.6%	4.0%	3.5%	3.9%
D/(D+E)	Proportion of debt in the capital mix	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**8.5%**	**9.1%**	**9.2%**	**9.8%**	**9.1%**	**9.7%**	**9.1%**	**9.7%**	**9.0%**	**9.7%**
	Selected range	**8.0%**	**9.0%**	**9.0%**	**10.0%**	**9.0%**	**10.0%**	**9.0%**	**10.0%**	**9.0%**	**10.0%**

Source: KPMG Corporate Finance analysis

Note 1: amounts may not add exactly due to rounding

Table 100: Build-up of selected discount rates for BHP Petroleum's assets continued

		GOM ORRI		Trion		Angostura & Ruby		Calypso	
Input	**Definition**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
R_f	Risk-free rate of return	1.8%	1.8%	2.3%	2.3%	1.8%	1.8%	2.3%	2.3%
β_a	Asset beta (ungeared beta estimate)	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10
β_e	Equity beta (regeared beta estimate)	1.26	1.39	1.23	1.36	1.23	1.36	1.23	1.36
MRP	Equity market risk premium	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
α	Country risk/project specific risk factor	(4.0%)	(4.0%)	2.5%	2.5%	2.5%	2.5%	3.5%	3.5%
K_e	**Cost of equity (nominal, post-tax)**	**5.4%**	**6.1%**	**12.2%**	**13.0%**	**11.7%**	**12.5%**	**13.2%**	**14.0%**
E/(D+E)	Proportion of equity in the capital mix	75%	75%	75%	75%	75%	75%	75%	75%
K_d	Cost of debt (post-tax)	2.1%	2.5%	3.2%	3.5%	2.3%	2.6%	3.2%	3.5%
D/(D+E)	Proportion of debt in the capital mix	25%	25%	25%	25%	25%	25%	25%	25%
WACC	**Weighted average cost of capital (nominal, post-tax)**	**4.6%**	**5.2%**	**10.0%**	**10.6%**	**9.4%**	**10.0%**	**10.7%**	**11.4%**
	Selected range	**4.5%**	**5.5%**	**10.0%**	**11.0%**	**9.0%**	**10.0%**	**10.5%**	**11.5%**

Source: KPMG Corporate Finance analysis

Note 1: amounts may not add exactly due to rounding

Appendix 6 – Listed companies – betas and gearing

Set out below is a summary of our analysis of the unlevered betas of various listed companies considered in each broad category of operations.

Upstream and midstream LNG production and processing

Table 101: Selected listed upstream and midstream LNG production and processing companies – financial gearing and ungeared beta

Comparable companies - Beta analysis						
		Market Cap	Debt to value		Unlevered beta	
Company name	Country	USDm	2-year avg	5-year avg	2-year weekly	5-year monthly
Exxon Mobil Corporation	United States	371,625	16%	13%	0.96	1.05
Chevron Corporation	United States	332,116	12%	12%	1.04	1.03
Shell plc	Netherlands	202,584	27%	24%	0.80	0.59
TotalEnergies SE	France	129,314	24%	21%	0.93	0.77
ConocoPhillips	United States	128,393	13%	16%	1.06	1.22
Equinor ASA	Norway	112,510	24%	25%	0.50	0.59
BP p.l.c.	United Kingdom	96,318	32%	27%	0.77	0.55
Eni S.p.A.	Italy	52,674	38%	33%	0.64	0.71
Woodside Petroleum Ltd	Australia	23,180	15%	15%	0.87	0.93
Santos Limited	Australia	19,257	23%	25%	1.09	1.21
Inpex Corporation	Japan	16,069	37%	28%	0.75	0.99
Origin Energy Limited	Australia	7,377	35%	37%	0.76	0.92
Mean (excl. outliers)			22%	21%	0.85	0.88
Median (excl. outliers)			24%	23%	0.84	0.93

Source: Capital IQ, latest available financial statements of the companies and KPMG Corporate Finance analysis

Notes:

1. *Market capitalisation is at 8 March 2022, converted to USD as at the same date based on prevailing spot prices (where relevant)*
2. *Debt is average short-term and long-term debt less average cash as disclosed by Capital IQ based on financial accounts available as at 8 March 2022*
3. *Where a company does not have any interest-bearing debt or the resultant net debt figure is negative, the debt to value ratio has been recorded as 0%*
4. *Outliers (shaded) have been excluded from the mean and median. For debt to value, outliers have been assessed based on statistical analysis of the data set on a category-by-category basis. For unlevered beta, outliers have been assessed based on statistical confidence levels*
5. *"n/a" denotes insufficient observations.*

Having regard to the above, we consider an ungeared beta range of 0.9 to 1.0 to be reflective of an upstream and midstream LNG production and processing operation.

Conventional upstream hydrocarbon production

Table 102: Selected listed conventional upstream hydrocarbon production companies – financial gearing and ungeared beta

Comparable companies - Beta analysis						
		Market Cap	Debt to value		Unlevered beta	
Company name	Country	USDm	2-year avg	5-year avg	2-year weekly	5-year monthly
Canadian Natural Resources Limited	Canada	69,422	28%	29%	1.06	1.06
CNOOC Limited	Hong Kong	58,119	23%	23%	0.73	0.79
Occidental Petroleum Corporation	United States	51,000	44%	32%	1.11	1.45
Aker BP ASA	Norway	23,425	18%	19%	0.96	1.38
PTT Exploration and Production Public Company	Thailand	18,235	5%	4%	0.89	1.28
APA Corporation	United States	13,396	41%	36%	1.46	2.43
Lundin Energy AB (publ)	Sweden	11,651	21%	26%	0.70	1.03
Harbour Energy plc	United Kingdom	4,849	n/a	n/a	n/a	n/a
Petro Rio S.A.	Brazil	4,605	13%	12%	1.76	1.72
Oil India Limited	India	3,459	44%	36%	0.39	0.59
Beach Energy Limited	Australia	2,809	1%	0%	0.98	1.59
Kosmos Energy Ltd.	United States	2,768	57%	48%	1.11	1.59
DNO ASA	Norway	1,604	32%	17%	0.67	1.83
Tullow Oil plc	United Kingdom	1,168	83%	67%	0.33	0.86
Mean (excl. outliers)			27%	24%	0.93	1.35
Median (excl. outliers)			26%	25%	0.96	1.38

Source: Capital IQ, latest available financial statements of the companies and KPMG Corporate Finance analysis

Notes:

1. *Market capitalisation is at 8 March 2022, converted to USD as at the same date based on prevailing spot prices (where relevant)*
2. *Debt is average short-term and long-term debt less average cash as disclosed by Capital IQ based on financial accounts available as at 8 March 2022*
3. *Where a company does not have any interest-bearing debt or the resultant net debt figure is negative, the debt to value ratio has been recorded as 0%*
4. *Outliers (shaded) have been excluded from the mean and median. For debt to value, outliers have been assessed based on statistical analysis of the data set on a category-by-category basis. For unlevered beta, outliers have been assessed based on statistical confidence levels*
5. *"n/a" denotes insufficient observations.*

Having regard to the above, we consider an ungeared beta range of 1.0 to 1.1 to be reflective of a conventional upstream hydrocarbon production operation.

Midstream and pipeline companies

Table 103: Selected listed midstream and pipeline companies – financial gearing and ungeared beta

Comparable companies - Beta analysis						
		Market Cap	Debt to value		Unlevered beta	
Company name	Country	USDm	2-year avg	5-year avg	2-year weekly	5-year monthly
Phillips 66 Partners LP	United States	9,593	27%	29%	0.62	0.78
APA Group	Australia	8,493	45%	47%	0.33	0.26
Plains All American Pipeline, L.P.	United States	7,974	47%	39%	0.85	1.17
Shell Midstream Partners, L.P.	United States	5,526	47%	43%	0.56	0.88
Equitrans Midstream Corporation	United States	3,085	57%	n/a	0.26	n/a
NuStar Energy L.P.	United States	1,854	50%	48%	0.63	1.20
Transportadora de Gas del Sur S.A.	Argentina	1,801	23%	19%	0.61	0.93
BP Midstream Partners LP	United States	1,784	18%	n/a	0.81	n/a
Mean (excl. outliers)			37%	41%	0.63	0.99
Median (excl. outliers)			45%	43%	0.62	0.93

Source: Capital IQ, latest available financial statements of the companies and KPMG Corporate Finance analysis

Notes:

1. *Market capitalisation is at 8 March 2022, converted to USD as at the same date based on prevailing spot prices (where relevant)*
2. *Debt is average short-term and long-term debt less average cash as disclosed by Capital IQ based on financial accounts available as at 8 March 2022*
3. *Where a company does not have any interest-bearing debt or the resultant net debt figure is negative, the debt to value ratio has been recorded as 0%*
4. *Outliers (shaded) have been excluded from the mean and median. For debt to value, outliers have been assessed based on statistical analysis of the data set on a category-by-category basis. For unlevered beta, outliers have been assessed based on statistical confidence levels*
5. *"n/a" denotes insufficient observations.*

Having regard to the above, we consider an ungeared beta range of 0.8 to 0.9 to be reflective of a midstream and pipeline operation.

Liquefaction and processing

Table 104: Selected listed liquefaction and processing companies – financial gearing and ungeared beta

Comparable companies - Beta analysis						
		Market Cap	Debt to value		Unlevered beta	
Company name	Country	USDm	2-year avg	5-year avg	2-year weekly	5-year monthly
Cheniere Energy, Inc.	United States	34,145	56%	58%	0.51	0.63
SBM Offshore N.V.	Netherlands	2,660	58%	54%	0.41	0.46
Golar LNG Limited	United States	2,064	57%	50%	0.69	0.53
Mean (excl. outliers)			57%	54%	0.54	0.55
Median (excl. outliers)			57%	54%	0.51	0.55

Source: Capital IQ, latest available financial statements of the companies and KPMG Corporate Finance analysis

Notes:

1. *Market capitalisation is at 8 March 2022, converted to USD as at the same date based on prevailing spot prices (where relevant)*
2. *Debt is average short-term and long-term debt less average cash as disclosed by Capital IQ based on financial accounts available as at 8 March 2022*
3. *Where a company does not have any interest-bearing debt or the resultant net debt figure is negative, the debt to value ratio has been recorded as 0%*
4. *Outliers (shaded) have been excluded from the mean and median. For debt to value, outliers have been assessed based on statistical analysis of the data set on a category-by-category basis. For unlevered beta, outliers have been assessed based on statistical confidence levels*
5. *“n/a” denotes insufficient observations.*

Having regard to the above, we consider an ungeared beta range of 0.5 to 0.6 to be reflective of a liquefaction and processing operation.

Appendix 7 – Selected upstream and midstream LNG production and processing comparable companies

Company	Description
Exxon Mobil Corporation (**Exxon**)	Exxon Mobil is a US-based multinational company that explores for and produces crude oil and natural gas. It operates through upstream, downstream and chemical segments. Exxon Mobil's operations are primarily in Asia and the US, with other operations in Oceania, Americas, Africa and Europe. The company is headquartered in Irving and was founded in 1870.
Chevron	Chevron produces, transports and processes crude oil and natural gas worldwide. The company is also involved in chemical and mining operations, power generation, and energy services. Chevron's operations are predominantly located in the US and Australia. Chevron was founded in 1879 and is headquartered in San Ramon.
Shell	Shell is a global energy and petrochemical company involved in the exploration, production, refining and marketing of hydrocarbons, as well as the manufacturing and marketing of chemicals. Shell's operations span Asia, Europe, Oceania, North and South America and Africa. The company was founded in 1907 and is headquartered in London.
TotalEnergies	TotalEnergies is an integrated global energy company that discovers, produces, refines and markets oil and gas, as well as manufacturing petrochemicals. TotalEnergies is headquartered in Paris and was incorporated in 1924.
ConocoPhillips	ConocoPhillips explores for, produces, transports and markets crude oil, bitumen, natural gas, LNG and natural gas liquids. ConocoPhillips' operations are predominantly in the US with additional interests in the Asia/Pacific, Middle East, Africa, Europe and Canada. ConocoPhillips was founded in 1917 and is headquartered in Houston.
Equinor ASA (**Equinor**)	Equinor engages in the exploration, production, transportation, refining, and marketing of petroleum and petroleum-derived products in Norway and internationally. Founded in 1972 as Statoil ASA, the company changed its name to Equinor ASA in May 2018. The company is headquartered in Stavanger.
BP	BP is an integrated energy business with operations in Europe, North and South America, Australia, Asia and Africa. The company produces and refines oil and gas and invests in upstream, downstream, and alternative energy companies as well as providing fuel, energy, lubricants and petrochemicals to customers worldwide. BP was founded in 1908 and is headquartered in London.
Eni S.p.A. (**Eni**)	Eni is an Italian multinational oil and gas company which engages in the exploration, development and production of crude oil and natural gas. The exploration & production segment is involved in the research, development, and production of oil, condensates and natural gas. The gas & LNG segment engages in the supply and wholesale of natural gas by pipeline, international transport and purchase and marketing of LNG. The refining & marketing and chemicals segment is involved in the processing, supply, distribution, and marketing of fuels and chemicals. The company is headquartered in Rome and was founded in 1953.
Santos	Santos explores for, develops, produces, transports, and markets hydrocarbons in Australia and the Asia Pacific. The company's five principal assets are located in the Cooper Basin, Queensland and NSW, Papua New Guinea, Northern Australia and Timor-Leste, and Western Australia. Santos Limited was incorporated in 1954 and is headquartered in Adelaide.
Inpex Corporation (**Inpex**)	Inpex engages in the research, exploration, development, production, and sale of oil, natural gas, and other mineral resources in Asia, Oceania, Europe, the Middle East, Africa, North America and South America. The company was founded in 1966 and is headquartered in Tokyo.

Company	Description
Origin Energy Limited (**Origin**)	Origin engages in the exploration and production of natural gas, electricity generation, wholesale and retail sale of electricity and gas, and sale of liquefied natural gas in Australia and internationally. Its exploration and production portfolio includes the Bowen and Surat basins in Queensland, the Browse basin in Western Australia and the Beetaloo basin in the Northern Territory. Origin Energy Limited was incorporated in 1946 and is headquartered in Sydney.

Source: Capital IQ

Appendix 8 – Upstream and midstream LNG production and processing comparable company multiples

Table 105: Upstream and midstream LNG production and processing 1P and 2P multiples

Company	Market cap A$m	Enterprise A$m	Reserves and Resources 1P Reserves MMboe	2P Reserves MMboe	Multiples 1P Reserves A$m/MMboe	2P Reserves A$m/MMboe
Exxon Mobil Corporation	512,693	586,042	18,536		32	
Chevron Corporation	458,188	499,591	11,264		44	
Shell plc	279,485	363,164	9,400		39	
TotalEnergies SE	178,402	236,421	12,328		19	
ConocoPhillips	177,131	198,549	6,101		33	
Equinor ASA	155,218	183,867	5,356		34	
BP p.l.c.	132,881	210,110	17,983		12	
Eni S.p.A.	72,669	111,309	6,628		17	
Woodside Petroleum Ltd	32,041	38,310	1,592	2,292	24	17
Santos Limited	26,568	33,544	1,010	1,676	33	20
Inpex Corporation	22,169	37,647	3,645	6,311	10	6
Origin Energy Limited	10,177	15,277	450	695	34	22
Low					10	6
Mean					28	16
Median					32	18
High					44	22

Source:Capital IQ, company financial statements and reports, publicly available resource information of relevant companies and KPMG Corporate Finance Analysis

Notes:

1. Enterprise value for selected listed companies has been calculated as market capitalisation as at 8 March 2022, converted to AUD as at the same date based on prevailing spot exchange rates (where relevant), and the latest net debt/cash of the selected company and adjusted for outside equity interests reported prior to 8 March 2022

2. Where the Reserves are not 100 percent owned, all calculations are based on the company's relevant interest

3. The table above shows Reserve valuation comparisons for companies predominantly focused on upstream and midstream LNG production and processing. In the case where the comparable companies' Reserves contain other hydrocarbons (for example condensate), a total contained boe equivalent Reserve has been calculated

4. 1P and 2P multiples have been calculated based as enterprise value divided by total contained boe Reserves respectively

5. Shaded cells indicate the information was not available; Reserves estimates for the relevant classification were not available as at 8 March 2022

6. As at 8 March 2022, the most recently available reserves disclosed for TotalEnergies and BP were as at 31 December 2020

7. Reserves disclosed by Inpex Corporation include reserves attributable to non-controlling interests.

In considering the observed multiples, we would highlight:

- Exxon's 1P Reserves are primarily located in Asia and the US, which contain approximately 35% and 32% of 1P Reserves respectively. Exxon has other operations in Oceania, other Americas, Africa and Europe. Of Exxon's 1P Reserves, approximately 66% are classified as 1P developed reserves. Exxon's 1P Reserves comprise approximately 18% unconventional reserves, predominantly located in the US
- Over half of Chevron's 1P Reserves are sourced from the US and Australia, with its remaining sources of reserves diversified across Africa, Asia, Europe, and other Americas. Of Chevron's 1P Reserves, 66% are classified as developed 1P Reserves. Chevron's production includes unconventional production from the Permian Basin and Eagle Ford Shale in the US contributing 25% of its total liquids production and 14% of its total gas production in 2021
- 85% of Shell's 1P Reserves are classified as developed 1P Reserves. Approximately 45% of Shell's 1P Reserves are located in Asia and comprise natural gas, oil, natural gas liquids and bitumen. Shell has additional reserves located in Europe, Oceania, North and South America and Africa. Shell has additional interests in unconventional assets in Canada and Argentina
- TotalEnergies' 1P Reserves are comprised of approximately 65% developed 1P Reserves. The company's largest single source of 1P Reserves (approximately 24%) is located Russia, with other 1P Reserves located across Asia, North and South America, Europe, Oceania and Africa
- ConocoPhillips' operations are predominantly in the US, in which 71% of 1P Reserves are located and 63% of 2021 production is sourced. ConocoPhillips also has interests in reserves across the Asia/Pacific, Middle East, Africa, Europe and Canada. ConocoPhillips' US and Canadian assets comprise unconventional plays in the Permian Basin, Eagle Ford and Montney
- Equinor's operations are primarily located in Norway, with approximately 72% and 69% of total 2021 production and 1P Reserves respectively. Equinor has additional 1P Reserves in North America, Africa and Europe, with 61% of its 1P Reserves classified as developed 1P Reserves
- BP holds approximately 50% of its 1P developed and undeveloped reserves in Russia, which also account for 32% of its production. Outside of Russia, BP has developed and undeveloped 1P Reserves in Europe, the UK, North and South America, Asia, Oceania and Africa. 56% of BP's reserves are classified as developed 1P Reserves
- Eni's 1P Reserves contain 71% 1P developed reserves and 29% 1P undeveloped reserves. Eni's largest source of production is from its operations in Africa, in which over 50% of its 1P Reserves are located. Eni has additional 1P Reserves located across Europe, Kazakhstan, Oceania and North and South America
- Santos' operations are focused in Australia, Papua New Guinea and Timor-Leste. Approximately 53% of Santos' 1P Reserves are classified as 1P developed reserves and 45% of its 2P Reserves are classified as developed 2P Reserves. Santos have reported that approximately 17% of its 1P Reserves and 20% of its 2P Reserves are unconventional

- Inpex has disclosed its reserves inclusive of non-controlling interest, which has the effect of understating the implied 1P multiples. Approximately 58% of Inpex's 1P Reserves is sourced from the Middle East and Africa, while 27% is sourced from Oceania and Asia. Of Inpex’s 1P Reserves, approximately 72% are classified as 1P developed reserves
- Origin’s 2P Reserves are located entirely in Australia. Approximately 88% and 60% of 1P and 2P Reserves respectively, are classified as developed.

Appendix 9 – Selected conventional upstream hydrocarbon production comparable companies

Company	Description
Canadian Natural Resources Limited (**Canadian Natural**)	Canadian Natural acquires, explores for, develops, produces, markets and sells crude oil, natural gas, and natural gas liquids. The company produces natural gas, synthetic crude oil, light and medium crude oil, bitumen and heavy crude oil. It operates primarily in Western Canada, the UK portion of the North Sea and Offshore Africa. Canadian Natural was incorporated in 1973 and is headquartered in Calgary.
CNOOC Limited (**CNOOC**)	CNOOC, an investment holding company, explores for, develops, produces, and sells crude oil and natural gas. The company also holds interests in various oil and gas assets in Asia, Africa, North America, South America, Oceania, and Europe. The company was incorporated in 1999 and is based in Hong Kong.
Occidental Petroleum Corporation (**Occidental Petroleum**)	Occidental Petroleum engages in the acquisition, exploration and development of oil and gas properties in the US, Middle East, Africa, and Latin America. It operates through three segments: oil and gas, chemical and midstream and marketing. Occidental Petroleum Corporation was founded in 1920 and is headquartered in Houston.
Aker BP ASA (**Aker**)	Headquartered in Fornebu, Norway, Aker engages in the exploration, development, and production of oil and gas on the Norwegian Continental Shelf. The company operates five assets: Alvheim, Ivar Aasen, Skarv, Ula and Valhall. Founded in 2001 as Det norske oljeselskap ASA, the company changed its name to Aker BP ASA in 2016.
PTT Exploration and Production Public Company Limited (**PTTEP**)	PTTEP engages in the exploration and production of petroleum predominantly in Thailand with additional interests in South America, Africa, Africa, the Middle East and other Asian areas. The company was founded in 1985 and is headquartered in Bangkok.
APA Corporation (**APA**)	APA Corporation explores for, develops and produces oil and gas properties. It has operations in the US, Egypt and the UK, as well as exploration activities offshore Suriname. The company also operates gathering, processing and transmission assets in West Texas. APA was founded in 1954 and is based in Houston.
Lundin Energy AB (publ) (**Lundin**)	Lundin engages in the exploration, development, and production of oil and gas properties primarily in Norway. The company was incorporated in 2001 and is headquartered in Stockholm.
Harbour Energy plc (**Harbour**)	UK-based Harbour, an oil and gas company, operates in the UK, Norway, Indonesia, Vietnam, Brazil, Falkland Islands, Mauritania, and Mexico. The company was founded in 2007 and is based in Edinburgh.
Petro Rio S.A. (**Petro Rio**)	Brazilian company Petro Rio engages in the exploration, development, and production of oil and natural gas properties in Brazil and internationally. In addition, it imports, exports, refines, sells, and distributes oil, natural gas, fuels and oil by-products. Petro Rio was incorporated in 2009 and is headquartered in Rio de Janeiro.
Oil India Limited (**Oil India**)	Oil India explores for, develops, and produces crude oil and natural gas in India and internationally. The company operates through crude oil, natural gas, liquified petroleum gas, pipeline transportation and renewable energy segments. The company was founded in 1889 and is based in Noida.
Beach Energy Limited (**Beach Energy**)	Beach Energy Limited operates as an oil and gas exploration and production company. The company engages in onshore and offshore oil and gas production in five producing basins across Australia and New Zealand. It also explores, develops, produces and transports hydrocarbons and sells gas and liquid hydrocarbons. Beach Energy Limited was incorporated in 1961 and is headquartered in Adelaide.

Company	Description
Kosmos Energy Ltd. (**Kosmos Energy**)	Kosmos Energy, a deep-water independent oil and gas exploration and production company, has primary assets in offshore Ghana, Equatorial Guinea and the US Gulf of Mexico, as well as a gas development offshore Mauritania and Senegal. The company was founded in 2003 and is headquartered in Dallas.
DNO ASA (**DNO**)	DNO, a Norwegian-based company, engages in the exploration, development, and production of oil and gas assets in the Middle East and the North Sea. Its flagship project is the Tawke field which is located in the Kurdistan region of Iraq. The company was founded in 1971 and is headquartered in Oslo
Tullow Oil plc (**Tullow**)	Founded in 1985, Tullow is headquartered in London and engages in the oil and gas exploration, development, and production activities primarily in Ghana and South America.

Source: Capital IQ

Appendix 10 – Conventional upstream hydrocarbon production comparable company multiples

Table 106: Conventional upstream hydrocarbon production 1P and 2P multiples

Company	Market cap A$m	Enterprise value A$m	Reserves and Resources 1P Reserves MMboe	Reserves and Resources 2P Reserves MMboe	Multiples 1P Reserves A$m/MMboe	Multiples 2P Reserves A$m/MMboe
Canadian Natural Resources Limited	95,774	114,867	12,813	16,951	9	7
CNOOC Limited	80,181	98,787	5,373		18	
Occidental Petroleum Corporation	70,359	109,384	3,512		31	
Aker BP ASA	32,317	35,536	641	802	55	44
PTT Exploration and Production Public Company Limited	25,156	27,267	1,353	2,123	20	13
APA Corporation	18,481	30,926	913		34	
Lundin Energy AB (publ)	16,074	15,895		639		25
Harbour Energy plc	6,690	11,109		642		17
Petro Rio S.A.	6,354	7,077	121	209	58	34
Oil India Limited	4,772	8,325	337		25	
Beach Energy Limited	3,875	3,886	183	339	21	11
Kosmos Energy Ltd.	3,819	7,272	300	580	24	13
DNO ASA	2,213	2,729	91	132	30	21
Tullow Oil plc	1,612	6,688		231		29
Low					9	7
Mean					30	21
Median					25	19
High					58	44

Source:Capital IQ, company financial statements and reports, publicly available resource information of relevant companies and KPMG Corporate Finance Analysis

Notes:

1. Enterprise value for selected listed companies has been calculated as market capitalisation as at 8 March 2022, converted to AUD as at the same date based on prevailing spot exchange rates (where relevant), and the latest net debt/cash of the selected company and adjusted for outside equity interests reported prior to 8 March 2022

2. Where the Reserves are not 100 percent owned, all calculations are based on the company's relevant interest

3. The table above shows Reserve valuation comparisons for companies predominantly focused on conventional upstream hydrocarbon production. In the case where the comparable companies' Reserves contain other hydrocarbons (for example condensate), a total contained boe equivalent Reserve has been calculated

4. 1P and 2P multiples have been calculated based as enterprise value divided by total contained boe Reserves respectively

5. Shaded cells indicate the information was not available; Reserves estimates for the relevant classification were not available as at 8 March 2022

6. As at 8 March 2022, the most recently available reserves disclosed for CNOOC Limited, Harbour Energy and Petro Rio were as at 31 December 2020

7. As at 8 March 2022, the most recently available reserves disclosed for Oil India was as at 31 March 2021

8. As at 8 March 2022, the most recently available 1P reserves disclosed for Aker was as at 31 December 2020

9. Reserves disclosed by APA Corporation include reserves attributable to non-controlling interests.

In considering the observed multiples, we would highlight:

- Canadian Natural has material reserves in unconventional onshore projects located in North America. These projects are focused on oil sands production in Western Canada and account for approximately 30% of total crude oil production. International reserves are located in the mature North Sea (offshore Norway) and offshore Africa in the Cote d'Ivoire. Approximately 70% of Canadian Natural's 1P Reserves are developed
- Approximately 58% of CNOOC's 1P Reserves and 67% of hydrocarbon production is sourced from China. Approximately 47% of 1P Reserves were classified as developed reserves
- Occidental sources approximately 27% of its revenue from Chemical and Midstream and Marketing operations, with the remainder sourced from oil and gas sales. Approximately half of Occidental's 1P Reserves is comprised of conventional oil, with the remainder equally split between gas and natural gas liquids. Approximately 74% of Occidentals 1P Reserves are located in the US
- Aker BP's reserves are located entirely on the Norwegian continental shelf, with oil and gas production from six field centres, of which, Aker BP is the operator of five. Aker BP's exploratory resources are also located in both offshore and onshore Norway. Approximately 80% of Aker BP's 1P Reserves are classified as developed reserves
- Approximately 46% of the 1P Reserves of PTTEP were located in Thailand, with the remainder located across South America, Africa, Africa, the Middle East and other Asian areas. These 1P Reserves are comprised of 74% natural gas and 26% crude oil and condensate
- APA Corporation has disclosed its reserves inclusive of non-controlling interest, which may understate the implied 1P and 2P multiples. Of APA's 1P Reserves, over 90% were classified as 1P developed reserves. Approximately 68% of APA's 1P Reserves are located in the US, 22% in Egypt and 11% in the North Sea. Per APA's 2020 annual report, 55% of its production was conventionally sourced with the balance from unconventional production. Approximately 65% of production was sourced from the US
- Lundin's disclosed reserves and resources are located entirely on the Norwegian continental shelf, with oil and gas comprising 93% and 7% of disclosed 2P Reserves respectively. Production is sourced from three assets that produce both oil and gas
- Harbour Energy resulted from the recent merger of Premier Oil and Holdings Limited (**Chrysaor**). Harbour Energy's reserves are primarily comprised of oil and gas reserves in Indonesia, the UK, Norway and Vietnam, with the majority of these reserves located in the North Sea and production in each area
- Petro Rio's 2P Reserves and contingent resources interests are located entirely in offshore Brazil. Of Petro Rio's 1P Reserves, 55% are classified as 1P developed reserves and 97% are oil 1P Reserves
- 94% of Oil India's 1P Reserves are classified as developed 1P Reserves. Of Oil India's 1P Reserves, 62% is oil and condensate and 38% is natural gas and 80% is located in India. Oil India's international assets include a 20% interest in an unconventional shale asset in the US (containing 2P Reserves only) as well as a 50% interest in a 2P hydrocarbon reserve in Russia

- Beach Energy's projects are located entirely in Australia and New Zealand. Beach Energy's 1P Reserves and 2P Reserves comprise approximately 80% gas. Beach Energy's largest project (accounting for 20% of 1P Reserves) is the onshore South Australian Cooper Basin, which focusses on unconventional shale hydrocarbon production. Approximately 49% of Beach Energy's 1P Reserves are classified as developed 1P Reserves
- Kosmos' 1P Reserves are comprised of 64% developed and 36% undeveloped 1P Reserves. Approximately 53% of Kosmos' 1P Reserves are located in Ghana, with the remainder split between the US GoM (28%) and Equatorial Guinea (19%)
- DNO's 2P Reserves are primarily located in Kurdistan (Iraq) (59%) and Norway (40%) and comprise predominantly oil reserves. Of these 2P Reserves, 52% are developed reserves, while 54% of 1P Reserves are developed reserves
- Tullow's production operations are primarily in Africa, with 87% of 2P Reserves located in offshore Ghana, comprising both oil and gas. Production from these wells is from conventional extraction methods.

Appendix 11 – Selected upstream and midstream LNG production and processing comparable transactions

Target	Description
Australia Pacific LNG Pty Ltd. (**APLNG**)	On 8 December 2021 ConocoPhillips exercised its pre-emption right to acquire an additional 10% minority stake in APLNG from Origin for A$1.97 billion (US$1.4 billion), increasing its interest to 47.5% in APLNG. APLNG is located in onshore eastern Australia and produces natural gas and liquefied natural gas. As of the transaction date, APLNG had 1P Reserves of 1.2 billion boe.
Oil Search Limited (**Oil Search**)	On August 2, 2021, Santos made a non-binding and indicative merger proposal for Oil Search. Under the terms of the transaction, Oil Search shareholders received 0.6275 new Santos shares for each Oil Search share held via a scheme of arrangement. The merger proposal implied a transaction price of AUD 4.29 per Oil Search share. Following the merger Oil Search shareholders own approximately 38.5% of the merged group and Santos' shareholders own approximately 61.5%.
ConocoPhillips Northern Australia Assets (**ConocoPhillips Northern Australia Assets**)	On 13 October 2019, Santos entered into an agreement to acquire interests in ConocoPhillips Northern Australia Assets for A$1,900 million (US$1,265 million). As part of the transaction, Santos acquired an additional 37.5 % interest in the Barossa project and Caldita Field, an additional 56.9% interest in the Darwin LNG facility and Bayu-Undan Field, 40% interest in the Poseidon Field and 50% interest in the Athena Field. Post completion, Santos holds 68.4% stake in Darwin LNG facility and Bayu-Undan Field, 62.5% stake in Barossa and 40% interest in the Poseidon Field and ConocoPhillips holds no stake in Darwin LNG facility and Bayu-Undan Field.
Partex Holding BV (**Partex**)	On 16 June 2019, PTTEP signed a share purchase agreement to acquire Partex from Calouste Gulbenkian Foundation for A$1,026 million (US$716 million). As at the transaction date, Partex and its underlying projects had 2P interests of 65 MMboe in locations spanning predominantly Asia, Africa, Brazil and the Middle East.

Appendix 12 – Upstream and midstream LNG production and processing comparable transaction multiples

Table 107: Upstream and midstream LNG production and processing 1P and 2P multiples

Target	Acquirer	Announcement date	Interest acquired	Implied EV	Reserves and Resources		Multiples	
					1P Reserves	2P Reserves	1P Reserves	2P Reserves
				A$m	MMboe	MMboe	A$m/MMboe	A$m/MMboe
Australia Pacific LNG Pty Ltd.	ConocoPhillips	8 Dec 21	10%	27,075.7	1,201	1,853	23	15
Oil Search Limited	Santos Limited	20 Jul 21	100%	11,755.5	355	407	33	29
ConocoPhillips Northern Australia Assets	Santos Limited	13 Oct 19	100%	1,269.3		61		21
Partex Holding BV	PTTEP HK Holding Limited	17 Jun 19	100%	826.7		65		13
Low							23	13
Mean							28	19
Median							28	18
High							33	29

Source: Capital IQ, company financial statements and reports, publicly available resource information of relevant companies and KPMG Corporate Finance Analysis

Notes:

1. Reserve multiples are calculated using the Enterprise Value implied by the transaction and 1P and 2P reserves sourced from latest disclosures announced by the target prior to the announcement of the transaction

2. Implied enterprise value calculated using the consideration offered by the acquirer and the target's net debt/cash position reported prior to the announcement of the transaction

3. Where the transaction involved a company acquiring an interest of below 100 percent, the consideration has been grossed up to reflect an implied acquisition of 100 percent

4. The table above shows Reserve valuation comparisons for transactions predominantly focused on upstream and midstream LNG production and processing. In the case where the comparable target's Reserves contain other hydrocarbons (for example condensate), a total contained boe equivalent Reserve has been calculated

5. 1P and 2P multiples have been calculated based as implied Enterprise Value divided by total contained boe reserves respectively

6. Shaded cells indicate the information was not available; Reserves estimates were not available.

In considering the observed multiples, we would highlight:

- The APLNG interest acquired by ConocoPhillips is located on onshore eastern Australia in the Otway Basin. It comprises a gas liquefaction plant, production and pipeline system and upstream exploration resources
- Oil Search's operations were located primarily in Papua New Guinea, with additional operations in the US and Australia. 71% of Oil Search's 1P Reserves were classified as developed 1P Reserves at the date of the transaction and gas reserves comprised 86% of 1P Reserves. Oil Search's key assets were in production, predominantly sourced from Papua New Guinea
- Santos' purchase on the northern Australia assets of ConocoPhillips comprised an interest in two projects in operation and an interest in an exploratory resource. Of the projects in operation, Santos acquired an interest in the Darwin LNG infrastructure
- The assets of the acquired Partex were located in the Middle East, with interests in seven projects, primarily as a non-operating partner. The major projects include two onshore oil producing fields in Oman as well as the Oman LNG project, which is a gas liquefaction complex, and the ADNOC gas processing project.

Appendix 13 – Selected conventional upstream hydrocarbon production comparable transactions

Target	Description
Conventional upstream hydrocarbon production comparable transactions	
Quadrant Energy Australia Limited (**Quadrant Energy**)	On 22 August 2018, Santos Limited entered into a sale and purchase agreement to acquire Quadrant Energy from Wesfarmers Limited, Brookfield Asset Management Inc, Macquarie Corporate Holdings Pty Limited, AMB Holdings Pty Ltd, CDPQ, and Quadrant management. On completion of the transaction Santos paid an amount of US$1.93 billion, comprising the purchase price of US$2.15 billion less completion adjustments and cash acquired. Quadrant Energy holds natural gas and oil production, near and medium term development, appraisal and exploration assets across more than 52,000 km² of acreage, predominantly in the Carnarvon Basin offshore Western Australia.
Seven Generations Energy Ltd (**Seven Generations Energy**)	On 10 February 2021 ARC Resources Ltd entered into a definitive agreement to acquire Seven Generations Energy from Canada Pension Plan Investment Board and others, with ARC issuing approximately 369.4 million shares to acquire all of the outstanding Seven Generations Energy shares. Seven Generations Energy is a public oil and gas company with assets located in the liquids-rich Kakwa region of northwest Alberta, comprised of tight, liquids-rich natural gas properties covering 531,210 net acres.
Tartaruga Verde Field (BM-C-36 Concession) And Module III of Espadarte Field (**Tartaruga Verde Field**)	On 24 April 2019, Petronas Petroleo Brasil Ltda executed a sale purchase agreement to acquire a 50% working interest in Tartaruga Verde Field (BM-C-36 Concession) and Module III of Espadarte Field from Petróleo Brasileiro S.A. – Petrobras for US$1.3 billion. Tartaruga Verde Field (BM-C-36 Concession) And Module III of Espadarte Field comprised an oil and gas field, which is located in Brazil.
United Kingdom Oil and Gas Business of ConocoPhillips (**UK O&G Business of ConocoPhillips**)	On 18 April 2019, Chrysaor E&P Limited entered into an agreement to acquire the UK O&G Business of ConocoPhillips for US$2.7 billion. The subsidiaries acquired consisted of the company's exploration and production assets in the UK, which produced approximately 72,000 boe per day in 2019.
OML 17 and Related Assets (**OML 17 and Related Assets**)	On 15 January 2021, Tnog Oil & Gas Ltd acquired a 45% stake in OML 17 and Related Assets from Nigerian Agip Oil Company Ltd, the Shell Petroleum Development Company of Nigeria Limited, and Total E&P Nigeria Limited.
Shenzi Deepwater Oil Field in the Gulf of Mexico (**Shenzi Deepwater Oil Field**)	On 5 October 2020, BHP Group Plc signed a Membership Interest Purchase and Sale Agreement to acquire an additional 28% stake in the Shenzi Deepwater Oil Field for approximately US$510 million. After completion BHP holds a 72% stake and Repsol holds a 28% stake. Shenzi Deepwater Oil Field, whose first oil and natural gas production was achieved in 2009, is a standalone tension leg platform that is installed in approximately 1,340m of water.
Premier Oil (**Premier**)	On 6 October 2020, Chrysaor entered into an agreement to acquire Premier in a reverse merger transaction. Under the terms of the transaction, Premier acquired Chrysaor in return for the issuance of new Premier shares and Premier's approximately US$2.7 billion of total gross debt and cross currency swaps will be repaid and cancelled. On completion of the transaction, Premier was renamed Harbour Energy plc (**Harbour**). At the date of the transaction, Premier had 151 MMboe of 2P Reserves and 694 MMboe of contingent resources.

Target	Description
Deep Water Gulf of Mexico Assets of LLOG Exploration Offshore LLC and LLOG Bluewater Holdings LLC (**Deep Water Gulf of Mexico Assets**)	On 19 April 2019, Murphy Exploration & Production Company - USA (**Murphy**) entered into a definitive agreement to acquire the Deep Water Gulf of Mexico Assets from LLOG Exploration Offshore LLC and LLOG Bluewater Holdings LLC for US$1.6 billion. The purchase consideration comprised an upfront cash consideration of US$1,375 million and additional contingent consideration payments based on certain conditions. As at the transaction date, the Deep Water Gulf of Mexico Assets included 66 MMboe and 122 MMboe of 1P and 2P Reserves respectively.
Working Interests in Draugen and Gjøa (**Draugen and Gjøa**)	On 20 June 2018, OKEA AS agreed to acquire working interests in Draugen and Gjøa from A/S Norske Shell for A$467 million (NOK 2,930 million) paid in cash. OKEA acquired a 44.56% operating interest in Draugen and 12% non-operating interest in Gjøa. Under the terms of the agreement Shell will pay OKEA an additional future payment subject to OKEA completing the decommissioning of the asset. 80% of decommissioning financial liabilities remained with Shell up to an agreed limit. The underlying 1P Reserves of Draugen and Gjøa were 59.4 MMboe and 72.8 MMboe respectively.
Murphy Sabah Oil Co., Ltd. and Murphy Sarawak Oil Company Ltd. (**Murphy Co.s**)	On 10 July 2019, PTT Exploration and Production PCL acquired Murphy Sarawak Oil Company Ltd. and Murphy Sabah Oil Co., Ltd. from Murphy Oil Corporation for a consideration of AU$3,005 million (US$2,135 million). The acquisition included 5 petroleum exploration and production projects – the Sabah K project, the SK309 & SK311 project, the Sabah H project, the SK314A project and the SK405B project. Out of these projects, 2 have commenced operations, 1 is under development and 2 are exploration projects with total estimated 1P Reserves of all projects of 129 MMboe.

Appendix 14 – Conventional upstream hydrocarbon production comparable transaction multiples

Table 108: Conventional upstream production 1P and 2P multiples

Target	Acquirer	Announcement date	Interest acquired	Implied EV	Reserves and Resources		Multiples	
					1P Reserves	2P Reserves	1P Reserves	2P Reserves
				A$m	MMboe	MMboe	A$m/MMboe	A$m/MMboe
Seven Generations Energy Ltd.	ARC Resources Ltd.	10 Feb 21	100%	4,706.0		1,540		3
OML 17 and Related Assets	TNOG Oil and Gas Limited	15 Jan 21	45%	2,092.5		1,200		2
Shenzi Deepwater Oil Field in Gulf of Mexico	BHP Group Plc (nka:BHP Group (UK) Ltd)	6 Oct 20	28%	2,386.3	103	146	23	16
Premier Oil plc	Chrysaor Holdings Limited (nka:Harbour Energy plc)	6 Oct 20	100%	5,273.0		151		35
Deep Water GoM Assets of LLOG Expl. Offshore LLC and LLOG Bluewater Holdings LLC	Murphy Exploration & Production Company – USA	23 Apr 19	100%	1,786.5	66	122	27	15
United Kingdom Oil and Gas Business of ConocoPhillips	Chrysaor E&P Limited	18 Apr 19	100%	3,966.2	99		40	
Murphy Sabah Oil Co., Ltd. and Murphy Sarawak Oil Company Ltd.	PTT Exploration and Production PCL	21 Mar 19	100%	3,004.9	129		23	
Quadrant Energy Australia Limited (nka:Santos WA Energy Limited)	Santos Limited	22 Aug 18	100%	2,629.9		220		12
Working Interests in Draugen and Gjøa	OKEA AS (nka:OKEA ASA)	20 Jun 18	100%	466.6	35	42	13	11
Low							13	2
Mean							25	13
Median							23	12
High							40	35

Source: Capital IQ, company financial statements and reports, publicly available resource information of relevant companies and KPMG Corporate Finance Analysis

Notes:

1.Reserve multiples are calculated using the Enterprise Value implied by the transaction and 1P and 2P reserves sourced from latest disclosures announced by the target prior to the announcement of the transaction

2.Implied enterprise value calculated using the consideration offered by the acquirer and the target's net debt/cash position reported prior to the announcement of the transaction

3.Where the transaction involved a company acquiring an interest of below 100 percent, the consideration has been grossed up to reflect an implied acquisition of 100 percent

4.The table above shows Reserve valuation comparisons for transactions predominantly focused on conventional upstream hydrocarbon production. In the case where the comparable target's Reserves contain other hydrocarbons (for example condensate), a total contained boe equivalent Reserve has been calculated

5.1P and 2P multiples have been calculated based as implied Enterprise Value divided by total contained boe reserves respectively

6.Shaded cells indicate the information was not available; Reserves estimates were not available.

In considering the observed multiples, we would highlight:

- Quadrant Energy's reserves and operations are located in the Carnarvon Basin in offshore Western Australia. Approximately 75% of Quadrant Energy's reserves are classified as developed 2P Reserves, including 85% of gas reserves classified as 2P Reserves. Of Quadrants five main assets, it is the operator of 3, and a participant in two others, all of which are in operation
- Seven Generations' reserves are primarily located in Western Canada and were producing at the time of the transaction
- ConocoPhillips' UK Oil and Gas portfolio comprised 99 MMboe of 1P Reserves located in the British North Sea, the majority of which were in production
- The sale of Oil Mining Lease 17 and related assets appears to have been made in line with the Federal Government of Nigeria's aim of developing Nigerian companies in the oil and gas sector. It is unclear to what degree the transaction price / multiple was impacted by sovereign risk. The reserves are located onshore Nigeria and contained a number of producing wells
- The Shenzi development is located in the Gulf of Mexico, and in production at the time of the transaction
- The Premier transaction was a reverse takeover. We have calculated the implied multiple on the basis that Premier was the target for reserves and consideration. Consideration comprised payments to creditors and equity (held by pre-deal creditors and shareholders) in the enlarged entity at completion. Premier's reserves were comprised of oil and gas reserves in Indonesia, the UK and Vietnam, with the majority of these reserves located in the UK and production in each area
- The Deep Water Gulf of Mexico Assets acquired by Murphy included seven producing fields and four development projects in the Mississippi Canyon and Green Canyon areas. The underlying 2P Reserves were comprised of 72% oil
- The working interests in Draugen and Gjøa acquired by Okea were located in offshore Norway. Approximately 81% of the acquired 2P Reserves were classified as developed 2P Reserves, with the majority those not developed approved for development. The majority of these reserves were in production at the transaction date
- The assets purchased by PTTEP from Murphy were producing assets located in offshore Malaysia, of which the underlying 1P Reserves were 46% developed 1P Reserves. The reserves were comprised of 60% oil and 38% gas.

Appendix 15 – GaffneyCline report

Gaffney Cline

Independent Technical Specialist's Report for Woodside Petroleum Limited's Acquisition of BHP Petroleum's Assets

Prepared for

KPMG Financial Advisory Services (Australia) Pty Ltd

March 2022

Gaffney Cline

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Approved by Gaffney, Cline & Associates

Project Manager: ______________________ March 2022

Zis Katelis, Technical Director

Reviewed by: ______________________ March 2022

Doug Peacock, Technical Director

Reviewed by: ______________________ March 2022

Arse Clarijs, Regional/Technical Director

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Appendices

1 Introduction

At the request of KPMG Financial Advisory Services (Australia) Pty Ltd, of which KPMG Corporate Finance is a division (KPMG Corporate Finance or Independent Expert), Gaffney, Cline & Associates Limited (GaffneyCline) has prepared this Independent Technical Specialist's Report (ITSR) on various assets of Woodside Petroleum Limited (Woodside) and BHP Petroleum International Pty Ltd (BHP Petroleum). KPMG Corporate Finance was engaged by Woodside to prepare an Independent Expert Report (IER) in relation to the proposed transaction with BHP Petroleum which may result in Woodside acquiring all the assets of BHP Petroleum in consideration for the issue of new Woodside shares (Proposed Transaction).

Woodside's conventional oil and gas assets are located onshore and offshore Australia, offshore Senegal and onshore British Columbia, Canada. BHP Petroleum's conventional oil and gas assets are located onshore and offshore Australia, in the United States' and Mexican sectors of the Gulf of Mexico (GOM), and offshore Trinidad and Tobago[1].

As part of KPMG Corporate Finance's engagement for the IER they were required to value the petroleum assets of both Woodside and BHP Petroleum (collectively the Assets), including each company's current interests in:

- petroleum assets currently on production (including the potential to extend project life through further development)
- petroleum assets under development but not yet on production
- any other contingent and/or prospective resources, early-stage petroleum assets or targets not already captured in petroleum assets included in the above

In addition, KPMG Corporate Finance was required to consider the impact on values to any of the Assets because of the Proposed Transaction and therefore required GaffneyCline to consider the scheduling of individual development projects and how that might change following completion of the Proposed Transaction.

KPMG Corporate Finance indicated in GaffneyCline's assignment instructions that GaffneyCline was required to comply with the Regulatory Guide 111 - Content of expert reports (RG111), Regulatory Guide 112 - Independence of experts (RG112) and the Australasian Code for Public Reporting of Technical Assessments and Valuation of Mineral Assets, as amended (the VALMIN Code 2015). As an appropriate specialist assigned to assist KPMG Corporate Finance in the valuation of the Assets, GaffneyCline has complied with the regulations for the work performed in this report.

[1] BHP Petroleum also has assets in Algeria but plans to divest them. These assets are not covered by this ITSR as Woodside and BHP Petroleum have agreed that BHP Petroleum will retain the economic benefits thereof from the proposed Merger effective date, including the net proceeds from divestment. If the divestment has not completed prior to completion of the proposed Merger, Woodside will run the Algerian assets on behalf of BHP Petroleum under an arrangement whereby BHP Petroleum will retain all economic exposure and indemnify Woodside for any costs and liabilities associated with Algeria until such time as both parties agree alternative arrangements or Algeria lapses (whichever is earlier).

KPMG Corporate Finance discussed the requirement for a specialist with Woodside, who engaged Gaffney, Cline & Associates Ltd as the Independent Technical Specialist (Specialist) to report to KPMG Corporate Finance as independent expert (Independent Expert).

GaffneyCline advised KPMG Corporate Finance that it is independent of Woodside and BHP Petroleum for the purpose of the ITSR submission. By accepting the terms of the ITSR engagement, GaffneyCline confirmed that it is, and has remained, independent of Woodside and BHP Petroleum for the preparation of this Independent Technical Specialist's Report. Woodside was responsible for the fees of GaffneyCline and in undertaking the ITSR GaffneyCline accepted instructions exclusively from, and provided advice and reporting exclusively to, KPMG Corporate Finance.

KPMG Corporate Finance assignment instructions included the following summary work scope for GaffneyCline to prepare for this report:

- For producing/near-term producing assets, provide, where discounted cash flow (DCF) is considered the most appropriate valuation methodology, an electronic version of a base case (2P or 2C) operational cash flow model to a pre-tax line for each relevant project (including processing operations where appropriate) based on underlying technical and operational assumptions considered to be reasonable by GaffneyCline. KPMG Corporate Finance instructed that the starting point for the base case models was the production and processing economic models prepared by Woodside and/or BHP Petroleum, including where considered appropriate the benefit of life of field extension/development activities being carried out or planned (collectively the Technical Models). The Technical Models were required to be prepared on both a pre-transaction and post-transaction basis where GaffneyCline considered completion of the Proposed Transaction was likely to have an impact on value because of the potential rescheduling of development activities in the expanded asset portfolio of Woodside following completion of the transaction. Based on the assignment instructions, KPMG Corporate Finance was responsible for the final market valuation of the producing assets, including, where required, other valuation mechanisms as per VALMIN requirements.
- A valuation of any interests deemed to be material for the overall valuation, in the Assets of Woodside and BHP Petroleum that are not captured in the Technical Models contemplated above, including any residual contingent and/or prospective resources, early-stage petroleum assets or targets (Residual Assets). Materiality of cut-off of the individual assets within the Residual Assets, as well as any residual asset retirement obligations (ARO). Materiality of cut-off of the individual assets within the Residual Assets and/or ARO was set at US$50 MM by KPMG Corporate Finance (provided the aggregate of all Residual Assets and the aggregate ARO did not exceed US$250 million in either Woodside or BHP Petroleum). KPMG Corporate Finance provided the macroeconomic inputs for consistency between the two reports (e.g. commodity price assumptions, discount rates and foreign exchange rates).
- An independent report summarising the outcome of GaffneyCline's work in relation to the Technical Models and the valuation of any Residual Assets (the Specialist Report or ITSR).

In preparation of the Independent Technical Specialist's Report , GaffneyCline relied upon, without independent verification, information furnished by, or on behalf of, Woodside and BHP Petroleum with respect to the property interests being evaluated, production from such properties, current cost of operations and development, current prices for production, agreements related to current and future operations and sale of production, estimation of taxes, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of the Independent Technical Specialist's Report.

GaffneyCline also 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 (**Appendix I)**.

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

A glossary of abbreviations is shown in **Appendix II**.

1.1 Woodside

The bulk of Woodside's assets are offshore Western Australia, largely linked to LNG projects, notably North West Shelf (NWS), Pluto and Wheatstone. Woodside's non-Australian assets are in Myanmar, Senegal and Canada, of which the Sangomar development in Senegal, operated by Woodside, is the most significant. Woodside also has exploration acreage in the Democratic Republic of Congo (Congo) and South Korea.

Woodside and BHP Petroleum both have interests in the NWS gas and oil projects, and in the Scarborough LNG project (including the Jupiter and Thebe Fields) in Australia, both operated by Woodside. Besides these, Woodside and BHP Petroleum have no common assets.

On production since 1984, the NWS development complex produces from multiple gas and oil fields covering 21 blocks located ~130 km offshore. Twelve gas fields have been developed (eight currently producing) with a combination of platforms and subsea wells and gas is exported from the offshore North Rankin Complex and Goodwyn Alpha Platform via two pipelines to the onshore Karratha Gas Plant for LNG and domestic gas use. A further field, Lambert Deep, is currently being developed, but production has recently started to decline. Additional potential exists to develop two satellite fields and four small discoveries, but these are currently regarded as sub-commercial. The NWS oil assets comprise three mature producing fields (Cossack, Wanaea and Hermes) and three undeveloped discoveries (Egret, Eaglehawk and West Dixon), though these are also considered sub-commercial.

Woodside and BHP Petroleum's oil assets in NWS comprise three mature producing fields (Cossack, Wanaea and Hermes) and three undeveloped discoveries (Egret, Eaglehawk and West Dixon). Reserves are attributed to the three producing fields and Contingent Resources (Development Not Viable) are attributed to the three discoveries, which have volumes that are too small to warrant commercial development currently.

Woodside has an interest in the Brunello and Julimar Fields offshore Western Australia, together forming the Julimar Development Project. It is a subsea development to supply gas and condensate to the Wheatstone Project's onshore LNG trains and domestic gas plant at the Ashburton North Strategic Industrial Area via the Chevron-operated Wheatstone platform. Production from Brunello commenced in 2017. The Julimar-Brunello phase 2 fabrication and installation of the subsea tie-back was completed in Q3 2021, which comprised subsea pipeline structures, umbilical and manifold equipment. The project was preparing for cold commissioning and start-up in Q4 2021 and came on stream in December 2021. Further development phases are anticipated.

Also, offshore Western Australia, Woodside has interests in an exploitation permit supplying gas from subsea wells via a minimum facilities platform in shallow water to the Pluto LNG plant, located close to the Karratha Gas Plant. Gas and condensate Reserves are attributed to the producing Pluto and Xena Fields and to Pyxis. The Pluto and Xena Fields are producing, and Pyxis came on stream in November 2021.

Woodside and BHP Petroleum both have interests in the undeveloped Scarborough gas field and two satellite discoveries, Jupiter and Thebe located offshore Western Australia. The fields will be developed with subsea wells in some 1,400 m water depth, tied back to a semisubmersible floating production unit (FPU), and gas will be transported 430 km by pipeline to the onshore Pluto LNG plant at Karratha. A Final Investment Decision (FID) was taken in November 2021, with first cargo loading in 2026 from Scarborough, followed by the satellite fields in later phases. Gas Reserves are attributed to the Scarborough Field LNG project with contingent resources attributed to Jupiter and Thebe.

Woodside also has interests in five undeveloped gas discoveries (Remy, Martell, Martin, Noblige and Larsen Deep) in the WA-404-P permit offshore Western Australia, approximately 100 km northwest of the Pluto Field in water depth of 1,500 m. The discoveries are being evaluated for possible subsea development utilising a floating production facility, tied back ~100 km to the Pluto trunkline, to supplement Pluto LNG in later life, but are currently considered sub-commercial.

Greater Enfield and Vincent comprise a collection of oil and gas fields located in the Exmouth sub-basin of the Northern Carnarvon Basin, offshore Western Australia, in production since 2008. The producing fields are tied back to the Ngujima-Yin FPSO located over the Vincent Field and currently produce approximately 30,000 bopd. There are five further discoveries in Greater Enfield, but with no immediate plans to develop them. Two gas discoveries, Ragnar and Toro, are located ~40 km from the Greater Enfield area but are currently viewed as technically and commercially immature due to their small volumes and distance from infrastructure.

Woodside has interests in two further gas discoveries, Ragnar and Toro, located ~40 km from the Greater Enfield area offshore Western Australia. The volumes are small and tie-back development options are being evaluated. Gas Contingent Resources are attributed to the two discoveries.

In the Browse Basin, offshore Western Australia, Woodside has interests in five licences containing three large undeveloped gas and condensate discoveries (Torosa, Calliance and Brecknock). The development concept is a subsea tie-back to two FPSOs, from where gas would be exported via pipeline to the North Rankin Complex where it would join the supply of gas from the North West Shelf (NWS) Fields to the onshore Karratha Gas Plant. The estimated timing for first gas is 2030 (to fill ullage in the NWS facilities) but the commercial viability of the development remains uncertain.

Greater Sunrise comprises the Sunrise and Troubadour Fields, located in northern Australian and Timor-Leste waters. The Governments of Australia and Timor-Leste and the Sunrise Joint Venture will enter a new production sharing contract which will replace the four current titles and negotiations are understood to be ongoing. The fields lie approximately 150 km southeast of Timor-Leste and 450 km north of Australia in an area where the water depth varies between 100 and 600 m. No development concept has yet been selected and the development status remains uncertain.

At the effective date of this ITSR, Woodside had an interest in offshore Block A6 in the Rakhine Basin of Western Myanmar operated by TotalEnergies, ~260 km west of Yangon in water depth ranging from 30 to 2,500 m. The number, phasing and location of the wells were still being optimised as of 31 December 2021; however, Woodside issued an ASX announcement in January 2022 stating that it had decided to withdraw from its interests in Myanmar.

In Senegal, Woodside has interests in the offshore Sangomar Exploitation Licence and an adjacent Evaluation Extension Area. Multiple oil and gas reservoirs have been intersected and appraised in the Sangomar Field and it is currently under development, with the first production well drilled during 2021. The development comprises an FPSO with subsea wells and includes water injection for pressure maintenance and gas injection for gas disposal. Subsequent phases are contingent on the outcome of the first phase and could include intensive development of oil reservoirs and a gas export project. The Evaluation Extension Area contains the undeveloped FAN discovery and the SNE North Prospect.

Woodside has an interest in unconventional (shale) gas deposits of the Kotcho shale Formation in the Liard Basin onshore British Columbia, Canada. The Liard discovery was appraised with the intention of supplying feedstock to an envisaged LNG plant on the coast near Kitimat (the KLNG plant). However, the KLNG concept has been abandoned and the operator, Chevron is also divesting from the upstream asset. Woodside is in the process of taking over most of Chevron's upstream interest and is retaining its position in Liard to evaluate further market opportunities for the potentially large volume of gas, although currently there are no viable plans for exploitation. Contingent Resources (Development Not Viable) are attributed for a nominal recovery of dry gas.

Table 1.1 lists the licences in which Woodside hold working interests (WI) as of 31 December 2021. Reserves, Contingent Resources and/or Prospective Resources have been attributed to most of these licences.

Table 1.1: Summary of Woodside's Licences as of 31 December 2021

<table>
<tr><th>Country</th><th>Licence Block</th><th>Field/ Development</th><th>Woodside WI (%)</th><th>Final License Expiry</th></tr>
<tr><td rowspan="11">Australia</td><td>WA- 1-L to 6-L, 23-L, 24-L, 30-L, 52-L, 53-L, 56-L to 58-L, WA-7-R R4, WA-28-P R8</td><td>NWS Gas</td><td>15.78%</td><td rowspan="11">Extendable</td></tr>
<tr><td>WA-9-L, WA-11-L, WA-16-L,</td><td>NWS Oil</td><td>33.33%</td></tr>
<tr><td>WA-34-L</td><td>Pluto LNG</td><td>90.00%</td></tr>
<tr><td>WA-49-L, WA-356-P R2, WA-536-P</td><td>Wheatstone LNG (Brunello & Julimar)</td><td>65.00%</td></tr>
<tr><td>WA-61-L, WA-62-L</td><td>Scarborough LNG</td><td>73.50%</td></tr>
<tr><td>WA-61-R, WA-63-R</td><td>Thebe & Jupiter backfill to Scarborough</td><td>50.00%</td></tr>
<tr><td>WA-93-R & WA-94-R</td><td>Ragnar & Toro</td><td>70.00%</td></tr>
<tr><td>WA-404-P</td><td>Remy, Martell, Martin, Noblige and Larsen Deep discoveries</td><td>100.00%</td></tr>
<tr><td>WA-28-L & WA-59-L</td><td>Gr. Enfield Oil and Vincent</td><td>60.00%</td></tr>
<tr><td>WA-28-R to WA-32-R, TR/5 and R2</td><td>Browse Basin (Torosa, Calliance and Brecknock)</td><td>30.60%</td></tr>
<tr><td>NT/RL2 & NT/RL4</td><td rowspan="2">Gr. Sunrise (incl. Troubadour)</td><td>35.00% for RL2, 26.67% for RL4</td></tr>
<tr><td>Timor Leste</td><td>PSC JPDA 03-19 & 03-20</td><td>27.67%</td><td>Oct-2026 for 03-19 and Nov-2026 for 03-20</td></tr>
<tr><td>Myanmar</td><td>Block A6</td><td></td><td>40.00% (25.00% post government back-in)</td><td>December 2022</td></tr>
<tr><td rowspan="2">Senegal</td><td>Sangomar Exploitation Licence</td><td>Sangomar</td><td>82.00%</td><td>December 2048, extensions possible.</td></tr>
<tr><td>Evaluation Extension Area</td><td>Exploration & Appraisal</td><td>90.00%</td><td>October 2021: 3-year extension application submitted.</td></tr>
<tr><td>Canada</td><td>Liard</td><td>Liard</td><td>50.00%[3]</td><td>Multiple renewals</td></tr>
</table>

Notes:
1. Licences are easily extended in Australia when production remains commercial
2. Licences in Australia and Canada are subject to tax/royalty fiscal regimes, whereas those in Myanmar, Timor Leste and Senegal are in the form of Production Sharing Contracts (PSC) or similar
3. Woodside's WI in Liard is expected to increase to 94.90% once transfer of certain leases is completed.

Reserves Summary

Proved (1P) and Proved plus Probable (2P) Reserves net to Woodside are summarised in **Table 1.2**. The volumes reported as Reserves are sales quantities and exclude volumes of hydrocarbons consumed in operations as fuel (CiO). To facilitate comparison with the companies' annual reporting, CiO quantities are shown in **Appendix III**.

Table 1.2: Woodside Summary of Net Entitlement Reserves as of 31 December 2021

(a) Woodside Oil, Condensate and Gas

Country	Asset	Oil and Condensate Reserves (MMBbl)		Gas Reserves (Bscf)	
		Proved	Proved plus Probable	Proved	Proved plus Probable
Australia	North West Shelf	24.0	30.7	625	825
	Wheatstone LNG (Brunello & Julimar)	8.8	16.5	513	798
	Pluto LNG	19.5	24.3	1,448	1,801
	Scarborough LNG	-	-	4,762	7,429
	Greater Enfield	16.0	24.1	-	-
Senegal	Sangomar	100.6	148.1	-	-
Total		**168.9**	**243.7**	**7,349**	**10,854**

(b) Woodside NGL/LPG

Country	Asset / Project	NGL/LPG Reserves (MMBbl)	
		Proved	Proved plus Probable
Australia	North West Shelf	2.4	3.2

Notes:
1. Reserves net to company are the company's net economic entitlement under the terms of the contract that governs each asset. For Australia this is equal to the company's working interest share of gross field Reserves less any royalty taken in kind. For Senegal, it is equal to the company's share of Cost Recovery, Profit Oil and Tax Barrels (if any) under the terms of the relevant PSC.
2. Totals may not exactly equal the sum of the individual entries due to rounding.
3. For NWS, NGL composition is equivalent to LPG as they include only C3-C4 hydrocarbons.
4. As recommended by PRMS, GaffneyCline does not include Consumed in Operation (CiO) volumes in Reserves; GaffneyCline reports only Sales volumes as Reserves.

Contingent Resources Summary

Contingent Resources net to Woodside are summarised in **Table 1.3**. The Contingent Resources are shown on a working interest (WI) basis, i.e. as the company's WI fraction of the gross field Contingent Resources. The WI basis volumes do not represent the company's actual net entitlement under the terms of the contract that governs the asset, which would be lower for PSCs or where royalty is deductible. The WI basis volumes are quoted here since many of the projects are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the net entitlement. Only the 2C (Best estimate) Contingent Resources are presented here.

Table 1.3: Summary of Contingent Resources Net to Woodside (WI Basis) as of 31 December 2021

Country	Asset / Project	2C Contingent Resources		Classification
		Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Australia	NWS Gas: facility upgrades, infill wells, workovers and new developments	0.3	12	Pending
		7.4	221	Unclarified
		1.9	53	Not Viable
	NWS Oil: facility upgrades, infill wells, workovers and new developments	7.2	3	Unclarified
		3.8	4	Not Viable
	Pluto turn-down rate reduction	0.6	53	Pending
	Pluto infill wells	2.7	231	Unclarified
	Brunello (Wheatstone LNG)	0.2	15	Unclarified
	Thebe and Jupiter (Greater Scarborough)	-	659	Pending
	WA-404-P (Remy, Martell, Martin, Noblige and Larsen Deep)	19.5	1,006	Not Viable
	Greater Enfield (incl. Vincent)	32.2	43	Not Viable
	Ragnar and Toro (WA-93-R & WA-94-R)	2.2	270	Not Viable
	Browse Basin (Torosa, Calliance and Brecknock)	119.3	4,469	On Hold
	Greater Sunrise	75.6	1,717	On Hold / Not Viable
Myanmar	Block A6	-	567	Not Viable
Senegal	Sangomar Phase 1 WI	22.1	-	Pending
	Sangomar Phases 2-5 + Gas export	214.0	301	Unclarified
	FAN discovery	81.0	-	Unclarified
Canada	Liard	-	13,350	Not Viable

Notes:
1. Net Contingent Resources in this table are Company's working interest fraction of the gross field Contingent Resources; in assets governed by a PSC or similar contract, they do not represent the Company's actual net entitlement under the terms of the contracts that governs the asset, which would be lower.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e., no "Chance of Development" (Pd) factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined for PSCs.
4. No deduction has been made for fuel, flare and shrinkage.
5. Note that on 27 January 2022 (after the effective date of this ITSR), Woodside announced it was withdrawing from its interests in Myanmar.

Prospective Resources Summary

Woodside's global exploration portfolio consists of assets in Australia, Senegal, South Korea and the Democratic Republic of Congo. These prospects range from Near Field Exploration (NFE) opportunities in Australia and Senegal to stand-alone exploration projects in Australia, South Korea and Congo.

All the prospects/leads mentioned here could potentially be drilled within the next five (5) years; additional prospectivity with no firmly planned drilling has been excluded from the assessment.

Woodside has identified nine gas prospects/leads with 2U (best estimate) Prospective Resources varying between 30 and 769 Bscf and Chance of Geologic Success (P_g) between 15% and 72%, plus two oil rospects with 2U Prospective Resources varying between 40 and 375 MMBbl and P_g between 24% and 91%.

GaffneyCline has reviewed the Prospects and Leads mentioned above. This review has broadly confirmed the assessments by the companies, although GaffneyCline has modified both the Prospective Resource estimates and P_g where it deems it to be required. These changes do not unduly impact the overall exploration portfolios of the companies.

It should be noted that the P_g reported here represents an indicative estimate of the probability that drilling a prospect would result in a discovery. This does not include any assessment of the risk that the discovery, if made, may not be developed. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.

1.2 BHP Petroleum

BHP Petroleum has significant assets in Western Australia and south-eastern Australia, as well as in the Gulf of Mexico (US and Mexico), and Trinidad and Tobago. The NWS and Greater Scarborough assets in which BHP Petroleum and Woodside (operator) share interests, are covered in the preceding section.

Bass Strait comprises some 24 oil and gas fields in the Gippsland basin, offshore the south-eastern margin of Eastern Victoria, Australia. Production commenced in 1969 and current production is primarily gas with condensate and declining oil rates from maturing oil fields. Most fields were developed with steel jackets in shallow water and mono-tower platforms or subsea tiebacks and two large, concrete gravity-based platforms have also been installed. Oil and gas from nearly 300 wells is transported to onshore plants at Longford and Long Island in multiple gas and oil pipelines. Development planning for four further discoveries (North Turrum, Sweetlips, Wirrah and East Pilchard) is maturing, but not yet certain.

The Macedon dry gas field is located in the Exmouth sub-basin, about 40 km north of Exmouth in Western Australia in water depth of 160 to 190 m. It has been developed with four subsea wells and gas is produced to the onshore Macedon gas plant, through a 90 km pipeline. First gas production was in 2013 and future plans include a compression project and three infill wells.

Also, in the Exmouth sub-basin of Western Australia, BHP Petroleum operates the Pyrenees subsea development of up to seven oil accumulations located immediately to the northwest of Macedon in 200 m water depth. Production commenced in 2010 and the oil is processed on the Pyrenees Venture FPSO, while gas is used as fuel. The development occurred in three phases and the fields are mature. Future plans include an infill dual lateral and water shut-off operation (Phase 4) and additional infill drilling (Phase 5).

BHP Petroleum also has an interest in the Scafell gas discovery within the existing Pyrenees field production licence. Development of Scafell is likely to be as a tie-back to the Macedon manifold and timing will depend on when the Macedon gas production comes off plateau or when there is an increase in WA domestic gas demand.

BHP Petroleum has interests in four developments in the Green Canyon area of the US Gulf of Mexico (GOM): Shenzi, Shenzi North together with Wildling, operated by BHP Petroleum; and Atlantis and Mad Dog, operated by BP.

The Shenzi oil field was discovered in 2002 in the GOM in ~1,340 m water depth. The reservoirs are deep at 6,700 to 8,530 mss. The field was initially developed in 2007 with two subsea wells and a manifold tied to the Marco Polo tension leg platform (TLP). The development was then expanded with the Shenzi TLP, four more subsea manifolds and multiple wells. A subsea multiphase pumping project sanctioned in 2021 is currently in execution with production expected to start in 2022. Future development opportunities include conversion of a well from production to water injection, a side-track of a production well and the drilling of an additional producer/injector pair.

The Shenzi North and Wildling oil discoveries made in 2015 and 2017 respectively are located directly north of Shenzi. The fields have been appraised and the development plan is a daisy chained tie-in of two subsea production wells in each field to existing Shenzi facilities. Shenzi North was sanctioned in the third quarter of 2021 and is in Execution phase as of end 2021, while the proposed Wildling development entered Definition phase in 2021. Understanding of reservoir performance under depletion drive will help to plan a possible later phase waterflood.

The Atlantis phased development comprises a semi-submersible facility with subsea wells in ~2,135 m of water. There are 29 producing wells and three water injection wells. Oil production commenced in 2007 and production rates have been maintained at approximately 100 Mbopd since 2014, when the second phase of development was completed. Phase 3 was sanctioned in 2019 and drilling commenced the same year. By September 2021, five of the eight Phase 3 wells had been drilled, with three being completed and put online and two requiring sidetracks. Phase 3 drilling is expected to be completed in early 2023. Beyond Phase 3, continuous drilling is assumed until 2029 to bring online 12 additional producers and six water injectors. Despite the field having been in production for more than 14 years, much potential remains and there are several possible future projects, including one or two new water injectors and a side-track in the short term, expansion of Drill Centres 1, 2 and 3 with three, four and four new infill wells respectively and facilities expansion to incorporate subsea multiphase pumps.

The Mad Dog oil field was discovered in 1998 in water depth of 1,340 m. First production occurred in January 2005 and there are ten producing wells. The Mad Dog facility comprises a 16-slot, dry-tree, floating spar hull with integrated production and drilling capability. The facility will reach the end of its original design life late in 2024 and BP has undertaken studies to extend the life nominally to 2045. Oil and sales gas are exported through the Caesar and Cleopatra export pipeline systems in which BHP Petroleum has equity of 25% and 22% respectively. Phase 2 of the development has commenced and is scheduled to start contributing to production in 2022. Future projects will likely include implementation of water injection in the north and west, development of the southwest and infill drilling to supplement Phase 2 wells. Further potential might be realised by extending the A-spar life beyond 2045.

In Trinidad and Tobago, BHP Petroleum operates assets in three clusters: Shallow Water (the Greater Angostura Complex), Deep Water North (the Calypso Development) and Deep Water South (Magellan).

The Greater Angostura Complex, in production since 2005, includes producing oil and gas fields (AP3, Aripo, Horst, Kairi and Canteen) and discoveries (Howler and Canteen North). Additionally, the Ruby (oil and gas) and Delaware (gas) fields came on stream in 2021. Potential future plans include development of the Canteen North and Howler discoveries, lowering abandonment pressure in the Canteen, Kairi, Horst and Aripo fields and developed gas discovered in the Nariva age sands.

The Calypso Development area encompasses five gas discoveries (Bongos, Bele, Tuk, Hi-Hat, Boom) in water depth of ~2,000 m, resulting from the drilling of seven exploration wells. Several undrilled prospects in fault blocks immediately adjacent to discoveries remain to be tested in further appraisal. These are strongly supported by seismic attributes, and have high geological chance of success. Development initially appears likely to target parts of the Bongos, Bele and Tuk discoveries, including some of the undrilled fault blocks, but the development concept is still under study.

The Magellan asset comprises two dry gas discoveries (LeClerc and Victoria) in water depth of 1,800 m. A third exploration well was not successful. The total volume of gas discovered is not currently considered large enough to support a commercial standalone development.

BHP Petroleum has an operated interest in the Trion oil field in the Mexican sector of the GOM, discovered in 2012 in ~2,500 m water depth. The field was appraised with three wells after the discovery well, two of which have a single side-track each, resulting in a total of six reservoir penetrations. Seismic data has been pivotal in delineating the field and identifying potential compartments. The crest of the structure is at ~3,800 mss, and the pressure is high (>6,400 psia). Plans are maturing to develop the field with subsea wells, likely comprising 14 production wells, ten water injection wells and three dual completed gas injection wells. It is currently envisaged that the wells will be tied back to a floating production unit (FPU) and stabilised crude will be sent to a floating storage and offloading facility (FSO) for export via tanker. Gas that is not re-injected will be exported for sales. First oil could be in 2026, though the development is not yet sanctioned. The northernmost fault-controlled segment of the field is considered undiscovered and is a low-risk prospect.

Table 1.4 lists the licences in which BHP Petroleum hold working interests (WI) as of 31 December 2021. Reserves, Contingent Resources and/or Prospective Resources have been attributed to most of these licences.

Table 1.4: Summary of BHP Petroleum Licences as of 31 December 2021

Country	Licence Block	Field/ Development	BHP Petroleum WI (%)	Final License Expiry
Australia	WA- 1-L to 6-L, 23-L, 24-L, 30-L, 52-L, 53-L, 56-L to 58-L, WA-7-R R4, WA-28-P R8	NWS Gas	15.78%	Extendable
	WA-9-L, WA-11-L, WA-16-L	NWS Oil	16.66%	
	Vic/ L1 to L11, L13 to L20, L25, RL1, RL4	Bass Strait – GBJV	50.00%	
	Vic/ 9 and L25	Bass Strait – KUJV	32.50%	
	WA-42-L	Macedon	71.43%	
	WA-42-L & WA-43-L	Pyrenees and Scafell	71.43% & 39.999%	
	WA-61-L & WA-62-L	Scarborough LNG	26.50%	
	WA-61-R & WA-63-R	Thebe + Jupiter backfill to Scarborough	50.00%	
US GOM	GC 608, 609, 610, 652, 653 and 654	Shenzi	72.00%	Extendable
	GC608 & GC609	Shenzi N.	72.00%	
	GC564 & GC520	Wildling	100.00%	
	GC699, 742, 743 & 744	Atlantis	44.00%	
	GC 738, 781, 782, 824, 825, 826, 868 and 869	Mad Dog	23.90%	
Trinidad & Tobago	2(c)	Greater Angostura	45.00%	April 2026, extension for 5 years until April 2031
	2(c) Howler		64.30%	
	3(a)		68.46%	April 2031
	23(a) & 14	Calypso	70.00%	
	TTDAA5	Magellan	65.00%	
Mexico	Trion Contractual Area	Trion	60.00%	March 2052, extensions possible until Dec 2067.

Notes:
1. Licences are easily extended in Australia and US GoM when production remains commercial.
2. Licences in Australia, US GOM and Mexico are subject to tax/royalty fiscal regimes, whereas those Trinidad & Tobago are in the form of Production Sharing Contracts (PSC) or similar.

Reserves Summary

Proved (1P) and Proved plus Probable (2P) Reserves net to BHP Petroleum are summarised in **Table 1.5**. The volumes reported as Reserves are sales quantities and exclude volumes of hydrocarbons consumed in operations as fuel (CiO). To facilitate comparison with the companies' annual reporting, CiO quantities are shown in **Appendix III**.

Table 1.5: BHP Petroleum Summary of Net Entitlement Reserves as of 31 December 2021
BHP Petroleum Oil, Condensate and Gas

Country	Asset	Oil and Condensate Reserves (MMBbl)		Gas Reserves (Bscf)	
		Proved	Proved plus Probable	Proved	Proved plus Probable
Australia	North West Shelf	19.2	24.9	603	795
	Bass Strait	10.6	17.9	344	600
	Macedon	-	-	223	278
	Pyrenees	10.0	19.0	-	-
	Scarborough LNG	-	-	1,717	2,679
US GOM	Shenzi	64.0	91.9	6	12
	Shenzi North	16.4	26.8	5	8
	Atlantis	59.4	153.9	22	42
	Mad Dog	129.2	180.0	12	20
Trinidad & Tobago	Angostura	1.6	1.9	159	219
	Ruby	1.4	1.8	24	33
Total		**311.9**	**518.0**	**3,116**	**4,685**

BHP Petroleum NGL/LPG

Country	Asset / Project	NGL/LPG Reserves (MMBbl)	
		Proved	Proved plus Probable
Australia	North West Shelf	2.3	3.1
	Bass Strait	16.5	28.8
US GOM	Shenzi	1.7	3.1
	Shenzi North	1.1	1.7
	Atlantis	2.9	5.6
Total		**24.5**	**42.3**

Notes:
1. Reserves net to company are the company's net economic entitlement under the terms of the contract that governs each asset. For Australia and USA, this is equal to the company's working interest share of gross field Reserves less any royalty taken in kind. For Trinidad & Tobago, it is equal to the company's share of Cost Recovery, Profit Oil and Tax Barrels (if any) under the terms of the relevant PSC.
2. GOM Reserves are net of Royalty although payments are in cash.
3. Totals may not exactly equal the sum of the individual entries due to rounding.
4. For Bass Strait and NWS, NGL composition is equivalent to LPG as they include only C3-C4 hydrocarbons. GOM NGL volumes represent C2-C5+ hydrocarbons
5. As recommended by PRMS, GaffneyCline does not include Consumed in Operation (CiO) volumes in Reserves; GaffneyCline reports only Sales volumes as Reserves.

Contingent Resources Summary

Contingent Resources net to BHP Petroleum are summarised in **Table 1.6**. The Contingent Resources are shown on a working interest (WI) basis, i.e. as the company's WI fraction of the gross field Contingent Resources. The WI basis volumes do not represent the company's actual net entitlement under the terms of the contract that governs the asset, which would be lower for PSCs or where royalty is deductible. The WI basis volumes are quoted here since many of the projects are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the net entitlement. Only the 2C (Best estimate) Contingent Resources are presented here.

Table 1.6: Summary of Contingent Resources Net to BHP Petroleum (WI Basis) as of 31 December 2021

Country	Asset / Project	2C Contingent Resources		Classification
		Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Australia	NWS Gas: facility upgrades, infill wells, workovers and new developments	0.3	12	Pending
		7.4	221	Unclarified
		1.9	53	Not Viable
	NWS Oil: facility upgrades, infill wells, workovers and new developments	3.6	1	Unclarified
		1.9	2	Not Viable
	Bass Strait: N. Turrum, Sweetlips/Wirrah	16.3	118	Pending
	Bass Strait East Pilchard	1.8	20	Unclarified
	Macedon compression	-	41	Pending
	Macedon/Muiron infills	-	59	Unclarified
	Macedon Black Pearl tie-in	-	7	Not Viable
	Pyrenees Phase 4	3.2	-	Pending
	Pyrenees Phase 5	13.2	-	Unclarified
	Scafell	-	38	Not Viable
	Thebe and Jupiter (Greater Scarborough)	-	659	Pending
US GOM	Shenzi side-tracks & infills	25.0	7	Unclarified
	Wildling	36.9	11	Pending
	Atlantis SSMMP + WI + infills	66.9	28	Unclarified
	Atlantis expansions and infills	21.4	10	Not Viable
	Mad Dog WI expansion	15.9	-	Pending
	Mad Dog extensions and infills	54.3	4	Unclarified
Trinidad & Tobago	Angostura Block 2(c)	1.3	219	Not Viable
	Calypso	4.9	2,584	Unclarified
	Calypso	-	293	Not Viable
	Magellan	-	313	Not Viable
Mexico	Trion	256.8	79	Pending
	Trion post licence + gas blowdown	25.8	131	Unclarified

Notes:
1. Net Contingent Resources in this table are Company's working interest fraction of the gross field Contingent Resources; they do not represent the Company's actual net entitlement under the terms of the contracts that governs the assets, which would be lower for PSCs or where royalty is deductible.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e., no "Chance of Development" (Pd) factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. No deduction has been made for fuel, flare and shrinkage.

Prospective Resources Summary

BHP Petroleum's global exploration portfolio consists of assets in Mexico, Trinidad and Tobago, Canada, Australia and USA. They contain Prospects ranging from NFE opportunities in Mexico, Trinidad and Tobago, Australia and USA to stand-alone exploration projects in the USA and Canada. Other Prospects such as those in Barbados and Egypt are not discussed as they are not sufficiently mature to be included in this assessment.

BHP Petroleum has identified two gas Prospects with 2U Prospective Resources varying between 85 and 300 Bscf and P_g between 85% and 90%, plus 11 oil Prospects with 2U Prospective Resources varying between 4.4 and 440 MMBbl and P_g between 11% and 90%.

GaffneyCline has reviewed the Prospects and Leads mentioned above. This review has broadly confirmed the assessments by the companies, although GaffneyCline has modified both the Prospective Resource estimates and P_g where it deems it to be required. These changes do not unduly impact the overall exploration portfolios of the companies.

It should be noted that the P_g reported here represents an indicative estimate of the probability that drilling a prospect would result in a discovery. This does not include any assessment of the risk that the discovery, if made, may not be developed. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.

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 Woodside and BHP Petroleum, 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, Woodside and BHP Petroleum 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 I**).

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 recognised 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.

Woodside provided 100% Gross numbers for analysis of their financial models whilst BHP Petroleum 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 Woodside and BHP Petroleum 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 categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status. 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 categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by the economic status.

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 recognised 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 Woodside and BHP Petroleum 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 Woodside or BHP Petroleum 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

GaffneyCline is an independent international energy advisory group of more than 55 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with Woodside and BHP Petroleum. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or are related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

The ITSR team was led by Mr Zis Katelis, a Technical Director in GaffneyCline who has over 25 years' industry experience. He holds a BSc with Honours (Geophysics) from Monash University in Victoria. He is currently a member of the Society of Petroleum Engineers. Zis also contributed directly to the technical work on various Australian assets for this report.

The report was reviewed by Mr Doug Peacock, a Technical Director in GaffneyCline, who has over 35 years' industry experience. He holds an MSc in Petroleum Geology from Imperial College in London and a BSc Geological Sciences from Leeds University. He is a member of the Society of Petroleum Engineers, the Petroleum Exploration Society of Great Britain (PESGB), the South East Asia Petroleum Exploration Society (SEAPEX) and the American Association of Petroleum Geologists (AAPG).

The report was also reviewed by Ms Arse Clarijs, a Regional and Technical Director in GaffneyCline, who has over 30 years' industry experience. She holds an MSc in Petroleum Geoscience from the University of Brunei and a BSc Geology Gadjah Mada University in Indonesia. She is a member of the American Association of Petroleum Geologists (AAPG), the Indonesia Petroleum Association (IPA), the Indonesia Geologist Association (IAGI) and the Southeast Asia Petroleum Exploration Society (SEAPEX).

3 Methodology

Woodside and BHP Petroleum have provided GaffneyCline with Reserves and Resources estimates prepared by both companies and/or third-party consultants, for their oil and gas assets in each company's operating area along with supporting technical data and models. All of the Woodside and BHP Petroleum assets have been reviewed as part of this Proposed Transaction assignment.

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 Woodside and BHP Petroleum. Where GaffneyCline opined that the presented valuation scenario profiles required modification, GaffneyCline made these modifications and presented the modified profiles to KPMG Corporate Finance. Where GaffneyCline opined that the presented valuation scenario profiles were reasonable they were adopted from Woodside/BHP Petroleum 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 Woodside and BHP Petroleum 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. 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 Resources assets for valuation by KPMG Corporate Finance.

GaffneyCline has provided Base Case production and cost valuation scenario profiles to KPMG Corporate Finance based predominantly on a technical reconciliation of 2P/2C (or best technical estimate) 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.

GaffneyCline has assessed Contingent Resources projects by reviewing the applicable volumes with respect to the proposed development plan that GaffneyCline believes is most likely to be sanctioned. A Chance of Development for Contingent Resources projects has generally been utilised and the specific factors and contingencies affecting the Chance of Development are discussed per asset where applicable. For certain near-field assets, GaffneyCline has opined on the portfolio of Contingent Resource projects and included only projects assessed to be technically mature with appropriate commercial outcomes for the total 2C volume (based on Internal Rate of Return (IRR)) rather than utilising a Chance of Development risk factor for every single project in the portfolio of opportunities. This is discussed in more detail for the applicable assets.

A Chance of Development as defined by the PRMS refers to the *"estimated probability that a known accumulation, once discovered, will be commercially developed".* For the Contingent Resources projects contained in this report GaffneyCline has in general considered the probability that the project will achieve a final investment decision in the proposed time frame based on the current information and status of the project. The Chance of Development estimate is derived by considering each project's technical and commercial maturity, potential commercial outcome, stakeholder commitment and other project specific risks that could result in a delay in the final investment decision. Project delay risks are reflected in the chance of development estimates to account for a potential time value loss. Once the final investment decision is taken, there could be project execution risks and other typical upstream business-related risks; such risks are not part of the chance of development estimation.

GaffneyCline investigated assets with Contingent Resources in the Development Pending, Development on Hold and Development Unclarified project maturity sub-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 Resources projects that GaffneyCline has assessed as Not Viable, after an independent assessment, are not included in valuation scenario profiles provided to KPMG Corporate Finance.

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 Mscf to KPMG Corporate Finance based on a review of comparable transactions. 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.

In assessing a value for Woodside and BHP Petroleum 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 Woodside and BHP Petroleum efforts to obtain farminees were also considered.

The above elements were reviewed to consider the appropriate method to define 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 Woodside and BHP Petroleum 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. BHP and Woodside are currently measuring and tracking their greenhouse gas (GHG) emissions (measured in CO_2 equivalent estimates) from their operations.

GaffneyCline has estimated net carbon liabilities for Assets under review based on the existing Australian regulations. GaffneyCline has not added any additional carbon liability costs for any anticipated changes in regulations or voluntary carbon offsets. For the Woodside and BHP Petroleum portfolio of assets, carbon liabilities are applicable for only Australian operations under the Safeguard Mechanism.

The Safeguard Mechanism places a legislated obligation on Australia's largest greenhouse gas emitters to keep net emissions below their business-as-usual (or baseline) levels set by the Australian Clean Energy Regulator (CER) and applies to facilities with direct Scope 1 emissions of more than 100,000 tonne of CO2-e per year. Companies who exceed their baseline levels must purchase Australian Carbon Credit Units (ACCUs) to offset their excess emissions. Baselines are set in different ways depending on whether the facility is new, the applicable industrial sector and whether the baseline is fixed or annually adjusted for production. A baseline may be adjusted to accommodate economic growth or natural resource variability. ACCU prices are largely determined by the available supply of ACCUs from registered projects and the demand by organisations to voluntarily reduce their reported emissions through offset with the ACCU and the Australian government purchases.

ACCU's are an Australian traded entity and not necessarily equivalent or exchangeable for other international carbon credits.

In the Woodside portfolio of Australian assets, currently only Pluto LNG, NWS LNG and Greater Enfield assets come under the Safeguard Mechanism. In the BHP Petroleum portfolio of Australian assets, only Bass Strait and Pyrenees assets come under the Safeguard Mechanism. GaffneyCline has verified with data from CER that emissions from the assets of both of these companies are currently below baseline thus incur no carbon liabilities.

Due to the level of optionality in calculating the baseline and subsequent negotiations involved with CER, it is not possible for GaffneyCline to verify the projected baselines and emissions liabilities proposed by Woodside and BHP Petroleum. Going forward GaffneyCline has accepted the Woodside assumption of US$ 20/ tCO2-e (RT2022) ACCU price from 2022 to 2024 and US$ 80/ tCO2-e (RT2022) from 2025 onwards. Regulatory CO2-e emission liabilities are less than 10% of the total OPEX for the assets under review thus not material to this transaction. GaffneyCline has accepted the total carbon emissions and regulatory carbon liabilities projections provided by Woodside and BHP Petroleum.

For Woodside assets, positive future regulatory carbon liability is assessed by Woodside for the following assets: Pluto upstream, Julimar and Brunello upstream, Greater Enfield, NWS midstream due to Browse development, and the Scarborough upstream and midstream developments. GaffneyCline audited the total carbon emissions values provided by Woodside for the Australian assets by benchmarking them for carbon intensity per unit production. Carbon intensity checks confirmed that after adjustment for reservoir CO_2 emissions, total carbon emissions intensity is consistent with industry known/benchmarked quantities for LNG production. GaffneyCline therefore estimated the total carbon emissions using Woodside's calculated values adjusted for the GaffneyCline production profile scenarios. GaffneyCline presents the regulatory carbon cost in the profiles documented in this report where applicable.

For the BHP Petroleum non-overlapping assets, BHP Petroleum estimated zero future regulatory carbon liability because they are below baseline. GaffneyCline audited the total carbon emissions calculations provided by BHP for their Australian assets and found them to be reasonable and confirmed they are below baseline. GaffneyCline estimated total carbon emissions using BHP calculated values (which GaffneyCline confirmed are consistent with industry benchmarks) adjusted for GaffneyCline production profile scenarios.

For Reserves estimates included in this report, GaffneyCline has conducted an economic assessment of Woodside and BHP assets in order to only derive the economic limit for production, the Net Entitlement Reserves. The assessments are based upon GaffneyCline's understanding of the fiscal terms governing these assets and the various economic and commercial assumptions described in sections 14 and 15.

For Woodside, GaffneyCline's technical due diligence utilised Woodside's Long Term Forecasts as provided for the Reserves work performed in this report. GaffneyCline is aware that there is always an iterative process where Woodside incorporates more recent performance data and technical models for their reserves estimates. GaffneyCline evaluated production data as of 31 December 2021 to opine on the reasonableness overall of the Long Term Forecasts provided to estimate GaffneyCline's reserves of the assets. Differences may exist based on the latest data and models Woodside is utilising in their reserves estimates with an additional difference due to the average heating values utilised by GaffneyCline when reviewing the Long Term Forecast.

For BHP Petroleum, GaffneyCline's technical due diligence focused on reviewing the supporting technical data and inputs (e.g. IPM models), which formed the basis for the Reserves numbers. GaffneyCline subsequently cross-referenced outputs from the technical models with the BHP Petroleum Petrolook database along with the different business plan outputs provided by BHP. GaffneyCline opined on the overall reasonableness of the technical models and Petrolook database numbers provided, and these checks formed the basis of GaffneyCline's estimate of the Reserves of the BHP Petroleum assets.

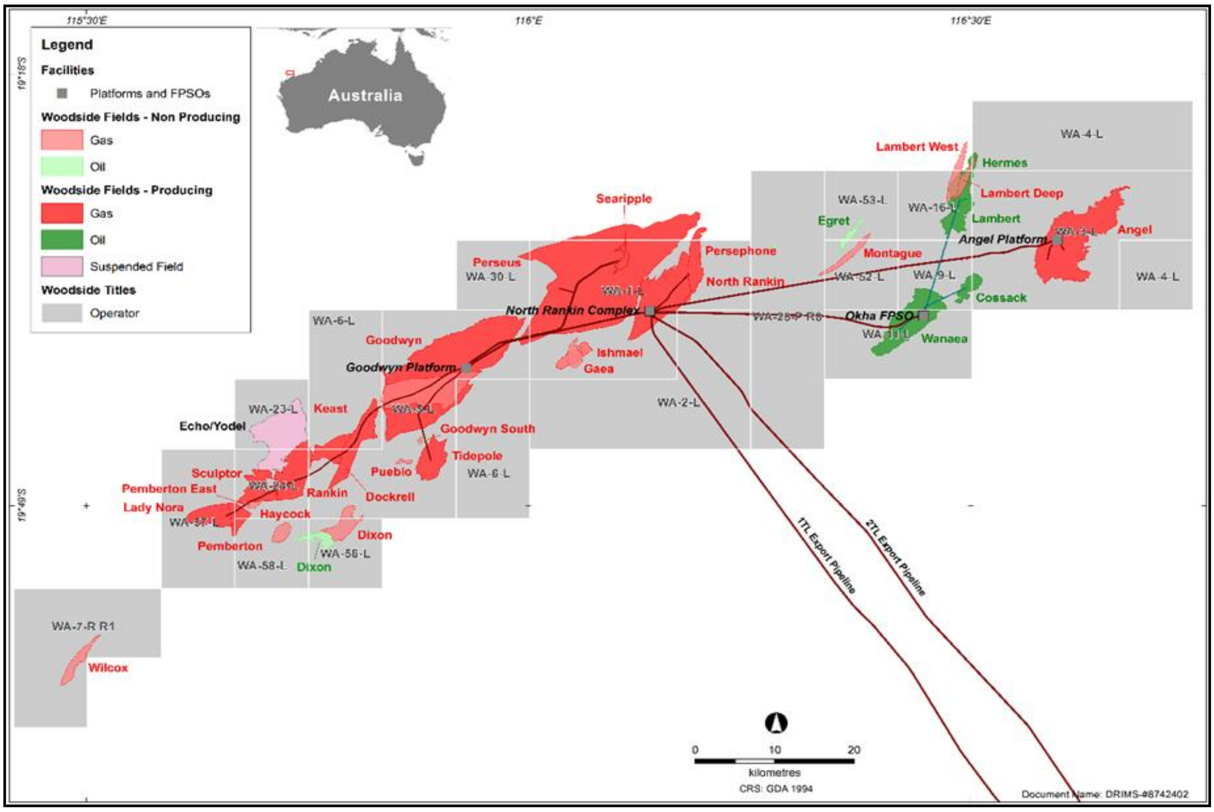
Woodside Assets

4 Woodside Australia

4.1 North West Shelf Gas

The North West Shelf (NWS) gas fields are located about 130 km offshore Western Australia (**Figure 4.1**). The produced gas is gathered at the North Rankin complex and then sent to the Karratha Gas Plant (KGP) via two export pipelines. The end products are domestic gas and export LNG. Woodside operates the NWS gas fields and holds a 15.78% stake in the joint venture which comprises BHP Petroleum, Chevron, BP, Shell, MIMI and CNOOC. Woodside owns 16.67% of NWS pipelines and KGP.

Figure 4.1: North West Shelf Gas and Oil Fields

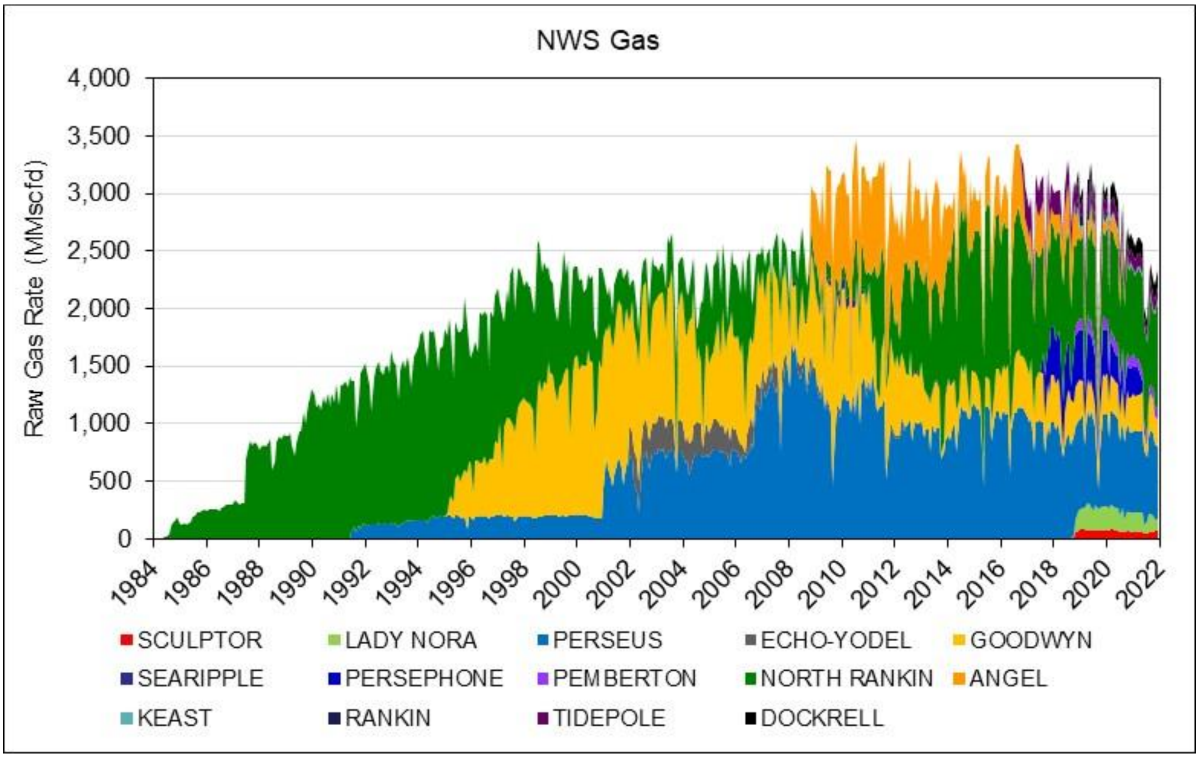


Source: Woodside

4.1.1 Field Description and Recoverable Volumes

Gas production began in 1984 from the North Rankin Field (**Figure 4.2**). Since then, twelve more fields have been brought online, with four not on production as of 31 December 2021. The earliest fields brought online (North Rankin, Perseus, Goodwyn) were mainly developed with platform wells. Goodwyn and North Rankin both had gas injection/cycling to improve recovery of condensate for much of their early history. Later fields were mainly developed with subsea tie-back wells. As export capacity continued to grow with the addition of more trains, so did production, which eventually peaked at 3 Bscfd in 2008 (corresponding to the offshore production rate required to keep the KGP full). However, since 2021, production from the NWS has been offshore constrained, with production declining in most fields. To maximise gas supply to the KGP, effort is ongoing to upgrade water handling capabilities, shut-off water production, add perforations to existing producers and reduce separator pressure.

Figure 4.2: North West Shelf Gas Fields Historical Production



Source: Data from Woodside.

Table 4.1 provides a summary of the gas fields in the NWS area, including non-producing discoveries. Woodside's forecasts shows that the top four fields (North Rankin, Perseus, Goodwyn and Lady Nora-Pemberton) collectively contribute over 80% of the total NWS gas 2P gross Reserves. As such, GaffneyCline has focused the analysis of NWS Gas on these four fields (excluding the Goodwyn GDEFA reservoir due to its small volumes). An overview of the properties of these fields/reservoir groups is shown in **Table 4.2**.

Table 4.1: Gross Technical Remaining Recoverable Volumes by Field

Field	Status	Produced Raw Gas (Bscf)	Remaining Recoverable			
			Low Estimate		Best Estimate	
			Gas (Bscf)	Cond. (MMBbl)	Gas (Bscf)	Cond. (MMBbl)
North Rankin	Producing	9,501	1,680	25.7	1,912	27.9
Perseus	Producing	7,611	1,080	22.2	1,829	34.1
Goodwyn	Producing	4,771	1,052	24.5	1,105	25.9
Lady Nora-Pemberton	Producing	299	306	7.7	445	10.4
Persephone (*)	Not producing	448	0	0.0	0	0.0
Dockrell	Producing	124	165	6.0	285	9.7
Keast	Producing	26	62	1.1	81	1.4
Sculptor-Rankin	Producing	116	0	0.0	102	2.5
Tidepole	Producing	280	189	3.8	188	3.7
Angel (*)	Not producing	2,129	0	0.0	0	0.0
Searipple	Not producing	59	0	0.0	0	0.0
Echo-Yodel	Not producing	534	0	0.0	0	0.0
Lambert Deep	Execute	0	190	1.9	193	1.9
Total		**25,898**	**4,724**	**92.9**	**6,140**	**117.5**

Notes:
1. The top four fields account for approximately 80% of the NWS total remaining technically recoverable gas volumes (best estimate).
2. Persephone Field (*) is not producing, although attempts have been made to restart one well. Angel Field (*) is not producing. The Angel NE attic infill well was re-evaluated during 2019; however, it remains commercially not viable.
3. Remaining Recoverable Volumes are remaining technically recoverable volumes with no economic cut-off applied.
4. Gas volumes reported in this table are "wellhead" or "wet" volumes. Adjustments to sales gas volumes are accounted for in the economic evaluation for Reserves reporting.
5. Produced Raw Gas is total produced gas minus injection.

Table 4.2: Subsurface Description of Main NWS Gas Fields

	North Rankin	Perseus	Goodwyn		Lady Nora/ Pemberton
			GG	GH	
Formation	Mungaroo, Brigadier & NR	Legendre	Brigadier & Mungaroo	Brigadier & Mungaroo	Brigadier & Mungaroo
Depth (m TVDss)	3,000	3,197	2,800	2,839/3,028	3,000
Initial Pressure (psia)	4,720	4,396	4,400-4,500	4,439/4,709	4,654
Initial Temperature (°C)	106	108.7	108	116	116
Porosity (%)	16-20	20-22	30	14-22	21
Permeability (mD)	130-2,000	~100-1,000	100-1,000	1,000-5,000	4,000
Fluid Type	Wet gas	Wet gas	Wet gas	Wet gas	Wet gas

The longest producing gas field in the NWS is North Rankin, which was discovered in 1971 and appraised between 1972 and 1980. Twenty-two dry wellhead development wells have been drilled in the field to produce from the Upper and Lower reservoirs. As of YE2021, ~9.5 Tscf of gas had been produced (total produced gas minus injected gas) from North Rankin. Despite the age and maturity of the field, North Rankin is expected to contribute significantly to future NWS gas production until the end of the shelf's life; the field also serves as swing producer for the shelf. North Rankin production is currently in decline; work performed from 2019 through 2021 has been successful in reducing the decline.

Located about 20 km west of the North Rankin Field is the Perseus field (**Figure 4.1**), discovered in 1972 and appraised in 1990. First production was in 1991, followed by further appraisal in 1995 and 1996. Perseus was found to extend into the neighbouring licence block held by Mobil and Phillips in 1997. Following that, in 2001, the NWS venture participants together with Mobil and Phillips signed the Perseus/Athena Cooperative Development Agreement (PACDA) which governs the development, production and operation of the Perseus field. Production from Perseus comes through ten wells, seven of which are from the North Rankin A platform, while the remaining three are subsea wells tied back to the Goodwyn A platform. As of YE2021, nine wells remain active. Perseus production is in decline; work performed from 2019 to 2021 has helped to slow the decline.

The Goodwyn gas condensate field is located about 30 km southwest of the North Rankin field. Discovered in 1971, production from Goodwyn commenced in 1995 upon the completion of the Goodwyn A platform and to date, 21 development wells have been drilled and completed. The field comprises a series of stacked reservoirs dipping northwards, sub-cropping the overlying Cretaceous shales that provide the up-dip seal. Two of the 21 development wells produce from the GH reservoir units; four produce from the GG reservoir units (GF5-GG4); another three produce from the GDEFA (GD4-GF3) reservoir units. Due to the small volumes in Goodwyn GDEFA, GaffneyCline has focused its analysis of Goodwyn on the GG and GH reservoir groups. Goodwyn GG production is currently in decline; work performed in late 2019 and early 2020 has helped to boost recent production. Within the same field, the Goodwyn GH reservoir produced steadily at 150 MMscfd between mid-2016 and mid-2018. In late 2018, production rate was stepped down to around 125 MMscfd and has been in slow decline since. Three new infill wells were recently drilled to boost production from the Goodwyn GH reservoir starting in 2022, based on Woodside 2H2021 Long Term Forecast.

The Lady Nora-Pemberton fields are located about 70 km southwest of the North Rankin Field. Lady Nora-Pemberton comprises two separately discovered fields: the Pemberton Field discovered in 2006, and the Lady Nora Field discovered in 2007. Three development wells have been drilled and completed in 2018 as gas cap producers. The two fields were found to be in communication due to pressure responses observed in the LPA01 well (Pemberton) prior to coming online, due to production from the LPA02 and LPA03 wells (Lady Nora). All three wells are tied back to the Goodwyn A platform. Lady Nora-Pemberton gas production is currently in decline.

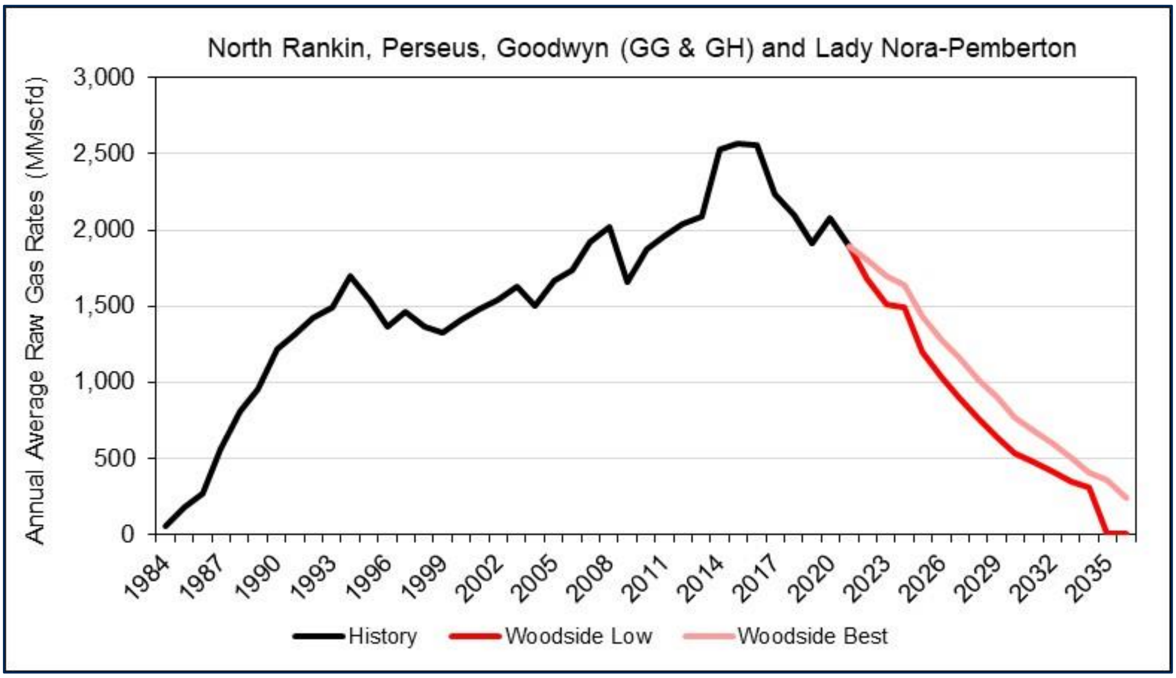
4.1.2 Field Development and Production Profiles

GaffneyCline has carried out Decline Curve Analysis (DCA) to review Woodside's production forecasts and estimates of technical remaining developed volumes individually for each of the major fields or reservoirs, North Rankin, Perseus, Goodwyn (GG & GH) and Lady Nora-Pemberton. Woodside's forecasts have been generated using a combination of dynamic and network modelling. At the aggregated level, the difference in volumes estimated by Woodside and GaffneyCline is within tolerance. As these fields/reservoirs collectively constitute more than 80% of the NWS Gas volumes, GaffneyCline has accepted Woodside's NWS gas forecasts for estimating Reserves. Woodside's Long Term Forecasts are the individual asset team's view of the production and cost profiles, effectively the designated latest business view. GaffneyCline understands that Woodside may use more recent performance data and technical models for its reserves estimates. GaffneyCline evaluated production data up to end 2021 to opine on the reasonableness overall of the Long Term Forecasts provided, and used these in making GaffneyCline's estimates of reserves. GaffneyCline also used average heating values rather than values per component. Differences may therefore exist between GaffneyCline's and Woodside's reserves estimates. **Figure 4.3** shows Woodside's aggregated forecasts for the top four fields. Both Woodside and GaffneyCline's forecasts exhibit continued decline in these fields, with compression and infill wells having minor effects in reducing the decline.

For condensate, GaffneyCline has compared the ratio of Woodside's condensate to gas forecasts against historical condensate/gas ratios (CGR) for each field, which are reasonably in line. On the basis of this comparison, GaffneyCline deems Woodside's condensates forecasts reasonable.

For undeveloped volumes associated with infill wells (applicable to Goodwyn GG), GaffneyCline has constructed type curves based on analogue wells for forecasting. Undeveloped volumes associated with compression have been forecast by extending DCA forecasts. **Table 4.1** summarises Woodside's estimated technical remaining volumes for the NWS Gas fields, which GaffneyCline has accepted.

Figure 4.3: Top Four Fields Aggregated NWS Gas Production History and Forecasts



4.1.3 Contingent Resources

GaffneyCline has reviewed Woodside's Contingent Resources and has found them reasonable. Woodside's Contingent Resources opportunities in NWS Gas and their estimated 2C volumes are reported in **Table 4.3** and **Table 4.4**.

Table 4.3: Gross Contingent Resources for Developed NWS Gas Fields as of 31 December 2021

Field	PRMS Sub-Classification*	2C Contingent Resources		Descriptions
		Dry Gas (Bscf)	Cond. (MMBbl)	
Angel (*)	Not Viable	63	3	1 infill well
Dockrell	Unclarified	101	5	2 infill wells
Goodwyn	Pending	3	0	1 well workover
	Pending	26	0	1 facility upgrade
	Unclarified	109	5	3 well workovers, 2 facility upgrades
Keast	Pending	45	2	1 infill well
North Rankin	Unclarified	165	3	2 facility upgrades
	Unclarified	78	1	1 infill well
Persephone	Not Viable	18	2	1 infill well
Perseus	Unclarified	444	15	1 facility upgrade
Sculptor	Unclarified	35	1	1 infill well, cyclic production
Tidepole	Unclarified	147	4	2 infill wells, 1 facility upgrade
	Not Viable	16	1	1 infill well
Totals		**1,249**	**42**	

Note: The Angel Field (*) is currently not producing. Angel NE attic infill well was re-evaluated during 2019, however remains not commercially viable.

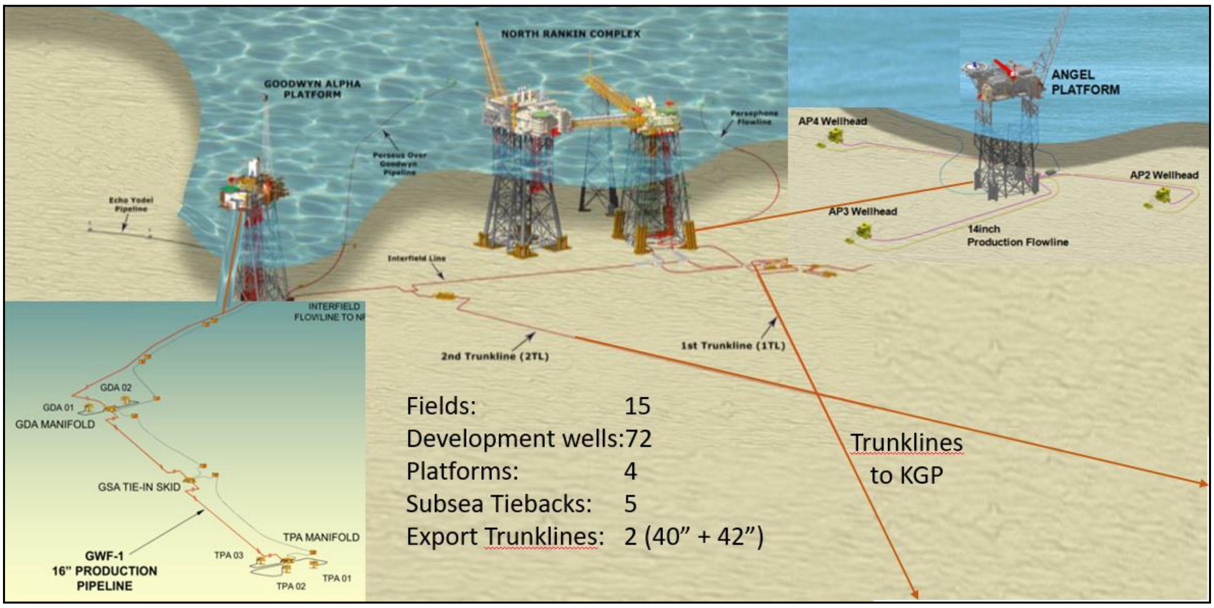
Table 4.4: Gross Contingent Resources for Undeveloped NWS Gas Fields as of 31 December 2021

Field	PRMS Sub-Classification*	2C Contingent Resources	
		Dry Gas (Bscf)	Cond. (MMBbl)
Tidepole East	Unclarified	49	2
Wilcox	Unclarified	133	7
Dixon	Unclarified	138	4
Haycock	Not Viable	6	0
Montague	Not Viable	57	2
Gaea & Ishmael	Not Viable	100	3
Lambert West	Not Viable	63	1
Pemberton East	Not Viable	15	0
Totals		**561**	**19**

4.1.4 Facilities and Cost Estimates

The offshore development comprises four conventional platforms (Goodwyn A, North Rankin A & B, and the Angel platform) hosting platform wells and subsea tiebacks. Export compression is provided on both the Goodwyn and North Rankin platforms delivering gas to two export trunklines, (40” and 42”) 185 km to KGP (**Figure 4.4**).

Figure 4.4: North West Shelf Facilities (Composite)



Source: Woodside

The NWS offshore facilities operate at high reliability with North Rankin reporting 99.7% reliability, Goodwyn A 99.2%, and Angel 98.3%.

KGP (**Figure 4.5**) came on stream in 1989 from 2 x 2.5 MTPA LNG trains, with an additional 2.5 MTPA train added in 1992. Trains 4 and 5, each of 4.6 MTPA were added in 2004 and 2008 respectively, bringing total capacity to 16.7 MTPA LNG export capacity, requiring 3,000 MMscfd feed gas from offshore. As the offshore fields are declining, there is available ullage to process non-NWS gas (**Figure 4.5**).

As the offshore fields decline, the overall system turndown rate can be stepped down by shutting down LNG trains, and by ceasing production through one of the two export trunk lines. In this way, the minimum facilities throughput can be reduced to 350 MMscfd into a single liquefaction train (Train 5), at 2 MTPA LNG production rate.

The Pluto-KGP interconnector line allows Pluto gas to be processed at KGP, forecast to commence in 2022 at some 100 to 150 MMscfd. In 2024, some 200 MMscfd of third party gas from the onshore Waitsia development is planned. The plant will earn tolling revenues from these liquefaction agreements. The most material backfill opportunity comes from development of the Browse Fields (Section 4.9), where the current development concept will process up to 1.9 Bcfd of gas through the KGP facilities, potentially extending facilities life by 15 years to 2058.

Figure 4.5: Karratha Gas Plant

Source: Woodside

4.1.4.1 Facilities Operability, Integrity, and Infrastructure

The NWS offshore facilities and the KGP have been in service for over 35 years with no significant unplanned service outages. Recent high level operability reports show upstream facilities reliability ranging from 98.3% to 99.7%, excellent performance for facilities of this age. In the longer term, the two parallel gas export lines and four parallel liquefaction trains at the KGP provides the opportunity to step down system capacity as the offshore production declines.

The KGP provides gas sales access to the world LNG market, and is also linked to the Western Australian domestic market via the Dampier to Bunbury natural gas pipeline. The KGP is located next to, and is interconnected with, the Pluto LNG plant allowing some degree of capacity sharing between the two liquefaction facilities.

4.1.4.2 Decommissioning and Restoration (D&R) Planning

Decommissioning and Restoration (D&R) Planning is an ongoing activity in the NWS offshore operations. The Operator plans to spend an average of US$50 MM in real terms (RT) per annum continuously until the end of field(s) life, with the major offshore D&R program budgeted thereafter. Currently, D&R plans are being matured for the Echo-Yodel field, which ceased production in 2012.

4.1.4.3 Cost Review

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering CAPEX, OPEX and D&R costs for the NWS offshore and KGP onshore operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline's review of costs for all Woodside's Australian assets focused on consistency (all costs in RT2022 basis and consistent with the activity plan and production profile), and cost levels (checks focusing on OPEX vs. annual production, and D&R estimates). The detailed costs were analysed and categorised to support economic analysis. For NWS, GaffneyCline accepted Woodside's detailed cost forecasts as reasonable.

Gross CAPEX for further development activities relating to the NWS gas Reserves case is estimated to be US$4,841 MM.

4.1.5 GaffneyCline's Production and Cost Valuation Profiles NWS Gas

GaffneyCline's valuation scenario production profile for Woodside's NWS gas assets is given in **Figure 4.6** with the associated real term cost profiles provided in **Figure 4.7**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing and Lamber Deep (in the execute phase) fields listed in **Table 4.1**. (The profile comprises field level forecasts from CWLH (associated gas from NWS Oil), North Rankin, Perseus (broken down by production over North Rankin and Goodwyn facilities), Lambert Deep, Goodwyn (broken down into reservoir groups GDGEGFA, GG and H), Keast, Lady Nora, Pemberton, Dockrell, Sculptor, Tidepole. No production is expected from Athena, Persephone, Angel, Dix, Wilcox and Rankin from 2022 onwards).

The regulatory carbon cost assumption for NWS gas is as per Woodside's below baseline assumption of zero for this project.

Figure 4.6: 100% NWS Gas Fields Production Profile

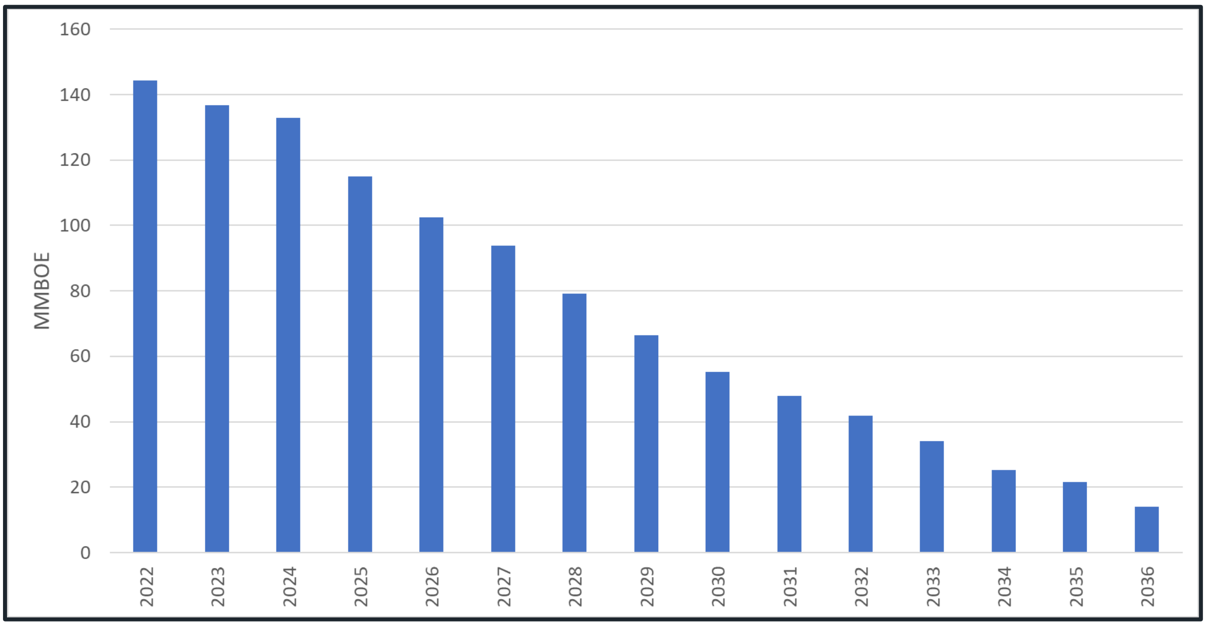
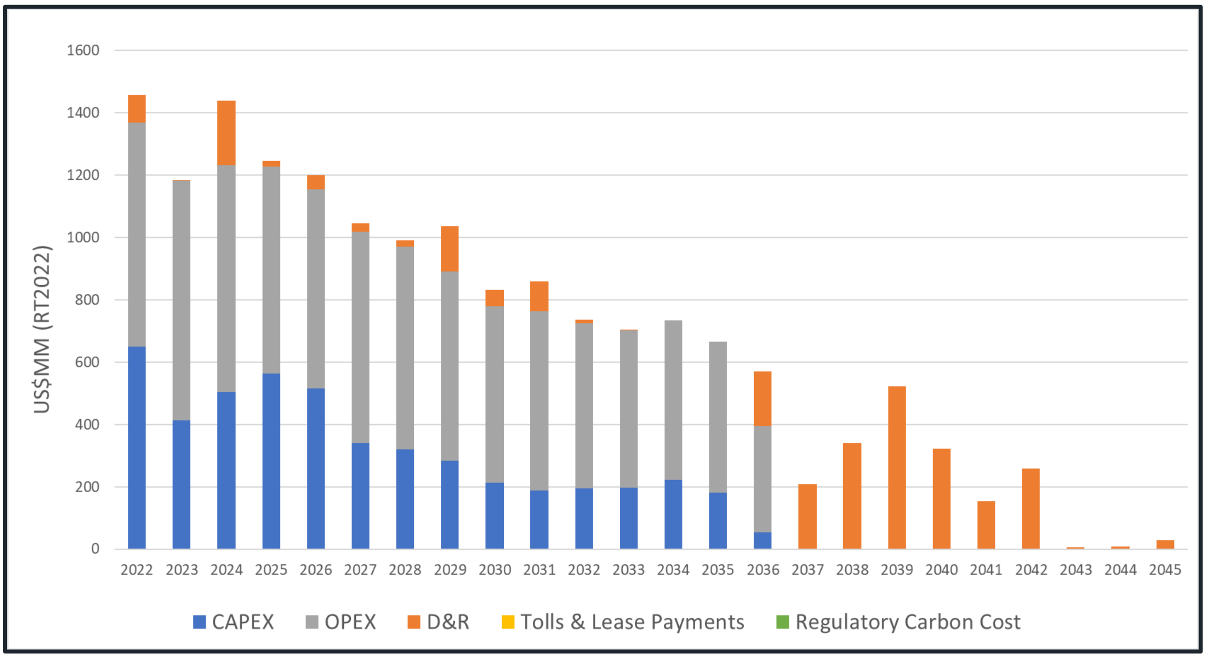


Figure 4.7: 100% NWS Gas Fields Cost Profile



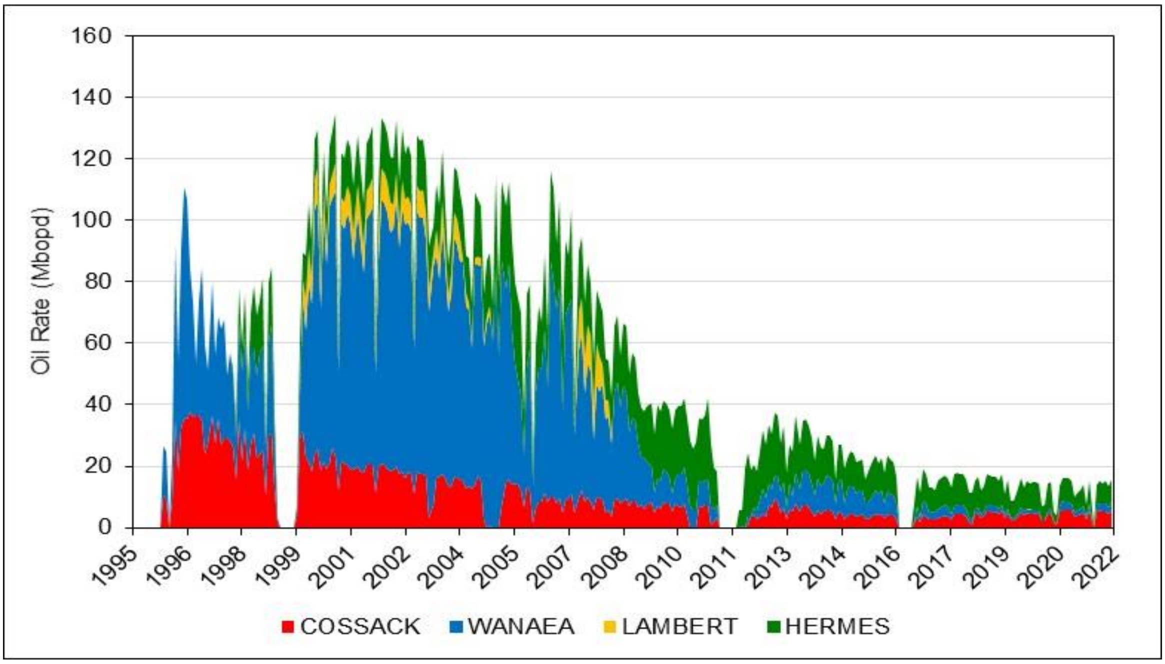
4.2 North West Shelf Oil

The NWS oil fields, located offshore Western Australia, consist of three producing fields (Cossack, Wanaea, and Hermes) and a fourth field, Lambert, which has ceased production (Figure 4.1). Additionally, there are three undeveloped discoveries: Egret, Eaglehawk and West Dixon. Woodside operates the NWS oil fields and holds a 33.33% stake in the joint venture which comprises BHP Petroleum, Chevron, BP, and MIMI.

4.2.1 Field Description and Recoverable Volumes

Oil production began in 1995 from the Cossack and Wanaea Fields (**Figure 4.8**) followed by Hermes and Lambert in 1997 and 1999 respectively. Production gradually ramped up until 2010, after which rates have been in decline. The Lambert Field stopped producing in 2008 after recovering 17.5 MMBbl of oil. The Cossack, Wanaea and Hermes Fields are producing through the Okha FPSO. **Table 4.5** shows a summary of the reservoir properties and the estimated remaining recoverable volumes are shown in **Table 4.6**.

Figure 4.8: NWS Oil Fields Production History



Source: Data from Woodside

Table 4.5: Subsurface Description of Producing NWS Oil Fields

	Cossack Wanaea Lambert Hermes
Initial Pressure (psia)	4,240-4,510
Initial Temperature (deg C)	108-114
Porosity (%)	16.5-18.5
Permeability (mD)	200-800
Fluid Type	Oil

Table 4.6: Estimates of Gross Remaining Technically Recoverable Volumes by Field as of 31 December 2021

Field	Status	Produced		Remaining Recoverable			
				Low Estimate		Best Estimate	
		Oil & Condensate (MMBbl)	Gas (Bscf)	Oil (MMBbl)	Raw Gas (Bscf)	Oil (MMBbl)	Raw Gas (Bscf)
Cossack	Producing	97	13	9	0.1	11	0.6
Wanaea	Producing	270	306	1	0.0	5	0.3
Lambert	Ceased	18	5	0	0.0	0	0.0
Hermes	Producing	118	42	15	0.1	15	0.8

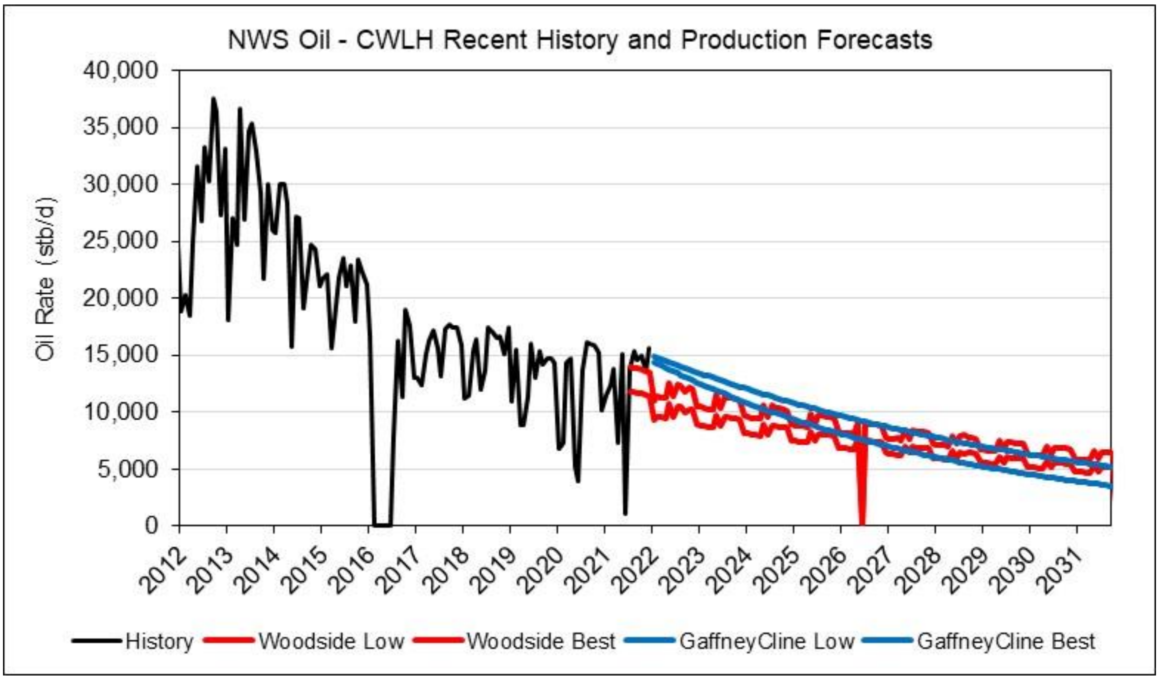
Note: Volumes shown here are remaining technically recoverable volumes with no economic cut-off applied.

4.2.2 Field Development and Production Profiles

GaffneyCline has reviewed Woodside's production forecasts for producing fields by carrying out DCA at the aggregated field level. No future activities are planned for the producing fields.

GaffneyCline's overall NWS oil production forecasts are shown in **Figure 4.9** in comparison to Woodside's. Overall, GaffneyCline's forecasts start at higher initial rates, but have steeper decline rates. Woodside's initial rates are influenced by production rates in the first half of 2021, which are on average lower than in the second half of 2021. The volumes under both GaffneyCline and Woodside's profiles are within tolerance and GaffneyCline has accepted Woodside's forecasts in **Figure 4.9**, which correspond to the recoverable volumes in **Table 4.6**, for reporting Reserves.

Figure 4.9: Comparison of GaffneyCline and Woodside NWS Oil Technical Profiles



4.2.3 Contingent Resources

GaffneyCline has reviewed Woodside's estimates of Contingent Resources using a similar methodology to the NWS Gas review and has found Woodside's estimates to be reasonable. Woodside's Contingent Resources opportunities in NWS Oil and their estimated 2C volumes are reported in **Table 4.7** and **Table 4.8**.

Table 4.7: Gross Contingent Resources for Developed NWS Oil Fields as of 31 December 2021

Field	PRMS Sub-Classification	2C Contingent Resources		Descriptions
		Oil (MMBbl)	Dry Gas (Bscf)	
Cossack	Dev on hold	6.9	0.94	1 infill well
	Dev unclarified	6.4	0.87	1 facility upgrade
	Dev not viable	0.7	0.10	1 well workover
Wanaea	Dev not viable	0.9	1.15	4 well workover, 1 well workover
Lambert	Dev on hold	0.9	0.29	1 well workover
Hermes	Dev on hold	0.2	0.08	1 facility upgrade
	Dev unclarified	7.2	2.82	1 facility upgrade
Totals		**23.2**	**6.24**	

Note: Raw gas CR were calculated using GOR of 138, 1,289, 330 and 395 scf/stb for Cossack, Wanaea, Lambert and Hermes respectively.

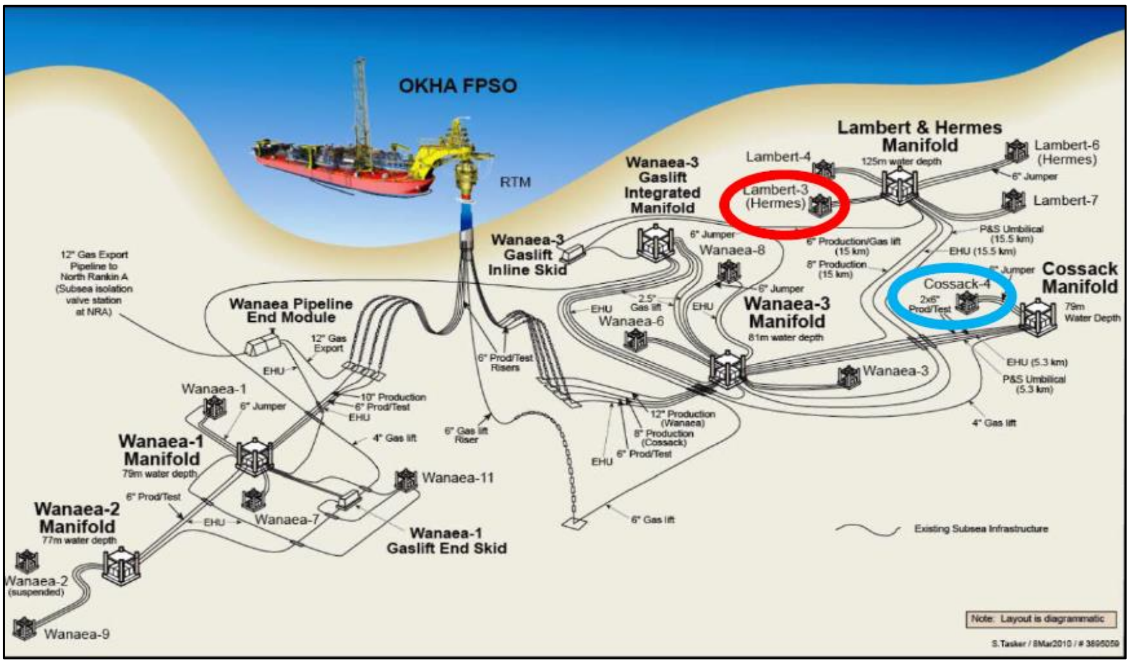
Table 4.8: Gross Contingent Resources for Undeveloped NWS Oil Fields as of 31 December 2021

Field	Development Status	2C Contingent Resources	
		Oil (MMBbl)	Dry Gas (Bscf)
Eaglehawk	Dev not viable	0.3	0.00
Egret	Dev not viable	7.3	6.70
West Dixon	Dev not viable	2.3	0.00
Totals		**9.9**	**6.70**

4.2.4 Facilities and Costing

The NWS Oil fields produce to the Okha FPSO (**Figure 4.10**). The development originally used the Cossack Pioneer FPSO, however this was replaced by the Okha in 2011. The four fields are developed with 13 subsea wells in 80 to 100 m water depth, of which five are in fulltime production and eight are shut in. The Okha processing capacity of 60 Mbopd and 150 Mblpd is greater than current production rates. Okha UWILD (Under Water Inspection In Lieu of Drydocking) was completed in 2021. The subsea infrastructure has experienced integrity issues, however, Woodside's management of change process is used to manage any integrity issues as they arise. Facility lifetime extension projects have been completed.

Figure 4.10: NWS Oil Fields Development



4.2.4.1 *Facilities Operability, Integrity, and Infrastructure*

The NWS oil facilities (OKHA FPSO) have been in service for over 25 years with production outages every five years (2011, 2016, and 2021) for planned dry dock and vessel inspection. As noted above, the subsea infrastructure has experienced reliability issues (primarily in the controls system) which are being addressed in the maintenance and repair program. In 2020, OKHA system reliability, at 86%, fell below targeted levels. The 2021 turnaround work scope should improve this performance.

The OKHA production system allows independent oil export, supported by a gas export pipeline to North Rankin A.

4.2.4.2 *Decommissioning and Restoration (D&R) Planning*

As noted in Section 1.1.4, current operational planning is focused on facilities uptime and integrity, with limited near-term D&R activity. The Operator has, however, developed a phased D&R plan commencing at the end of field life and extending over 8 years thereafter. Recent regulatory focus on prompt D&R planning and execution may accelerate this phasing.

4.2.4.3 *Cost Review*

GaffneyCline has reviewed a detailed (30 line items) cost forecast provided by WEL covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the NWS oil operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline's review focused on consistency (all costs in RT2022 basis and consistent with the activity plan and production profile), and cost levels (checks focusing on OPEX vs. annual production, and D&R estimates). The detailed costs were analyzed and categorised to support economic analysis. GaffneyCline accepted WEL's CAPEX and OPEX cost forecasts as reasonable. D&R cost estimates, however, were materially increased in our review to reflect current D&R scope and the full exploration, appraisal and production well count remaining.

Gross CAPEX for further development activities relating to the NWS oil Reserves case is estimated to be US$80 MM.

4.2.5 GaffneyCline's Production and Cost Valuation Profiles NWS Oil

GaffneyCline's valuation scenario production profile for Woodside's NWS oil assets is given in **Figure 4.11** with the associated real term cost profiles provided in **Figure 4.12**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing fields listed in **Table 4.6**. (The profile comprises field level forecasts from Cossack, Wanaea and Hermes. No production is expected from Lambert. No CR projects have been included).

The regulatory carbon cost assumption for NWS oil is as per Woodside's below baseline assumption of zero for this project.

Figure 4.11: 100% NWS Oil Fields Production Profile

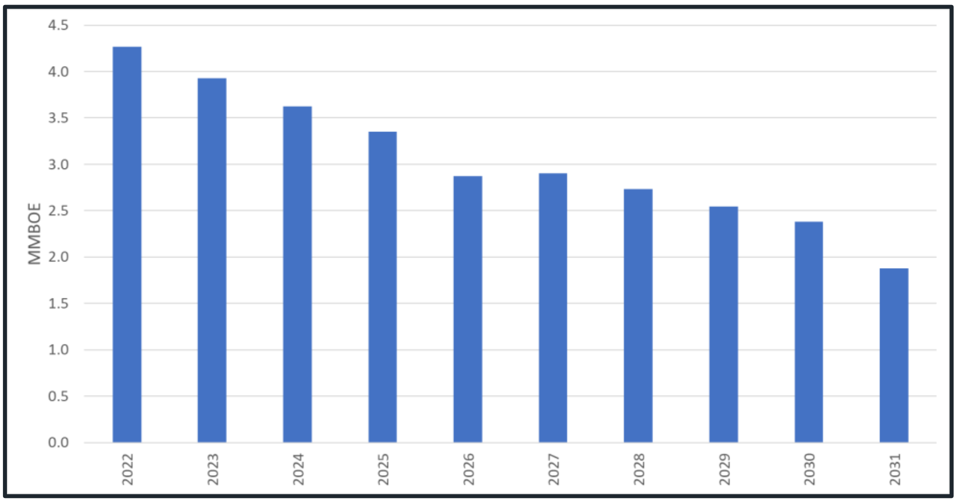
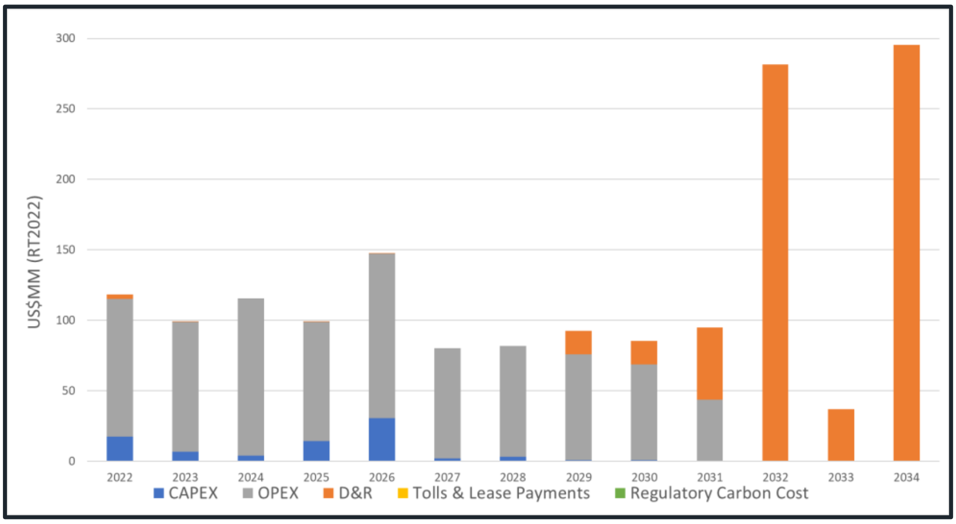


Figure 4.12: 100% NWS Oil Fields Cost Profile

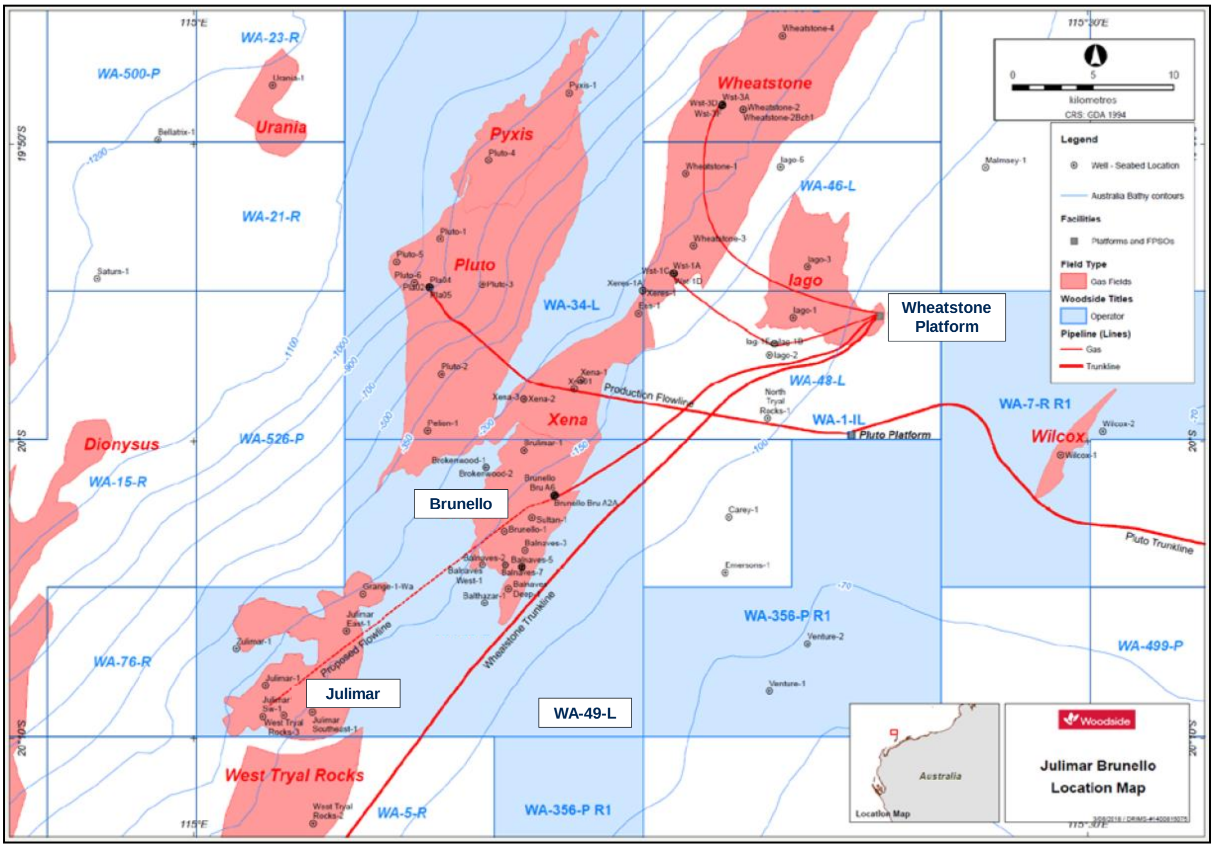


4.3 Wheatstone LNG (Brunello-Julimar)

4.3.1 Field Description

Woodside acquired its 65% interest in the Brunello and Julimar Fields from Apache in 2015. The fields are contained within the WA-49-L permit, located in the Carnarvon Basin, offshore Western Australia and together form the Julimar Development Project (**Figure 4.13**). The Julimar Development Project is a subsea development to supply raw gas and condensate from the fields to the Chevron-operated Wheatstone platform and from there to the Wheatstone Project's onshore LNG trains and domestic gas plant at the Ashburton North Strategic Industrial Area.

Figure 4.13: WA-49-L Location Map



Source: modified from Woodside

The Julimar Field was discovered in 2007 with the drilling of the Julimar-1 well which encountered gas bearing fluvial channel sands of the Triassic Mungaroo Formation. The field consists of NE-SW trending stacked Mungaroo fluvial channel belts which are often isolated via intra-formational seals and dipping shallowly to the north. In total there is approximately 600 m of accumulation thickness and the field is bounded by major faults to the east and west and stratigraphically trapped to the north. Multiple pressure regimes, fluid compositions, gas-water contacts and residual gas columns have been identified during appraisal drilling. Field development is heavily reliant on seismic data to define geobody extent and hydrocarbon contacts in unpenetrated sands. Woodside has completed the JDP2 drilling program and commissioning began in early December 2021.

The Brunello Field was also discovered in 2007 with the drilling of the Brunello-1/ST1 well approximately 17 km northeast of the Julimar-1 discovery well. Brunello-1/ST1 encountered 37 m of net pay in the Mungaroo. The field is located on the Brunello Horst and is composed of a number of gently dipping Triassic Mungaroo sandstones that sub-crop the regional Base Cretaceous Unconformity. The structure is low relief with a maximum gas column of ~40 m, bound to the south by a sub-crop boundary and to the east and west by faults. Communication between reservoirs is uncertain and pre-production depletion from neighbouring fields suggests complex communication pathways.

The Brunello Field is currently being produced via five wells. First gas was achieved in September 2017. JDP2 drilling which will see the initial development of the Julimar Field was completed in 4Q 2020 with first gas planned for late 2021.

GaffneyCline has made probabilistic (Monte Carlo) estimates of the GIIP for the Julimar and Brunello individual reservoirs for both fields (**Table 4.9**). Inputs allowed for uncertainties in mapping, petrophysical properties and fluid contacts.

Table 4.9: Estimates of GIIP for the Brunello and Julimar Fields

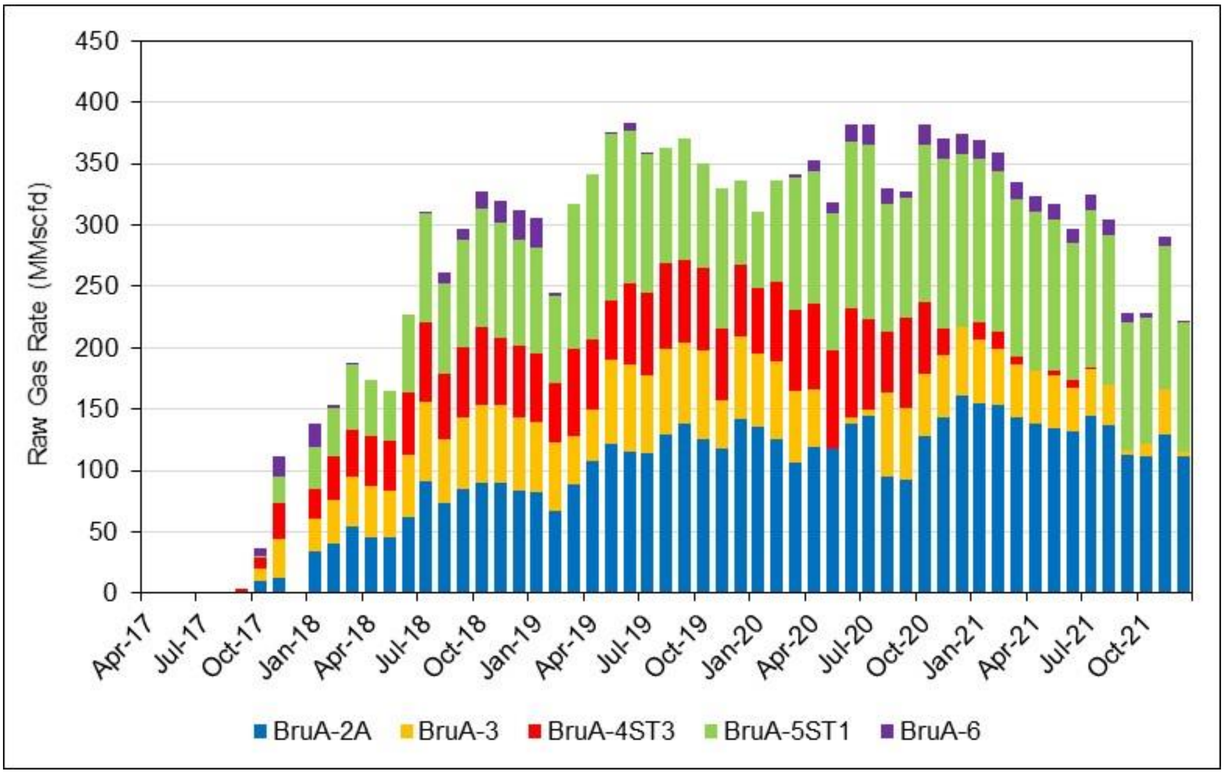
Field	Reservoir / Sand	GIIP (on and off Block) (Bscf)	
		Low Estimate	Best Estimate
Brunello	B6 (TR28.0)	348	448
	B7 (TR27.3)	86	134
	B8 / B9 (TR27.0)	357	449
	B10 (TR26.0)	412	547
	B49 (TR21.3)	47	82
	B50 (TR 21.3)	181	271
	B60 (TR 20.6)	149	216
	Arithmetic Total	**1,580**	**2,146**
Julimar	J12	25	53
	J14	68	89
	J16	47	85
	J25	167	285
	J45	53	113
	J50	111	156
	J54	93	123
	J56	217	285
	J65	63	104
	J67	107	144
	J75	14	26
	J85	59	114
	Arithmetic Total	**1,025**	**1,578**
Arithmetic Total All		**2,604**	**3,724**

Gas production from Brunello commenced on 18 September 2017 from well BruA-4ST3, sand B6. The remaining four wells; BruA-2A (sand B8), BruA-3 (sand B7), BruA-5ST1 (sand B10) and BruA-6 (sand B50) were put on production the following month. Production from BruA-6 has been constrained (<20 MMscfd) due to higher than anticipated mercury levels in the deeper B50 reservoir. Cumulative raw gas production as of 31 December 2021 is 454 Bscf (**Table 4.10** and **Figure 4.14**). BruA-2A and BruA-5ST1 are the two main producers and have contributed 67% of total production thus far.

Table 4.10: Brunello Historical Gas Production as of 31 December 2021

Well	Reservoir	Cumulative Produced Raw Gas (Bscf)
BruA-2A	B8/B9 (TR27.0)	161
BruA-3	B7 (TR27.3)	69
BruA-4ST3	B6 (TR28.0)	64
BruA-5ST1	B10 (TR26.0)	148
BruA-6	B50	12
Field		**454**

Figure 4.14: Brunello Historical Production as of 31 December 2021



BruA-4ST3 started to produce water in September 2020 and has been shut in since June 2021. BruA-2A experienced early formation water breakthrough in June 2021. The Brunello deep reservoirs (B50 and B60) have high mercury content, and currently B50 is only developed by the BruA-6 well, from which production is restricted.

In BruA-3 (Sand B7) the observed pressure is declining faster than expected, and in BruA-5ST1 (Sand B10) the pressure decline is less than previous forecast. Communication between the reservoir units is uncertain, pre-production depletion from neighbouring fields has suggested complex communication pathways with competitive drainage of Pluto/Xena fields. The B6 and B7 sands were originally thought to be connected, but production data shows communication between them to be negligible.

Julimar commenced production in the first week of December 2021 and total cumulative gas as of 31 December 2021 is 2.7 Bscf.

4.3.2 Field Development and Production Forecasts

Gas and condensate recovery factors have been estimated for all sands, taking into account historical performance. **Table 4.11** shows the recovery factor for gas and condensate assigned to the different units, used for the probabilistic calculation of Low and Best EUR volumes per reservoir. The resulting average raw gas and condensate EURs based on Monte Carlo probabilistic and deterministic methods are presented in **Table 4.12**.

Table 4.11: Recovery Factor Ranges Used for Resource Estimates

Field	Reservoir / Sand	Gas RF (%)		Condensate RF (%)	
		Low	Best	Low	Best
Brunello	B6	18%	15%	17%	14%
	B7	79%	80%	73%	76%
	B8/B9	47%	49%	37%	41%
	B10	82%	83%	65%	69%
	B50	30%	43%	26%	38%
	B60	18%	29%	16%	26%
Julimar	J12	67%	73%	61%	68%
	J14	54%	71%	49%	67%
	J16	46%	62%	41%	58%
	J25	32%	50%	27%	44%
	J45	20%	53%	17%	46%
	J50	72%	77%	64%	71%
	J54	58%	60%	52%	56%
	J56	78%	80%	70%	75%
	J65 West	56%	59%	50%	55%
	J67	63%	69%	56%	64%
	J85	23%	55%	20%	48%

Table 4.12: Estimates of Ultimate Recovery for the Brunello and Julimar Fields

Field	Reservoir / Sand	Ultimate Recovery (on and off block)			
		Raw Gas (Bscf)		Condensate (MMBbl)	
		Low Estimate	Best Estimate	Low Estimate	Best Estimate
Brunello	B6 (TR28.0)	64	65	0.8	0.8
	B7 (TR27.3)	67	107	0.9	1.5
	B8 / B9 (TR27.0)	198	254	5.8	8.9
	B10 (TR26.0)	340	453	6.8	9.6
	B50 (TR 21.3)	61	112	0.8	1.6
	B60 (TR 20.6)	31	61	0.4	0.9
	Arithmetic Total	**761**	**1,053**	**15.5**	**23.3**
Julimar	J12	18	39	0.2	0.5
	J14	40	62	0.5	0.8
	J16	25	52	0.3	0.7
	J25	62	142	0.9	2.3
	J50	82	119	1.0	1.6
	J54	55	74	0.6	1.0
	J56	172	228	1.9	3.0
	J65	37	62	0.4	0.8
	J67	70	99	0.8	1.4
	J85	17	58	0.3	1.0
	Arithmetic Total	**576**	**934**	**6.9**	**13.1**
Arithmetic Total All		**1,337**	**1,988**	**22.4**	**36.4**

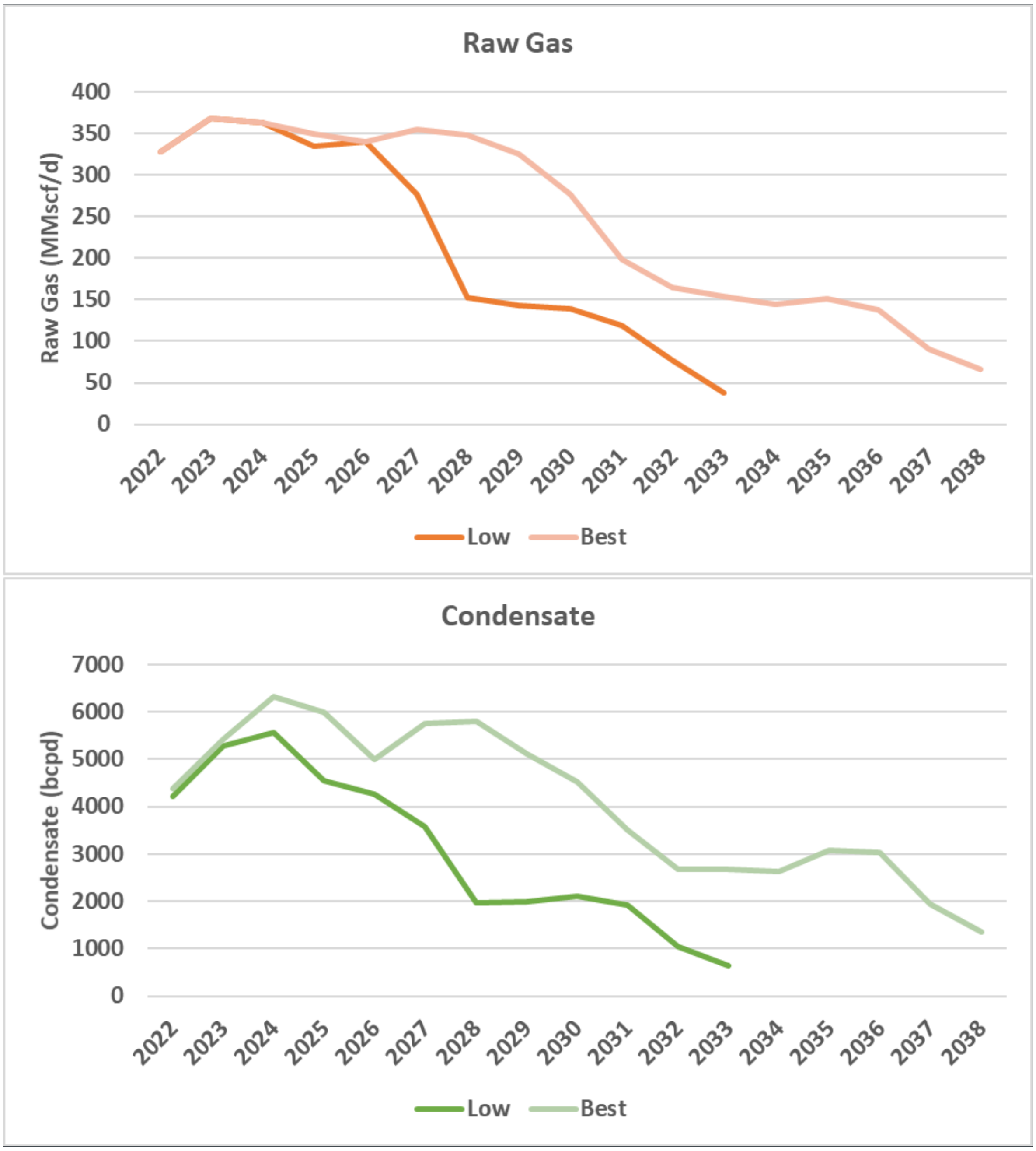
IPM-RESOLVE models have been prepared for supporting the production forecasting, by providing a sense of plateau lengths, Phase 3-4 well schedules, compression timings and decline rates. The final low and best estimate production profiles are generated by scaling Woodside's raw gas and condensate profiles to match GaffneyCline's low and best estimates of EUR. GaffneyCline's Low estimate EUR utilises the average between an arithmetic addition and probabilistic addition of the individual Brunello and Julimar reservoirs to account for possible dependency criteria. Reservoirs J45 and B49 have been excluded based on the recent Julimar wells and Woodside development strategy. The summary of remaining recoverable volumes is provided in **Table 4.13** and **Figure 4.15** shows GaffneyCline's low and best raw gas and condensate production profiles for the Woodside Phase 1-4 development scenarios.

Table 4.13: Woodside Gross Remaining Recoverable Raw Gas and Condensate

Commodity	Low Estimate	Best Estimate
Raw Gas (Bscf)	978	1,526
Condensate (MMBbl)	13.6	25.4

Notes:
1. Volumes shown here are remaining technically recoverable volumes with no economic cut-off applied.
2. Gas volumes reported in this table are "wellhead" or "wet" volumes. Adjustments to sales gas volumes are accounted for in the economic evaluation for Reserves reporting.

Figure 4.15: GaffneyCline Production Profiles Raw Gas and Condensate



4.3.3 Facilities and Costing

The Wheatstone LNG fields are developed as a combined subsea tie-back development to the Chevron-operated Wheatstone platform. The project is a phased development and is summarised in **Table 4.14**.

Table 4.14: Brunello and Julimar Development Project Summary

Development Phase	Notional Timing	Field	Development
JDP1	Ready for Start-up (RFSU) 2017 (complete)	Brunello	5 wells, Brunello manifold, two flowlines to Wheatstone Platform
Compression Stage 1	Installed, commissioned May 2022	Julimar/Brunello	Compression
JDP2	Commissioned November 2021, online December 2021	Julimar	4 well subsea tie-back
JDP3	October 2025	Julimar	~4 well subsea tie-back
JDP4	April 2028	Julimar/Brunello	~2 well infill wells in existing manifolds plus mercury removal unit
Compression Stage 2	2031	Julimar/Brunello	Compression
Compression Stage 3	2037	Julimar/Brunello	Compression

The development of Julimar and Brunello consists of subsea gas production wells drilled from three main drill centres. Each well is or is planned to be tied into a subsea manifold located at the drill centres. The manifolds will be connected using intra-field flowlines and connected to the Wheatstone Platform by twin raw gas production lines.

In the initial phase, which came on stream in 2017, the Brunello field was developed with five producing wells tied back 22 km to Wheatstone by two 18” flowlines. In a second development phase (currently in progress), the gathering system will be extended a further 22 km to tie in the Julimar field, and four Julimar development wells drilled. Phase 2 production commenced in December 2021. Subsequent phases will add up to six further Julimar development wells. The combined production is processed at the Wheatstone platform, where some 20% of capacity (or 388 MMscfd) is allocated to the Brunello-Julimar development. Within this overall constraint, production from the BruA-6 well must be limited to 20 MMscfd due to high mercury levels in this well. The upstream development is illustrated in **Figure 4.16.**

The Wheatstone platform, pipeline, and onshore LNG plant are operated by Chevron, with Woodside holding a 13% WI. After separation on the platform, gas and condensate are dehydrated and compressed for transport 225 km to the onshore LNG plant, together with gas and condensate from other Chevron-operated fields. The LNG plant is a two-train 10.4 MTPA liquefaction plant, which can also supply up to 200 TJ/day of domestic gas.

Figure 4.16: Brunello and Julimar Development Concept

Source: Woodside

4.3.3.1 Facilities Operability, Integrity, and Infrastructure

As a subsea tieback to the Wheatstone development, the reliability of the Julimar-Brunello development is largely dependent on the uptime of the host platform facilities and the downstream Wheatstone LNG plant. Brunello has been in production since late 2017. Apart from Wheatstone-related production outages (e.g. LNG train shut downs), Brunello has experienced occasional production curtailment related to miscellaneous subsea equipment failures and high mercury levels in the produced gas of one well.

4.3.3.2 Decommissioning and Restoration (D&R) Planning

Woodside's D&R plan commences in the final year of Julimar-Brunello production and extends over six years. This is a reasonable D&R project phasing and is accepted by GaffneyCline. It is likely that Julimar-Brunello D&R will be carried out as a part of the larger Wheatstone decommissioning, so the actual timing may depend on the Wheatstone field performance.

4.3.3.3 Cost Review

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the offshore Julimar-Brunello and onshore Wheatstone operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline's review focused on consistency (all costs in RT2022 basis and consistent with the activity plan and production profile), and cost levels (checks focusing on OPEX vs. annual production, and D&R estimates). The detailed costs were analyzed and categorised to support economic analysis. GaffneyCline has accepted Woodside's detailed cost forecasts as reasonable. Gross CAPEX for further development activities relating to the Brunello and Julimar Reserves case is estimated to be US$989 MM

4.3.4 Resources Estimates

Reserves are attributed to development of Brunello and Julimar (Section 4.3.2). Contingent Resources (Development Unclarified) are attributed for the re-perforation of a well (BruA-6) in a shallow reservoir (B49) in Brunello (**Table 4.15**). Further evaluation is required for feasibility due to mercury contaminants.

Table 4.15: Contingent Resources for Brunello as of 31 December 2021

Field	Gross 2C Contingent Resources	
	Dry Gas (Bscf)	Condensate (MMBbl)
Brunello (B49)	23.0	0.3

4.3.5 GaffneyCline's Production and Cost Valuation Profiles Brunello-Julimar

GaffneyCline's valuation scenario production profile for Woodside's Brunello-Julimar assets is given in **Figure 4.17** with the associated real term cost profiles provided in **Figure 4.18**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing fields/reservoirs listed in **Table 4.12**.

The regulatory carbon cost assumption for Brunello-Julimar is as per estimated carbon emissions that are above Woodside's baseline assumption for this project.

Figure 4.17: 100% Brunello-Julimar Production Profile

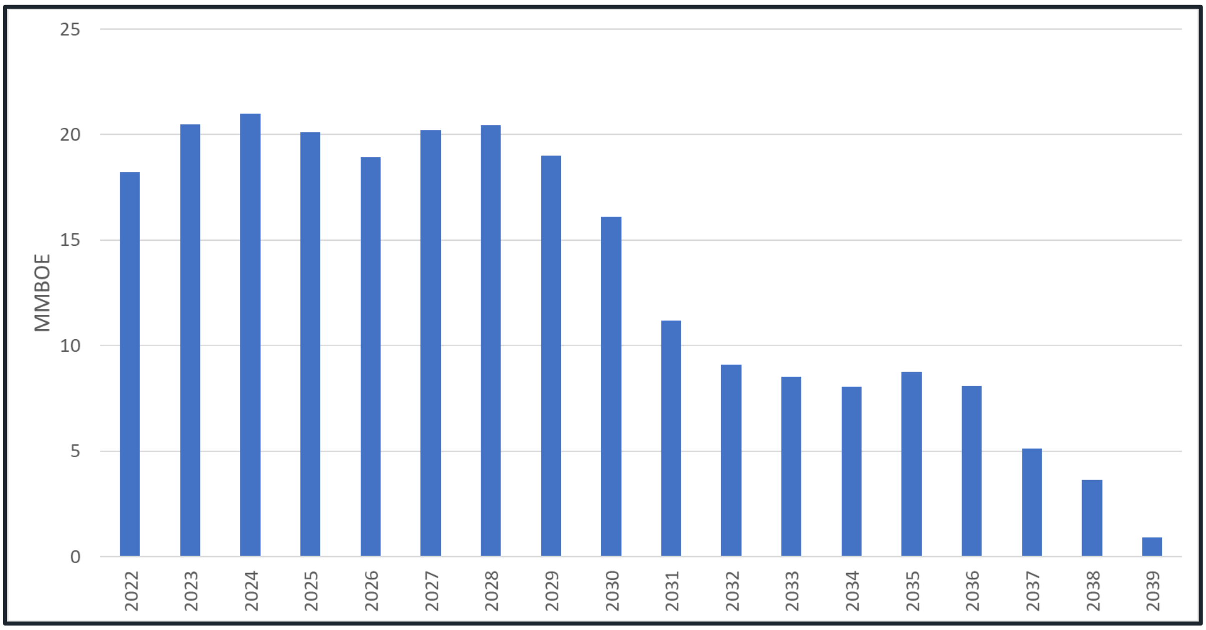
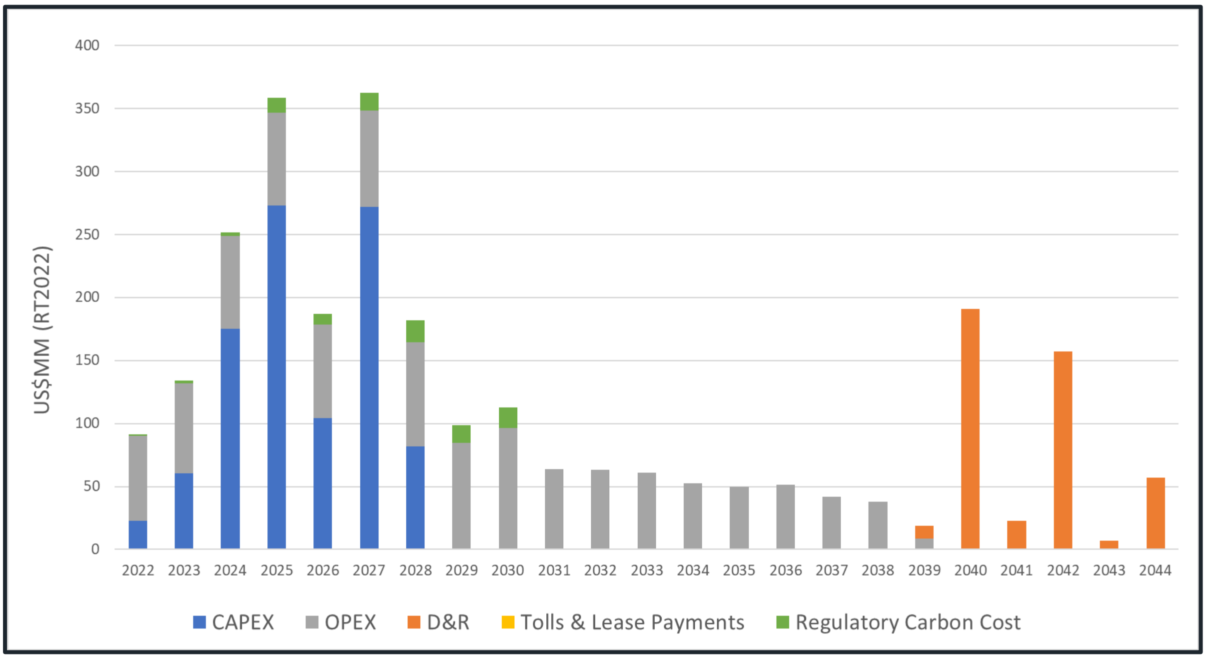


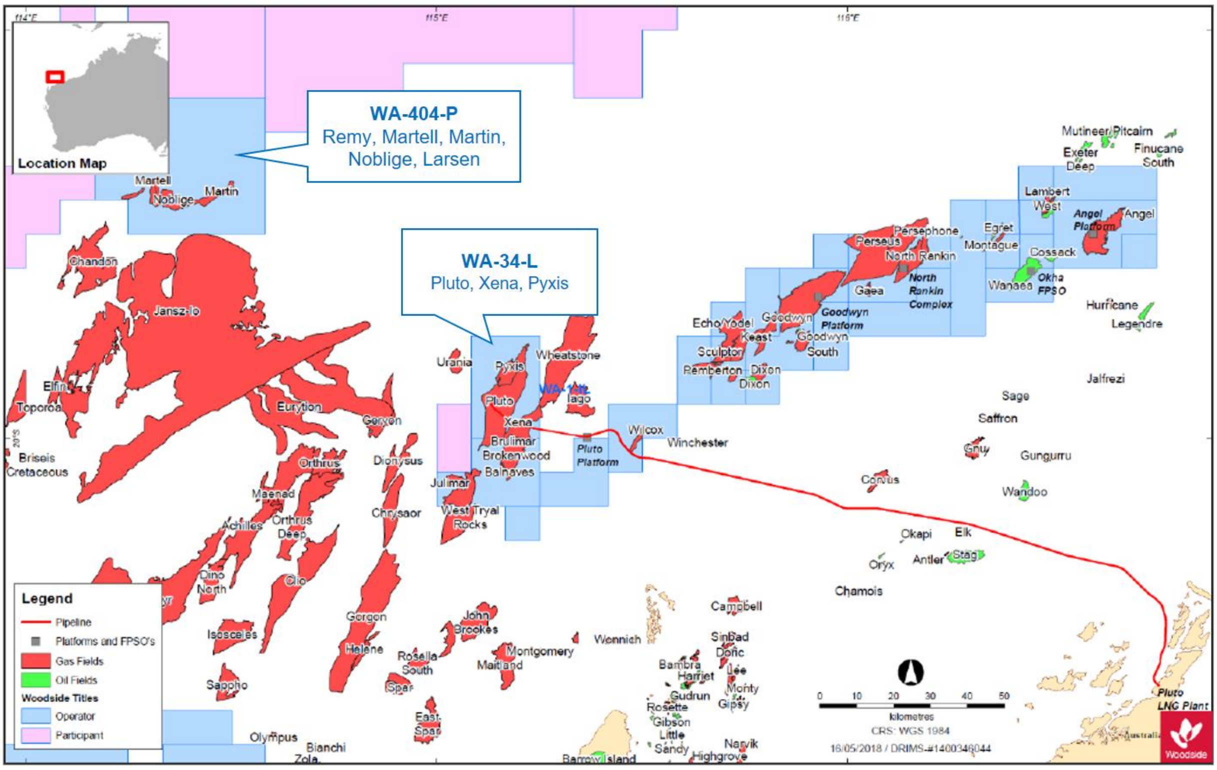
Figure 4.18: 100% Brunello- Julimar Cost Profile



4.4 Pluto LNG

The Pluto LNG asset encompasses the Pluto, Xena and Pyxis Fields in the WA-34-L permit, in which Woodside has a 90% working interest, located offshore Western Australia approximately 190 km northwest of Karratha (**Figure 4.19**). The Pluto Field is in 850 m water depth, while Xena is in 200 m and Pyxis is in 960 m. Pluto was discovered in 2005, within the exploration permit WA-350-P, which was awarded to Woodside in 2003. This was followed by the discovery of Xena (well Xena-1ST1) in 2006. Five Pluto appraisal wells and two Xena appraisal wells were subsequently drilled. The main reservoir in Pyxis was penetrated by the Pluto-4 appraisal well in 2006 and was appraised by Pyxis-1 well in 2015. The production licence WA-34-L was granted in 2007 and production of gas and condensate started from Pluto and Xena in 2012. Pyxis came on stream in November 2021.

Figure 4.19: Greater Pluto Location Map



Source: Woodside

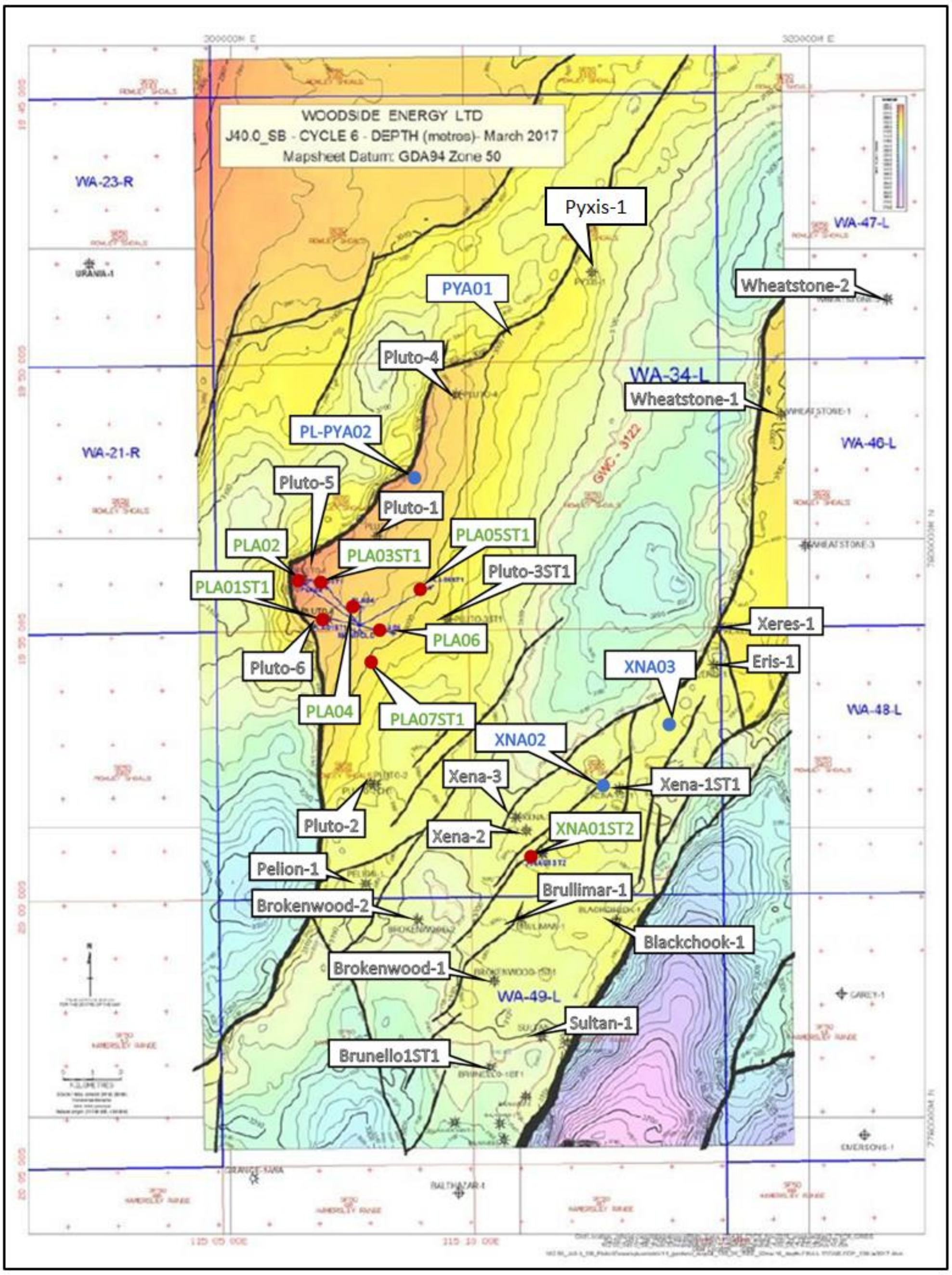
4.4.1 Field Description

The Pluto-Xena-Pyxis group of fields is located in the Northern Carnarvon Basin, up on the northern flank of the Dampier Sub-basin as it transitions into the Rankin Platform. Nearby major fields include the Brunello-Julimar Fields to the south, Wheatstone Fields to the northeast, and Jansz-Io further to the west.

The reservoirs of the Pluto and Xena Fields are Late Triassic, fluvial deposits of the Mungaroo Formation, and the overlying Late Triassic, estuarine deposits of the Brigadier Formation. The Mungaroo reservoirs are generally good quality, with approximately 25% porosity and multi-Darcy permeability, with slightly less better sandstone quality in the Brigadier Formation. The gas bearing reservoir in the Pyxis Field is the J40, middle-shoreface shallow water sandstone of the Late Jurassic (Oxfordian) Eliassen Formation. The reservoir has excellent quality, with average porosity approaching 30% and 2.5 mD average permeability. The top of the reservoir is encountered at a depth of around 3,000 mss.

The Pluto structure is an easterly tilted fault block, with major bounding faults as its western, north-western and northern margins and dip closure to the south and east. The Xena structure is a north-south trending horst block with dip closure to the south and on trend with Wheatstone Field to the north-east. The Pyxis accumulation is a combination of structural-stratigraphic trap, with low relief dip closing the eastern and northern side, faults closing its western side, and a pinch-out on its southern side. A structure depth map of the J40 formation in **Figure 4.20** shows the location of the wells.

Figure 4.20: Structural Depth Map with Locations of Pluto, Xena and Pyxis Wells



Source: Woodside

4.4.2 Field Development and Production Forecasts

As of 31 December 2021, the greater Pluto area has been developed by eight subsea Pluto wells, including the Pluto north infill well PL-PYA02, which came online in November 2021. The Pluto/Xena gas fields have been partially developed with seven subsea wells in Pluto and one subsea well in Xena. All wells are still on production except for one well that watered-out. Pluto well PLA03 is unlikely to produce in the future, following water breakthrough in 2014. The Xena field is under development by a single well XNA01. Similarly, the Pyxis Field is under development by a single development well PYA01, which came online in November 2021. By 31 December 2021 Pluto-Xena had produced 2,730 Bscf of dry gas and 10.6 MMBbl of condensate, and Pyxis had produced 3.4 Bscf of gas.

Future development will consist of drilling two additional wells: one well in Xena (XNA02), to come online in 2023, and a Pluto infill well (PLA08) that is not yet sanctioned and will come online in 2024. These wells will all be tied back to the existing Pluto/Xena development.

On the facility side, the Pluto water handling unit (PWH) on the Pluto A platform is expected to come online July 2022 with a design capacity of 22,000 bwpd. This is far higher than the existing capacity of 330 bwpd and this will greatly increase the flexibility to continue to flow wells that have experienced formation water breakthrough.

Woodside generates production forecasts from an ensemble of history-matched dynamic models, supported by a new 4D seismic survey that was acquired in 2020.

GaffneyCline estimated recoverable volumes of raw gas by multiplying the GIIP estimates with gas recovery factors derived from sensitivities run on the dynamic simulation model. GaffneyCline then compared the recoverable volumes and forecasts from Woodside and observed that they were within audit tolerance of 10%, and therefore GaffneyCline accepts the forecasts from Woodside.

The production profile used by GaffneyCline for evaluation reflects ullage availability, venture-agreed allocated liquefaction capacity and estimated field deliverability over time. Both the low estimate and best estimate production forecasts show gas rates varying between 950 and 1,050 MMscfd from 2022 to 2025 inclusive before declining.

The Pluto production profies are not presented herein due to the sensitive nature of the information. **Table 4.16** lists the remaining recoverable volumes.

Table 4.16: Pluto LNG Remaining Technically Recoverable Volumes as of 31 December 2021

Field	Low		Best	
	Raw Gas (Tscf)	Condensate (MMBbl)	Raw Gas (Tscf)	Condensate (MMBbl)
Pluto/Xena/Pyxis	1.8	22	2.3	27

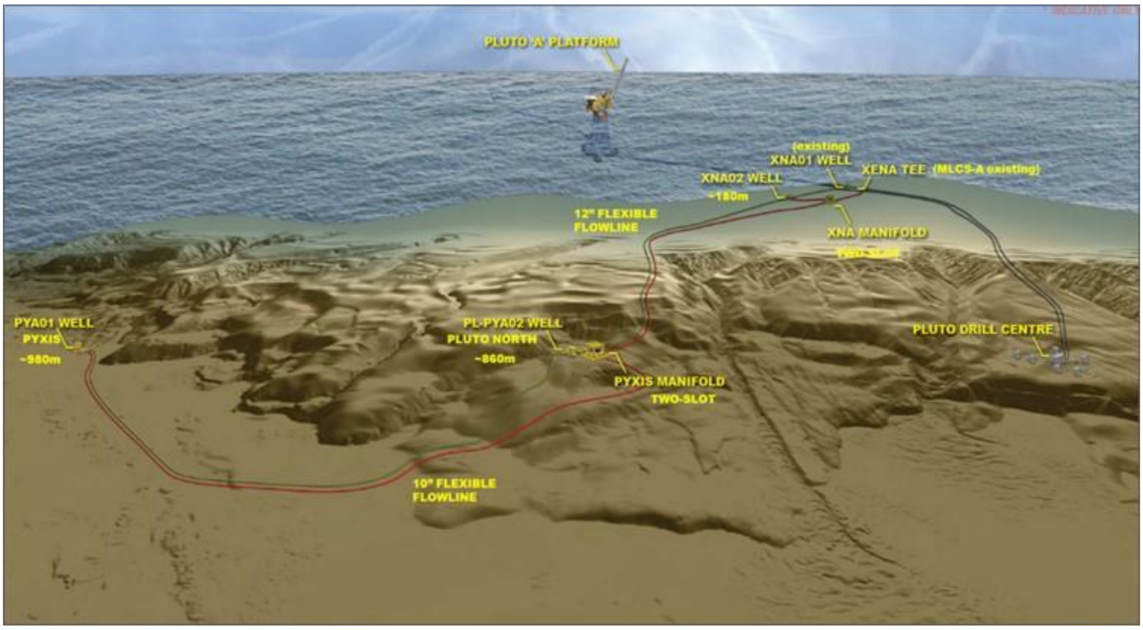
Note: Volumes shown here are remaining technically recoverable volumes with no economic cut-off applied.

4.4.3 Facilities and Costing

The subsea wells of Pluto are tied back 27 km to the shallow water (85 m), minimum facilities, Pluto A platform (unmanned) where water handling and well control facilities are located. The single well Xena Field development also ties into this subsea system. From Pluto A, full reservoir production flows to shore in a 36" x 180 km trunk line to the Pluto LNG plant. The Pluto development wells are large-bore, high-capacity wells which, together the Xena well, can supply 900 MMscfd to Pluto LNG Train 1. No compression is currently installed, although the Pluto FDP recommends onshore depletion compression could be installed upstream of the LNG plant, if justified. The Pluto development is shown in **Figure 4.21**.

The Pluto LNG project, located some 5 km from the Karratha Gas Plant, currently consists of a single train, 5 MTPA, liquefaction facility together with up to 40 TJ/day of domestic gas supply consisting of 25 TJ/day from Pluto and 15 TJ/day from LNG trucking. Under the Scarborough field development, an additional train will be added to the Pluto LNG (see section 4.5 below).

Figure 4.21: Pluto LNG Development Scheme



Source: Woodside

4.4.3.1 *Facilities Operability, Integrity, and Infrastructure*

The Pluto offshore facilities and the onshore LNG plant have been in service since end 2012, with one full shutdown apparent at the end of 2019 for some 5 weeks and shorter shutdown/turnarounds (~2 week) late 2013 and 2015. This level of planned shutdown interval is normal for a facility of this nature. Facilities reliability was recorded at 97.2% in 2020.

The Pluto LNG facility provides gas sales access to the world LNG market, and is also linked to the Western Australian domestic market via the Dampier to Bunbury natural gas pipeline. Pluto LNG is located next to, and is interconnected with, the KGP, allowing some degree of capacity sharing between the two liquefaction facilities. The Pluto LNG site has expansion space available for additional train(s), with Train 2 currently under construction to support the Scarborough development.

4.4.3.2 Decommissioning and Restoration (D&R) Planning

Woodside plans to commence D&R planning 3 to 4 years prior to the forecast end of field life. D&R expenditure extends over 9 years (upstream) to 13 years (downstream), realistic phasing for a D&R project of this scale.

4.4.3.3 Cost Review

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering CAPEX, OPEX, and D&R costs for the Pluto offshore and onshore operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed cost forecasts as reasonable.

Gross CAPEX for further development activities relating to the Pluto Reserves case is estimated to be US$1,300 MM.

4.4.4 Resources Estimates

Reserves attributed to Pluto, Xena and Pyxis assume a minimum trunkline turn-down of 250 MMscfd.

Contingent Resources are attributed for incremental volumes estimated to be recoverable by reduction the trunkline turn-down rate from 250 MMscfd to 100 MMscfd (Development Pending) and for four infill wells (Development Unclarified) (**Table 4.17**).

Table 4.17: Gross Greater Pluto Contingent Resources as of 31 December 2021

Project	Gas (Bscf)	Condensate (MMBbl)	Development Status
Tail gas to 100 MMscfd	59	0.7	Pending
TR30, TR27 and Xena TR34 Infill wells	198	2.3	Unclarified
Pluto TR27.2 Channel Infill well	59	0.7	Unclarified
Total	**316**	**3.7**	

4.4.5 GaffneyCline's Production and Cost Valuation Profiles Pluto

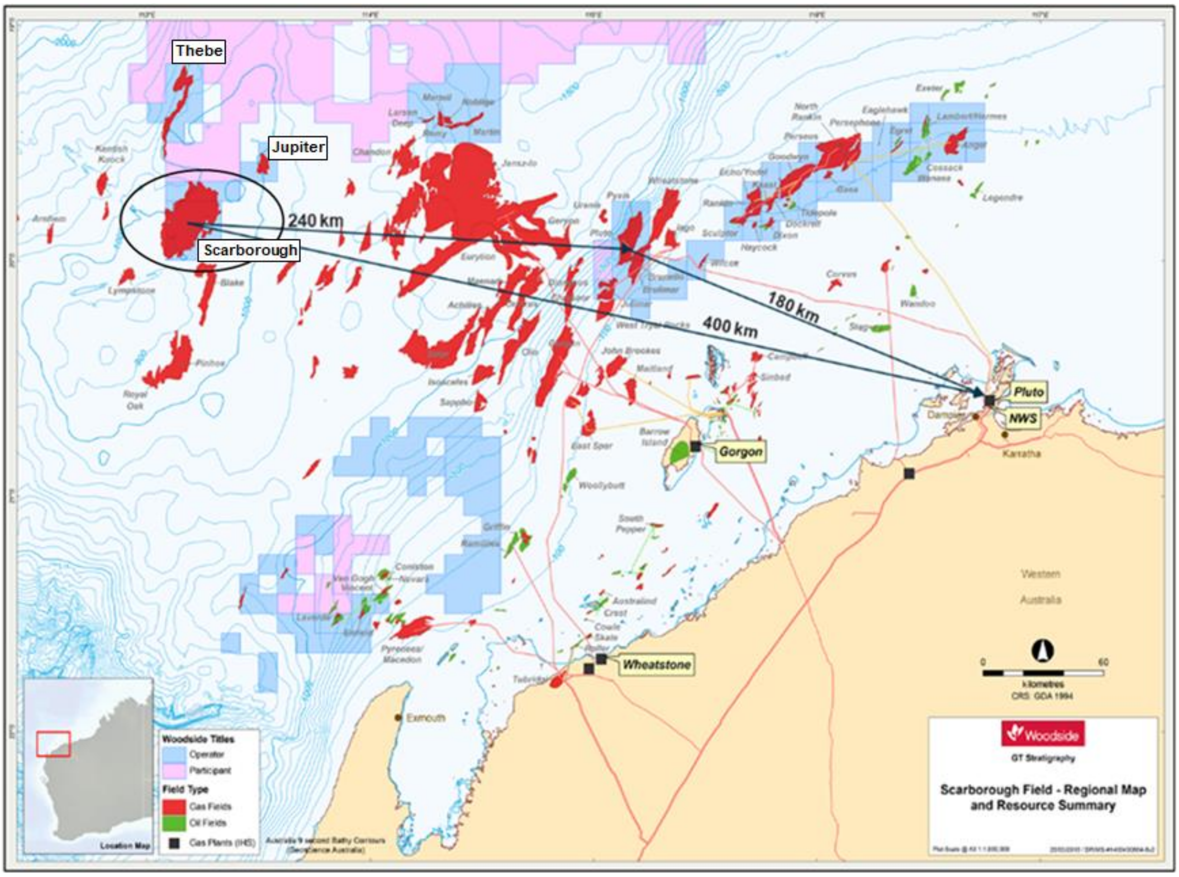
GaffneyCline generates production profiles and associated cost profiles as discussed in earlier sections for KPMG valuation scenario inputs. Full life of project year on year Pluto production profiles are not presented herein due to the commercially sensitive nature of the information. The basis of the inputs to the profiles are however discussed in the preceding sections.

The regulatory carbon cost assumption for the Pluto Asset is as per Woodside's above baseline assumption for this project.

4.5 Scarborough LNG

Woodside and BHP Petroleum have interests in the Scarborough Field, situated predominantly in leases WA-61-L (previously WA-1-R) and WA-62-L (previously WA-62-R) approximately 375 km from Karratha in water depth of ~1,400 m (**Figure 4.22**), and in the two satellite fields Jupiter and Thebe. In February 2020 an agreement was reached between Woodside and BHP Petroleum to align their participating interests across the two titles, resulting in Woodside holding a 73.5% interest and BHP Petroleum holding the remaining 26.5% interest in each.

Figure 4.22: Scarborough, Jupiter and Thebe Field Location Map



Source: Woodside

4.5.1 Field Description

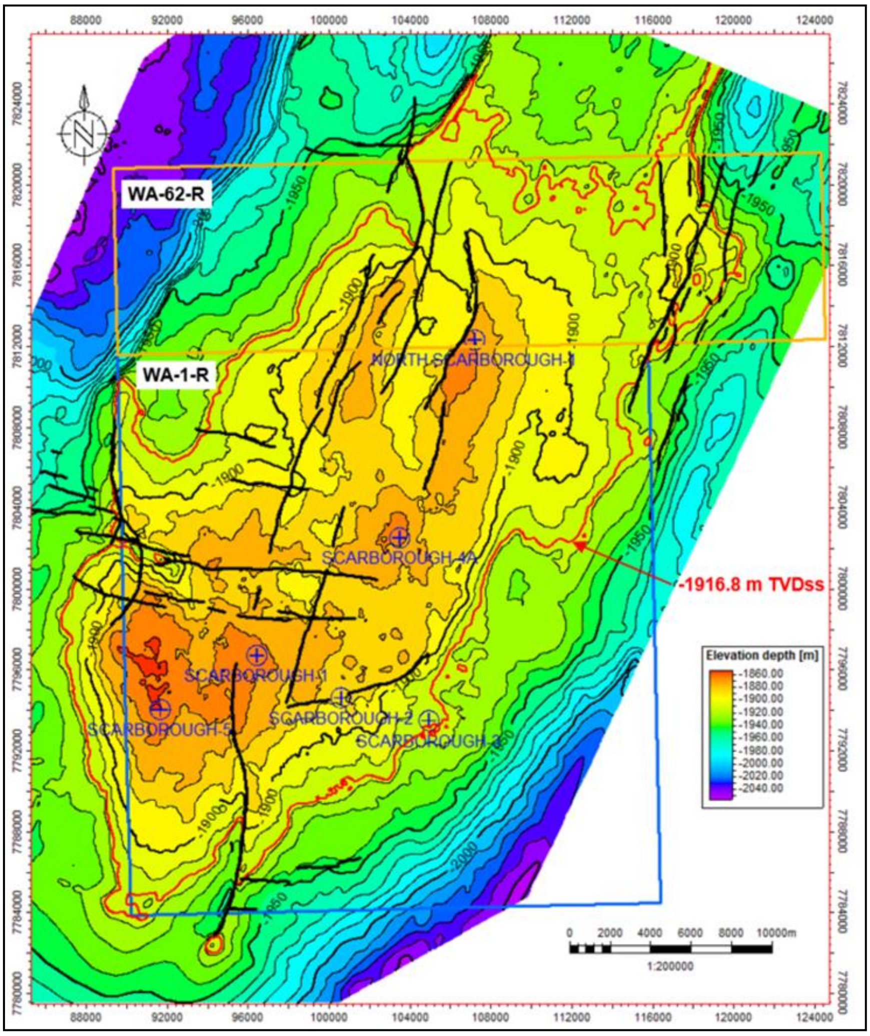
The field is formed of a four-way dip closed NNE trending anticline and was discovered in 1979 with the drilling of the Scarborough-1 exploration well, which intersected high quality gas bearing sandstones with a gross column of approximately 110 m. An appraisal well, Scarborough-2 was drilled in 1996 before the first 3D seismic survey covering the field was shot in 2004. Four subsequent appraisal wells were drilled on Scarborough between 2004 and 2021. Field appraisal confirmed a field wide GWC and a relatively uniform gas composition.

The reservoir interval is formed of the Early Cretaceous Lower Barrow Group. The provenance of the Scarborough Field reservoirs is the Australian craton with sediments transported via the prograding Barrow Group Delta system to a shelf break located approximately 50 km to the south of the Scarborough Field.

The reservoir sands consist of a three-tiered, basin floor turbidite fan. The Lower Fan unit (K17.04, K17.02, K16.9, K16.7 and K16.4) is a high-quality sand with high NTG and contains the majority of the GIIP. It is formed of amalgamated turbidite, channel and lobate sandstone deposition and represents the beginning of the waning of the Lower Barrow Group system. The overlying Middle (K17.1, K17.06) and Upper Fans (K17.3, K17.2) are more localised and discrete with lower NTG and represent the continued waning and backstepping of the depositional system.

Cores from Scarborough wells show poorly consolidated, fine to medium grained sands with minor clay components. The Lower Fan reservoir sands have porosity of 23 to 40% and permeability of 0.65 to 9 D. The Upper and Middle Fan sands have core porosity of 23 to 37% and permeability of 0.5 to 7.5 D. **Figure 4.23** shows a depth structure map of the K17.06 reservoir interval.

Figure 4.23: GaffneyCline Depth Structure Map of K17.06



GaffneyCline generated surface attributes for the reservoir units UF-K17.3, K17.2; MF-K17.1, K17.06 and LF-K17.04, K17.02, K16.9, K16.7, K16.4, which were utilised to evaluate uncertainty in GRV of the basin floor sands. Areal polygons were combined with the depth surfaces to estimate overall ranges of uncertainty in GRV. Reservoir parameters from GaffneyCline's petrophysical analysis (NTG, porosity, water saturation) were used to make probabilistic and deterministic estimates per reservoir unit. The GIIP for each fan was subsequently estimated as an average between the probabilistic and deterministic outputs. GaffneyCline's estimates of GIIP are given in **Table 4.18**.

Table 4.18: GaffneyCline's Estimates of GIIP for the Scarborough Field as of 31 December 2021

Fan	Reservoir	GIIP (Bscf)	
		P90	P50
Upper	K17.3	148	321
	K17.2	241	322
Middle	K17.1	196	286
	K17.06	1,924	3,082
Lower	K17.04	2,915	3,643
	K17.02	6,773	8,225
	K16.9	1,730	2,105
	K16.7	74	91
	K16.4	78	95

Nearby offset wells, Jupiter-1 and Thebe-1 are the discovery wells of additional gas accumulations located to the NE and N of Scarborough respectively. The Jupiter gas accumulation is contained within the youngest section of the Triassic Mungaroo Formation. The Jupiter-1 well penetrated 16.3 m of net gas pay with average porosity of 23.6%. The reservoir consists of argillaceous sandstones, silts and clays. The Jupiter structure is located at the culmination of a plunging Triassic tilted fault block which is onlapped and overlain by the Upper Dingo Claystone which acts as the lateral and top seal for the field. A well-defined flat spot is observed on seismic data, coincident with a depth between the lowest known gas at 1,925 mss and the highest known water at 1,930 mss, and this is interpreted to be the GWC.

The Thebe gas accumulation is contained within fine-grained argillaceous sandstones of the Mungaroo Formation. The Thebe-1 well was drilled in 2007 and discovered gas at the top of the Mungaroo with a net pay section of 51.2 m and average porosity of 27.1%. An appraisal well, Thebe-2 was drilled in 2008 to test the northern extension of the field. The field is formed of two connected foot-wall accumulations developed by two offset, SW-NE trending en-echelon faults. The fault blocks are onlapped and overlain by the Dingo Formation which forms the top and lateral seal for the reservoir. The field GWC is defined at 2,317 mss based on pressure data and is consistent with a field wide flat spot associated with amplitude brightening in the seismic data.

Both the Thebe and Jupiter Fields offer future development opportunities to be used as backfill into the Scarborough FPU. GaffneyCline has reviewed probabilistic GIIP estimates provided by Woodside (**Table 4.19**).

Table 4.19: GaffneyCline's Estimates of GIIP for the Jupiter and Thebe Fields as of 31 December 2021

Field	GIIP (Bscf)	
	P90	P50
Jupiter	379	791
Thebe	2,500	2,970

4.5.2 Development Plan and Production Forecasts

Scarborough

The Scarborough dry gas field will be developed with 13 subsea wells drilled in two phases, tied back to a semisubmersible hull Floating Production Unit (FPU). GaffneyCline estimated recoverable volumes of gas by multiplying the GIIP estimates with gas recovery factors derived from sensitivities run on the dynamic simulation model. Low estimate and best estimate estimates of gross technically recoverable volumes of gas are 7.6 Tscf and 11.9 Tscf respectively. GaffneyCline's production forecasts are scaled from the Woodside forecasts to honour the GaffneyCline gas recoveries. The production profiles used by GaffneyCline for evaluation reflect ullage availability, venture-agreed allocated liquefaction capacity and estimated field deliverability over time. The forecasts show production starting in 2026 and ramping up to maintain rates between 1,300 MMscfd and 1,600 MMscfd from 2027 to 2034 in the low estimate and to 2041 in the best estimate before declining.

Scarborough production forecasts are not presented herein due to the sensitive nature of the information.

Table 4.20 lists the raw and dry gas, and condensate volumes that have been estimated using the same yields that Woodside has used. Condensate yields have been checked against oil and gas composition and are deemed reasonable.

Table 4.20: Scarborough Remaining Technically Recoverable Volumes

Field	Low Estimate		Best Estimate	
	Raw Gas (Tscf)	Cond (MMBbl)	Raw Gas (Tscf)	Cond (MMBbl)
Scarborough	7.6	0	11.9	0

Thebe

The Thebe dry gas field will be developed to backfill production from the Scarborough gas field, and development will comprise eight vertical subsea wells, tied back to the Scarborough FPU.

Woodside estimates recoverable volumes using probabilistic estimates of GIIP and a recovery factor range from sensitivities run on the dynamic model. Gas recovery is limited by water breakthrough. GaffneyCline reviewed the volumetric estimates and recovery factors in order to formulate its independent opinion and found Woodside's estimates of recoverable volumes to be optimistic. **Table 4.21** shows GaffneyCline's estimates of GIIP and 2C Contingent Resources (Development Pending).

Table 4.21: GaffneyCline's Estimates of GIIP and Contingent Resources for the Thebe Field

Parameter	Units	Best Estimate
GIIP	(Bscf)	2,970
RF	(%)	35%
Gross 2C Contingent Resources	(Bscf)	1,040

Jupiter

The Jupiter dry gas field will be developed to backfill production from the Scarborough and Thebe gas fields, and development will comprise two vertical subsea wells, tied back to the Scarborough FPU. Subsurface studies to mature the subsurface understanding of Jupiter are planned for 2021. This will include reprocessing the existing seismic data using Full Waveform Inversion (FWI) and updating the seismic interpretation for any new insights.

Woodside estimates recoverable volumes using a recovery factor range derived from dynamic models. Gas recovery is limited by water breakthrough. GaffneyCline reviewed the volumetric estimates and dynamic models in order to formulate its independent opinion and found Woodside's estimates of recoverable volumes to be optimistic.

Table 4.22 shows GaffneyCline's estimates of GIIP and Contingent Resources (Development Pending).

Table 4.22: GaffneyCline's Estimates of GIIP and Contingent Resources for the Jupiter Field

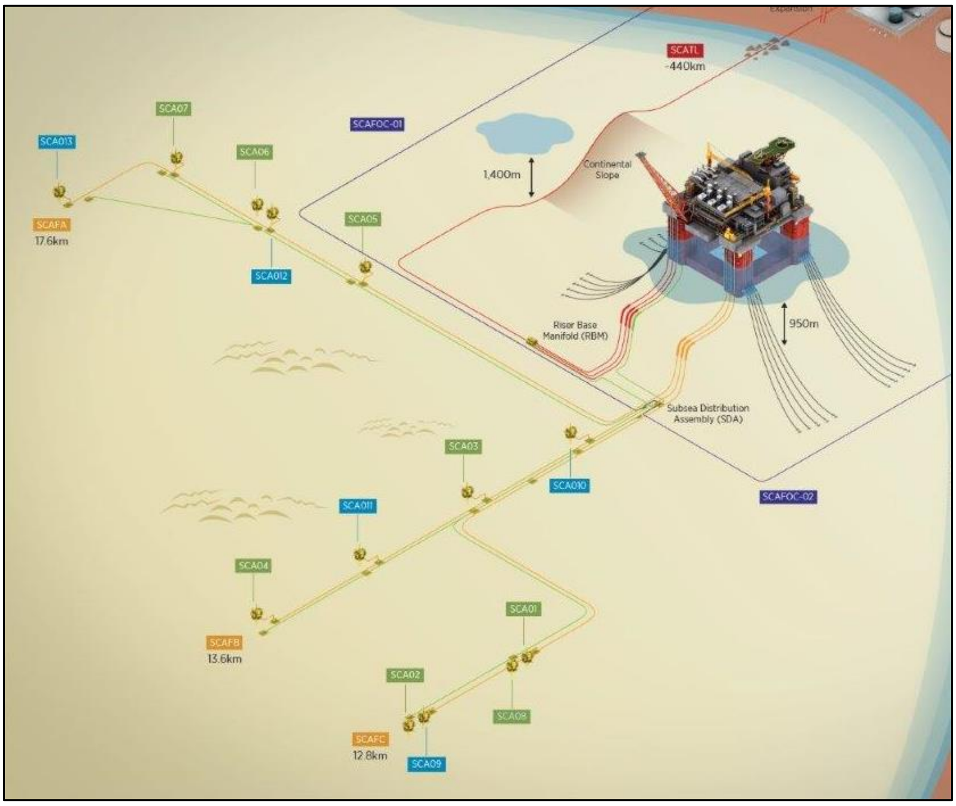
Parameter	Units	Best
GIIP	(Bscf)	791
RF	(%)	35%
Gross 2C Contingent Resources	(Bscf)	277

4.5.3 Facilities and Cost Estimates

The Scarborough Field will be developed with subsea wells in some 1,400 m water depth, tied back to a semisubmersible floating production unit (FPU) moored in 950 m water depth. The subsea development is planned for up to thirteen wells, although the facility will commence production from a first phase of eight high-rate wells. Gas will be dehydrated and compressed on the FPU (capacity 1,750 MMscfd) and transported in a 32"/36" pipeline, 430 km to shore to the Pluto LNG plant at Karratha. The offshore development concept is shown in **Figure 4.24**.

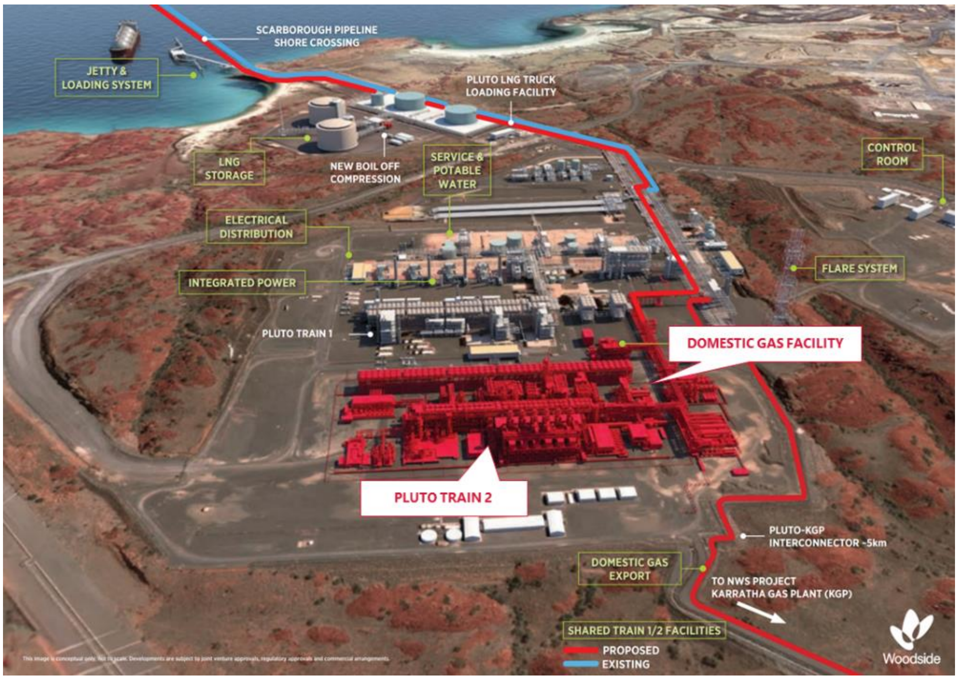
Scarborough gas will be liquefied in a new Train 2 expansion to the existing Pluto LNG plant. Pluto Train 2 will have a capacity of 5 MTPA LNG and up to 225 TJ/day domestic gas supply. An additional 2 to 3 MTPA can be liquefied using capacity in Pluto Train 1, providing an overall deliverability of up to 8 MTPA LNG from the Scarborough field. To further optimise the utilization of installed capacity, a 5 km interconnector pipeline has been installed to link the Pluto and Karratha Gas Plant (KGP) LNG facilities, which can also deliver to the Western Australia domestic gas market through the Dampier to Bunbury pipeline. An overview of the Pluto Train 2 development is shown in **Figure 4.25**.

Figure 4.24: Scarborough Offshore Development Concept



Source: Woodside

Figure 4.25: Pluto Train 2 Overview



Source: Woodside

A Final Investment Decision (FID) was taken in November 2021, with first gas planned 48 months after FID and the first LNG cargo 6 months thereafter. Woodside has provided current, FID-ready capital and operating cost estimates for the initial phase of the Scarborough development. GaffneyCline has reviewed and accepted the development costs, with minor adjustments for consistency with its production profiles.

4.5.3.1 Facilities Operability, Integrity, and Infrastructure

The Scarborough offshore development is designed with a fibre optic cable link to the coast, allowing the facility to be monitored and operated from shore. The offshore FPU is designed to an overall reliability and availability target of at least 97%. Downstream, Scarborough gas will be processed in a dedicated new train at Pluto LNG facilities (Train 2).

Pluto Train 2 is interconnected with the existing Train 1, and (through T1).

4.5.3.2 Decommissioning and Restoration (D&R) Planning

Scarborough end of field life is not expected to occur before 2050, so D&R planning is at a conceptual level. Woodside's D&R estimate appears to be based on current good industry practice, i.e. full removal of the FPU and all subsea flowlines and equipment. This is a reasonable basis and is accepted by GaffneyCline.

4.5.3.3 Cost Review

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering CAPEX, OPEX, and D&R costs for the offshore Scarborough and onshore Pluto Train 2 operations from 2021 to the end of field life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed cost forecasts as reasonable. Note that the construction costs of Train 2 and the offshore development have been substantially covered by contract, limiting the escalation risk.

Gross CAPEX for development of the Scarborough Reserves case is estimated to be US$6,213 MM.

A substantial part of Scarborough's costs are incurred as tariffs paid by the Scarborough JV to the downstream Pluto Train 2 venture, for LNG and Domestic gas liquefaction and processing services. GaffneyCline has reviewed these tariff flows and adjusted to an RT2022 basis and GaffneyCline's production profiles.

4.5.4 Resources Estimates

Reserves are attributed to the Scarborough Field and Contingent Resources (Development Pending) are attributed to Thebe and Jupiter.

4.5.5 GaffneyCline Production and Cost Valuation Profiles Scarborough

GaffneyCline generated production profiles and associated cost profiles for KPMG valuation scenario inputs. Full life of project year on year Scarborough production profiles are not presented herein due to the commercially sensitive nature of the information. The basis of the inputs to the profiles are however discussed in the preceding sections. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the recoverable volumes of the sanctioned Scarborough field tabulated in **Table 4.20.**

The regulatory carbon cost assumption for Scarborough is as per Woodside's above baseline assumption for this project.

4.5.6 Recommended Valuation Range for Thebe and Jupiter Fields

The Thebe and Jupiter Fields may possibly be developed via a subsea tie-back to the Scarborough FPU as backfill opportunities. Thebe, being the larger accumulation, has a higher likelihood of being developed by 2040 to support the plateau production from the Scarborough field in the best-case scenario. GaffneyCline has utilised a transaction multiple range of 0.1 US$/Mcf to US$0.19 US$/Mcf to provide a value range for these discoveries. This is discussed in more detail in Section 4.10.3 and shown in **Table 4.30** where selected market comparable transactions are reviewed. The estimated valuation range for the 520 Bscf net Woodside 2C resource (50% Woodside WI) is US$52 MM to US$99 MM.

GaffneyCline therefore recommends a valuation range of **US$52 MM** to **US$99 MM** for the Thebe discovered resource for KPMG's consideration.

Jupiter is a much smaller accumulation with a best estimate 2C of 277 Bscf (100%) so there may likely be a higher unit cost development associated with this accumulation. Jupiter also has drilling risk due to the shallow hazards. The Jupiter seabed conditions, due to the pockmarks, present an uncertainty on any future development and drilling drainage pattern. GaffneyCline recommends no material value for the discovered Jupiter field.

4.6 WA-404-P Permit

The WA-404-P asset encompasses undeveloped discoveries Remy, Martell, Martin, Noblige and Larsen Deep, all located within the WA-404-P permit, offshore Western Australia, approximately 100 km northwest of the Pluto Field in water depth of 1,500 m (**Figure 4.19**). The permit was awarded in 2007, with ten commitment exploration wells drilled since 2009. In addition to the commitment wells, an appraisal well, Noblige-2, was drilled in August 2011.

Development of these discovered gas accumulations is conceptually planned to backfill Pluto LNG.

4.6.1 Field Description

Martell-1 well was drilled in 2009 to target the Upper Mungaroo Formation within a constrained fault block (**Figure 4.26**). The well encountered gas from 2,750 mTVDss, penetrating a 113 m gas column. The interval has multiple layers with variable NTG. The reservoir is good quality with mean porosity of 23% and permeability of 900 mD. The Low, Best and High estimates of GIIP are 225, 384 and 559 Bscf.

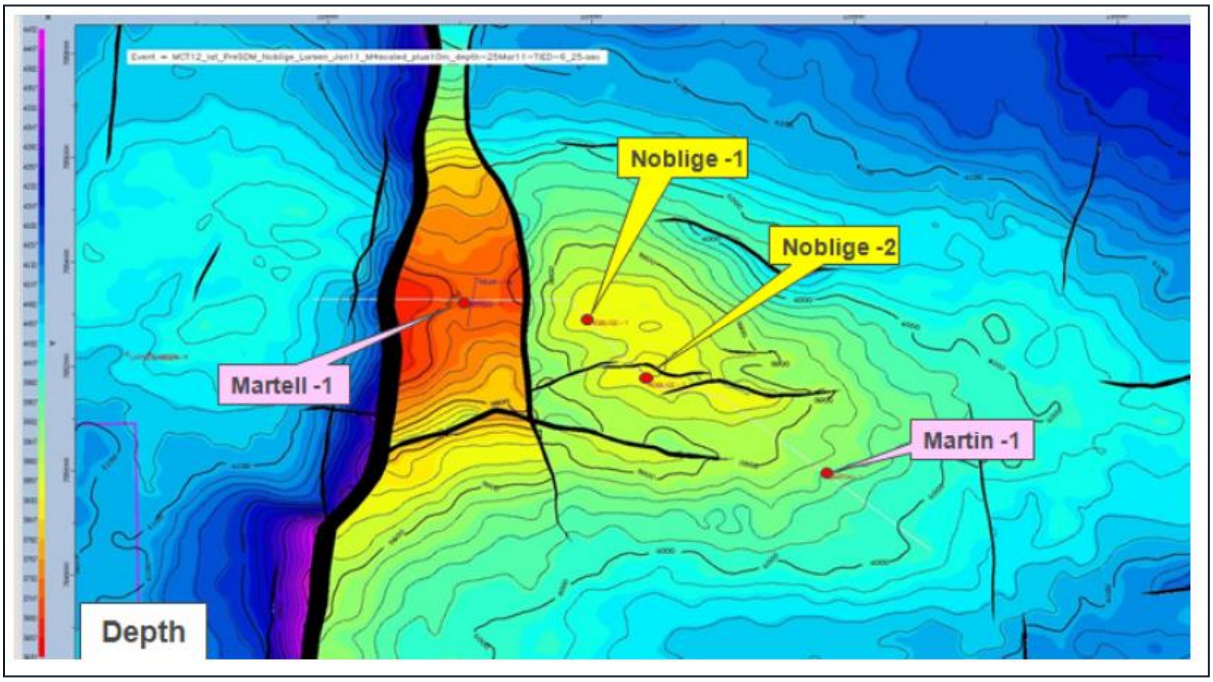
The Larsen Deep gas accumulation was discovered by Larsen Deep-1 well, drilled in 2010. Gas was encountered within a sandstone of the Mungaroo Formation, at a depth of around 4,600 m TVDss. Three gas samples were recovered using a wireline formation tester tool. The discovered accumulation is thought to be trapped stratigraphically in a channel feature, as shown by amplitude response in the seismic data. The Low, Best and High estimates of GIIP are 19, 65 and 119 Bscf.

The Noblige-1 well was drilled in 2010 to target the Mungaroo Formation within a four-way dip closure. The well penetrated gas at multiple levels between depths of 3,280 m and 4,148 mTVDss. Noblige-2 appraisal well was drilled in 2011 to assess the range of reservoir quality away from the seismic 'bright spot' area. The well encountered three undrilled reservoirs and obtained downhole samples. The Low, Best and High estimates of GIIP are 364, 615 and 1,007 Bscf.

The Remy-1A well was drilled in 2010 in a horst block at the Mungaroo Formation level. The well encountered two main gas bearing intervals between 4,100 and 4,500 m TVDss. The Low, Best and High estimates of GIIP are 47, 130 and 358 Bscf.

Martin Field was discovered in 2011 by the drilling of Martin-1, which was targeting the Mungaroo Formation within a three-way dip closed structure. The well intersected a gas column at 4,623 m TVDss, with 83.6 m gross pay. The Low, Best and High estimates of GIIP are 108, 372 and 635 Bscf.

Figure 4.26: Depth Structure Map of Mungaroo Reservoir showing Locations of WA-404-P Main Discoveries



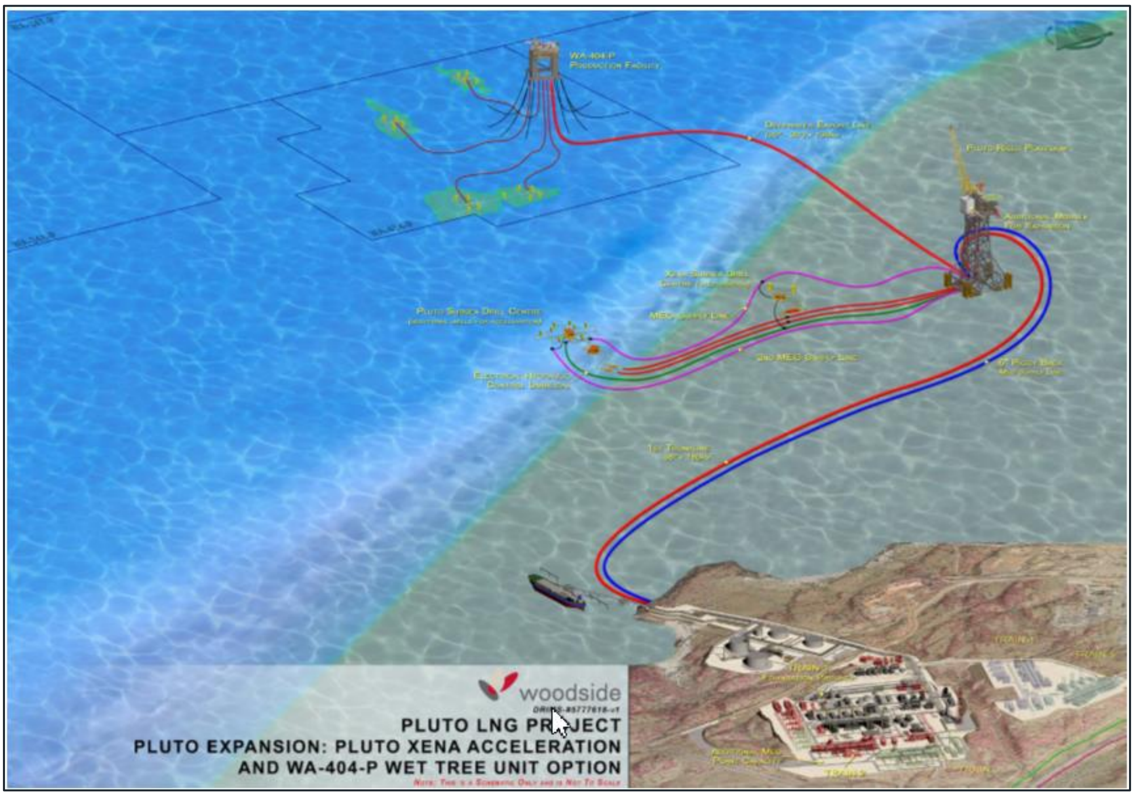
Source: Woodside

4.6.2 Development Plan and Production Forecasts

The fields are all undeveloped. **Figure 4.27** shows the conceptual development plan comprising a seven well wet-tree tieback to a conventional semi-submersible substructure and topsides, which is tied back subsea some 100 km to the Pluto trunkline. Due to the higher development costs, WA-404-P is only considered as a longer-term Pluto supply option with timing to meet deliverability requirements in approximately 2029.

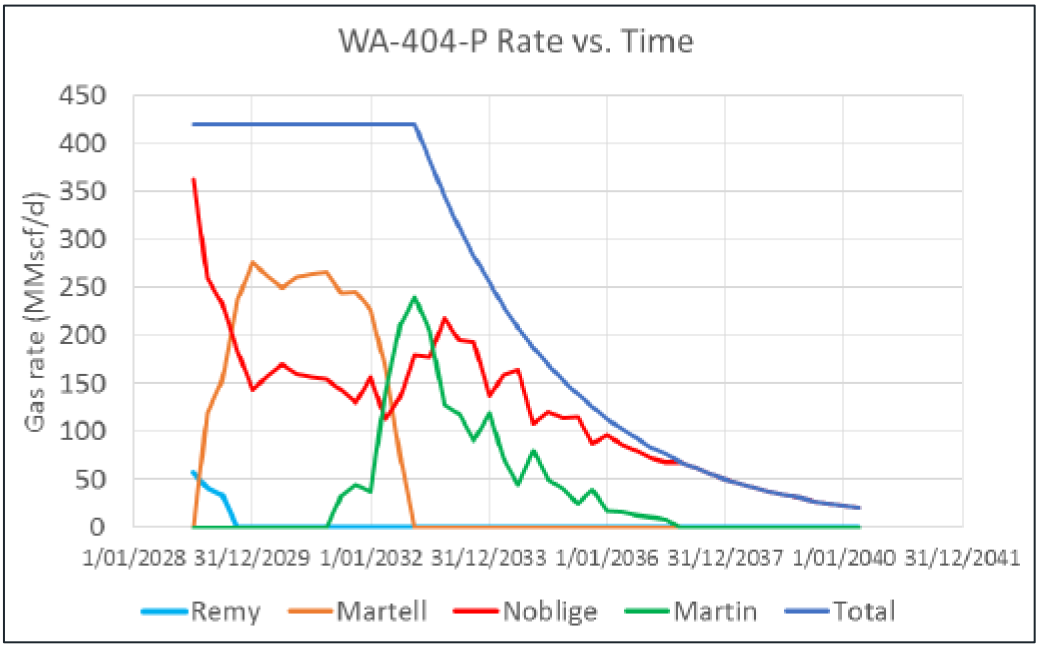
Figure 4.28 shows the combined technical forecasts for projects within WA-404-P.

Figure 4.27: WA-404-P Development Plan



Source: Woodside

Figure 4.28: WA-404-P Technical Profiles (Undeveloped)



Source: Woodside

4.6.3 Resources Estimates

Table 4.23 lists the potentially recoverable volumes, which are classified as Contingent Resources (Development Not Viable).

Table 4.23: WA-404-P Contingent Resources by Discovery as of 31 December 2021

Field	Gas (Bscf)	Condensate (MMBbl)	Development Status
Larsen	41	0.4	Not Viable
Remy	37	0.7	Not Viable
Martel	244	8.9	Not Viable
Martin	**256**	**3.6**	Not Viable
Nobligue	428	5.9	Not Viable
Total	**1,006**	**19.5**	

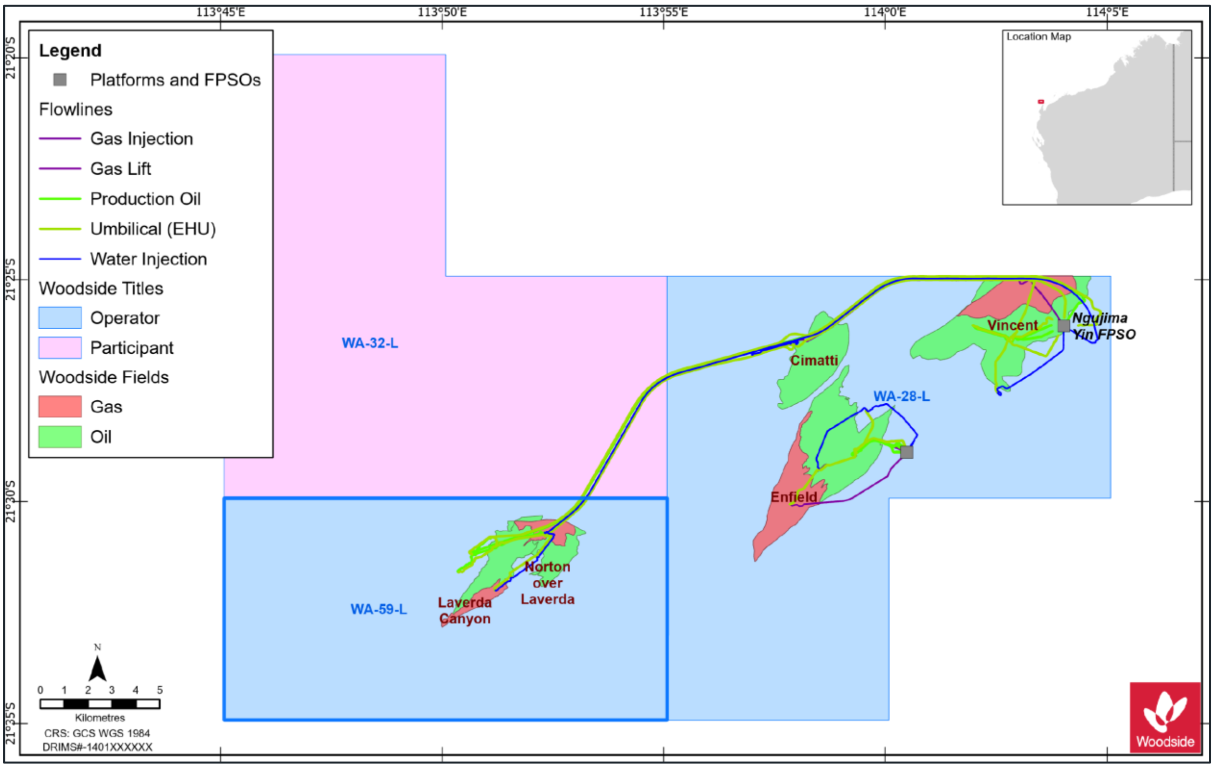
GaffneyCline includes these volumes for completeness; however no value is assigned given their Development Status.

4.7 Greater Enfield Oil and Vincent

Greater Enfield consists of the following fields: Cimatti, Laverda Canyon and Norton over Laverda. Greater Enfield and the Vincent Field are on production via the Ngujima-Yin FPSO. The Enfield oil field itself ceased production in 2018. Vincent and Cimatti are located within the WA-28-L permit, at 380 m and 500 to 580 m water depth respectively. Laverda Canyon and Norton over Laverda are located within WA-59-L permit at approximately 800 m water depth. Woodside has 60% interest in both permits. The fields are located about 40 km off the North-West Cape of Western Australia (**Figure 4.29**). Additionally, in the Laverda area there are the undeveloped discoveries Laverda West, Laverda East, Opel and Norton Central. The Enfield Field produced 81 MMBbl, but is no longer in production and is being prepared for abandonment and decommissioning.

The Greater Enfield Fields are located in the Exmouth Sub-basin of the Northern Carnarvon Basin. The reservoirs of these fields are the Late Jurassic Macedon Sandstone and the Early Cretaceous Lower Barrow Group.

Figure 4.29: Greater Enfield Asset Location Map



Source: Woodside

4.7.1 Field Description

The Vincent-1 well was drilled in 1998, followed with an appraisal well, Vincent-2, in 1999. The Vincent accumulation comprises high quality sandstone units of Late Jurassic-Early Cretaceous age Lower Barrow Group. The hydrocarbon (oil with a gas cap) was found in a northeast-southwest trending low relief, three-way dip closure against a fault. Immediately to the north in the neighbouring permit, the Van Gogh Field was discovered in the same reservoir in 2003. However, it was subsequently found that the two fields are separate, likely due to stratigraphic barrier, and they have not been unitised. The reservoir is of high quality with average porosity of 29% and average permeability of 4.5 D. The Vincent Field is an oil rim reservoir with a gas cap of approximately 160 Bscf and is supported by a strong bottom water/edge water aquifer.

The Cimatti field was discovered by the Cimatti-1 well in 2010. It was appraised by Cimatti-2, a sidetrack well drilled immediately after the first well. Cimati-1 targeted bright seismic amplitude at the Macedon Sandstone level and encountered 14.7 m of oil pay in a sandstone reservoir. The appraisal well encountered 5.9 m of oil pay 360 m to the northwest of the first well. The Cimatti structure is an elongated, northeast-southwest trending fault block at the east of the Enfield field. The reservoir was deposited in deep marine channels, and consists of high quality, clean, medium grained sandstone. The oil in Cimatti is relatively light compared to offset fields, with density of 31°API and viscosity of 0.5 cP and has a favourable mobility ratio for water flooding.

The Laverda Canyon Field was discovered by the Laverda-1 well, drilled in 2000, which encountered 64 m of oil with 9 m of gas cap in the Macedon Sandstone reservoir at a depth of around 1,980 m TVDss. The Macedon Sandstone in the Laverda Canyon Field is deposited as channel fill within a marine canyon. The reservoir consists of two excellent quality sandstone packages: a high NTG, 8 to 14 m thick Upper Sand with permeability of 3 to 4 Darcy, and a more stratigraphically complex, lower NTG, up to 80 m thick Lower Sand, with an average permeability of 1 to 2 Darcy. The Lower Sand has multiple cut and fill events evident on seismic and is overlain by 15 to 20 m of sandy siltstone. It is a low relief structure and contains a 60 m oil column, which is of intermediate gravity, similar to that in offset fields Enfield and Stybarrow.

The Norton over Laverda Field was drilled in 2011 by Laverda North-1 and -2 which encountered hydrocarbons in the Early Cretaceous sandstone of the Lower Barrow Group. The wells also encountered oil in the Macedon Sandstone to the north of Laverda Canyon. Another well, Laverda East-1 which was drilled in 2011 also penetrated Norton over Laverda and found hydrocarbon in the Cretaceous sandstone. The Norton over Laverda oil and gas pool in the Lower Barrow Sandstone is trapped in a three-way dipping structure against a fault at its northern side. The reservoir is composed of thin (15 to 20 m) alternating fluvial and tide-dominated lower delta plain and estuarine sandstones of multi-Darcy permeability.

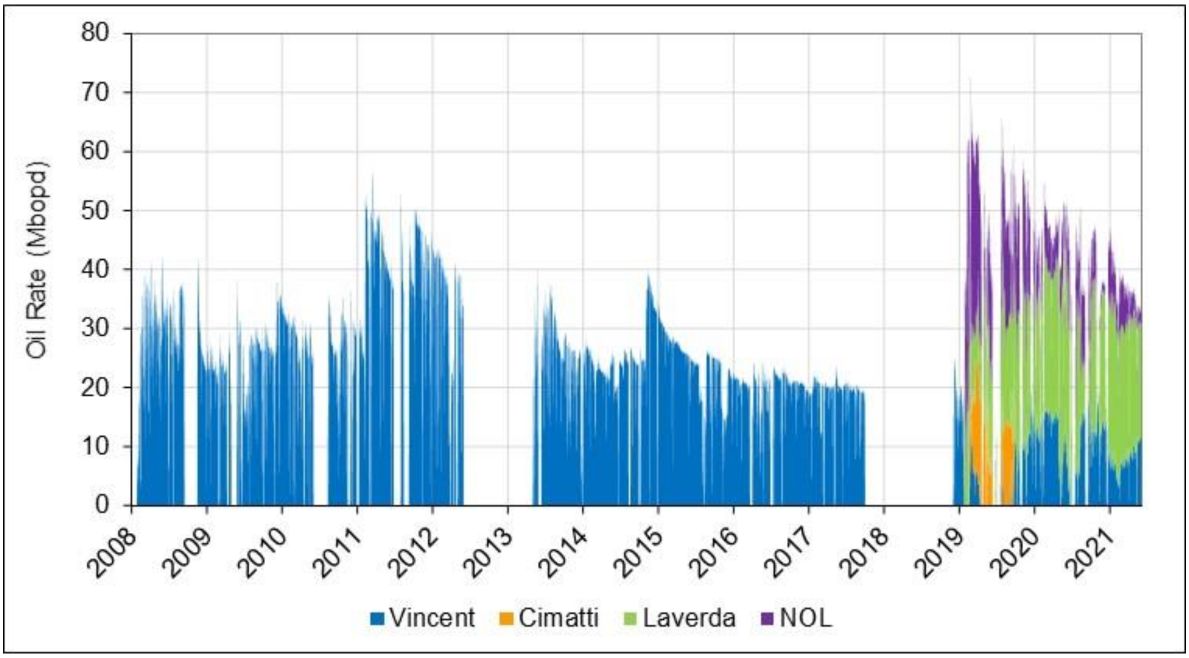
The Enfield oil field ceased production in 2018, having been developed with two gas injectors, eight water injectors and eight oil producers in the Macedon Sandstone Member. The remaining project is to abandon and decommission this field.

Laverda West, Laverda East, Opel, Norton Central and Skiddaw are undeveloped oil and gas fields located around the Laverda Canyon oil field, with relatively small estimates of recoverable volumes.

4.7.2 Field Development and Production Profiles

Vincent is developed with thirteen horizontal wells (seven bi-laterals and six tri-laterals). Two water injection wells are used for water disposal and there is one vertical gas injector for disposal of surplus gas. Production commenced in 2008 to the Ngujima Yin FPSO. Cimatti is fully developed with one horizontal production well and three water injection wells to keep the reservoir pressure above the bubble point. The Laverda Canyon Field is fully developed by two producer wells and three water injection wells. The Norton over Laverda Field is developed by three tri-lateral oil producing wells. The strong natural aquifer provides good pressure support to Norton over Laverda and the reservoir pressure remains above the bubble point. Cimatti, Laverda Canyon and Norton commenced production in 2019 via the Ngujima Yin FPSO. **Figure 4.30** shows the historical production from the four fields.

Figure 4.30: Historical Production of the Vincent and Greater Enfield Fields



GaffneyCline conducted performance analysis, decline curve analysis and analogue-based recovery factor checks to review Woodside's estimates and production forecasts for the Vincent and Greater Enfield fields. Best estimate production forecasts were accepted for all the fields except Cimatti, for which GaffneyCline created its own profile. Low estimate production profiles were accepted for Vincent and the Laverda Canyon, and GaffneyCline created its own for Cimatti and the Norton over Laverda fields.

Figure 4.31 shows the combined technical forecasts for the Vincent and Greater Enfield projects and **Table 4.24** lists the recoverable volumes. Termination of production forecast in 2028 is driven by the planned end of Vincent facilities' life. Volumes associated with a possible extension to 2032 are classified as Contingent Resources.

There are currently no development plans for Laverda West, Laverda East, Opel, Norton Central and Skiddaw and their small volumes may not be able to support commercial development. Under PRMS, the estimates of recoverable volumes are classified as Contingent Resources (Development Not Viable).

Figure 4.31: Greater Enfield and Vincent Technical Profiles (Developed)

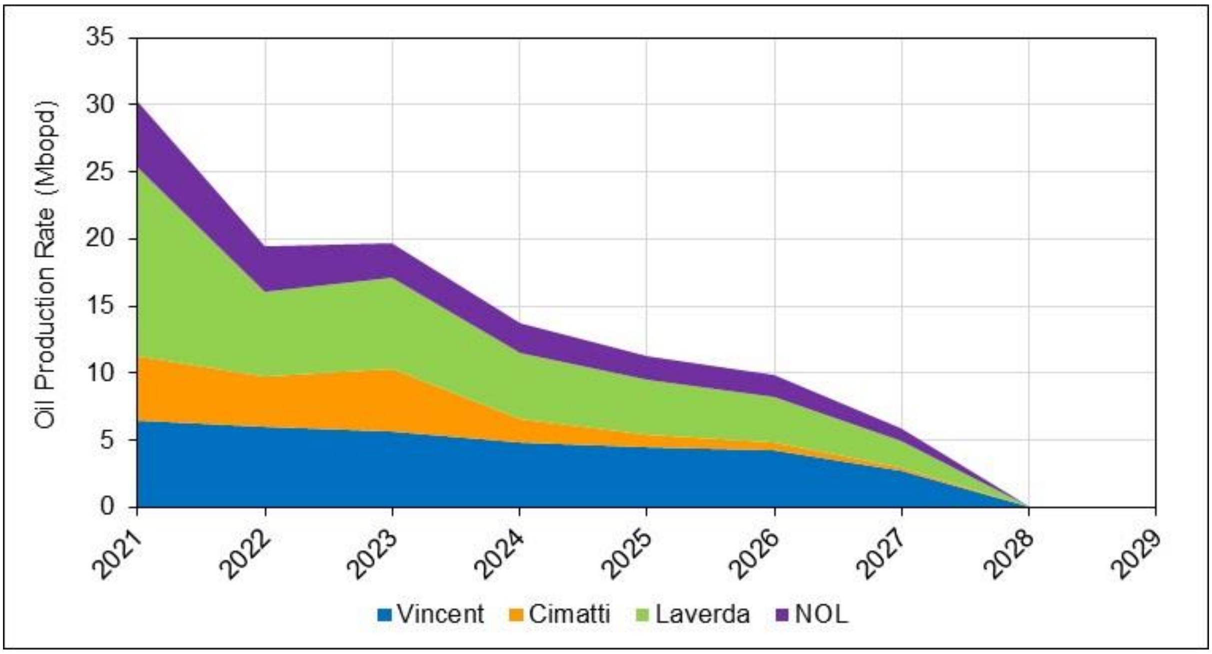


Table 4.24: Greater Enfield and Vincent Gross Technical Remaining Recoverable Volumes as of 31 December 2021

Field	Cumulative Production (MMBbl)	Remaining Recoverable Oil (MMBbl)	
		Low Estimate	Best Estimate
Vincent	78.1	8.4	12.5
Cimatti	2.2	3.3	6.2
Laverda Canyon	15.0	13.4	15.1
Norton Over Laverda	8.0	3.1	6.3

Note: Estimates to planned end of facilities' life in 2028

4.7.3 Resources Estimates

Reserves are attributed to future production from the four producing fields.

Additionally, Contingent Resources are attributed to various projects, classified as Not Viable because the volumes are currently considered too small for commercial development and there are currently no plans to develop them (**Table 4.25**). Contingent Resources were also included for Ngujima Yin FPSO extension past 2028 and this is discussed further in the facilities section.

Table 4.25: Greater Enfield Contingent Resources as of 31 December 2021

Field	2C Contingent Resources	
	Gas (Bscf)	Oil (MMBbl)
Vincent	-	17.7
Cimatti	-	0.7
Laverda Canyon	-	9.3
Norton over Laverda	-	8.2
Laverda West	54	6.8
Laverda East	1	2.9
Opel	17	3.0
Norton Central	-	4.4
Skiddaw	-	0.6
Totals	**72**	**53.6**

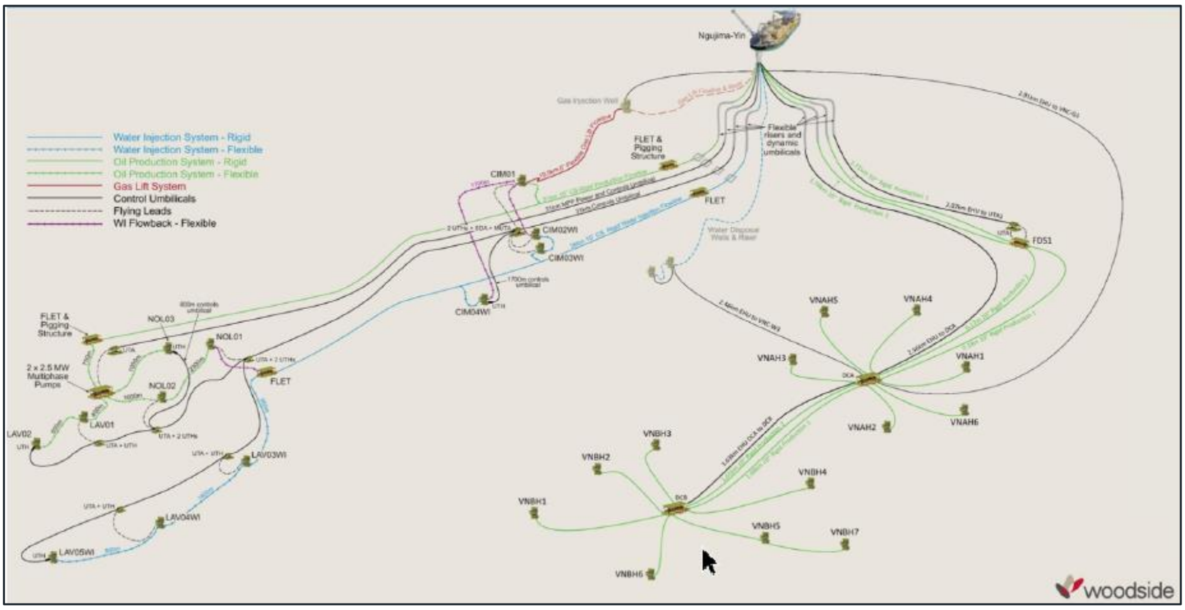
4.7.4 Facilities and Costing

The Ngujima-Yin FPSO is located over the Vincent Field in 350 to 400 m water depth. Development commenced with the Vincent Field, with the other fields tied back via a 31 km x 16" flowline. The FPSO has a design production capacity of 120 Mbopd, 155 Mbwpd and 250 Mblpd (gross liquids). Production is currently limited by water production, clean-up and disposal capacity.

The FPSO provides oil processing, water injection supply and injection, gas lift and gas injection. Since installation, the FPSO has been shut down for scheduled inspection and refurbishment in 2012 and 2018. The next scheduled turnaround is an 82-day shutdown planned for 2023 (typically 5-year intervals). An overview of the Greater Enfield development is shown in **Figure 4.32**.

Limited information is available on the facilities integrity of the FPSO or subsea system, however the Operator notes concern with "facilities availability, particularly water injection system and multiphase pumps".

Figure 4.32: Greater Enfield Development Plan



Source: Woodside

4.7.4.1 Facilities Operability, Integrity, and Infrastructure

The Vincent and Greater Enfield oil facilities (Ngujima Yin NY FPSO) have been in service since early 2008 with production outages every five years (2013 and 2018/19) for planned dry dock and vessel inspection. In total, the facility has been offline for 25 months of its 162 month service life, or 84.5% overall uptime. Reliability in 2020 was somewhat better at 88.4%; however, a planned 5-yearly dry dock and inspection will result in 5 months planned downtime in 2023.

The NY production system allows independent oil export and is currently self-sufficient in fuel gas.

4.7.4.2 Decommissioning and Restoration (D&R) Planning

Current operational planning is focused on facilities uptime and integrity, with limited near-term D&R activity. Woodside has, however, developed a phased D&R plan commencing three years prior to the end of field life and extending over 8 years. GaffneyCline considers this a reasonable planning.

4.7.4.3 Cost Review

GaffneyCline has reviewed a detailed cost forecast provided by Woodside covering CAPEX, OPEX, and D&R costs from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline accepted Woodside's CAPEX and OPEX cost forecasts as reasonable. D&R cost estimates, however, were materially increased in our review to reflect current D&R scope and the full exploration, appraisal and production well count remaining.

Gross CAPEX for further development activities related to the Greater Enfield Reserves case is estimated to be US$149 MM.

4.7.4.4 *Nguijima Yin FPSO Extension*

The Ngujima Yin FPSO (that handles Greater Enfield/Vincent Enfield production) has been in service since 2008 with regular 5-yearly (2013 and 2018/19) dry docking for inspection, maintenance and recertification. The next of these shutdowns is scheduled for 2023. The vessel is operating at 86.6% reliability, with downtime primarily related to the topsides operations (as opposed to wells & subsea).

Woodside are investing in topsides reliability upgrades and hope to have the FPSO reliability increased to 91% by 2024.

With continuing regular dry docking and maintenance, the vessel should be able to remain in service for another 5 to 10 years unless there is some fundamental (e.g. fatigue cracking) problem which may terminate its serviced life at 20 years. The 20-year design basis, while a theoretical minimum, is usually comfortably exceeded provided the Operator continues to inspect and maintain the vessel. GaffneyCline has therefore extended the production and cost profiles for valuation to account for this likely outcome.

4.7.5 GaffneyCline's Production and Cost Valuation Profiles Greater Enfield Oil and Vincent

GaffneyCline's valuation scenario production profile for Woodside's Greater Enfield Oil and Vincent asset is given in **Figure 4.33** with the associated real term cost profiles provided in **Figure 4.34**. All final sales products are converted to MMboe before aggregation utilising documented conversion factors in **Appendix IV**. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the recoverable volumes of the sanctioned Greater Enfield Oil and Vincent asset in **Table 4.24** with additional production post the facilities upgrade extending the life to 2032. GaffneyCline has considered the technical and commercial contingencies for the FPSO extension discussed in section 4.7.4.4 and considers the associated 2C Contingent Resource volume acceptable for the valuation profile.

The regulatory carbon cost assumption for Greater Enfield Oil and Vincent asset is as per Woodside's above baseline assumption for this project.

Figure 4.33: 100% Greater Enfield Oil and Vincent asset Production Profile

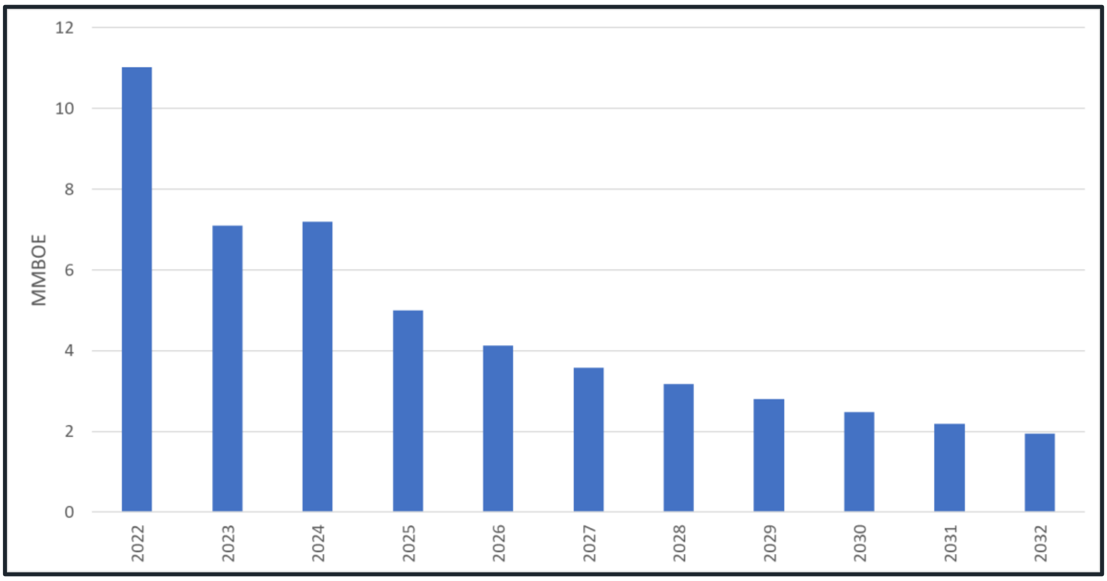
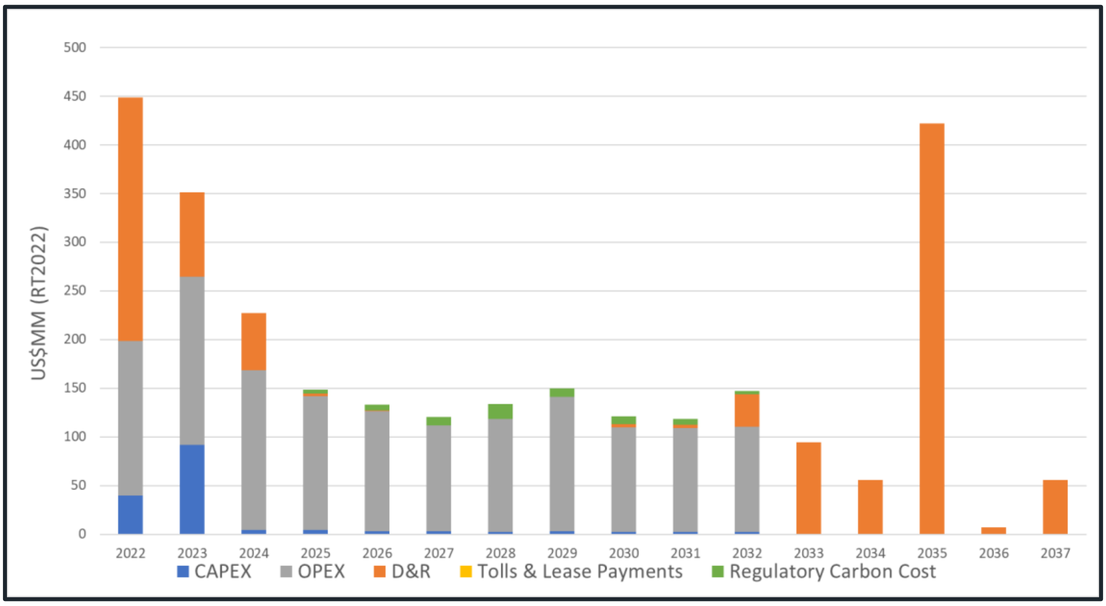


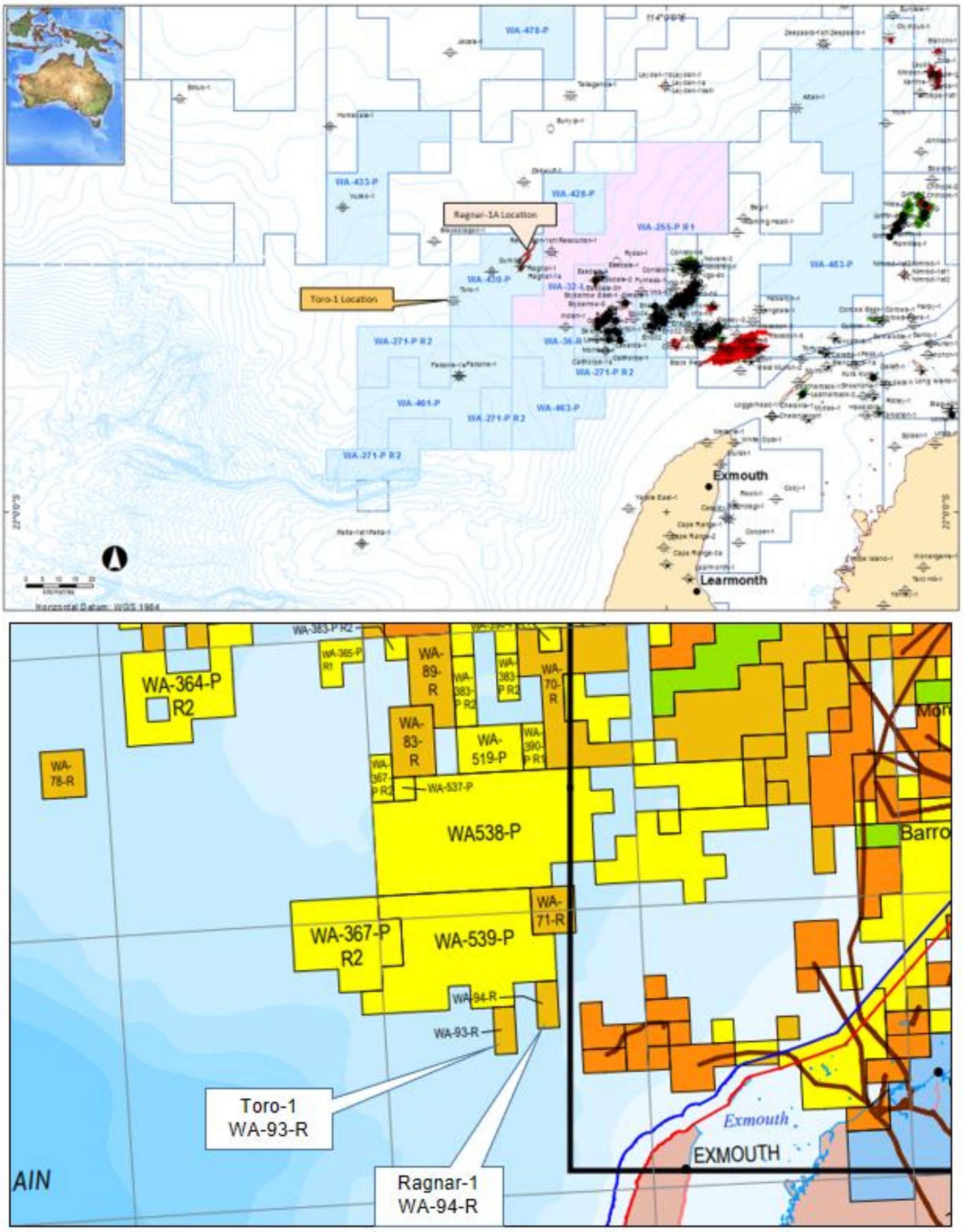
Figure 4.34: 100% Greater Enfield Oil and Vincent asset Cost Profile



4.8 Ragnar and Toro (WA-93-R and WA-94-R Leases)

The Ragnar-1 and Toro-1 wells were drilled in the WA-430-P permit in 2012 and 2014, respectively. In April 2020, when WA-430-P was surrendered, two smaller retention lease areas were carved out around the two assets: WA-93-R around Toro and WA-94-R around Ragnar. Woodside has 70% WI in each permit. These permits will expire in 2025, and Woodside is working to identify viable development options for them. **Figure 4.35** shows the locations of the wells and the location of the two new leases. Ragnar and Toro are located about 40 km from the Greater Enfield assets. Geologically, the wells were drilled in the Exmouth Sub-basin.

Figure 4.35: Location Maps of Toro and Ragnar (upper), WA-93-R and WA-94-R (lower)



Source: Woodside (upper), Australian National Petroleum Titles Administration - NOPTA (lower)

4.8.1 Field Description

Ragnar-1 encountered 75 m of gross gas column in the Triassic Mungaroo Formation sandstone units. Low, Best and High case estimates of GIIP for Ragnar are 241, 349 and 486 Bscf. The Ragnar structure is estimated to contain a mean 'on-block' recoverable raw gas volume of 277 Bscf.

Toro-1 was drilled approximately 22 km southwest of Ragnar in 1,160 m water depth as a follow-up to the Ragnar-1 discovery. The target was the Triassic Mungaroo sandstone reservoir in a two-way dipping horst block. The well encountered 151 m of gross gas column at 3,088 mss. The reservoir has 11 to 21% porosity and 25 to 200 mD permeability. A total of 9 fluid samples were acquired from two depths. Gas compositional analysis indicates an average CGR of 23 Bbl/Mscf. Non-hydrocarbons make up an average of 6 mole%.

Low, Best and High estimates of GIIP for Toro are 160, 234 and 326 Bscf. The Toro structure is calculated to contain a mean 'on-block' recoverable raw gas volume of 154 Bscf, not including inert components (CO_2, N_2). Approximately 3% of the structure is interpreted as lying outside the permit boundary.

4.8.2 Field Development Plan and Production Forecasts

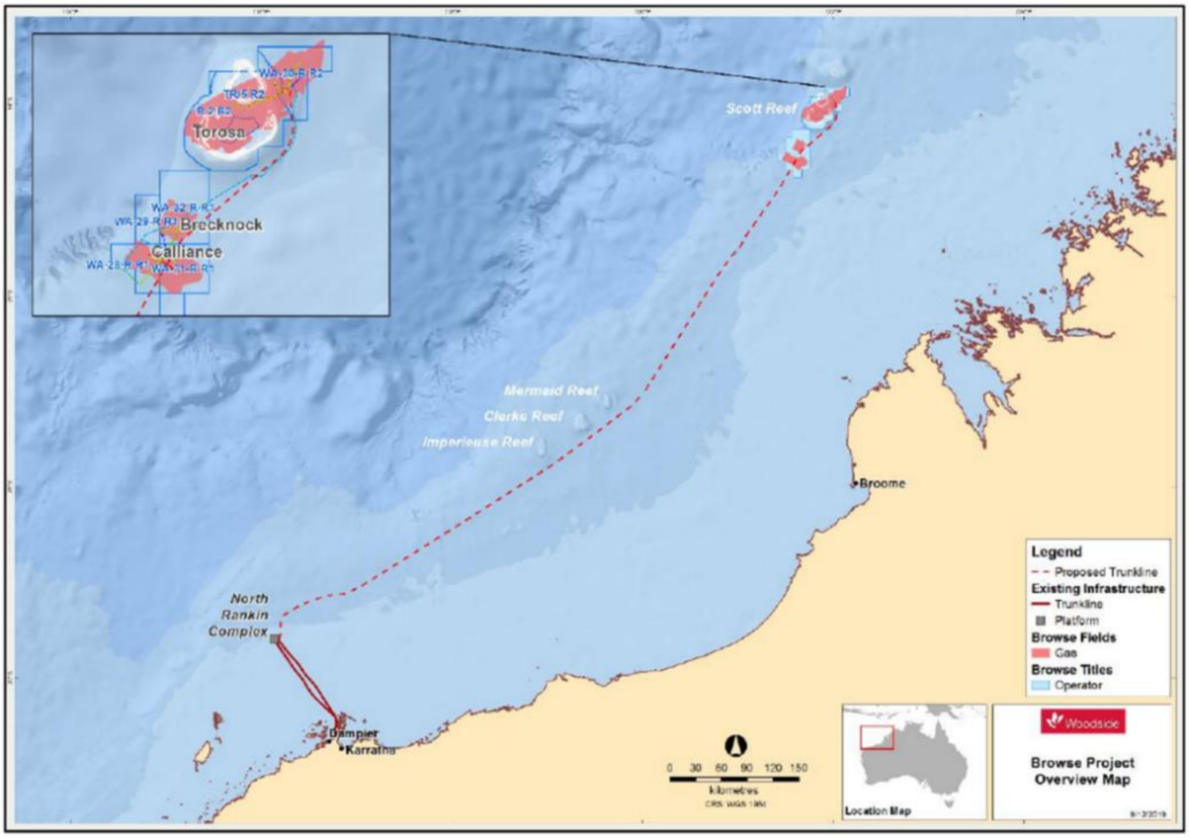
An integrated field development study of the Ragnar Field was conducted in 2013 to investigate the opportunity to produce Ragnar via a subsea pipeline tied back to the Greater Laverda project. However, the volumes were considered too small to justify the plan.

The Ragnar and Toro Fields are currently viewed as technically and commercially immature due to their small volumes and distance from infrastructure. Gross 2C Contingent Resources (Development Not Viable) of 385 Bscf gas and 3.2 MMBbl condensate are attributed to a potential development.

4.9 Browse (Torosa, Brecknock, and Calliance)

The undeveloped Torosa, Brecknock, and Calliance gas fields (collectively the Browse development) lie in the offshore Browse Basin, 425 km north of Broome, Western Australia (**Figure 4.36**). Gas was discovered at Torosa in 1971, Brecknock in 1979, and Calliance in 2000. Seventeen wells have been drilled across the fields, with twelve drilled since the petroleum retention leases (RLs) were first granted in 2003. Retention leases WA-28-R to WA-32-R (five) are in Commonwealth waters with two other leases in Western Australia State jurisdiction (TR/5 and R2). The Calliance and Brecknock fields lie in water depths of 500 to 700 m, while the Torosa field lies under Scott Reef with water depths varying from 0 to 475 m.

Figure 4.36: Browse Asset Location Map



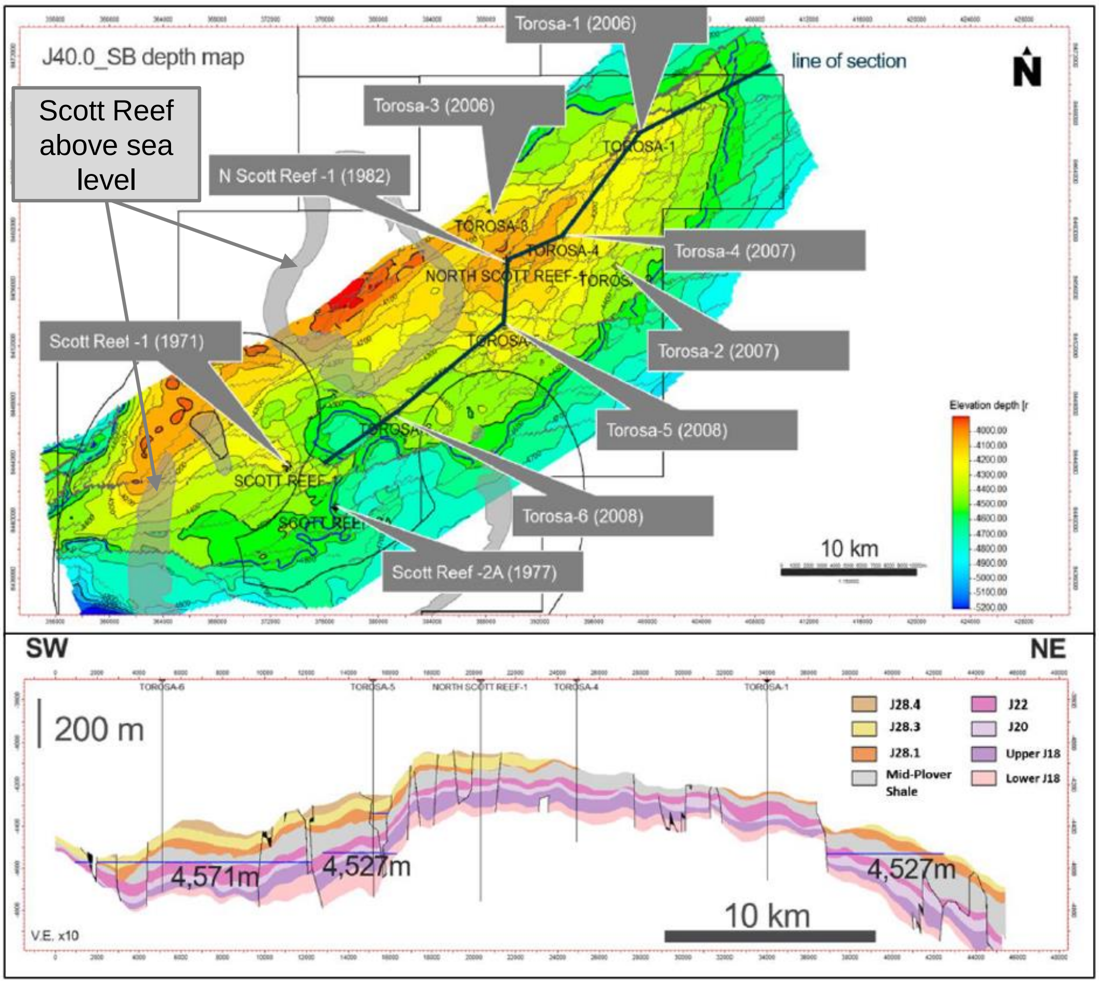
Source: Woodside

4.9.1 Field Description

Torosa

Torosa Field is 60 km long by 20 km wide with NE-SW oriented Jurassic-Triassic faults. It is fault-bounded to the west and dip closed to the north, south and east. The Jurassic J40.0 sequence boundary marks the top of the reservoir and the base of the regional seal in the area and is overlain by a thick sequence of shales and marls. Torosa is a complex structure on which nine exploration and appraisal wells have been drilled to date (**Figure 4.37**). Good quality 3D seismic data are available in the open water region, but there is a poorly imaged area under and adjacent to Scott Reef. This latter area also has a lower level of appraisal due to the limitations of the reef and associated physical environment imposing logistical issues.

Figure 4.37: Torosa Top J40 structure Map and Cross Section



Source: Woodside (GaffneyCline Modified)

Six drill stem tests were performed on three Torosa appraisal wells, Scott Reef-1, North Scott Reef-1 and Torosa-4, with rates varying from 10 to 46 MMscfd. The reservoir fluid is a lean gas condensate (CGR ~23 stb/MMscf) with moderate non-hydrocarbon content (8 to 12 mol% CO_2).

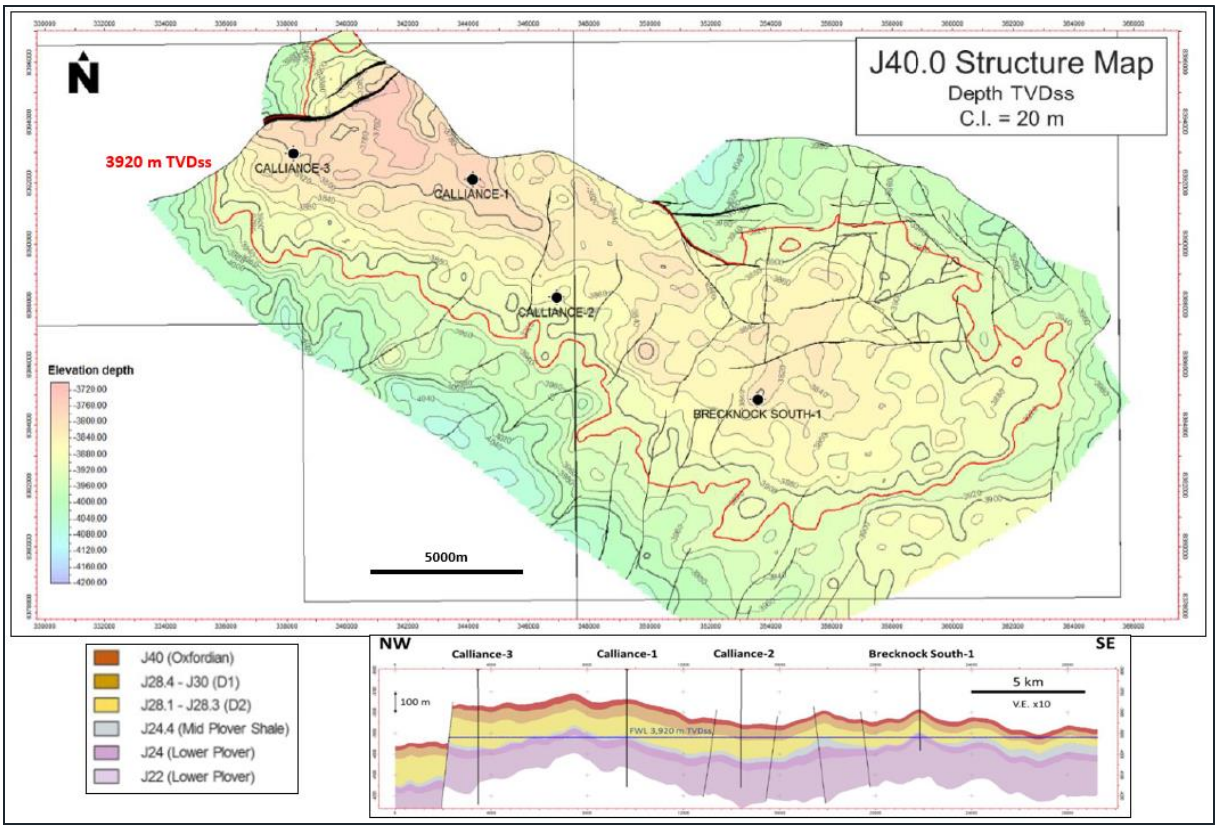
Woodside estimates that the proposed drainage plan will achieve good recoveries of 54% in the open water area. Volumes beneath Scott Reef are currently not part of the foundation project. The main uncertainties in Torosa are the Plover J28.3 reservoir distribution, J18 rock quality, fluid contacts across the field and potential compartmentalisation. An additional appraisal well is planned targeting volumes under North Scott Reef after field start-up.

GaffneyCline reviewed the static models provided by Woodside and considers the volume estimates as reasonable. The seismic interpretation was not reviewed but the documentation provided raised no concerns. Stratigraphic thicknesses of the reservoir intervals are an uncertainty in this syn-rift environment. The free water levels in the various fault blocks are also an uncertainty complicated by the distinct over-pressured aquifer. The overall recovery factor range of 33% to 39% is considered reasonable.

Calliance

Calliance is a broad low relief structure, 25 km long and 6 km wide as interpreted from the 3D seismic data and four exploration and appraisal wells (**Figure 4.38**). It consists of a NW-SE trending, tilted fault block at the Jurassic level. The field is bounded by major faults to the north and west, with a gentle dip closure to the south and east over older volcanic centres. The major NW-SE trending fault along its northern edge separates the field from the graben between Calliance and Brecknock. Calliance is covered by 3D seismic surveys which have been merged, reprocessed to pre-stack depth migration and includes a partial multi-azimuth (MAZ) depth migrated dataset.

Figure 4.38: Calliance Top J40 Structure Map and Cross Section



Source: Woodside (GaffneyCline Modified)

The Calliance Field was discovered by Brecknock South-1 in 2000. It encountered a 130 m gas column in the upper Plover Formation. The discovery was appraised by Calliance-1 (2005), Calliance-2 (2007) and Calliance-3 (2008). These wells were drilled 8-20 km northwest of the discovery well and penetrated a similar reservoir section with a maximum gas column at Calliance-1 of 180 m across the Vulcan and Plover Formations. In addition to the full suite of wireline log data, the three appraisal wells were extensively cored (~700 m) and two flow tests in Calliance-1 achieved rates of 41 MMscfd and 20 MMscfd.

The primary reservoir is interpreted to be well connected due to thick, good quality, high net-to-gross sands and generally short faults of minor throw. Reservoir fluid comprises a fairly lean gas condensate (CGR ~35 stb/MMscf) with moderate non-hydrocarbon molar content (8–12% CO_2). Woodside estimates a recovery factor of 66%, which compares well with industry analogues given the challenging and remote operational environment. **Table 4.26** shows estimates of GIIP, which GaffneyCline has reviewed and considers reasonable. The main subsurface uncertainties are the depth conversion in the low relief east of the field, the performance of the secondary J28.4-J30 reservoir unit and the aquifer strength. One appraisal well and an additional 3D seismic survey are planned.

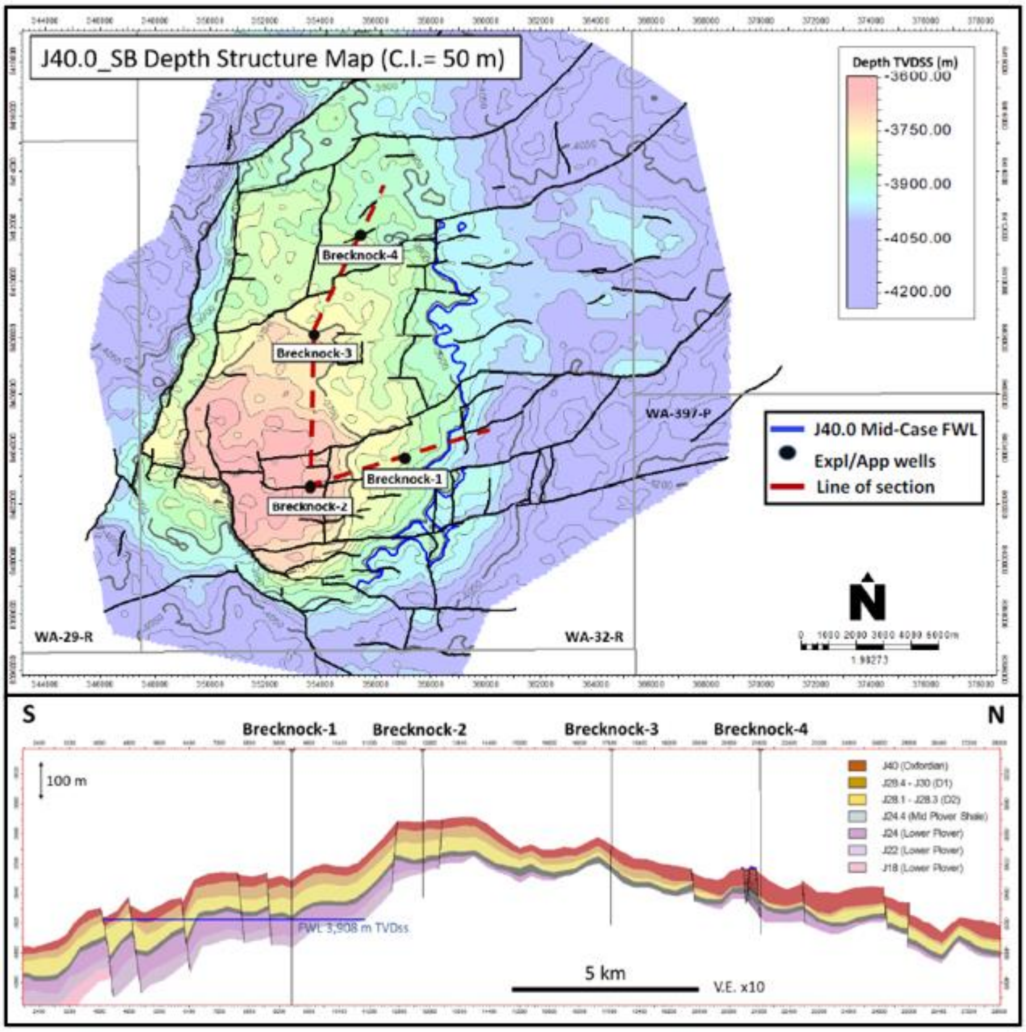
Brecknock

Brecknock is a dip and fault bounded anticlinal high relief structure consisting of the Plover Formation with moderate to good reservoir quality. The structure is 12 km by 8 km and is fault bounded on the west and south with dip closure at the Jurassic level to the east and north (**Figure 4.39**). The field is divided into regions by northeast to southwest trending faults. The Plover Formation reservoirs drape over a tilted Triassic basement fault block. Woodside report a change in seismic character from the flanks to the crest of the structure, which is interpreted to be due to the gradual thinning of the Plover reservoir section. The predominant reservoirs consist of fluvial, coastal, tidal and mouth-bar sediments that thin towards the crest and pinch-out to the north where the volcanics dominate. The two main reservoir units are the J22/J24 and J28.1-J28.3 with moderate to high net-to-gross, moderate to good porosities and permeabilities (100-1,000 mD). Two DSTs were performed in Brecknock-2 achieving rates of 44 MMscfd and 21 MMscfd.

The Brecknock development will depend on the production performance of the Calliance and Torosa fields. It is expected to be brought on stream in a second development phase to maintain plateau production rates at the Calliance/Brecknock FPSO. Four exploration and appraisal wells have been drilled on the structure. The reservoir fluid is a lean gas condensate (CGR ~25 Bbl/MMscf) with moderate non-hydrocarbon content (~8 mol% CO_2). Woodside's estimates of GIIP are indicated in **Table 4.26**.

GaffneyCline reviewed the static models provided by Woodside and considers the Contingent Resource estimates as reasonable based on the technical checks performed. No Seismic data were reviewed. The recovery factor range of 64% to 71% is considered reasonable for this geological environment and development plan.

Figure 4.39: Brecknock Top JB40 Structure Map and Cross Section



Source: Woodside (GaffneyCline Modified)

Woodside's estimates of gas initially-in-place and ultimate recovery volume ranges are shown in **Table 4.26** and **Table 4.27**.

Table 4.26: HCIIP Estimates, Torosa, Calliance and Brecknock Fields, as of 31 December 2021

Field	GIIP (Bscf)			CIIP (MMBbl)		
	Low	Best	High	Low	Best	High
Torosa	13,353	18,318	24,514	283	373	519
Calliance	9,691	12,342	15,912	354	450	532
Brecknock	2,388	3,825	4,600	54	92	120
Total	**25,432**	**34,485**	**45,026**	**690**	**915**	**1,170**

Notes:
1. Volumes are shown gross, including inert gas.
2. Totals may not be exactly equal to the sum of individual entries due to rounding

4.9.2 Field Development Plan and Production Profiles

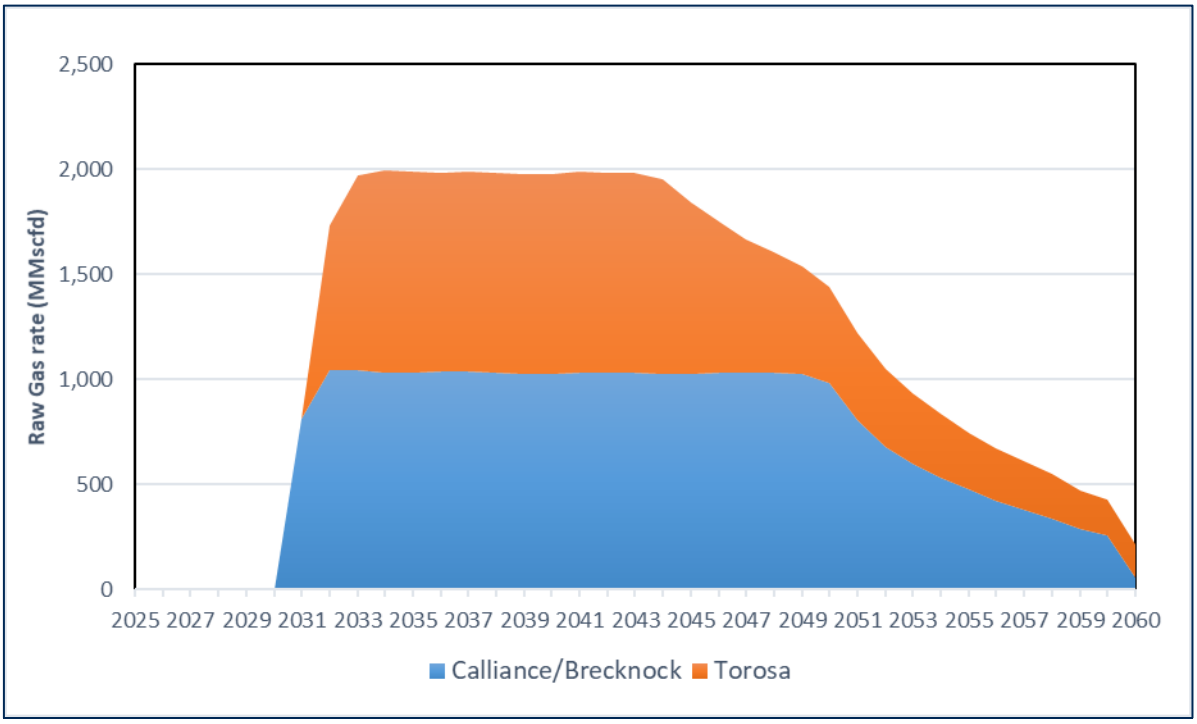
The development concept envisaged for the Calliance, Torosa and Brecknock Fields involves sub-sea wells tied back to two FPSOs, from where gas would be exported via pipeline to tie in to the existing Trunkline 2 (TL2) downstream of the North Rankin Complex, where it would join the supply of gas from the North West Shelf (NWS) fields to the onshore Karratha Gas Plant (see section 4.1). TL2 will be dedicated to Browse production.

The development is envisaged to be phased. In phase 1, twelve high rate, subsea wells would be drilled on Calliance and Torosa to supply the two FPSOs. Subsequent phases (2 to 4) will add up to twenty additional subsea wells in the base case. This would include 4 wells on the Brecknock field, which would be tied back to the Calliance FPSO when needed to maintain the plateau production rate. Technical data gathered as part of the initial development will help planning for subsequent phases.

The production profile presented by Woodside has first gas in 2030 and reaches the plateau rate of ~2 Bscfd by 2032, as shown in **Figure 4.40.** Wellhead gas is expected to have an average 10.5% of CO_2. Expected maximum condensate rates are 55 MBbl/d.

GaffneyCline reviewed the information included in the field development plan and conducted audit checks on fluid properties, recovery factors and deliverability. Woodside's production profile is considered reasonable.

Figure 4.40: Woodside's Combined "Browse to NWS" Production Profile



Source: Woodside

Table 4.27: Estimates of Recoverable Gas and Condensate from Browse Fields as of 31 December 2021

Field	Gross Best Estimate Recoverable Volumes	
	Dry Gas (Bscf)	Condensate (MMBbl)
Torosa	7,070	131
Calliance	6,790	211
Brecknock	2,460	49
Total	**16,320**	**390**

Notes:
1. Offshore Consumed in Operations (CiO) volumes of 689 Bscf are included in the above volumes.
2. Non-hydrocarbon components (mainly CO_2) of 1,717 Bscf are included in the above volumes.

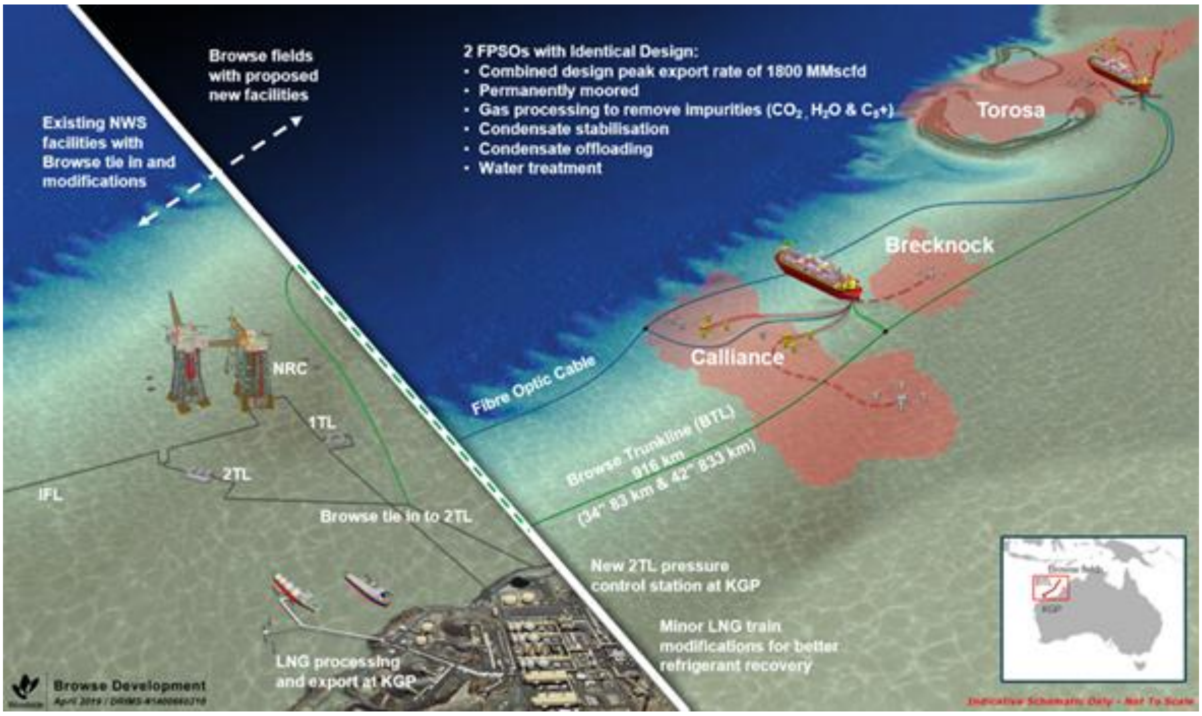
4.9.3 Facilities and Cost Estimates

The Browse development has gone through a number of concept development phases. Despite the large volumes of gas present, the remote location has made development challenging. Initial concepts to develop the fields with a greenfield LNG plant at James Price Point (2010), and with Floating LNG (FLNG) vessels (2015) failed to meet economic hurdles. During these earlier studies, development via the NWS liquefaction facilities at the Karratha Gas Plant (KGP) was considered but discarded due to the lack of available capacity at KGP.

It is now clear that there will be sufficient liquefaction ullage available at KGP from 2030 onwards to process the full Browse production (see NWS section 4.1.4). The current "Browse to North West Shelf (NWS) Project" concept has therefore been selected following a review of 39 development options conducted from 2016 onwards. Use of the existing NWS facilities reduces overall project CAPEX compared to a full greenfield development and is economically more attractive.

The Browse development overview is shown in **Figure 4.41**. Each of the two FPSO's will provide gas/liquids separation, gas processing and dehydration, condensate treatment and stabilization, and gas export compression. Gas exported to shore is expected to have 2.5% of CO_2, which will be further reduced at the LNG plant. In later years, depletion compression can be installed to improve recovery. The offshore facilities will be operated remotely via fibre optic cable link to an operations centre in Perth.

Figure 4.41: Browse Development Overview



The Torosa FPSO will supply gas to an 83 km x 34" pipeline, which will tie in to an 833 km x 42" pipeline from the Calliance FPSO to a tie in to the existing TL2 trunk-line to KGP, which will be dedicated to Browse production. In this way, full use is made of the existing NWS/KGP infrastructure and relatively minor modifications will be required to the KGP itself, apart from facilities life extension provisions.

The Browse development plan indicates a development period of 5 years from FID to first gas from the first (Calliance) FPSO. First gas on the second (Torosa) FPSO will follow 12 months later, allowing sequencing of the two vessels during construction.

The Browse to NWS Project is predominantly based on proven technologies with the development's two FPSOs and subsea and pipeline facilities within the range of industry experience, which should keep project execution risks manageable. The function of the FPSOs includes receipt of gas from the subsea system, acid gas removal and venting, gas hydrocarbon and water dew pointing, gas export compression, condensate stabilisation, storage and offloading, and produced water treatment for disposal. Woodside has included provisions in the design for potential future depletion compression, carbon capture and storage and produced water injection provided they are economically justifiable.

4.9.3.1 Facilities Operability, Integrity, and Infrastructure

The Browse development will be based on two FPSO's producing gas to the existing KGP. Significant investments are planned to the KGP to upgrade and extend facilities life.

The KGP is interconnected with the Pluto LNG facility via the Pluto-KGP interconnector and can also deliver gas to the Western Australia domestic gas market through the Dampier to Bunbury pipeline.

4.9.3.2 Decommissioning and Restoration (D&R) Planning

Browse end of field life is not expected to occur before 2050, so D&R planning is at a conceptual level.

4.9.3.3 Cost Review

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the offshore Browse and onshore KGP operations from 2021 to the end of field life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed CAPEX and OPEX cost forecasts as reasonable. GaffneyCline has amended the D&R estimate in line with current industry practice, i.e. removal of subsea flowlines and equipment, removal of the FPU's, and P&A of all wells. The export pipeline is assumed to be cleaned and left in situ.

Gross Life of Field CAPEX for the Browse development is estimated to be US$20,813 MM, of which US$14,337 MM estimated to first production.

4.9.4 Contingent Resources

GaffneyCline considers the potentially recoverable volumes for the Browse development project to be Contingent Resources (Development on Hold) as the JVP is yet to reach final commitment to develop. Contingent Resources volumes are shown in **Table 4.28**.

Table 4.28: Gross 2C Contingent Resources, Torosa, Calliance and Brecknock Fields, as of 31 December 2021

Field	Gross 2C Contingent Resources	
	Dry Gas (Bscf)	Condensate (MMBbl)
Torosa, Calliance and Brecknock	14,603	390

Notes:
1. Offshore Consumed in Operations (CiO) volumes of 689 Bscf are included in the above volumes.
2. Non-hydrocarbon components (mainly CO_2) of 1,717 Bscf are included in the above volumes.

4.9.5 GaffneyCline's Production and Cost Valuation Profiles for Browse

GaffneyCline's valuation scenario production profile for Woodside's Browse asset is given in **Figure 4.42** with the associated real term cost profiles provided in **Figure 4.43**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the recoverable volumes of the potential Browse Project 2C Contingent Resource Volumes documented in **Table 4.28**. The project Chance of Development (COD) is discussed in Section 4.9.6 with a recommendation for valuation purposes. Technical and commercial contingencies are also discussed that impact the project Chance of Development utilised for risk assessment.

The regulatory carbon cost assumption for the Browse Asset is as per Woodside's below baseline assumption for this project.

Figure 4.42: 100% Browse Asset Production Profile

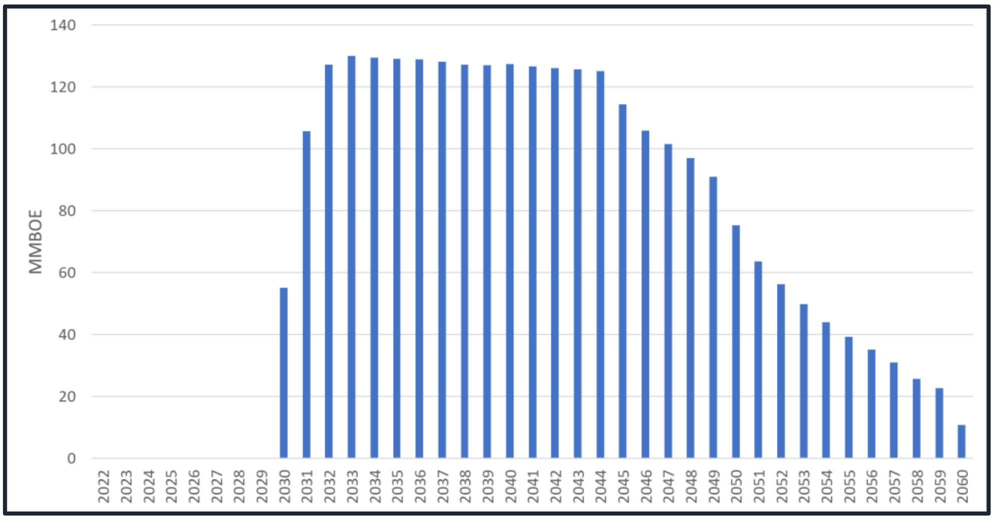
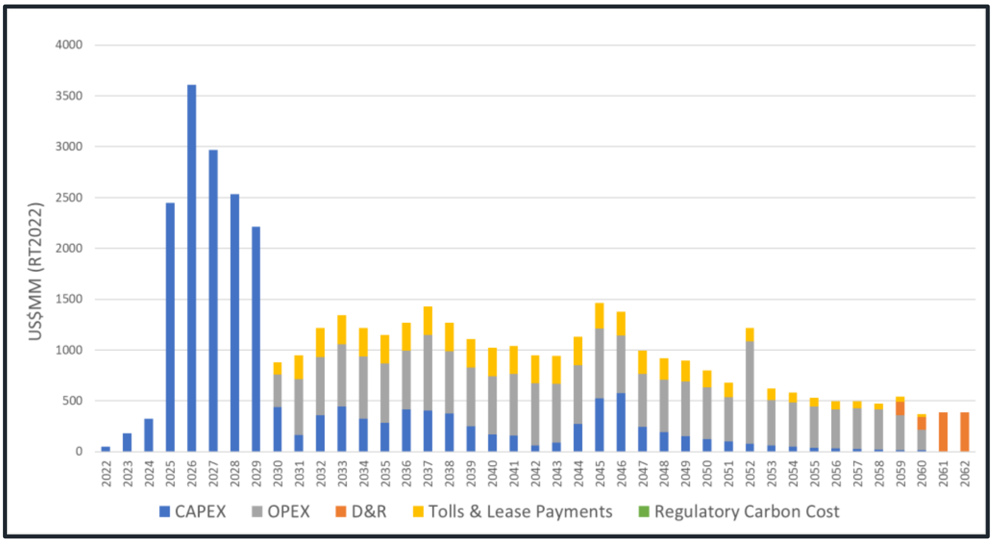


Figure 4.43: 100% Browse Asset Cost Profile



4.9.6 Browse Asset Chance of Development

The sub-classification status of the Browse Project is Contingent Resources - Development on Hold due to limited field project activity since 2010 and a number of other factors outlined below. An upstream development with a new greenfield LNG facility is not economically justifiable and the best chance of development is a backfill opportunity utilising existing LNG plants.

Woodside's current development planning case is backfilling the North West Shelf joint venture LNG trains starting in 2030. Agreement on the Browse development depends on the commercial negotiations regarding the tariffs to process the Browse gas into LNG and domestic gas. The NWS JV has six partners with equal shareholdings and potentially competing commercial interests. It is likely that the commercial negotiations between the Browse JV and the NWS JV could be a lengthy and difficult process.

The Browse raw gas has between 8.2% to 12.2% CO_2, and the current plan is to backfill the older less fuel-efficient NWS LNG plants. This will place the Browse development in a moderately high carbon intensity LNG project range. Projects with higher carbon emissions could attract further environmental scrutiny from various stakeholders. As a mitigation measure, the project may require carbon capture and/or carbon offsets that could erode the project economics. Woodside is in the initial stages of studying the possibility of carbon capture for the Browse development, but such costs are not available as part of the current evaluation case. Carbon mitigation measures may also result in significant delays or potentially the shelving of the project.

The Browse JV partners (Woodside, Shell, BP, Japan Australia LNG, PetroChina) need to agree on the Browse development plan as it is progressed. There is often a significant divergence on approaches related to carbon management with upstream players. There is also a growing divergence on economic hurdle rate requirements in relation to carbon intense projects. These issues between Browse JV partners could further delay the sanctioning of the project.

Considering the marginal economics, complex commercial negotiations, and environmental considerations, GaffneyCline considers the Browse project far from certain. Significant delays are still possible as there has been in the past for this project since the early 2000s. GaffneyCline recommends a 25% chance of development for KPMG's valuation analysis.

4.10 Greater Sunrise

The Sunrise and Troubadour fields, collectively known as the Greater Sunrise Fields, are currently located in Retention Leases NT/RL2 and NT/RL4 in Australian waters, and in PSC 03-19 and PSC 03-20 in Timor-Leste waters (formerly in the Joint Petroleum Development Area). Woodside is the operator with 33.44% interest. Pursuant to the treaty between Australia and Timor-Leste establishing their maritime boundaries in the Timor Sea brought into force on 30 August 2019, the Governments of Australia and Timor-Leste and the Sunrise Joint Venture are required to enter a new production sharing contract which will replace the four current titles. Negotiations are ongoing. The Sunrise Joint Venture (SJV) participants are Woodside (Operator), Timor Gap and Osaka Gas.

Woodside has informed GaffneyCline that the same treaty establishes the "Greater Sunrise Special Regime" and that Annex B, Article 2 thereof includes the following text: *"Title to Petroleum and Revenue Sharing:*

1. *Timor-Leste and Australia shall have title to all Petroleum produced in the Greater Sunrise Fields.*

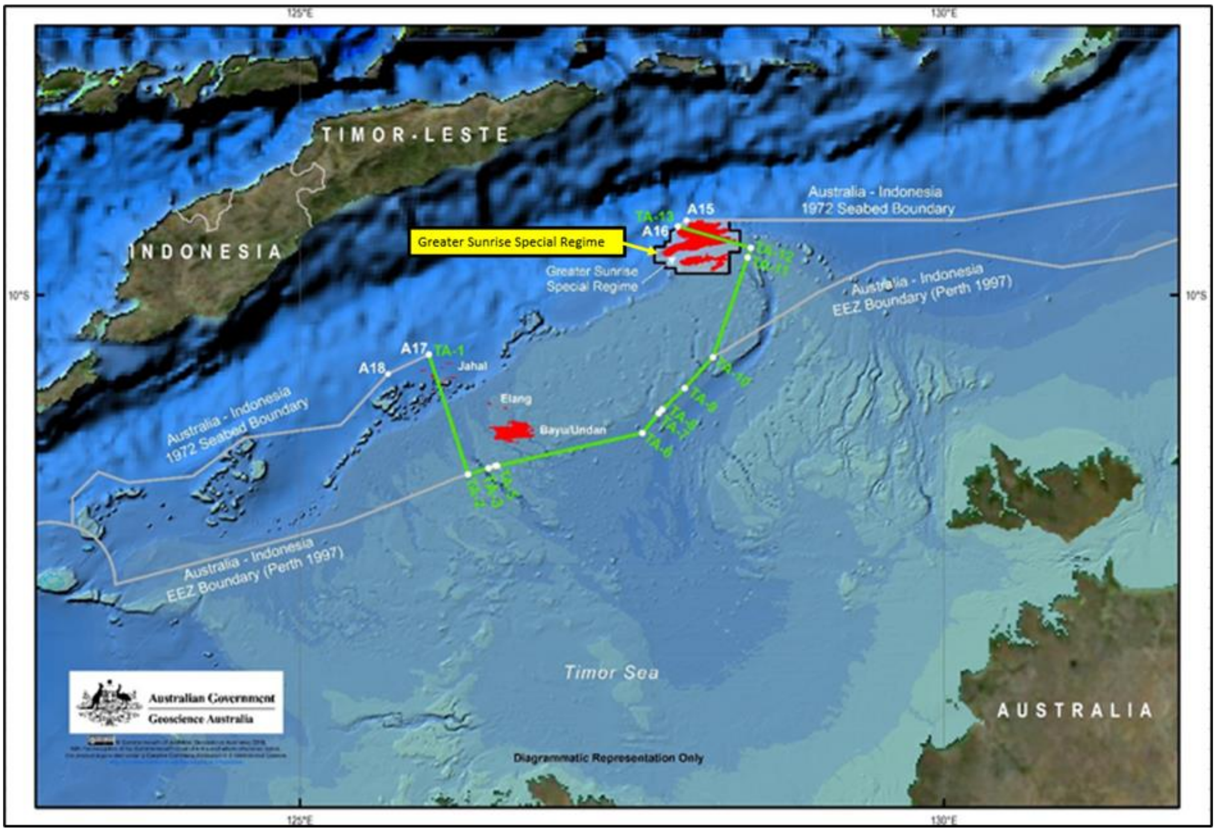
2. *The Parties shall share upstream revenue, meaning revenue derived directly from the upstream exploitation of Petroleum produced in the Greater Sunrise Fields:*

   a. *in the ratio of 70 per cent to Timor-Leste and 30 per cent to Australia in the event that the Greater Sunrise Fields are developed by means of a Pipeline to Timor-Leste; or*

   b. *in the ratio of 80 per cent to Timor-Leste and 20 per cent to Australia in the event that the Greater Sunrise Fields are developed by means of a Pipeline to Australia."*

These fields lie approximately 150 km southeast of Timor-Leste and 450 km north of Australia in an area where the water depth varies between 100 and 600 m. North of the Sunrise Field the water depth increases to approximately 3,000 m in the Timor Trough (**Figure 4.44**).

Figure 4.44: Greater Sunrise Fields Location Map



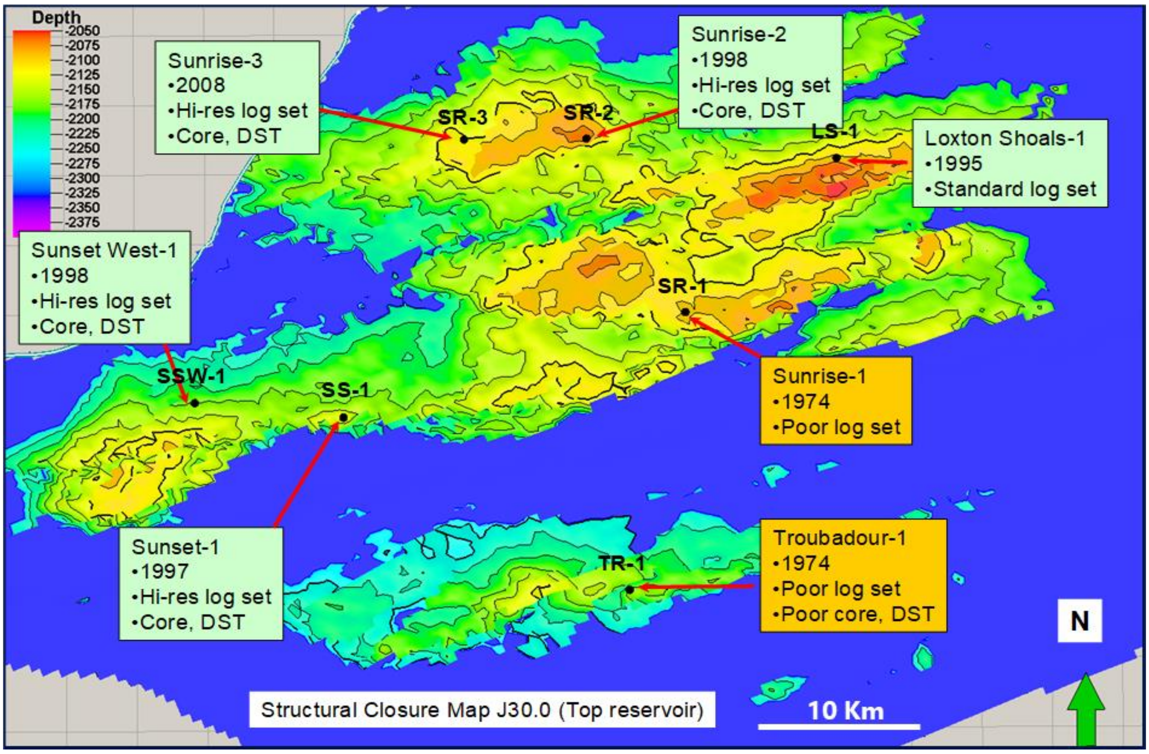
Source: Woodside

4.10.1 Field Description

The Greater Sunrise fields are located within the Bonaparte Basin on the Sunrise High, a major regional feature on the east of the Sahul Platform. The Greater Sunrise fields were discovered by the Troubadour-1 and Sunrise-1 wells in 1974. Since then, six appraisal wells have been drilled and, in 2000, the Mescal 3D seismic survey was acquired. Technical studies have confirmed the presence of a significant gas resource.

The 3D seismic data and well penetrations allow for the interpretation of the fault complex, which consists of large elongated east west trending fault blocks (75 x 50 km overall) with ~165 m of structural relief. A large fault (1 km throw) forms the northwest boundary of the closure, and a central easterly trending fault (150 m throw) separates the Sunrise Field from the Troubadour Field to the south. Smaller north-easterly and easterly faults with throws of less than 80 m are common. The Greater Sunrise map is presented in **Figure 4.45**.

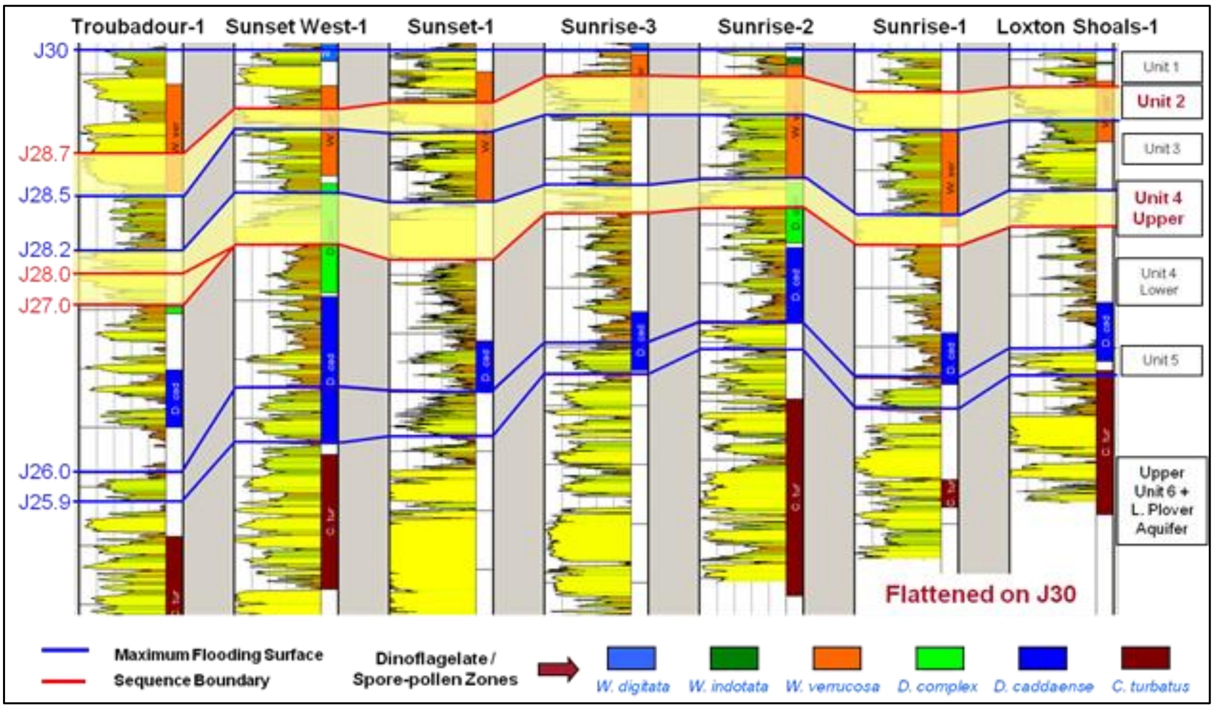
Figure 4.45: Greater Sunrise Top Reservoir Map above Free Water Level



The gas bearing reservoir interval at Sunrise and Troubadour is 60 to 80 m thick and composed of inter-bedded marginal marine to marine quartzose sandstones, siltstones and shales of the Middle Jurassic Plover Formation. Within this section, the majority (approximately 80%) of the gas occurs within two laterally extensive, middle to upper shoreface sandstone intervals (Unit 2 and 4) with average thicknesses of approximately 10 m. These two intervals are separated by a ~30 m thick sequence of marginal marine to marine heterolithic deposits (**Figure 4.46**).

Transgressive marine siltstones and claystones of the Flamingo Group (Callovian to early Oxfordian age) overlie the Plover Formation, forming the top seal. Woodside interprets that the edge aquifers to the east, south and west are expected to provide reasonable pressure support and water influx.

Figure 4.46: Greater Sunrise Wells Cross Section



3D seismic data acquired in 2000 and reprocessed in 2007 and 2008 are of reasonable quality and the wireline well data are extensive, with the Sunrise-3 well proving to be an excellent source of reservoir and test data. The main subsurface uncertainties are GIIP (with structure and facies predominating), reservoir behaviour, particularly that of intra field faults and their transmissibility, and aquifer support. Subsurface uncertainty, particularly dynamic performance, is a major risk and the development will be phased so that technical data acquired in early phases can be used to optimise future phases.

4.10.2 Field Development Plan and Production Profiles

The Sunrise Joint Venture Participants have completed a technical and commercial evaluation of various development concepts including a Floating Liquefied Natural Gas (FLNG) facility located over the Sunrise Field. However, at this stage there is no preferred concept. In the FLNG concept studied, the annual average sales capacity was approximately 4.1 Mt p.a. and the facility would separate condensate for export. The development wells and associated subsea infrastructure would be installed across five development phases, including compression, resulting in approximately 26 wells in total. The first development phase would consist of approximately seven production wells and associated subsea facilities.

Learnings from initial phase static and dynamic reservoir performance data would be used to further optimise future development phases including development of the Troubadour Field.

Based on the FLNG development case studied, gas recovery incorporating compression is projected to be 54%. This equates to a Sunrise Joint Venture agreed dry gas, 2C Contingent Resource estimate of 5.13 Tscf. The Sunrise Joint Venture agreed condensate CR estimate is 226 MMBbl.

The currently reported Resources estimates are based upon the results of studies completed in 2009. Woodside classifies the Sunrise/Troubadour project as Contingent Resources Development Not Viable. Under PRMS, the project might also be classified On Hold, due to the uncertainty of regulatory conditions, fiscal terms and development concept. GaffneyCline adopted Woodside's estimates of gross Contingent Resources (**Table 4.29**).

Table 4.29: GIIP and Gross Contingent Resources for Greater Sunrise as of 31 December 2021

Field	GIIP (Bscf)	Gross 2C Contingent Resources	
		Gas (Bscf)	Condensate (MMBbl)
Greater Sunrise	10,736	5,134	226

4.10.3 Recommended Valuation Range for Greater Sunrise

Due to ongoing negotiations with the Timor-Leste government on fiscal terms and potential development concepts, it is not possible to value Greater Sunrise using an income approach.

Most of the exploration and appraisal activity for this field was done during 1970s to early 2000s. The sunk cost approach for valuation does not provide a suitable reference for the assets as the cost information is old. There is also very limited on-going activity to calibrate the old cost information.

In GaffneyCline's view there is most likely no open market for this asset as it has been in negotiation with a long history of stalemates due to proposed project marginal economics. Shell and ConocoPhillips sold their equity position in Greater Sunrise to the Timor-Leste Government in Q4 2018 for US$ 300 MM and US$ 350 MM respectively. The Timor-Leste government may possibly be the only interested buyer for this asset.

The previous transactions with the Timor-Leste government provide comparable transaction guidance on market value. Other similar transactions are also applicable to define the lower value range to account for the fiscal uncertainty with the PSC under negotiation and approaching PSC expiry in 2026. The weaker financial position of the Timor-Leste government to fund an additional equity purchase as well as their share of the development costs is also a consideration for utilising a lower value.

GaffneyCline selected similar transactions for the Contingent Resources in Timor-Leste and Australian offshore with public domain cross-checks (**Table 4.30**).

Table 4.30: **Selected Market Comparable for Contingent Gas Resources**

Date	Asset	Seller	Buyer	Firm Price Paid	Net Resources	Firm Multiple
				US$ MM	Bcf	US$/Mcf
Nov 18	Greater Sunrise	Shell	Timor-Leste Government	300	1,624	0.18
Oct 18	Greater Sunrise	ConocoPhillips	Timor-Leste Government	350	1,832	0.19
Feb 18	Scarborough	ExxonMobil	Woodside	444	3,650	0.12
Jul 16	Scarborough, Jupiter/Thebe	BHP Petroleum	Woodside	250	2,600	0.10

Notes:
1. Source: GaffneyCline analysis, Public Domain.
2. Contingent payments excluded from analysis as timing during transaction was speculative.

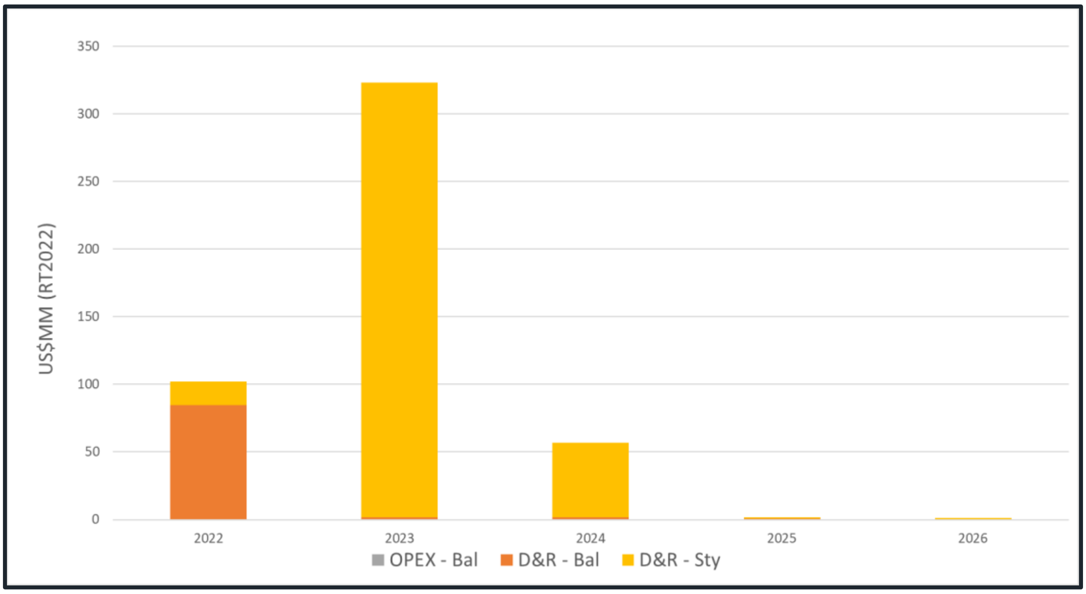
Based on the transaction multiple range of 0.1 US$/Mcf to US$0.19 US$/Mcf from **Table 4.30**, the estimated valuation for the 2039 Bscf net raw gas of Woodside's 2C resource is US$204 MM to US$387 MM.

GaffneyCline therefore recommends a valuation range of **US$204 MM** to **US$387 MM** for the Greater Sunrise discovered resources for KPMG's consideration.

4.11 Australian Non-Producing Assets

In addition to discovered and producing assets described above, Woodside also have outstanding D&R obligations in respect of two fields that have ceased production, where decommissioning and restoration activities are in planning or in progress. GaffneyCline has reviewed the D&R estimates of these fields, Balnaves and Stybarrow, and accepted or updated the costing basis in line with current industry practise (**Figure 4.47**).

Figure 4.47: Woodside100% D&R Balnaves and Stybarrow Cost Profile



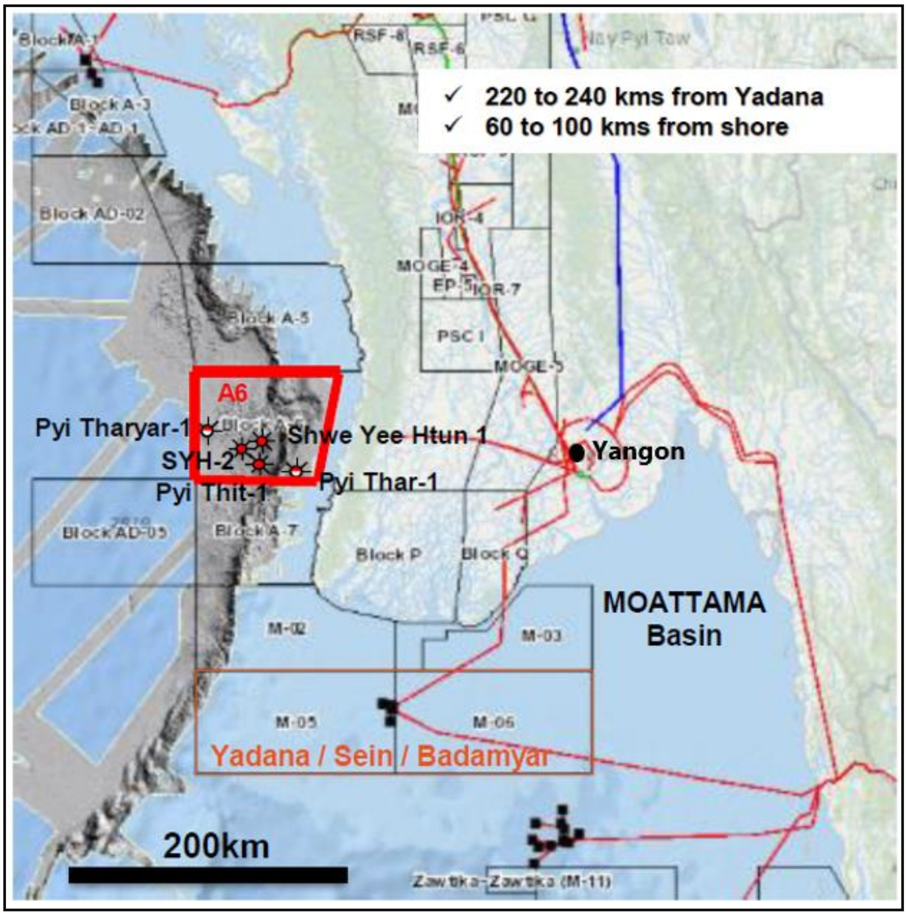
5 Woodside Myanmar

At the effective date of this ITSR, Woodside had an interest in offshore Block A6 in Myanmar. However, Woodside issued an ASX announcement in January 2022 that it had decided to withdraw from its interests in Myanmar. Nonetheless, given this ITSR's effective date, the asset is included in the ITSR and is briefly described below.

Woodside's Myanmar Block A6 is operated by TotalEnergies (**Figure 5.1**) and covers an offshore area of 8,928 km^2 in the Rakhine Basin of Western Myanmar. The A6 Block is situated in a water depth ranging from 30 to 2,500 meters and is located 260 km west of Yangon and 250 km northwest of the Yadana/Sein/Bandamyar offshore gas fields also operated by Total. The joint venture comprises Woodside (40%), MPRL (Government Liaison operator, 20%) and TotalEnergies (40%). However, after government back-in to any development, Woodside's interest would be reduced to 25%.

The Block A-6 PSC expires on the 23 December 2022. JV partners have been under negotiation with MOGE (Myanmar national oil company) for PSC retention. However, the future of any development in Block A-6 is uncertain due to the political situation in Myanmar. Note that on 27 January 2022 (after the effective date of this ITSR), Woodside announced it was withdrawing from its interests in Myanmar.

Figure 5.1: Woodside's Block A6 Myanmar



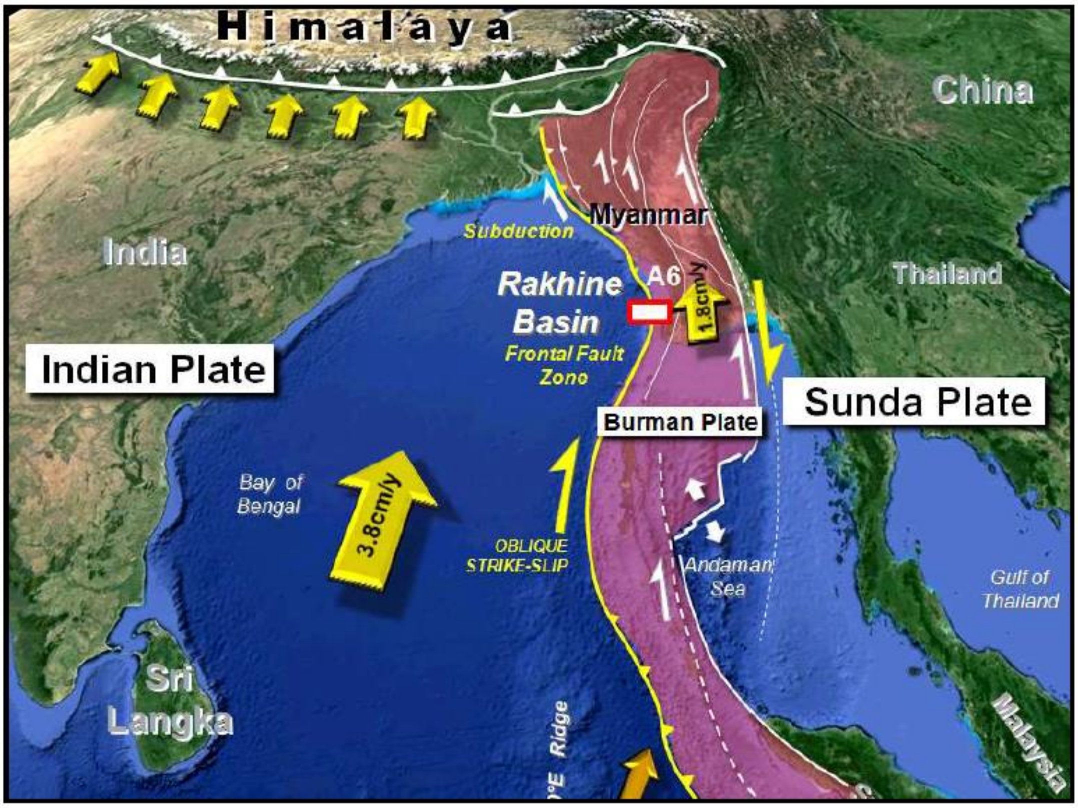
Source: Woodside (GaffneyCline Modified)

5.1.1 Field Description

The Rakhine Basin lies offshore Myanmar at the junction between the Indian and Sunda tectonic plates that are separated by a strike-slip frontal fault zone (**Figure 5.2**).

The basin receives sediment influx in the northern part from the Bramaputra/Gange system, whereas sediments from the paleo-Irrawady system fill the eastern part of the basin, where the A6 Block is located. The front thrust compression induced the Saung anticline structure, where several confined turbiditic channels are identified, which form the basis of the LCC-3C and LCC-1A discoveries.

Figure 5.2: Structural Setting



Source: Woodside

The Shwe Yee Htun (LCC-3C) gas accumulation was discovered by the Shwe Yee Htun-1 well, which was drilled between November 2015 and January 2016. Shwe Yee Htun-1 encountered 127.5 m of gross gas column, with 32 m of net sand in turbidite Pliocene Formation sandstone units. The Shwe Yee Htun gas accumulation was appraised by the Shwe Yee Htun-2 well between July and September 2018. Shwe Yee Htun-2 encountered 168 m of gross gas column with 41 m of net sand in the same formation. The Pyi Thit (LCC-1A) gas accumulation was discovered by the Pyi Thit-1 well in July 2017. Pyi Thit-1 encountered 65 m of gross gas column, with 32 m of net sand in Pleistocene Formation sandstone units.

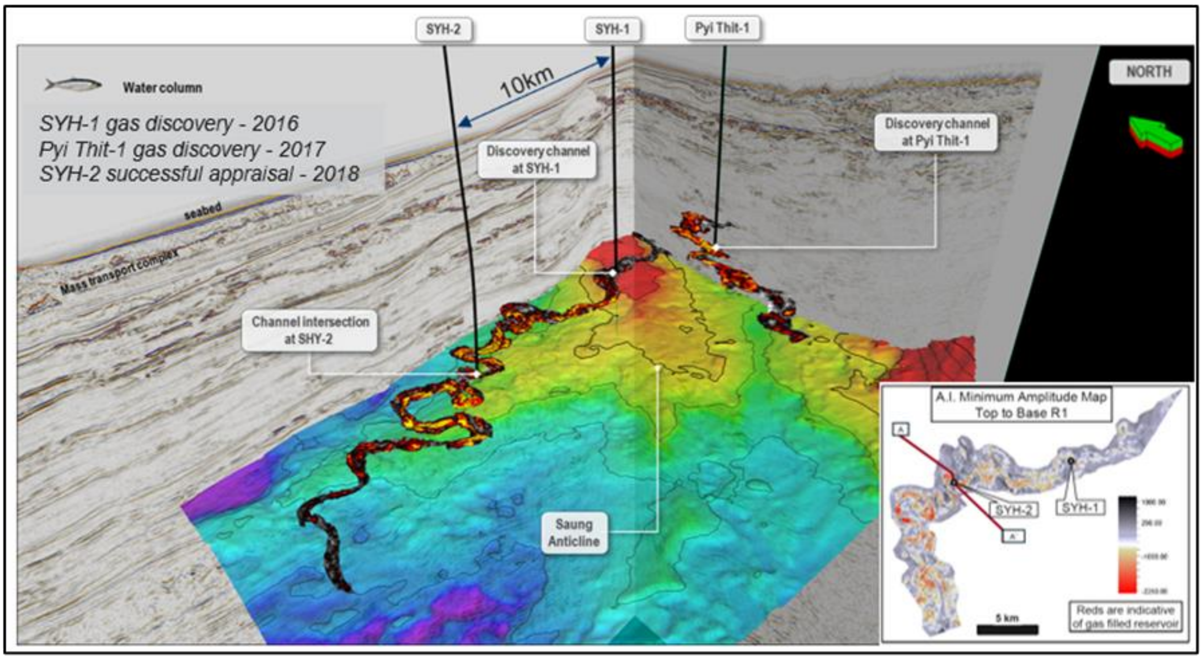
Gas compositional analysis of the numerous samples acquired indicates, on average, almost pure methane of biogenic origin (99.5% C1).

LCC-3C

Four LCC-3C gas bearing reservoirs were penetrated (R1, R2U, R2L and R3) by the two exploration/appraisal wells with biogenic dry gas and net sand thicknesses encountered of 10 to 20 m per reservoir. A porosity range of 18 to 23 % was measured with permeability at 50 to 65 mD estimated by the SYH-2 drill stem test (DST). The DST was performed across a 35 m section of the reservoir and flowed at ~53 MMscfd on a 40/64" choke over 80 hours.

The Free Water Level encountered is consistent with the DHI (Direct Hydrocarbon Indicator) observed on the seismic (**Figure 5.3**). GaffneyCline reviewed the static model provided by Woodside and considers the volume estimates as reasonable based on the technical checks performed. The volumes were reproduced in the Petrel model provided with estimates also confirmed utilising a 1D-Monte-Carlo analysis with GaffneyCline's vetted reservoir parameters. The mapped turbidite channels utilising the seismic amplitudes defined the lateral reservoir extents. This is one of the major uncertainties along with vertical connectivity, Net to Gross distribution and subsequent production contribution from thin and poorer facies in this slope turbidite environment. The recovery factor range of 64%, 69% and 73% are considered reasonable for this geological environment.

Figure 5.3: Shwe Yee Htun (LCC-3C) and Pyi Thit (LCC-1A)



Source: Woodside

LCC-1A

Three LCC-1A gas bearing reservoirs were penetrated (R1, R2 and R3) by the Pyi Thit 1 (PYT-1) exploration well which was plugged and abandoned on the 20 August 2017. Biogenic dry gas at ~99.5% C1 was encountered with net sand thicknesses of 20 to 30 m per reservoir. The porosity range was measured from 20 to 25% with a permeability at 150 mD as estimated by the PYT-1 DST. The DST was performed across a 29 m section of the reservoir and flowed at ~50 MMscfd on a 44/64" choke over 44 hours with strong reservoir pressure support. GaffneyCline reviewed the static model provided by Woodside and considers the volume estimates as reasonable based on the technical checks performed. A similar workflow to the LCC-3C review was also performed with similar uncertainties also applicable as discussed above. The recovery factor range of 64 to 70% is considered reasonable for this geological environment.

Table 5.1 includes the Gross Contingent Resource proposed by Woodside which GaffneyCline has reviewed and considers within audit tolerance for the LCC-3C and LCC-1A culmination.

Table 5.1: Myanmar GIIP and Gross Contingent Resources as of 31 December 2021

Reservoir	GIIP (Bscf)	Gross 2C Gas Contingent Resources (Bscf)
LCC-3C	2,590	1,787
LCC-1A	740	480
Total	**3,330**	**2,267**

Notes:
1. The Offshore Consumed in Operations (CiO) volumes are 33 Bscf for the LCC-3C and the LCC-1A joint development proposed by Total the operator.
2. Contingent Resources reported are 100% of the volumes estimated to be recoverable from LCC-3C and LCC-1A culmination in the event that it is developed.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that LCC-3C and LCC-1A 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).

5.1.2 Field Development Plan

The currently defined development plan consists of a subsea tie back to a new dehydration and compression platform located 65 km away on the shelf, and an export pipeline tied in downstream of Yadana (to a new riser platform). The number, phasing and location of the wells is still being optimised, but due to the current political instability in Myanmar, Woodside and the JV partners have all decisions under review.

The development concept envisages ten near-vertical gas producing wells with open hole gravel pack (OHGP) completions (six wells at start-up, two infill wells and two contingency wells drilled at a later stage to maintain the plateau).

A plateau rate of 400 MMscfd is envisaged with a shallow water hub on the shelf of the block where a conventional integrated processing platform would enable pressure break and gas treatment for further export. The platform would be installed by float-over with an export flowline of 265 km connected with a riser platform to both MGTC (Thailand export pipeline) and the Yangon domestic pipeline.

Woodside has indicated that the project is currently “sub-commercial and technically immature”, so GaffneyCline considers the project maturity sub-class as Development Not Viable.

5.1.3 Recommended Valuation Range for Myanmar Asset

The status of the block A-6 development is on hold due to the political situation in Myanmar as a result of the recent return to military rule. Woodside and partner TotalEnergies have stopped their project activities. Woodside has also demobilised all its offshore personnel and ceased any exploration activity in the country. The Block A-6 PSC expires on the 23 December2022. JV partners are under negotiation with MOGE (Myanmar national oil company) for PSC retention.

Given the uncertain political situation in Myanmar, both TotalEnergies and Woodside initially indicated to keep new projects under review until the political situation improves. The lack of investment commitment during PSC renewal negotiations so close to expiry could also lead to unfavorable terms or even no contract renewal. This makes the project timing and fiscal terms very difficult for modelling under an income approach.

There is also limited market comparable data available for Myanmar. The political situation from February 2021 after the military coup has also made any past transactions difficult to use as a comparable reference point. There is a very low investor appetite for Myanmar due to the risk of external sanctions, boycotts, or the worsening security situation. GaffneyCline considers that there is most likely no open market for this asset especially as the contract expiry approaches.

The Woodside share for Block A-6 cost spend to year end 2021 is US$165 MM. The Myanmar government could be the buyer of last resort for this asset by partially or fully paying for the Woodside costs spent. Considering the political environment and negotiation position of the Myanmar government such buyout seems an unlikely scenario before the PSC expiry in late 2022.

GaffneyCline verified with Woodside that liabilities and commitments for keeping current assets in Myanmar are not material. Overall, GaffneyCline recommends no material value to be assigned to the Myanmar assets.

Woodside announced on the 27 January 2022 to completely exit their Myanmar oil and gas investments and write-off all investments in the country.

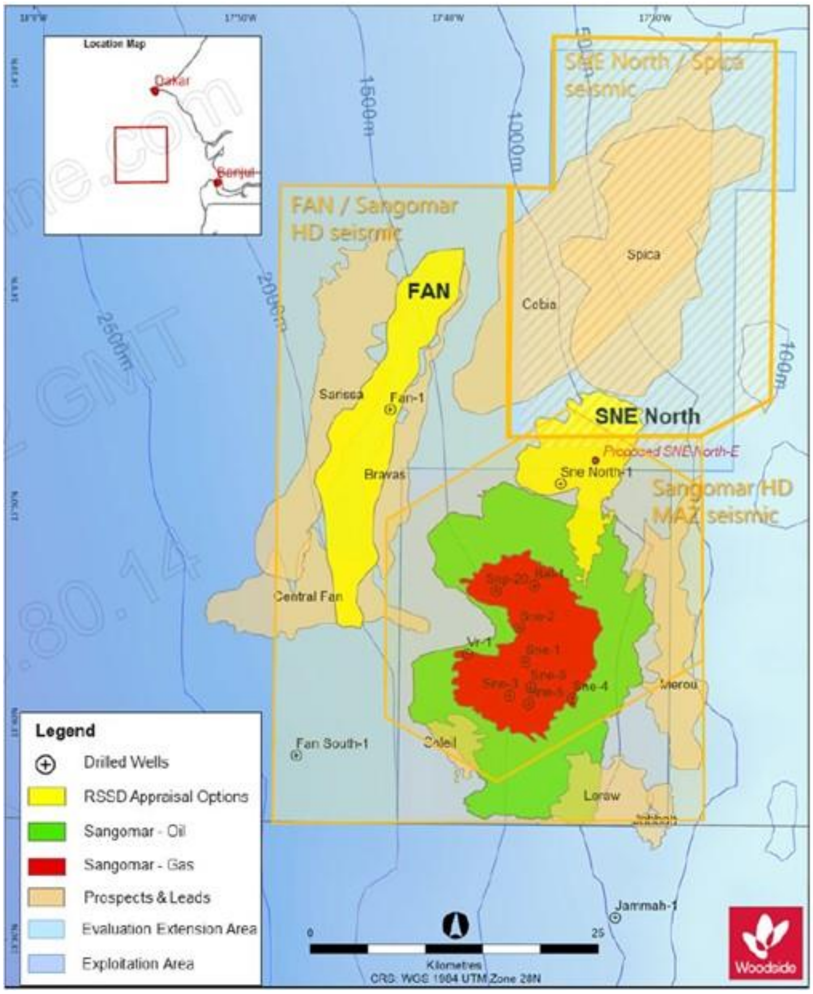
6 Woodside Senegal

Woodside is operator of the Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore (RSSD) Production Sharing Contract (PSC), which contains the Sangomar Exploitation Area, and is also operator of an Evaluation Extension Area (EEA), in which two discoveries, FAN and SNE North are located. Woodside has 82% participating interest in the Sangomar Exploitation Area and 90% in the EAA, the remaining 18% and 10% being held by PetroSen (the Senegalese National Oil Company). The Sangomar Field was previously known as SNE.

The EEA was due to expire in October 2021 and the RSSD JV submitted a PSC extension application to the Ministry of Energies in August 2021 for a period of three years. The RSSD JV remains on title whilst discussions on the terms of the extension are ongoing.

The RSSD licence is located offshore Senegal, approximately 100 km southwest of Dakar, in water depth ranging from less than 200 m to more than 2,000 m (**Figure 6.1**).

Figure 6.1: Location Map of the RSSD Licence and Discoveries



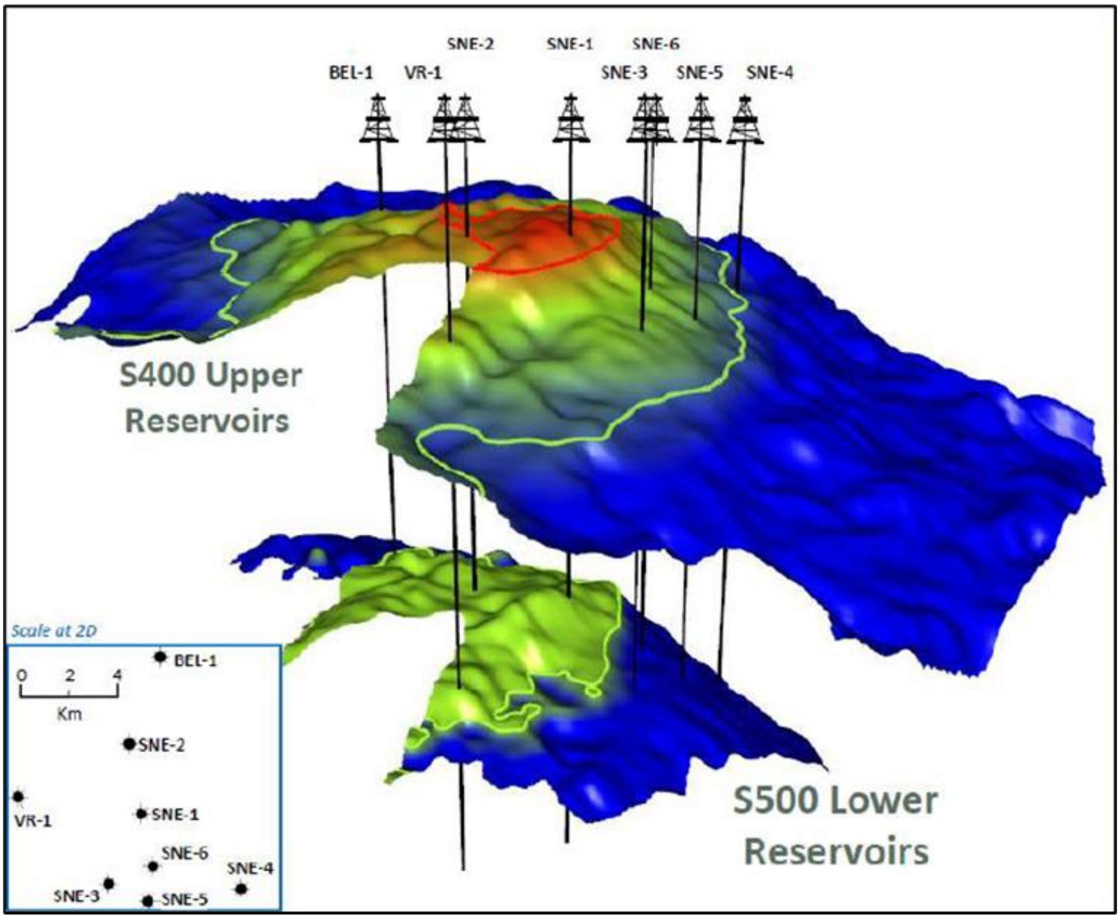
Source: Woodside

6.1 Sangomar Field

6.1.1 Field Description

Sangomar was discovered in 2014 by exploration well SNE-1 and has been appraised by seven further wells, SNE 2-6, BEL-1 and VR-1 (**Figure 6.2**). The exploration and appraisal wells found hydrocarbons at several horizons and confirmed two key reservoir zones: the S400 zone (S440, S460, S470, S480 and S490 reservoirs) and the deeper S500 zone (S520 and S540 reservoirs). The appraisal campaign has provided a good dataset comprising well data, geophysical logs, core, pressures and drill stem tests. Recent acquisition of a multi-azimuth seismic dataset has resulted in the re-interpretation of the field. These data provide the basis for the ongoing field development and can act as a baseline survey for any future 4D seismic acquisition. The multi-azimuth 3D seismic resulted in a change to the drilling sequence and reservoirs targeted in the first development well, drilled late in 2021, the results of which are interpreted to be positive.

Figure 6.2: Sangomar Reservoir Units and Appraisal Wells



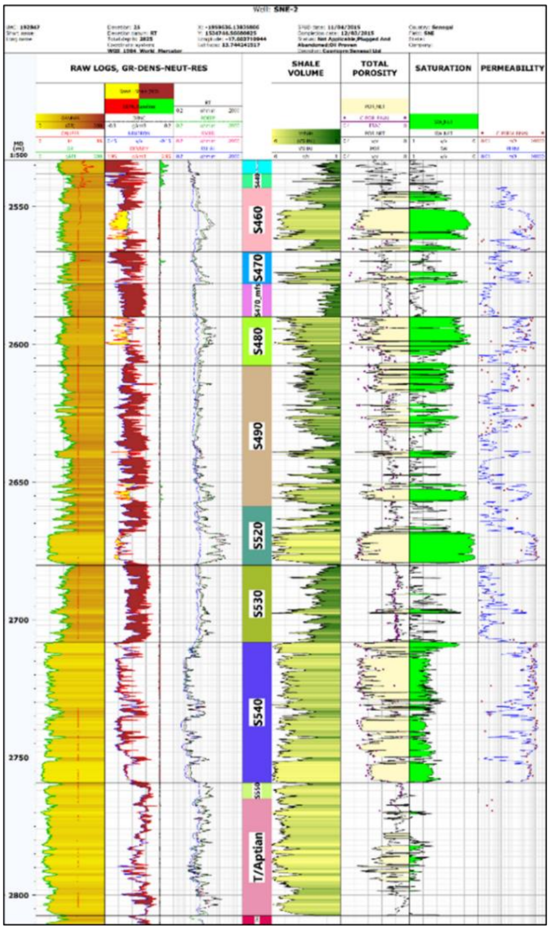
Source: Woodside

The multi-azimuth seismic data provides a significant uplift in data quality compared to the legacy 3D seismic (reprocessed several times). These new data provide better illumination of the reservoir and particularly provide a better image of the S400 reservoir interval.

The S500 sandstone reservoirs are interpreted to be lobe and channel deposits of submarine turbidites in a pro-delta setting, which infilled karstified topography at the top of the underlying carbonate platform. The S520 and S540 reservoirs, to be developed in Phase 1, comprise fine-grained, moderately to well sorted sandstones and present as stacked sands with blocky log profiles (**Figure 6.3**).

The lower S400 reservoir (S440 to S490) are finer grained sandstones, and are more variable than the S500 reservoirs, consisting of silty to very fine grained, moderate to well sorted sands with silty claystones and heterolithics, with high levels of bioturbation throughout. The S460 and S480 reservoirs are to be developed in Phase 1 and are considered to have been deposited by low-density turbidite flows within a pro-delta setting. Core and seismic data have been analysed and deposition is interpreted to have occurred as a complex of sediment wave features with a proportion of the deposition occurring within small channel features and levee settings. The multi-azimuth 3D seismic has provided additional higher resolution data and the interpretation of the sand-wave geometry is being refined and the results incorporated into the well planning.

Figure 6.3: Sangomar Type Well (SNE-2)



Source: Woodside

Average reservoir properties for the primary Sangomar reservoirs as reported in the Exploitation Plan are shown in **Table 6.1**.

Table 6.1: Sangomar Average Reservoir Properties

Item	SNE 460	SNE 480	SNE 520	SNE 540
Average gross thickness (m)	21	22	20	51
Average net to gross (%)	64	70	42	58
Net porosity (%)	22	22	24	24
Net permeability (mD)	57	91	456	453
Average pay water saturation (%)	32	31	13	23

In addition to the principal S400 and S500 reservoirs, a number of minor reservoirs have been found to be hydrocarbon bearing. The shallowest reservoirs are the gas bearing S410/S420, comprising mudstones and siltstones, heterolithics and thin bedded sandstones. The S410 has a higher net to gross ratio than the underlying S420. Pressure data indicate that the S410 and S420 are separate reservoirs and also that they lie on a separate pressure regime to the underlying oil field. The gas has a lower CO_2 content (<2%) than the main field.

The S440 reservoir is the shallowest oil-bearing reservoir and is relatively thin, comprising mudstone lithologies with thin sandstones, interpreted to have been deposited by distal low-density turbidity flow. The sediment may be infilling the lows between the sand waves in the underlying S460 reservoir.

The S470 oil bearing reservoir lies between the S460 and S480 reservoirs and is mudstone dominated but includes 1 to 4 m thick sharp based sandstones. These are interpreted to have been deposited as part of a developing lobe complex. None of these reservoirs are planned to be developed during Phase 1. Data and information gathered during Phase 1 will be required to assess their commercial potential.

From 2015 to 2017 DSTs were performed in SNE-2 (S520 and S490), SNE-3 (S490 and S480) SNE-5 (S480, S470 and S460) and SNE-6 (S480). The S540 reservoir has not been flow tested.

More than 80% of the estimated recoverable volumes attributed to the first phase of development are expected to be recovered from the S520 reservoir, in which a single DST in well SNE-2 was performed. Analysis of this test showed no barriers to flow at least to an estimated radius of 1.2 km, and high average effective oil permeability greater than 750 mD. In contrast every DST in the S460 and S480 has been interpreted with two or more boundaries, confirming the different flow characteristics (more tortuosity) of these reservoirs in comparison with the S520. Estimates of permeability for the S400 reservoirs vary between 30 mD and 210 mD.

An interference test involving SNE-5, SNE-6 and SNE-3 showed continuity over a distance of 1.5 km within the S480 reservoirs in the north-south direction but no continuity in the east-west direction over a distance of 2.0 km. This is consistent with the wavy nature of the sand deposition. Anisotropy of reservoir continuity results in uncertainty in the efficacy of the planned waterflood in the S400 reservoirs.

A comprehensive dataset of static pressures has been acquired in wells SNE-1 to 6, VR-1, BEL-1, as well as SNE North-1 and FAN-1. Best estimate fluid contacts from interpretation of pressure gradients are shown in **Table 6.2**. The GOCs in the S460 and S480 are for all practical purposes the same, as are the FWLs in the S520 and S540. Woodside has indicated that the second development well, drilled late in 2021 targeting the crest of S520, confirmed that no gas cap had been intersected there. This is interpreted to be a positive outcome.

Table 6.2: Sangomar Fluid Contacts from Pressure Measurements

Reservoir	FWL (mss)	GOC (mss)	Column Height (m)
S460	2,673	2,585	88
S480	2,673	2,587	86
S520	2,684	N/A	N/A
S540	2,682	N/A	N/A

Reservoir pressure and downhole fluid analysis indicate that BEL-1 is in a separate compartment to the core area of the field. However, this is expected to impact primarily the S400 reservoirs and it is not regarded material for the Phase 1 development.

Reservoir fluid properties from sampling are summarised in **Table 6.3**. The SNE reservoir fluid shows depth and lateral variation in properties such as saturation pressure, density, GOR and viscosity. These variations are more evident in the S400 reservoirs than the S500 reservoirs, although data coverage in the S500 reservoirs is lower.

Table 6.3: Sangomar Reservoir Fluid Properties

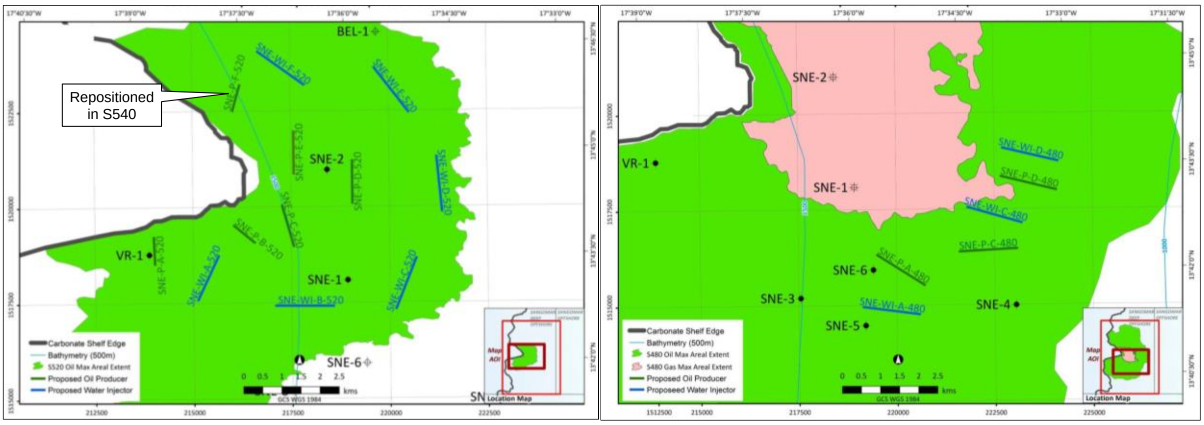
Item	S520	S520	S470	S480	S480
Well	SNE 2	SNE 1	SNE 3	SNE 4	SNE 1
Fluid type	oil	oil	oil	oil	gas
Sample depth (mss)	2,668	2,667	2,618	2,694	2,591
CO_2 (mol %)	13.4	12.0	7.4	0.4	14.6
GOR flashed (scf/stb)	897	798	848	507	N/A
Oil API	32	32	32	28	N/A
Dew Point (psia)	N/A	N/A	N/A	N/A	3,551 @ 69°C

6.1.2 Field Development and Production Profiles

Sangomar is being developed in a phased approach, with Phase 1 focused on the less complex high quality S520 reservoir and smaller scale developments of the S540, S460 and S480 reservoirs having an evaluation component. Phase 1 has 23 development wells and provides pre-investment in the FPSO and subsea infrastructure that will support later phases.

The development plan for the S520 consists of six horizontal producers and six horizontal peripheral water injectors located close to the OWC (**Figure 6.4**). Injectors and producers are expected to have between 750 m and 1,500 m of reservoir section open to flow. The development plan for the S540 reservoir consists of a high-angle production well and a gas injector in the aquifer to dispose of Phase 1 gas that cannot be commercialised and potentially to provide some pressure support. The S540 reservoir is expected to have a strong aquifer and the primary drive mechanism is natural aquifer influx.

Figure 6.4: Sangomar Development Well Locations in S520 (Left) and S460 (Right) Reservoir



Source: Woodside

Woodside has recently adjusted the arrangement of producers to five (from six) in the S520 and two (from one) in the S540. The extra producer in the S540 is also the first development well (originally SNE-P-F-520 in **Figure 6.4,** now SNP-20), which has been drilled, penetrating all reservoirs, as expected, and was completed with a horizontal section in the S540 reservoir late in 2021. Additionally, several batch wells have been drilled to top reservoir, and one has been drilled through the crest of the S520, confirming the absence of a gas cap late in 2021. Woodside advised that as of 31 December 2021, development well SSP-16 had landed in the S520 reservoir.

S460 and S480 have the highest STOIIP but expected recovery factors are lower and more uncertain than in the S520. The Phase 1 development concept for the S460 and S480 reservoirs consists of injector-producer pairs with parallel horizontal sections (one pair in the S460 and three pairs in the S480). In the S480 reservoir, the horizontal sections are oriented approximately ESE-WNW, i.e. transverse to the strike direction of sandstone waves to maximise the exposure of each injector and producer pair to multiple common sandstone packages (**Figure 6.4**). The proposed horizontal reservoir section for these wells is 1,500 m. Woodside advised that as of 31 December 2021, development well SSG-05 had landed in the S460 reservoir.

Phase 1 had FID in January 2020 with first oil scheduled for 2023. A gas injector in the S460 is planned to re-inject Phase 1 gas.

Reserves are attributed to Phase 1 of the Sangomar development. However, the efficacy of a waterflood in the S400 reservoirs has not been demonstrated and there are no analogue fields with successful waterflood to rely on. Therefore, Reserves for the Phase 1 development of the S400 reservoirs have been assigned for a depletion case only, with the balance of the estimated volumes recoverable from a waterflood being classified as Contingent Resources, the contingency being the successful demonstration of waterflood performance.

Phases 2 to 5, with 32 additional development wells, are expected to start production from 2027 and will exploit the S460 and S480 reservoirs further. Pending modifications introduced using learnings from Phase 1, eight injector-producer pairs are planned for S460 and seven pairs for S480. An additional gas injector is also planned for S460 in Phase 2. Contingent Resources are attributed to Phases 2 to 5. Phases 1 to 5 comprise the Full Field Development of Sangomar.

Concurrent with Phases 2 to 5 is the development with three wells and export of the associated and non-associated gas (the “Gas Export” project). Three additional gas production wells are envisaged in the S410 reservoir to supplement solution gas and provide a nominal gas export rate of approximately 70 to 80 MMscfd. The FPSO has been designed to accommodate the Gas Export project with little modification. However, many contingencies remain to be addressed, including definition of a market, pipeline export routes, gas sales contracts and flow rates. Contingent Resources are attributed to the Gas Export.

Beyond the Full Field Development, further long-term opportunities for infill drilling, enhanced oil recovery, development of minor reservoirs (S440 and S470) and exploration opportunities might be considered. No Contingent Resources are currently attributed to these notional developments.

Estimates of STOIIP and technically recoverable resources (TRR) for the Phases as per Woodside’s latest estimates are shown in **Table 6.4**. As described in previous sections, the exploitation plan has recently been modified by the replacement of a S520 production well with a S540 production well. The effect of this change and the results of the initial wells drilled late in 2021 are not reflected in the volumetric estimates shown in **Table 6.4**, as Woodside is currently evaluating the information. However, the results of drilling thus far are positive and therefore GaffneyCline has accepted the field level estimates of recoverable volumes shown in **Table 6.4** as a basis for reporting Reserves and Contingent Resources.

Sangomar is being developed with an FPSO connected to the subsea production system by flexible risers. The subsea infrastructure will consist of two 8” nominal diameter production flowline loops to the north and south of a large canyon on the sea-floor. Eighteen of the 23 Phase I wells are on the southern loop. The FPSO is a 100 Mbopd capacity double-hulled VLCC-conversion with a total liquids capacity of 130 Mblpd and will be permanently turret moored in the eastern side of the field in water depth of 780 m for the duration of the field life.

The produced gas will be processed and used as fuel and for lifting oil production and the excess gas will be reinjected in Phase I. The FPSO will have a gas handling capacity of 130 MMscfd with the ability for backflow to the FPSO for start-up gas or for associated and non-associated gas to be supplied to shore for a later gas export. In addition to the Phase 1 wells, the FPSO has flexibility for 65 more wells. COVID-19 has delayed the VLCC donor vessel arrival at the conversion yard, but the FPSO execution schedule remains on schedule to achieve first oil in 2023.

Table 6.4: Sangomar Estimates of Recoverable Volumes for Phased Development

Case	Reservoir	STOIIP (MMBbl)	TRR (MMBbl)			Recovery Factor	
			Phase 1	Phases 2-5	Full Field	Phase 1	Full Field
Low	S460	1,105	11	51	62	1%	6%
	S480	1,142	32	55	87	3%	8%
	S520	273	117	0	117	43%	43%
	S540	114	2	0	2	2%	2%
	Total	**2,634**	**162**	**106**	**268**	**6%**	**10%**
Best	S460	1,771	14	121	135	1%	8%
	S480	1,321	42	131	173	3%	13%
	S520	374	170	0	170	45%	45%
	S540	129	6	0	6	4%	5%
	Total	**3,595**	**231**	**253**	**484**	**6%**	**13%**

Source: Woodside

6.1.3 Cost Estimates

GaffneyCline has reviewed a range of project cost and supporting documentation provided by Woodside.

The CAPEX appears to be reasonable, based on GaffneyCline's experience. CAPEX for the 2P Reserves case is shown in **Table 6.5**. The potential benefit of water injection in the S460/480 reservoirs has been excluded from the Reserves cases, and accordingly the Phase 1 CAPEX has been adjusted down to include only the cost of one of the four intended S460/480 water injectors. Note that all four injection wells are intended to be drilled in Phase 1 of the current development plan. Any benefit from the effectiveness of the waterflood of the S460/480 reservoirs is accounted for in the Contingent Resources.

Table 6.5: Sangomar Capital Cost Estimate for Reserves Case

Phase 1 (US$ (MM))	2022	2023	2024
Drilling and Completion CAPEX	556	370	35
FPSO CAPEX	398	220	-
Subsea and Pipelines CAPEX	282	31	4
Project Owners Costs & General CAPEX	155	154	32
Total	**1,391**	**775**	**71**

Gross CAPEX for development of the Sangomar Contingent Resources case is estimated to be US$6,157 MM.

The OPEX estimates for the development were evaluated by GaffneyCline, taking into consideration the planned activities and work programs outlined in the documentation. The total OPEX comprises of FPSO, drilling and completion, and subsea and pipelines, of which the FPSO contributes most significantly to the total OPEX.

FPSO OPEX is broken down into fixed (including crew and routine maintenance), variable (including marine services and FPSO chemicals) and Woodside operator costs (including Senegal in-country costs).

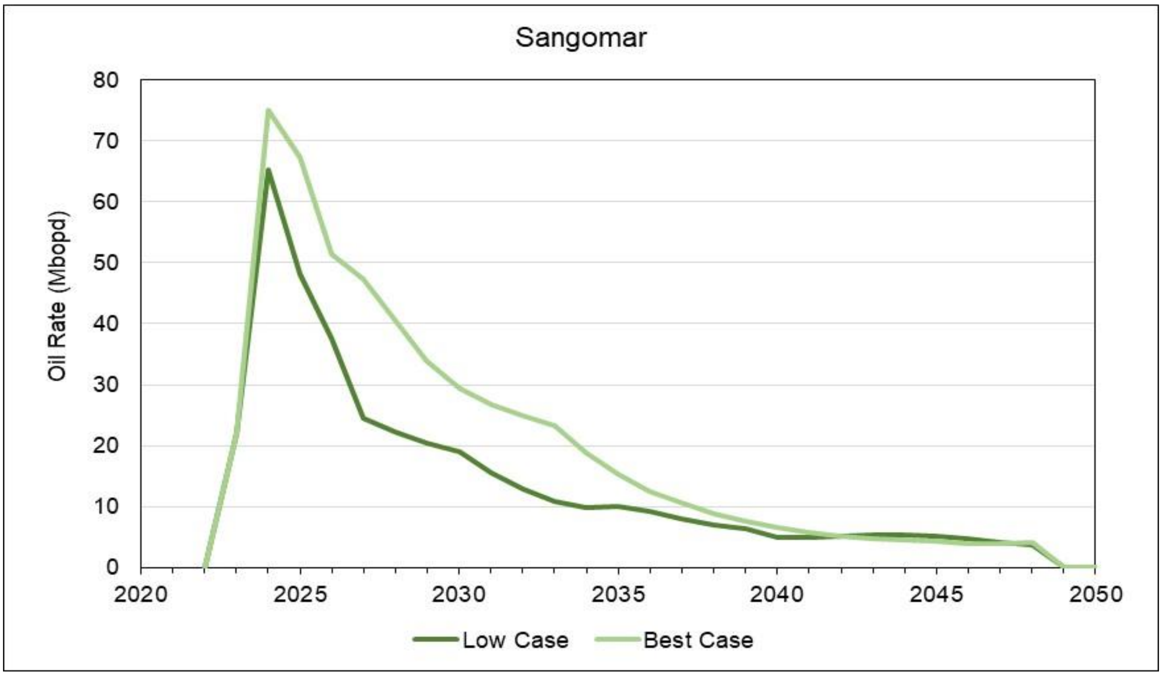
The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The Phase 1 OPEX profiles have been adjusted in the 1P and 2P Reserves cases to reflect the anticipated reduction in OPEX due to the inclusion of only one of the four intended S460/480 water injectors in the Reserves case. Further adjustments have been made to OPEX to account for changes in the variable OPEX components of the FPSO, drilling and completion and subsea and pipelines OPEX costs resulting from differences between the Woodside production profiles compared with the GaffneyCline profiles.

For the Reserves cases, the Phase 1 ABEX has been adjusted to account for the inclusion of only one of the four intended S460/480 water injection wells.

6.1.4 Reserves and Contingent Resources

Oil Reserves are attributed to the Phase 1 development, scheduled to start production in 2023, excluding the potential benefit of the water injection in the S400 reservoirs. The low and best estimates of gross recoverable volumes before imposing economic cut-offs are 143 and 204 MMBbl and the profiles are shown in **Figure 6.5**.

Figure 6.5: Sangomar Oil Production Profiles for Phase 1 Reserves Cases



Contingent Resources are attributed to the effective waterflood of the S400 reservoir of Phase 1 (Development Pending) and for development Phases 2 to 5, which are contingent on the performance of the S400 reservoirs during Phase 1 and scheduled to commence production in 2027/2028 (Development Unclarified) (**Table 6.6**). Contingent Resources are also attributable to a gas export project under evaluation and potentially commencing production in 2027, notionally delivering 72 MMscfd to shore for a period of 13 years or more (Development Unclarified).

Table 6.6: Sangomar Gross 2C Contingent Resources
as of 31 December 2021

Project	Gross 2C Contingent Resources		Development Status
	Oil / Condensate (MMBbl)	Gas (Bscf)	
Phase 1 effective waterflood	27	-	Pending
Phases 2 to 5	253	-	Unclarified
Gas Export	8	367	Unclarified
Total	**288**	**367**	

6.1.5 Infrastructure, Health, Safety and Environment

GaffneyCline has reviewed the environmental protection documentation provided by Woodside and has concluded that the documents are comprehensive and fit for purpose for such a development. The documents have systematically identified and assessed the significant environmental and socio-economic impacts associated with the development activities including any potential accidents and approved by the Senegalese Ministry of Petroleum and Energy. A decommissioning philosophy is mentioned, but further granularity will be required closer to the time, which can be managed through supplementary impact assessments and updates to project risk registers. The other relevant documentation reviewed by GaffneyCline is generally comprehensive and robust and provides confidence that the project will be able to meet the required standards.

Personnel will be transported to the offshore location by helicopter, which will be chartered from existing facilities at Dakar's Blaise International Airport, as well as by marine transfer with FPSO modifications included for this option. The Dakar multi-users' logistics and supply base is already developed and currently supports the drilling campaign.

GaffneyCline has reviewed the extensive Human Resources related documentation including the Sangomar Local Content Strategy, Code of Conduct, Whistleblower Policy, Anti-Bribery and Corruption Policy, Human Rights Policy, Diversity and Inclusion Policy. All the documents reviewed are comprehensive and provide assurance that policies and legislation are being followed, that the employee rights and responsibilities are protected with clear monitoring, evaluation and reporting structures.

GaffneyCline has also reviewed the Occupational Health and Safety documentation which is mainly covered in the ESIA (Section 10) as well as the Sangomar Project Health, Safety and Environment Management Plan, Woodside's Health, Safety, Environment and Quality Policy and the Sangomar Field Development Oil Pollution Emergency Plan. In addition, the ESIA covers Community Health and Safety relating to coastal communities as well as other marine users operating in the vicinity of the offshore area. The HSE documentation demonstrates a sound understanding of the HSE risks associated with the project.

6.2 Fan Discovery

The FAN discovery (well FAN-1) lies to the north-west of the Sangomar Field within the EAA and oil was encountered in Cenomanian aged sandstone, i.e. in different formations to the Sangomar Field. The reservoirs are generally thinly bedded and have low porosity and permeability. A second well, FAN South-1, was drilled to the south of the FAN-1 discovery and encountered hydrocarbons in a pressure isolated accumulation. The multi-azimuth seismic is expected to provide information on the distribution of the reservoir in the FAN discovery. If this interpretation is encouraging, it is anticipated that the discovery will be appraised, with potential to develop it as a satellite to Sangomar. Currently, nominal 2C gross Contingent Resources (Development Unclarified) of 90 MMBbl are attributed to FAN. Estimates of recoverable volumes for FAN are subject to a very wide range of uncertainty.

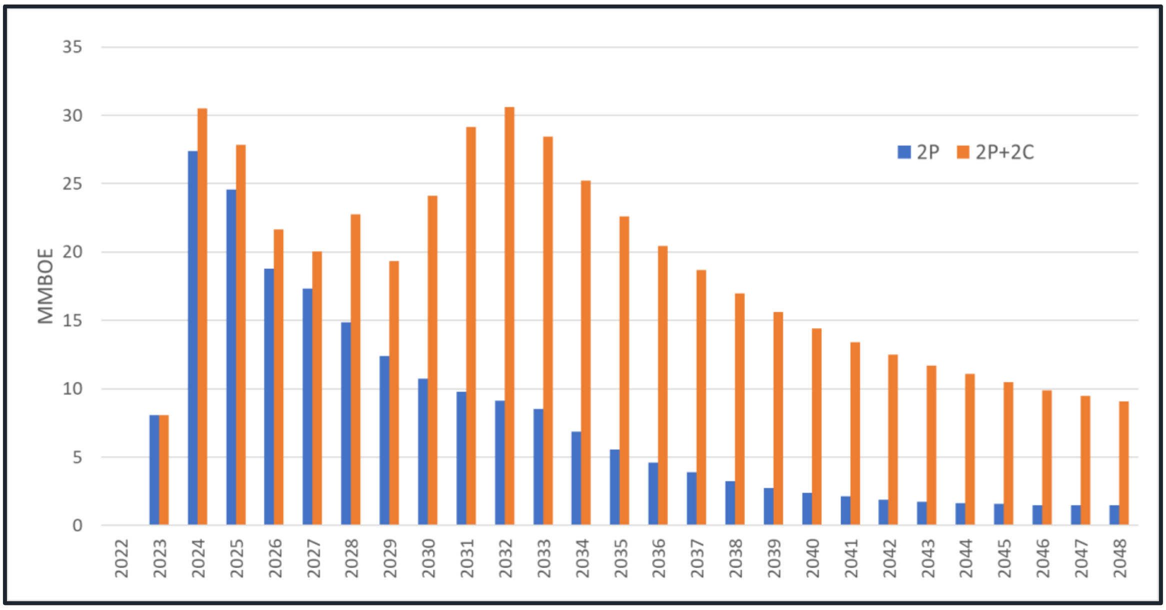
6.3 GaffneyCline's Valuation Profiles and COD for Sangomar

6.3.1 GaffneyCline's Production and Cost Valuation Profiles for Sangomar

GaffneyCline's valuation scenario production profile for Woodside's Sangomar asset is given in **Figure 6.6** with the associated real term cost profiles provided in **Figure 6.7** and **Figure 6.8** (split by Reserve and Resource class). All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the recoverable volumes of the sanctioned Sangomar Project (Phase 1) with a component of the 2C Contingent Resource Volumes from subsequent phases documented in **Table 6.4**. The project Chance of Development (COD) is discussed in Section 6.3.2 with a recommendation for valuation purposes. Technical and commercial contingencies are also discussed that impact the project Chance of Development utilised for risk assessment.

The regulatory carbon cost assumption for the Sangomar Asset is as per Woodside's non applicability assumption for this project.

Figure 6.6: 100% Sangomar Asset Production Profiles



Gaffney Cline

Figure 6.7: 100% Sangomar Asset Costs 2P + 2C Case Profile

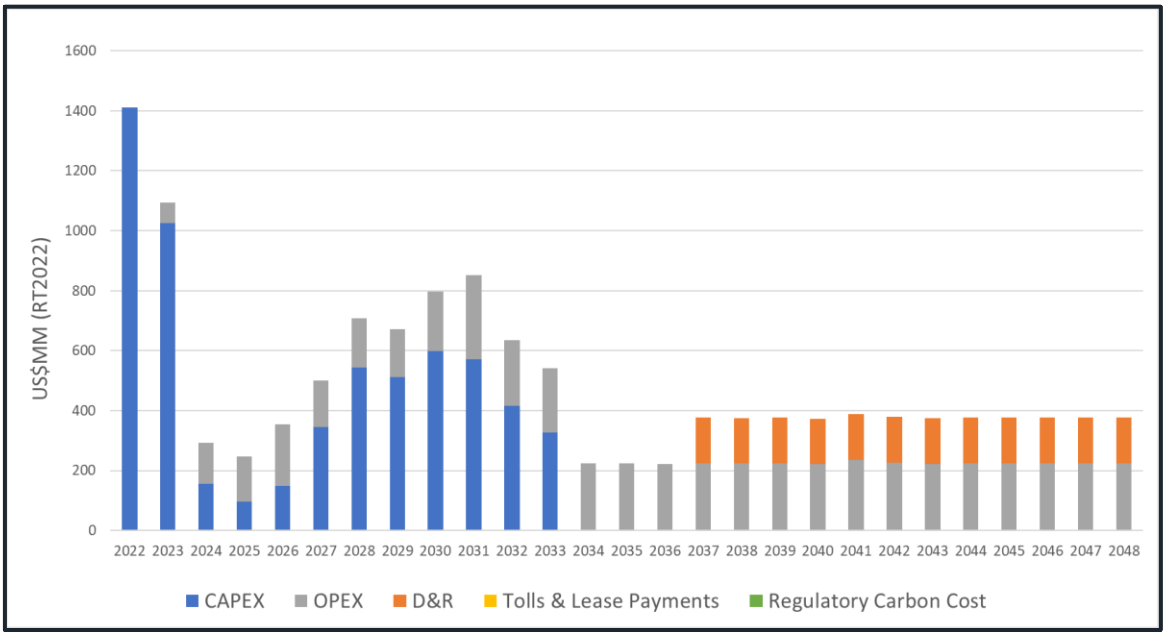
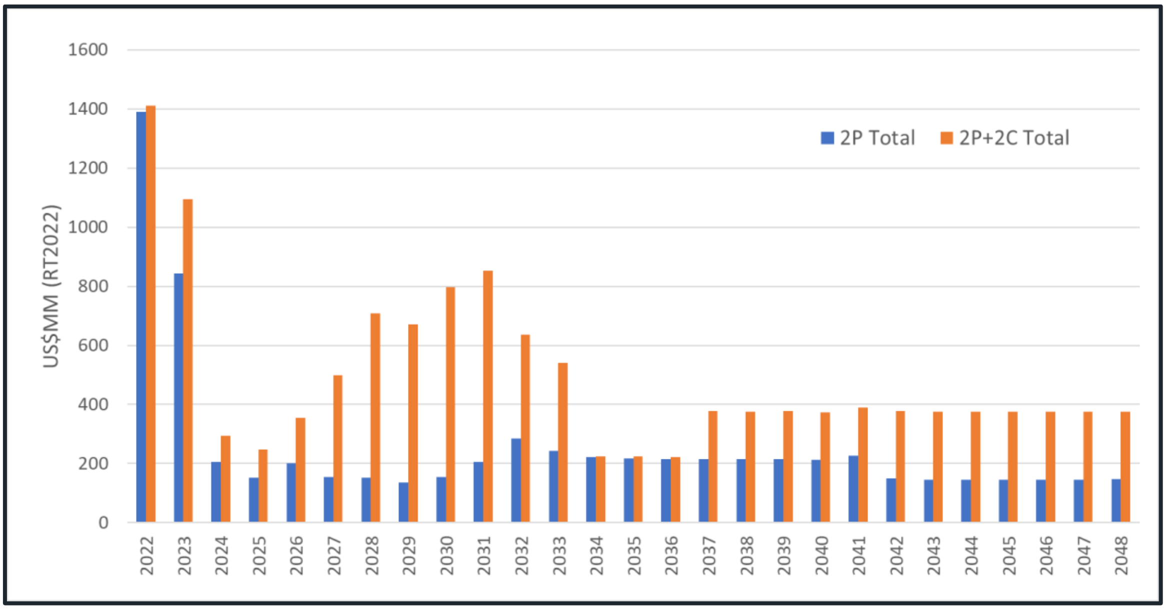


Figure 6.8: 100% Sangomar Asset Cost Profiles (separated for Reserves and Contingent Resources)



6.3.2 Sangomar Chance of Development

The Sangomar Phase 1 project excluding the Phase 1 waterflooding of the S400 Reservoir is classified as Reserves by GaffneyCline and therefore has no COD associated risking (2P 204 MMbbl). GaffneyCline considers the waterflooding in the S400 as requiring a proof of concept/pilot before it is classified as Reserves.

Contingent Resources in Sangomar include incremental recoverable volumes associated with Phase 1 waterflooding in the S400 reservoirs and recoverable volumes from subsequent development phases, which also focus on the S400 reservoirs. The classification status of recoverable volumes from Phase 1 waterflooding in the S400 is Contingent Resources - Development Pending, as development activities (Phase 1 injection wells in the S400 reservoirs) are ongoing to confirm its technical feasibility and subsequent commerciality. The classification status of Phases 2 to 5 volumes is Contingent Resources - Development Unclarified, as development is dependent on the Phase 1 outcome. A single value of chance of development is recommended as input to KPMG's valuation because the risk to the recoverable volumes associated with the Phase 1 water injection and Phases 2 to 5 are largely similar given the unusual nature of the sand geometry.

Although waterflooding is an industry-standard secondary recovery methodology, the unique depositional characteristics of the Sangomar S400 reservoirs mean the efficacy of this technique is highly uncertain in these formations. The operator has not presented and GaffneyCline is not aware of any valid analogues for recovery from water injection in the S400 reservoirs. Therefore, waterflooding must be demonstrated to be economically viable in the S400 reservoirs during Phase 1.

A positive outcome from Phase 1 waterflooding in the S400 reservoirs is expected to lead to a commitment to proceed with Phase 2 and later phases by the joint venture. Conversely, a negative outcome from Phase 1 waterflooding is likely to have an equivalent negative impact on Phases 2 to 5.

Considering the above, GaffneyCline recommends a 50% chance of development applied to all the Sangomar Contingent Resources for KPMG's valuation analysis. The COD is recommended to be applied to the incremental value difference of the 2P+2C (484 MMbbl) profile after the valuation is determined for the 2P profile only.

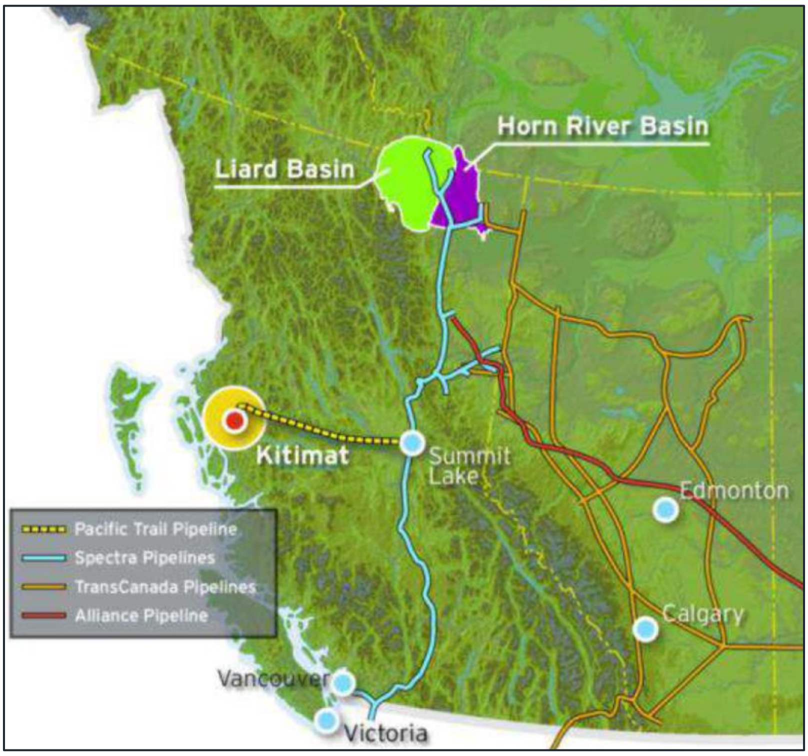
7 Woodside Canada

Woodside has an interest in a single asset in Canada, the Liard unconventional gas discovery.

7.1 Liard Basin Unconventional Gas (Canada)

Through its subsidiary, Woodside Energy International Canada, Woodside holds a 50% non-operated working interest in unconventional gas discoveries in the Liard Basin, located approximately 800 km northwest of Calgary, Alberta in northwest British Columbia (**Figure 7.1**). Woodside acquired Apache Canada Ltd.'s interest in the Liard Basin in April of 2015 as well as a 50% interest in the proposed Kitimat LNG (KLNG) facility at Bish Cove in British Columbia. Woodside transferred its role as upstream operator to Chevron in May 2015. Following relinquishments of ten leases due for expiry late in 2020, the remaining acreage is restricted to a "Core Area", covering approximately 1,700 km^2 which would be the focal point of any future development. Chevron, the operator, has until recently held the remaining 50% in both KLNG and the Liard Basin unconventional gas discoveries.

Figure 7.1: Location Map of Liard Basin



Source: Woodside

Development of the Liard Basin unconventional gas was intended to provide feedstock to the proposed KLNG facility via the existing third-party regional pipeline network and a proposed 480 km Pacific Trail Pipeline. However, Chevron announced its intention to divest its 50% interest in KLNG in December 2019 and this was followed by Woodside announcing in May 2021 that it also intends to exit its 50% non-operated participating interest in KLNG. The exit includes divestment or wind-up and restoration of assets, leases and agreements covering the 480 km Pacific Trail Pipeline route and the site for the proposed LNG facility at Bish Cove. This is ongoing.

Further work on the development of the Liard Basin unconventional gas has been suspended and Chevron has been relinquishing infrastructure-free leases, in accordance with its broader KLNG exit activities. However, Woodside announced that while it intends to exit KLNG, it intends to retain its upstream position in the Liard Basin, to investigate potential future natural gas, ammonia and hydrogen opportunities. This entails Woodside taking on those infrastructure-free leases (29 in total) at 100% as Chevron relinquishes. Woodside expects that the transfer of the 29 leases will be completed in Q1 2022. Woodside has indicated that all applicable leases have been included under a proven resource mechanism and require no further appraisal drilling and allowing unlimited annual renewals beyond the initial 10-year period, with minimal annual renewal payments (of ~US$0.7 MM). Leases with infrastructure remain jointly held, with Chevron as Operator.

GaffneyCline has classified the unconventional gas in the Liard Basin as Contingent Resources “Development Not Viable” on the grounds that there are no plans to develop or acquire additional data for the foreseeable future.

The Kotcho Shale Formation, the reservoir for the unconventional resources, is approximately 200 m thick and is deeply buried, at ~4,500 mss. It has high pressure of ~15,000 psia and high temperature of ~170°C. The gas is dry, comprising ~92% methane and ~8% carbon dioxide. A total of eleven exploration and appraisal wells have been drilled, six of which have been stimulated in the Kotcho Shale and put on production for various lengths of time. Woodside has indicated that a total of ~74 Bscf of gas has been produced. All wells have been shut-in since June 2019, with three suspended for potential future completion. Fracturing with up to 19 stages has been implemented successfully in two of the appraisal wells. Peak rates of up to 60 MMscfd were achieved and analysis of the production and test data by third party specialists has led to estimates of ultimate recoverable volumes per well (over 30 years) ranging from 30 to 170 Bscf.

There is a reasonable database for the Kotcho Shale Formation from seismic data and well penetrations as well as experience with fracturing and producing from the formation. A 3D seismic survey is available over the core area and this is supplemented with a good quality 2D seismic dataset. The Kotcho Shale Formation is well defined by seismic data, and extends beyond the licence area. GIIP for the development area within licence has been estimated from reservoir properties measured in the wells and extrapolated and interpolated from the well data. Woodside has estimated the GIIP to be approximately 51.6 Tscf within the development area. The formation is interpreted to have porosity of 1% to 7% and permeability of 12 to 360 nD (0.000012 to 0.000360 mD).

The conceptual development plan prepared by Chevron prior to its decision to exit was to supply feed to the proposed KLNG plant from the Liard core area with some 380 multi-stage fractured horizontal wells. While this concept is no longer relevant, the technical work undertaken to evaluate the envisaged project provides a basis for estimating potential recoverable volumes from Liard.

Woodside has used production data from the appraisal wells to develop well type curves, comprising estimates of initial well rates, decline rates and recovery per well, combined with assumptions of well spacing and drainhole length. Woodside has estimated the potential ultimate recovery from the field to be ~30.3 Tscf, corresponding to a recovery factor of 59%. After deductions for fuel and flare and for non-saleable non-hydrocarbons, the best estimate gross sales volume is ~26.7 Tscf. Woodside’s working interest 2C Contingent Resources, based on 50% equity are 13.35 Tscf. Woodside has indicated that its equity will be 94.9%, once all the infrastructure-free leases have been transferred.

While the production forecasts and estimates of recoverable volumes have been based on data acquired from the field, there is much uncertainty in the way the field might be developed in the future and in the estimation of Liard Basin recoverable volumes.

No robust analogues for the Liard Basin reservoirs have been identified with characteristics of depth and pressure similar to the Kotcho Shale Formation reservoirs from which to draw experience. Based on information provided by Woodside of other shale gas resources, GaffneyCline notes that Woodside's estimates of recovery factor and recovery per well for Liard (~80 Bscf) appear to be high, although the high pressure of the formation and the leanness of the gas are favourable characteristics for recovery. Nonetheless, the absence of valuable liquids in the produced wellstream and the high cost of drilling due to depth reduce the attractiveness of the development of Liard. Uncertainty in the estimated resources is secondary to the project risk, i.e. the chance of development, which GaffneyCline estimated to be less than 15%.

7.2 Recommended Valuation Range for Liard Asset Canada

Chevron and Woodside had been pursuing the sale of their stake in the Kitimat LNG project since 2019. The exit included the divestment or wind-up and restoration of assets, leases and agreements covering the 480 km Pacific Trail Pipeline (PTP) route and the site for the proposed LNG facility at Bish Cove. There have not been favourable responses from potential buyers in the past.

A winddown and site restoration is currently ongoing by Chevron and Woodside. Woodside indicate that the site restoration work will continue during the coming years. The PTP parentship was sold in early December 2021 to a Canadian infrastructure operator Enbridge. The proposed Kitimat LNG processing facility was not part of the Enbridge deal.

Woodside estimated their own share of future winddown liabilities to be between 70 to 75 US$ MM. GaffneyCline is unable to verify these liabilities without appropriate details which were not provided.

Woodside is retaining an upstream position in the Liard Basin, via the transfer of 29 non-infrastructure related Liard Basin leases (60% completion at time of writing), to study low-cost natural gas, ammonia and hydrogen opportunities in Canada.

There could be an option value in the upstream assets as cost to maintain them is insignificant. Given the lack of response from the marketplace in the past, the option value of this asset seems to be lower than the liabilities attached in winding down the asset. It is likely that a negative value was assigned by market participants during the Chevron and Woodside sales process.

In GaffneyCline's opinion the remaining Liard Basin asset value is likely between negative 50 million and zero as future Kitimat asset winddown liabilities would likely offset the potential option value of the Liard upstream asset. GaffneyCline recommends no material value to be assigned to the Liard assets.

8 Woodside Global Exploration Portfolio

Woodside's global exploration portfolio consists of assets in Australia, Senegal, Korea and Congo. They contain prospects and leads ranging from NFE opportunities in Australia and Senegal to stand-alone exploration projects in Australia, Korea and Congo.

All of the prospects/leads discussed here could potentially be drilled within the next five (5) years; additional prospectivity with no firmly planned drilling has been excluded from the assessment.

Woodside has identified nine gas prospects/leads with 2U (best estimate) Prospective Resources varying between 30 and 769 Bscf and Chance of Geologic Success (P_g) between 15% and 72%, plus 2 oil prospects with 2U Prospective Resources varying between 40 and 375 MMBbl and P_g between 24% and 91%.

All the prospects are anticipated to be drilled within the next five (5) years; additional prospectivity with no planned drilling has been excluded from the assessment.

8.1 Australia

The majority of Woodside's exploration portfolio is in Australia (**Table 8.1**). The prospects and leads are all gas and are located in the mature and well drilled sub-basins of the Northern Carnarvon Basin; with most located reasonably close to developed fields or at least to currently undeveloped discoveries.

Table 8.1: Woodside's Australian Exploration Portfolio

Sub-Basin	Permit	Woodside Equity	Prospect name	HC Type	Drill year
Barrow	WA-356-P / WA-536-P	65%	Carey South	Gas	2023
Barrow	WA-536-P	65%	Carey North	Gas	2025
Barrow	WA-49-L	65%	Gemtree	Gas	2023
Barrow	WA-49-L	65%	Penfolds	Gas	2024
Dampier	WA-5-L	16.70%	Castor Deep	Gas	2024
Exmouth Plateau	WA-404-P	100%	Armagnac	Gas	2024
Exmouth	WA-28-L	62%	Norton East	Gas	2022

The four assets in the Barrow sub basin, i.e. Carey South, Carey North, Gemtree and Penfolds, are located in the proximity of Brunello, Julimar, Pluto, Xena, and Iago gas producing fields, and are covered by 3D seismic data. The prospects target the Triassic age Mungaroo Formation, which has been proven to be productive in the area. The assets are considered to have relatively high chance of geologic success, with the remaining risks in specific prospects generally related to trap integrity and/or reservoir quality. Woodside plans to drill these assets in years 2023 to 2025, although the stated drill chance varied from 25% to 75%. The gas resources are generally envisioned as a backfill to the Wheatstone project, with tieback to the Brunello platform.

Castor Deep is located within the area of the North West Shelf gas producing fields, and targets the Late Triassic age sandstone reservoirs of the Mungaroo and Brigadier Formations. The prospect is covered by 3D seismic data and shows bright amplitudes at the reservoir levels. The chance of geologic success for the prospect is considered relatively high, with the reservoir effectiveness and trap integrity considered as the remaining risks. Currently, Woodside plans to drill the asset in 2024, with 25% chance of drill. The envisioned development is a pipeline to the nearby producing NWS platform.

Armagnac is a gas prospect identified through strong amplitude response in 3D seismic data. Located in the Exmouth Plateau, the prospect targets the Triassic age sandstone reservoir of the Mungaroo Formation, in a combined structural and stratigraphic trap. The chance of success of the prospect is elevated by the presence of strong seismic attributes. Woodside's current plan places the drill year for Armagnac at 2024, with 50% chance of drill. Several gas discoveries of similar type have been found within the same permit, but none of these have been developed.

Norton East, located in the Exmouth sub basin, is a gas prospect with a three-way dip closure trap identified through 3D seismic data. The prospect is located in the proximity of several currently producing oil and gas fields of the Greater Enfield area. The prospect targets several sandstone reservoirs of the Early Cretaceous and Late Jurassic, which have been found to be productive in the area. The chance of geologic success of the prospect is considered relatively high, with remaining risks in the reservoir quality and trap integrity. Woodside's current plan is to drill the prospect in 2022, with 25% chance of drill. The conceptual development plan is a subsea tieback to the nearest Greater Enfield facility.

8.2 Senegal

The SNE North oil prospect lies to the north of the Sangomar Field, offshore Senegal. The Sangomar Phase 1 development is currently underway and the SNE North Prospect is expected be drilled during the current drilling campaign (2H 2022). The prospect is assessed by Woodside to have a high chance of geologic success as hydrocarbons within the mapped closure have been established by the SNE North-1 exploration well which demonstrated the presence of gas in a separate accumulation to the Sangomar Field. The next well is designed to test the potential for an oil-leg below these gas bearing reservoirs.

The SNE North Prospect has been mapped using the recently reprocessed Maz 3D seismic data and the Prospective Resources estimates are based on the interpretation of these data. GaffneyCline has reviewed the Prospective Resources and associated chance of geologic success and finds them to be robust estimates.

If the exploration well is successful, it is anticipated that the discovery will be developed as a subsea tie-back to the Sangomar Field FPSO.

8.3 Congo

Woodside has a 42.5% working interest (50.0% paying interest) in deep water Block Marine XX offshore Congo, operated by TotalEnergies. The block was awarded following the 2016 Bid Round. Woodside has a 50% working interest. Woodside has an exploration well commitment and is currently planning to drill the Niamou Marine Prospect in 2023 (drill chance 50%).

The Niamou Marine prospect is a large sub-salt closure mapped on 3D seismic data. In the maximum case, the mapped closure extends into Gabon's offshore acreage. The prospect is located in 2,400 m water depth.

Woodside has considered both oil and gas cases (50:50 chance factor), based on basin modelling and potential source rock kinetics. The gas case is evaluated as uneconomic, and the oil gas is marginally economic even at very high resource volumes.

The critical issue in the evaluation of the Niamou Marine prospect is reservoir quality and therefore recovery per well. In the current model the well count is high (reflecting the relatively low reservoir quality) and this with the water depth of the prospect.

The project currently fails to meet Woodside corporate metrics.

8.4 Korea

Woodside's South Korean exploration portfolio comprises Blocks 8 and 6-1N, where Woodside holds 50% working interest. The blocks contain two leads located in the northern part of the Ulleung Basin, which is an immature, deepwater, Neogene back-arc basin, located east of the Korean peninsula. The leads are located in about 2,000 m water depth, some 50 km north of the currently producing gas field, Donghae-1. Of the two wells nearest to the leads (20 km away), one was a dry hole and one, Hongge-1, was a sub-commercial discovery, encountering gas within Middle Miocene sandstone reservoirs.

The Daege and Jibgae leads were identified based on 2008 vintage 2D and 2014 vintage 3D data; however, a new set of 3D seismic data was acquired in 2021 and is being integrated in the interpretation of the leads. The two leads are considered high risk and are at the immature stage of the exploration. Woodside's current plan places one well in each lead, with the Daege well given a 75% chance of drill and the Jibgae well a 25% chance of drill. The conceptual development plan involves a subsea tieback to a greenfield onshore domestic gas plant.

8.5 Exploration Valuation Methodology

All exploration prospects for Woodside and BHP Petroleum are offshore. GaffneyCline utilised an Expected Monetary Value (EMV) valuation method as the primary approach for recommending exploration value to KPMG. EMV method captures the binary nature of the exploration success and values the resulting outcome. There is limited market comparable information available for offshore exploration to use a market approach. GaffneyCline reviewed the exploration targets provided they are sufficiently mature and included by Woodside and BHP Petroleum in their five-year drilling program. The sunk cost approach is not a reflection of forward monetary value of mature prospects compared to the EMV method thus not utilised for value recommendations.

The EMV method is an approach that seeks to test potential future value based on a quantified assessment of risk and reward. The approach risk-adjusts a Discounted Cash Flow (DCF) analysis of an assumed discovery on a prospect by the assessed Geological Chance of Success (GCoS), and then deducts the amount of risk capital exposed.

The EMV formula:

EMV = NPV (successful development) * GCoS * CoD – [(1 – GCoS) + GCoS * (1-CoD)] * Risk Capital

Where:

NPV = Net Present Value of an assumed discovery of Median (P50) size on the prospect is utilised for this valuation by GaffneyCline

CoD = Chance of Development. For this valuation, CoD was assumed to be 100%

Risk Capital = Dry hole well cost (post tax and discounted)

Key Assumptions

Discount Rate

EMV analyses were conducted using a low discount rate and a high discount rate for each asset based on its location. **Table 8.2** below summarised the various discount rates by country, which were provided by KPMG.

Table 8.2: Discount Rate Range for EMV Calculations

Country	Low	High
Australia	12%	14%
United States of America	12%	14%
Canada	12%	14%
South Korea	12%	14.5%
Trinidad and Tobago	14%	17%
Senegal	15%	19%
Mexico	13%	16%
Republic of Congo	20%	25%

Oil and Gas Prices

KPMG oil and gas price forecasts were used in the DCF analyses.

Productions, Costs and GCoS

GaffneyCline audited 2U best case (P50) recoverable volumes and geological chances of success. GaffneyCline adjusted these numbers based on the review of available geological information provided. GaffneyCline audited the notional development plans, production, and cost profiles. GaffneyCline adjusted the Woodside and BHP Petroleum provided production and cost profiles based on GaffneyCline estimated 2U volumes and the latest schedule.

Fiscal Terms

Simple fiscal terms of each asset have been modelled for DCF analysis based on GaffneyCline's understanding of the terms.

8.6 Recommended Value Range for Woodside's Exploration Assets

Woodside provided detailed assumptions for exploration valuations for seven prospects. Four of these prospects are in Australia, namely Carey South, Gemtree, Castor Deep and Norton East. One each are in Senegal, South Korea and Congo namely SNE North, Daege and Niamou Marine respectively.

GaffneyCline calculated EMV positive numbers for only the Gemtree and Norton East prospects with an aggregated range of US$78 MM to US$118 MM.

Woodside's internal evaluation shared with GaffneyCline results in positive EMV for all prospects. The major difference between the GaffneyCline and Woodside EMVs is primarily due to the lower discount rate of 8% across the portfolio utilised by Woodside, the P50 volume and GCoS adjustments by GaffneyCline, and a more complex risking method based on various scenarios employed by Woodside. GaffneyCline has employed a consistent methodology for all prospect EMVs estimated to minimise any bias.

The GaffneyCline recommended value range for Woodside's Exploration Assets is **US$78 MM** to **US$118 MM** for KPMG's consideration.

BHP Petroleum Assets

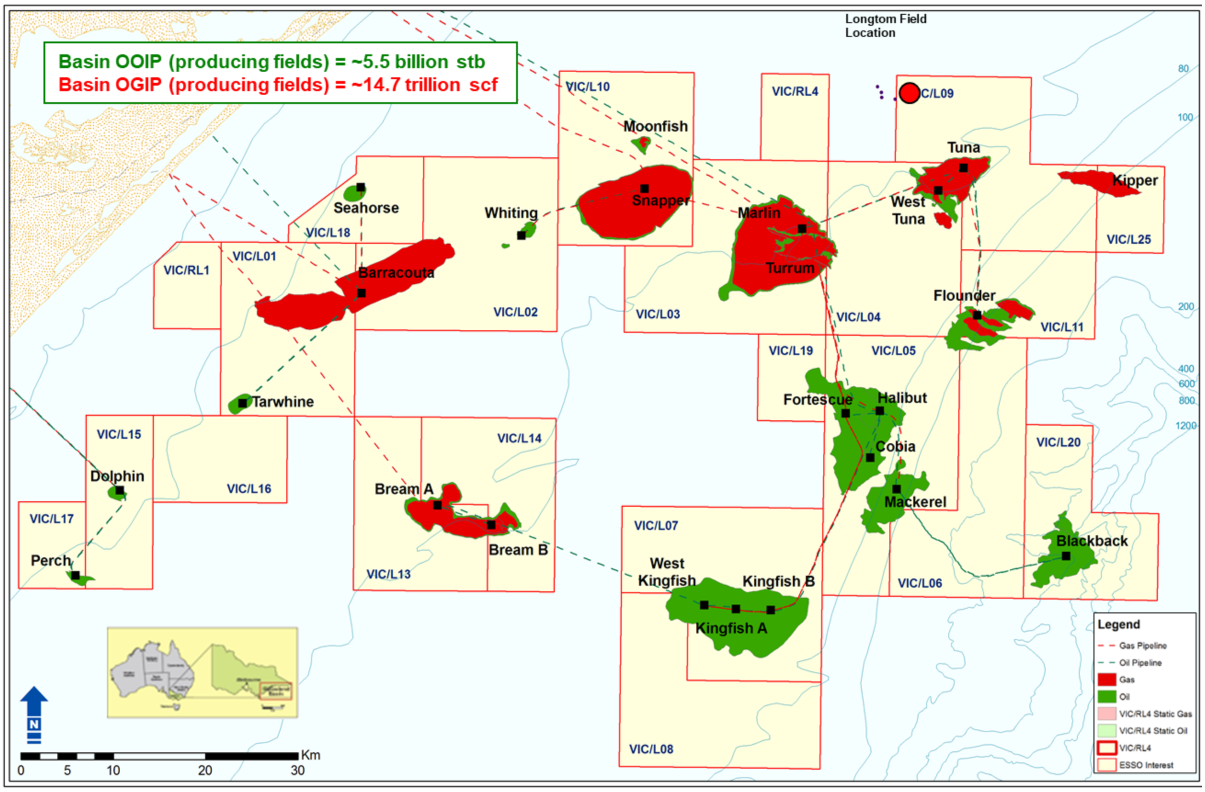
9 BHP Petroleum Australia

BHP Petroleum has interests in the NWS gas and oil projects, and in the Scarborough LNG project (including the Jupiter and Thebe Fields). Woodside also has interests in these same assets, and they are described in Section 4.1 (NWS) and in Section 4.5 (Scarborough, Jupiter and Thebe), and are not repeated here. The remainder of BHP Petroleum's Australian assets are described below.

9.1 Bass Strait

The Bass Strait oil and gas fields (**Figure 9.1**) are located within the Gippsland basin, offshore the south-eastern margin of Eastern Victoria, Australia. BHP Petroleum has interests in a total of eleven gas fields, four of which have oil rims, and thirteen oil fields.

Figure 9.1: Oil and Gas Fields of the Gippsland Basin

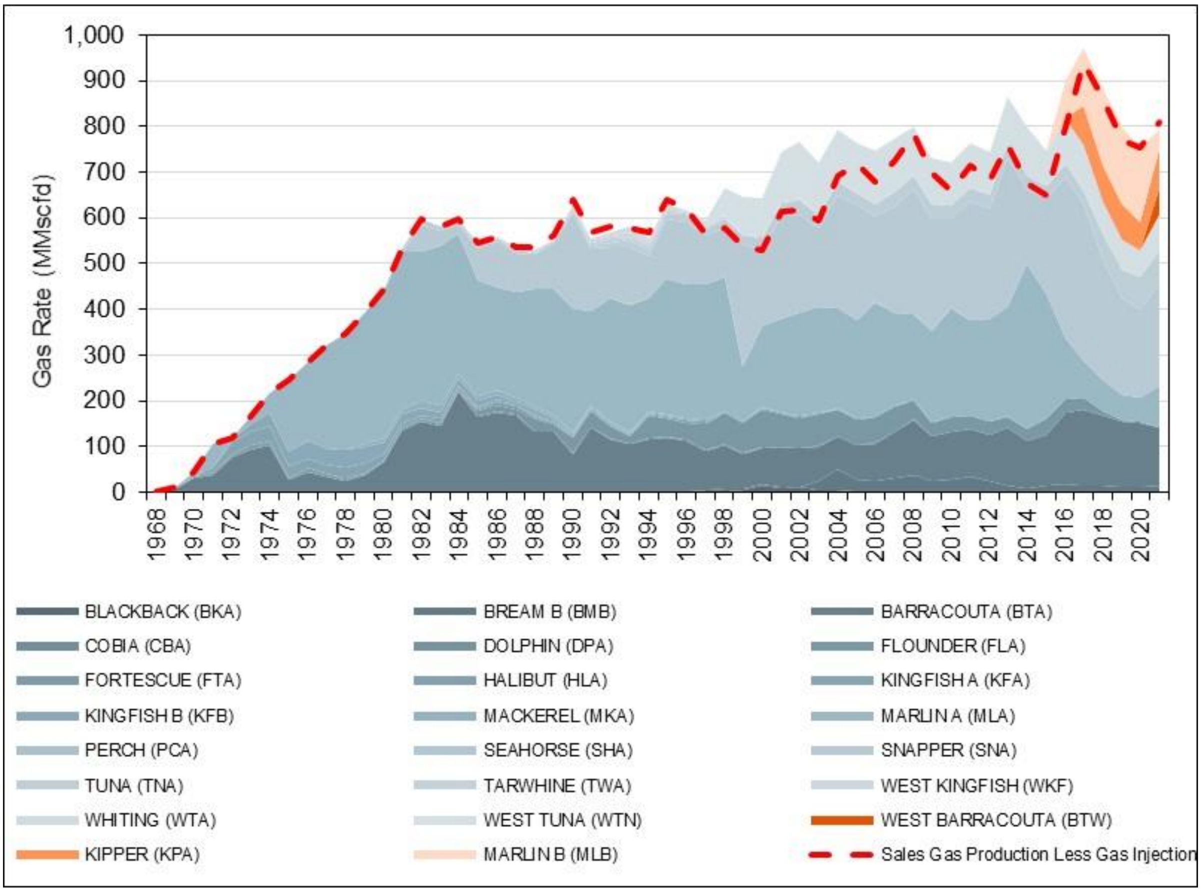


Source: BHP Petroleum

9.1.1 Field Description

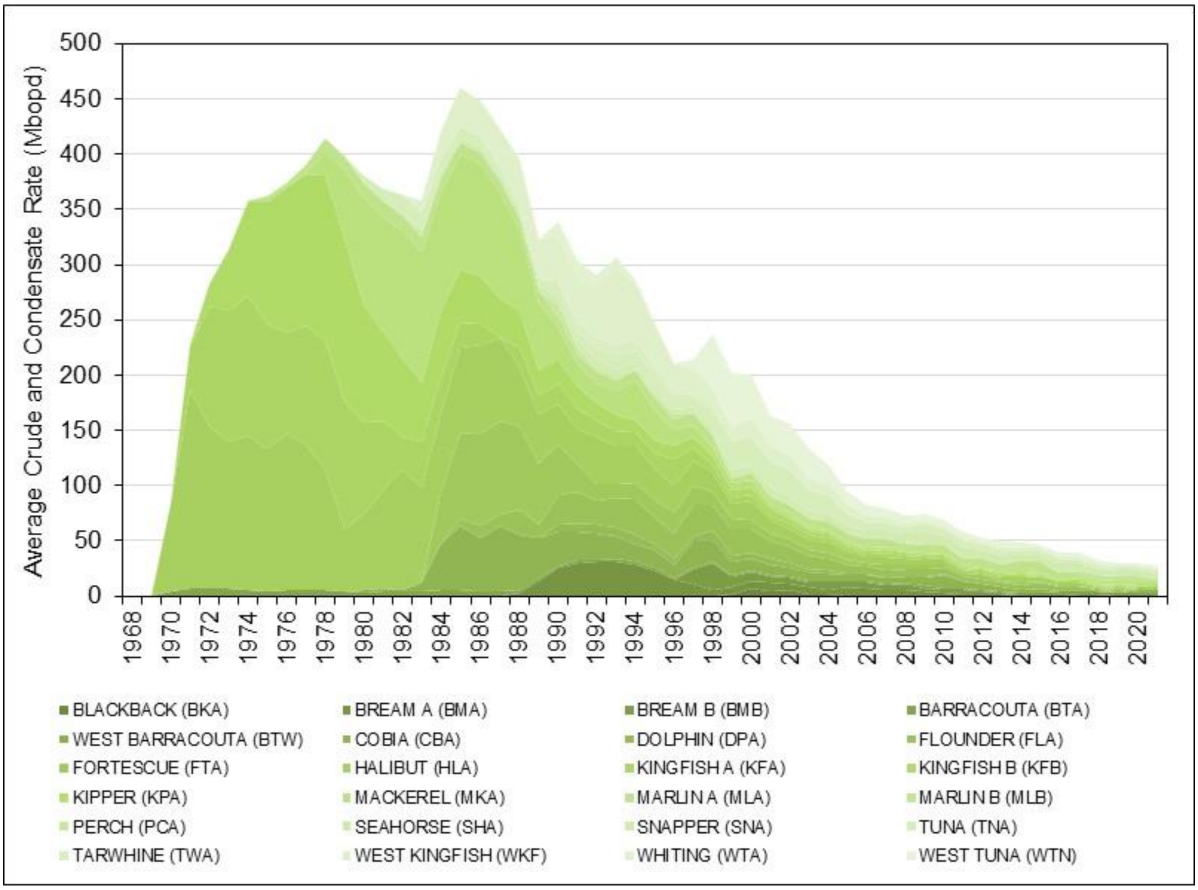
Based on the data provided by BHP Petroleum, during the latter part of 2021 the fields are producing at aggregate rates of ~830 MMscfd of sales gas, 26 Mbpd of oil/condensate and 36 Mbpd of NGL, with the majority of current gas production coming from the Snapper, Barracouta, Tuna, Turrum and Kipper Fields (**Figure 9.2** and **Figure 9.3**). There is significant seasonal variation in gas demand in Victoria with greater gas demand in the winter months compared to the summer months.

Figure 9.2: Bass Strait Historical Gas Production



Source: GaffneyCline from BHP Petroleum data

Figure 9.3: Bass Strait Historical Oil and Condensate Production



Source: GaffneyCline from BHP Petroleum data

BHP Petroleum's Bass Strait assets can be grouped into five predominantly gas producing hubs (Barracouta, Snapper, Marlin/Turrum, Tuna/West Tuna & Kipper Hub), and a group of oil fields slightly further offshore (**Figure 9.1**). A list of BHP Petroleum's Petrolook Reserve database is provided in **Table 9.1**. The list includes producing oil and gas fields and a large number of projects that are in various stages of evaluation and maturity, as well as several depleted fields. Seven additional depleted oil fields are not included in **Table 9.1**.

Reserves are attributed to the producing gas and oil fields. Four projects (North Turrum, Wirrah, Sweetlips and East Pilchard) are relatively mature Contingent Resources.

With the exception of Kipper, which is governed by the Kipper Unit Joint Venture in which BHP Petroleum has 32.5% interest, the rest of the fields are governed by the Gippsland Basin Joint Venture which consists of Esso (50%) and BHP Petroleum (50%) with Esso as the operator.

Produced wet gas is transported via pipeline to the Esso's Longford gas plant in Gippsland Victoria where the gas is processed and dried. Sales gas (mainly methane and ethane) is sold to the domestic market. Condensate is knocked out at the offshore platforms where it is combined with crude produced from the Kingfish, Cobia and Fortescue Fields and sent to the Longford crude stabilization plant. From Longford, stabilized crude & condensate and LPG are further piped via a 187 km long pipeline to the Long Island point facility at Hastings, Victoria before being further processed sold.

Table 9.1: Bass Strait Fields Summary (from BHP Petroleum)

Main Platform / Hub	Fields	Field Type	Development Status
Barracouta Hub	Barracouta	Producing Main Gas Field	Producing
	BTA West	Producing Main Gas Field	Producing
	BTA Deep Gas	Tight Deeper Sands of Main Field	Development Not Viable
	Whiptail	Barracouta Satellite Oil Field	Development Not Viable
	Mulloway	Barracouta Satellite Oil Field	Development Not Viable
	Tarwhine Prod	Barracouta Satellite Oil & Gas Field	Development Not Viable
	West Whiptail	Barracouta Satellite Oil Field	Development Not Viable
	Luderick	Barracouta Satellite Oil & Gas Field	Development Not Viable
Snapper Hub	Snapper	Producing Main Gas Field	Producing
	Snapper Deep	Tight Deeper Sands of Main Field	Development Not Viable
	Moonfish	Producing Oil & Gas Field	Producing
	Moonfish Gas N1.9	Producing Secondary Gas Field	Producing
	Moonfish W	Snapper Satellite Gas Field	Development Not Viable
	Wirrah	Snapper Satellite Oil & Gas Field	Development Pending
	Sweetlips	Snapper Satellite Gas Field	Development Pending
	Whiting	Snapper Satellite Oil & Gas Field	Development Uncertain
	Emperor	Snapper Satellite Oil & Gas Field	Development Not Viable
Marlin / Turrum Hub	Turrum	Producing Main Gas Field	Producing
	Turrum - Marlin N-1	Producing Secondary Gas Fields/Reservoirs	Producing
	North Turrum	Turrum Phase 3 (5 Well Development)	Development Pending
	SE Remora	Turrum Satellite Oil & Gas Field	Development Not Viable
	Remora	Turrum Satellite Oil & Gas Field	Development Not Viable
	Sunfish	Turrum Satellite Oil & Gas Field	Development Not Viable
Tuna / West Tuna Hub	Tuna M-1	Producing Main Gas Field	Producing
	Tuna Other	Producing Secondary Oil & Gas Fields	Producing
	Tuna-C-Gas	Tight Deeper Sands of Main Field	Development Not Viable
	SE Longtom	Tuna Satellite Gas Field	Development Not Viable
	Angelfish	Tuna Satellite Gas Field	Development Not Viable
	Flounder	Tuna Satellite Depleted Oil & Gas Field	Development Not Viable
Kipper Hub	Kipper	Producing Main Gas Field	Producing
	East-Pilchard	Kipper Satellite Gas Field	Development Unclarified
	Scallop	Kipper Satellite Oil & Gas Field	Development Not Viable
	Grunter	Kipper Satellite Oil & Gas Fields	Development Not Viable
Oil Fields	West Kingfish	Producing Oil Field	Producing Oil
	Cobia	Producing Oil Field	Producing Oil
	Halibut	Producing Oil Field	Producing Oil
	Central Fields		Development Not Viable
	Yellowtail	Cobia Satellite Oil Field	Development Not Viable
	Gudgeon	Cobia Satellite Oil Field	Development Not Viable

9.1.2 Field Development and Production Profiles

Reserves associated with most of the Bass Strait fields were based on production forecasts generated from BHP Petroleum's Bass Strait Network model, an integrated subsurface and surface network model that incorporates reservoir material balance and flow throughout the production system, accounting for production constraints from each part of the network. This is coupled to a plant model, tuned to match the liquid yields from the prior two years, to calculate forward estimates of NGLs and condensate.

GaffneyCline reviewed the BHP Petroleum 1P/2P integrated Bass Strait Network model, as well as the excel-based plant model. GaffneyCline has also re-run the 1P network model and verified that the outputs of the 1P network model align with the inputs into the plant model. The plant model utilised a custom-built macro script and takes inputs from the network model (namely gas rate, mass flow rate and compositional information) on a monthly basis, and generates outputs at a product level (namely sales gas in TJ, condensates, as well as NGLs – ethane, propane and butane). No abnormal observations were observed from spot checks on the plant model.

GaffneyCline further re-ran the plant model to verify that the outputs from the plant model are in line with the inputs into the results tool that further conditions the production forecasts which serves as inputs into the Petrolook Reserve volumes. Finally, GaffneyCline verified that the Reserve numbers reported by BHP Petroleum in its PetroLook and Resource Estimators Report (RER) do not materially deviate against the production forecast inputs provided by BHP Petroleum's business planning team, as well as the Low Case standardised measure of oil and gas (SMOG) forecasts. Based on these inputs, GaffneyCline generated a set of production forecast based on the plant model outputs and SMOG inputs. These production forecasts were used as the basis for the economic evaluation.

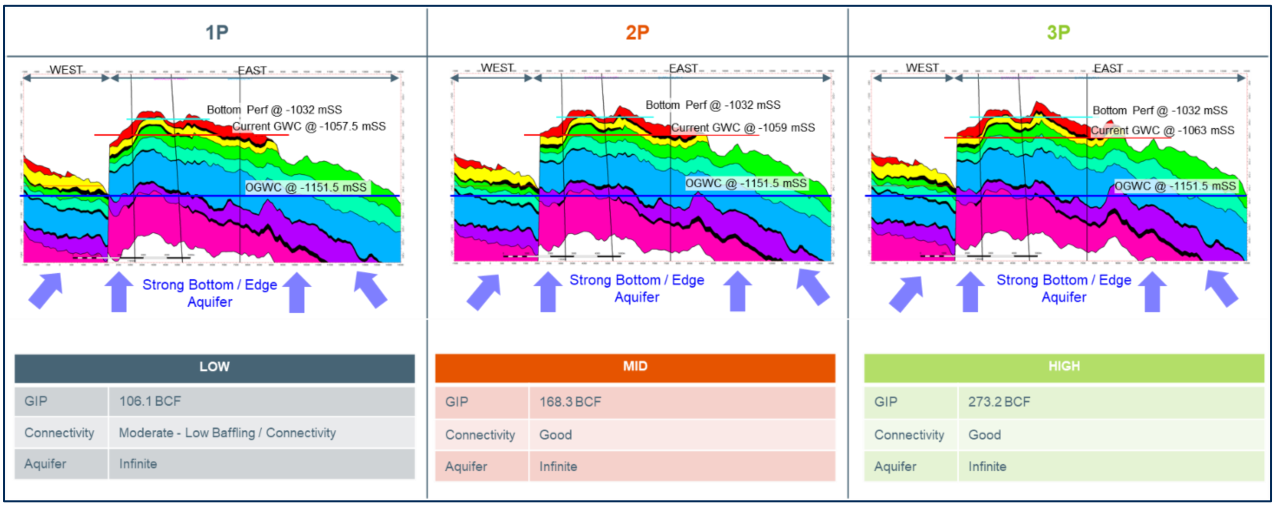
Individual fields have been grouped into the five main producing hubs and other oil fields (**Table 9.1**). Due diligence checks specific to the individual major fields (Barracouta, Snapper N1, Turrum L, Tuna M-1 and Kipper) have been performed.

Barracouta

The Barracouta N-1 gas field was the first offshore field discovered in Australia, in 1965 and gas production started in 1969. More recently in 2021, West Barracouta was developed via a 2 well subsea tieback.

The main depositional environment is coastal braid plains comprising high NTG fluvial sands with interbedded shales and extensive coals, as well as beach/shoreface successions comprising high NTG shoreface sands with localised dolomitisation. The field features excellent reservoir properties, with mean porosity ~23 to 30%, mean permeabilities ranging from 1 to 10D. Production is from a thick gas column (~140 m gross), with an oil rim (~8 m), supported with strong bottom water drive. **Figure 9.4** summarises the geologically derived remaining gas in place and provides a visual indication of the movement of the original gas water contact to current estimates of the gas water contact.

Figure 9.4: East Barracouta, Remaining Gas in Place and Movement of the Gas Water Contact



Source: BHP Petroleum

Gross cumulative production is ~2 Tscf of sales gas, 32.0 MMBbl of condensate and 88 MMBbl of NGLs, coming from ten producing wells in Barracouta, and two subsea tiebacks in West Barracouta. Currently, most of East Barracouta has been produced and the gas that remains is mainly attic gas.

Recent drilling results in West Barracouta were better than expected, which resulted in an increase in the remaining gas in place from the pre-drill estimates of 164 Bscf (low) and 225 Bscf (best) to 246 Bscf (Low) and 437 Bscf (Best). There are no plans for future development in Barracouta or West Barracouta. Estimates of remaining gas in place and remaining recoverable volumes are summarised in **Table 9.2**. GaffneyCline has reviewed the supporting technical work and these estimates appear reasonable.

Table 9.2: Barracouta N-1 Gas Field Remaining GIIP and EURs Summary from IPM MBal Models

Reservoir	Category	Remaining GIIP (Bscf)	Remaining Recoverable (Bscf)	Implied Recovery Factor
BTA N-1 (East)	Low	106	48	45%
	Best	168	97	58%
BTA N-1 (West)	Low	246	138	56%
	Best	437	288	66%

Notes:
1. GIIP for BTA N-1 (East) only considered attic volumes above the OWC as of 1 January 2020.
2. BTA N-1 (West) only came onstream in April 2021.

Snapper N-1/Moonfish

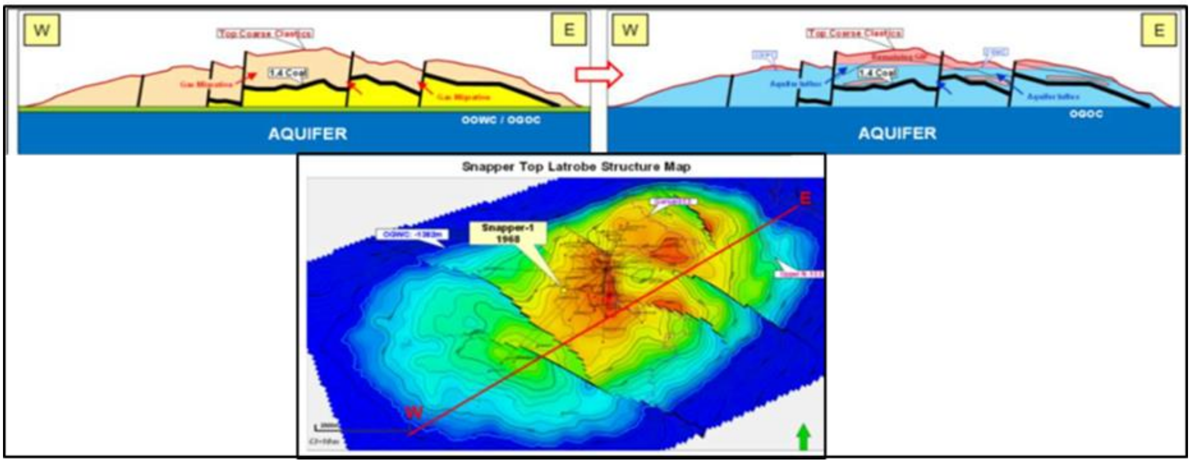
The Snapper N-1 gas field was discovered in 1968 and started production in 1981. A small satellite field to the north of Snapper called Moonfish, was also developed from the Snapper platform.

The main depositional environment is Eocene aged amalgamated fluvial sandstones. The field features excellent reservoir properties, with mean porosity around 25%, mean permeability ranging from 1 to 10 D. Production is from a thick gas column (max. 200 m gross), with an oil rim (~6 to 7 m) and is supported by strong bottom water drive.

As of 1 July 2021, gross cumulative production is 2.57 Tcf of sales gas, 51.0 MMBbl of condensate and 93.9 MMBbl of NGLs, coming from 27 producing wells.

Similar to East Barracouta, most of the gas from the Snapper Field has been produced and mostly attic gas remains in the N-1 upper sands. Reservoir monitoring has indicated that there are variable contacts across the field, along with some minor pockets of gas usually below coals. **Figure 9.5** shows a schematic cross section of the field which provides a visual indication of the movement and current interpretations of the gas water contact.

Figure 9.5: Field Schematic of Snapper and Contact Movement



Source: BHP Petroleum modified by GaffneyCline

Snapper is a mature producing field with good coverage from 45 wells. There is also an abundance of historical pressure data, as well as GWC surveillance in recent years to help constrain the forecasting model. Uncertainties in the material balance model relate mostly to parameters such as trapped gas saturation and sweep efficiency. There are no plans for future development in Snapper.

Production forecasts are based on material balance models which feeds into the integrated Bass Strait Integrated Production Modelling (IPM) network model. Remaining GIP and estimates of remaining recoverable volumes are summarised in **Table 9.3**. GaffneyCline has reviewed the supporting technical work and these estimates appear reasonable.

Table 9.3: Snapper Field GIIP, Remaining GIP and Remaining Recoverable Volumes

Reservoir	Category	GIIP (Bscf)	Remaining GIP (Bscf)	Remaining Recoverable Gas (Bscf)
N+1 and Gurnard	Low	3,409	372	205
	Best	3,868	513	317

Turrum L

The Turrum L gas field was discovered in 1966 and started gas production in 1997 via two Marlin-A platform recompletes. In 2004, a five well Phase 1 oil development commenced production targeting the L500 oil sands. In 2015, the Marlin-B platform was completed as part of the greater Kipper-Tuna-Turrum development together with a 5 well Phase 2 development, targeting the main L105-L400 gas sands with 4 of the 5 wells. The other well targeted the L500 oil sands.

The main depositional environment of the field is Paleocene aged fluvial channel and overbank deposits. The geological system is complex, consisting of stacked reservoir sands, multiple pressure zones and gas water contacts. The sands can broadly be grouped into five intervals, namely L60-99, L100, L105-L400, L420 and L500. Of these, the L60-90, L105-400 and L500-510 are currently on production.

The field features highly variable reservoir properties ranging in quality from low/moderate to excellent, with porosity around 12 to 20% and permeability ranging from 50 to 1,500 mD. Production is from a thick gas column (~400 m gross for L105-L400 gas reservoirs, 80-100 m gross for the L500-L520 gas and oil reservoirs). Net-to-gross for the L105-L400 sands is low to moderate, around 15 to 40% net sand. The drive mechanism is depletion drive for the shallower gas sands, and moderate aquifer drive for the deeper oil and gas sands. Gross cumulative production from the L105-400 reservoir is ~200 Bscf of sales gas, ~6 MMBbl of condensate and ~8 MMBbl of NGLs, coming from four producing gas wells. Gross cumulative production from the L500-510 reservoir is ~82 Bscf of free & solution gas, ~9 MMBbl of oil/condensate and ~4 MMBbl of NGLs. The L500-510 oil reservoir was producing until March 2020, after which gas cap blowdown commenced. Production is currently constrained to control sand production. The L60-99 reservoir recently came on stream and as of 31 December 2021 had produced 0.02 MMBbl of condensate, 0.03 MMBbl of NGL and 0.88 Bscf of gas.

Undeveloped Reserves are associated with the future installation of sand control. BHP Petroleum's current assumption is that three wells (B10, 15 &16) will be recompleted with 7" tubing during sand control installation in February 2023, which will then restart at high rates. Undeveloped Reserves include all volumes from 2,500 psi until abandonment since existing geomechanics work shows the onset of shear failure at around 2,500 psi. This is in line with actual field observations from the B4 well where sand was observed. Given that initial reservoir pressure was around 3,600 psia and the depletion drive nature of the field, there are significant volumes associated with production below the current 2,500 psi limit. **Table 9.4** provides a summary of the incremental volumes associated with this sand control project for the main fault block. The Turrum sand control project appears to be firm with a possible six month deferral of the start-up timing associated with overall optimization of Gippsland gas production and plant capacity.

There are also additional workovers planned to install smaller tubing to manage liquid loading due to pressure depletion, which has had the impact of accelerating production and reducing the fuel/flare burden of Turrum. GaffneyCline has also reviewed the inputs and forecasts from BHP Petroleum's MBAL model for Turrum L105-400 and overall, the technical work appears reasonable.

Table 9.4: Turrum Field Estimates of Gas Recovery With and Without Sand Control.

Reservoir	Category	GIIP (Bscf)	Gross Produced Wet Gas (Bscf)	Gross Remaining Recoverable Gas (Bscf)	
				Without Sand Control	Incremental With Sand Control
Main Fault Block (wells B10, B15, B16)	Low	707	211	55.4	275.9
	Best	830	211	109.1	329.0

Note: Excludes L130L sand.

Tuna M-1

The Tuna M-1 gas and oil field was discovered in 1968. The field commenced production from the oil rim in 1997 with 51 predominantly horizontal oil producers and gas injection in eight wells for pressure support. Subsequently, gas cap blowdown commenced in 2014.

The main depositional environment is marine shale grading upwards through lower shoreface, upper shoreface and estuarine units. The M sand is the main producing reservoir, which features excellent reservoir properties, with mean porosity around 24% and mean permeability ranging from 800 to 3,000 mD. Production is from an 80 m gas cap and an oil rim, originally 12 m thick, but now less than 1 m, assisted by strong edge/bottom water drive.

As of 1 July 2021, gross cumulative production was 194.5 Bscf of sales gas, 12.4 MMBbl of condensate and 25.7 MMBbl of NGLs. Currently, the field is producing mostly gas with minor oil.

Production forecasts are based on material balance models that feed into the Bass Strait Network model. GIIP and recoverable volumes from the tank model are summarised in **Table 9.5**.

Pressure and fluid contact data exists to help constrain the material balance forecast models. Even though there is a range of scatter observed in the pressure data, the overall trend is still quite evident. As for the fluid contact, there has been movement associated with pre-production gas cap expansion and gas injection prior to gas cap blowdown. The inputs and forecasts from BHP Petroleum's MBAL model for Tuna M-1 have been reviewed and the history match of pressure and fluid contact has been checked. Overall, the technical work appears reasonable.

Table 9.5: Tuna Field GIIP and Remaining Recoverable Volumes

Reservoir	Category	GIIP (Bscf)	Produced Gas (Bscf)	Remaining Sales Gas (Bscf)
Tuna M-1	Low	567	176	215
	Best	667	176	281

Note: Low and Best Case GIIPs are based on deterministic map based assessments. No current static model is available.

Kipper

The Kipper gas field was discovered in 1986. The field commenced production in 2017, tied back to the West Tuna platform.

The main depositional environment comprises coarse-grained braided fluvial deposits that are inter-bedded with flood plain mudstones, within the Golden Beach group. The field features good reservoir properties, with mean porosity around 16% and mean permeability ranging from <100 to 1,000 mD. Production is from a thick gas interval (~310 m gross intersected by Kipper-1), overlying a stratigraphically trapped, non-commercial, thin oil column. The drive mechanism is expected to be depletion drive.

As of 1 January 2021, gross cumulative production was 117.1 Bscf of sales gas, 3.1 MMBbl of condensate and 2.8 MMBbl of NGLs. As of September 2021, the field is producing at a rate of 123 MMscfd of gas, 1,521 bpd of condensate and 4,167 boepd of NGL from 2 wells (Kipper-A2 & Kipper-A4).

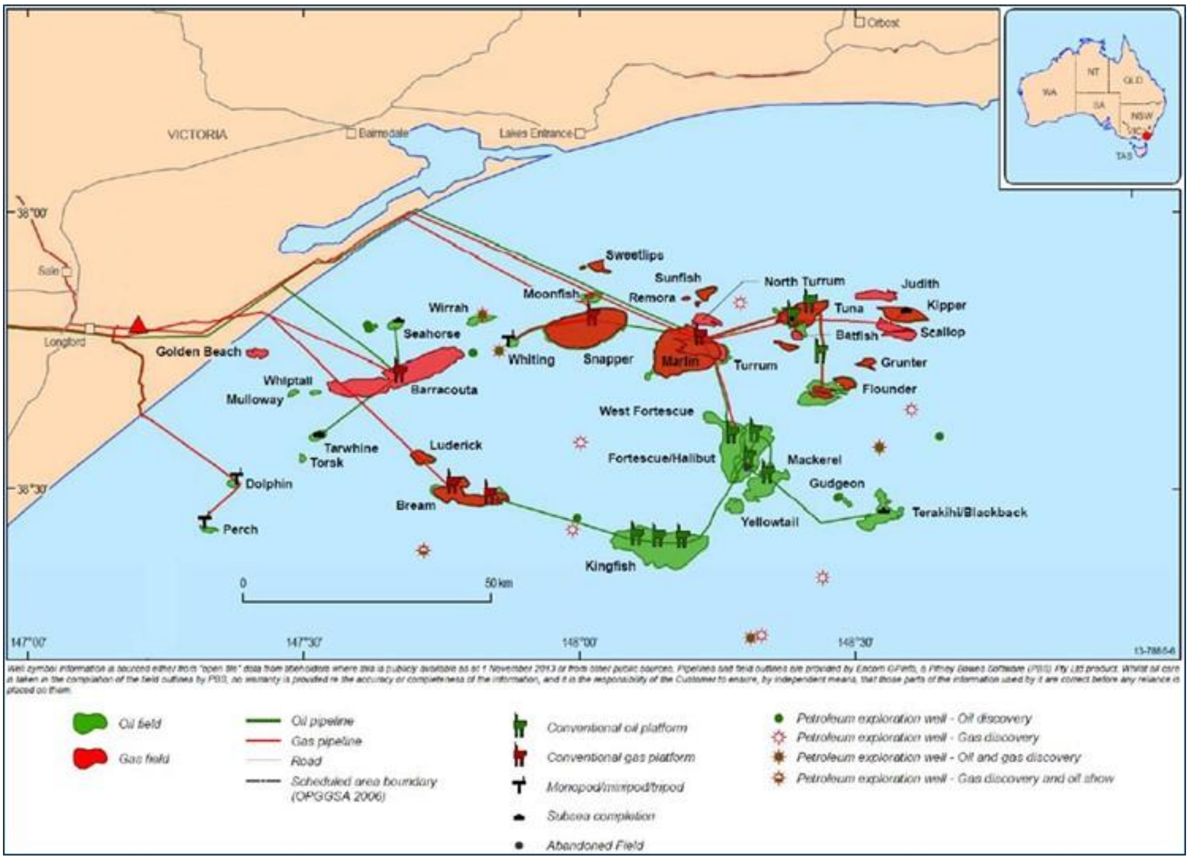
There are two main future development activities associated with Kipper. Phase 1B is associated with an infill well expected to be drilled in the next 5 years, mainly to accelerate production. The second development activity is the installation of compression facilities at West Tuna. The timing of compression is expected to be May 2024. Undeveloped Reserves are attributed to these projects.

GaffneyCline notes that BHP Petroleum's Reserve estimates align very closely with the Operator's own Reserve estimates. GaffneyCline reviewed the technical basis for estimating production profiles and Reserves and notes that the models have considered uncertainties relating to GIIP and reservoir connectivity as well as uncertainty in pressure associated with extrapolating wellhead pressure down to the reservoir datum. Overall, the technical work appears reasonable.

9.1.3 Facilities and Cost Estimates

The Bass Strait assets have been producing oil and gas since 1969. Thirteen oil fields and eleven gas fields have been developed with an integrated production system. Oil and gas production from nearly 300 active development wells is dewatered/dehydrated offshore and transported onshore in multiple gas and oil flowlines and pipelines. An overview of the Bass Strait development is shown in **Figure 9.6**. Fields and assets where BHP Petroleum hold no equity have been obscured for clarity.

Figure 9.6: Bass Strait Offshore Development Layout



Source: BHP Petroleum (Modified by GaffneyCline)

All of the fields, except Blackback, are located in water depths between 40 to 100 m, so most of them are conventional steel jackets. For some of the smaller tiebacks, mono-tower platforms or subsea tiebacks have been used. Two large, concrete gravity-based platforms are installed. **Table 9.6** shows the total wells and facilities inventory, onshore and offshore.

As noted above, the offshore facilities produce oil and gas to the onshore plants at Longford and Long Island. The Longford plant is a multi-train facility that conditions and compresses gas to sales specification, stabilizes crude, and separates Natural Gas Liquids (NGL) for further processing at the Long Island Point plant.

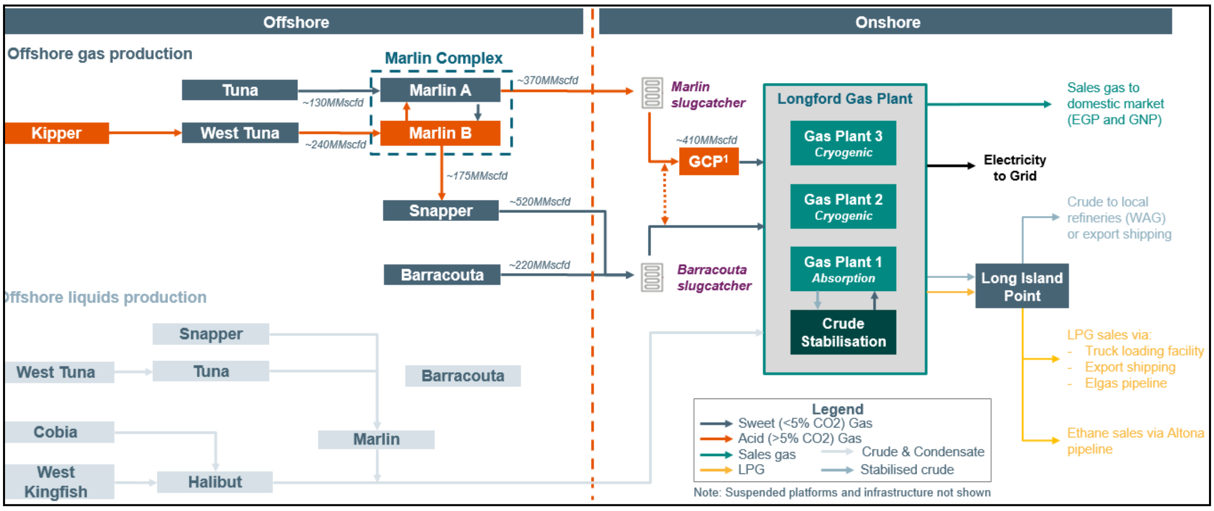
The Long Island Point plant, located 190 km from Longford, processes NGL's into ethane, propane and butane products for sale; and serves as a crude oil storage terminal for Bass Strait crude prior to domestic or export sales.

Table 9.6: Bass Strait Wells and Facilities Inventory

Category	Asset Type	Number
OFFSHORE		
Fields	Oil fields	13
	Gas Fields	7
	Gas Cap	4
Wells	Active wells	~300
	Inactive wells	~300
	E&A wells	~200
Facilities	Steel Jackets	16
	Concrete Gravity Base	2
	Monotowers	2
	Subsea	5
Flowlines & Umbilicals	Flowlines	Multiple
	Umbilicals	Multiple
ONSHORE		
Plants	Gas/oil processing	1
	NGL products	1
Pipelines	Pipelines	16 (922 km)

An overall block diagram of the offshore and onshore facilities is shown in **Figure 9.7**.

Figure 9.7: Bass Strait Development Block Diagram



Source: BHP Petroleum

9.1.3.1 *Facilities Operability, Integrity, and Infrastructure*

The Bass Strait development has been in production since 1969 with both gas and oil producing fields. As noted above, the system is complex with multiple producing fields, export pipelines and processing plants. Overall facilities integrity is managed within a long-term (10 years) shut-down planning driven by annual planned shutdowns of GP2 in the Longford Gas Plant of between 5 and 45 days/annum, generally planned for December. Within this shutdown window, offshore platform shutdowns are planned of 5 to 30 days duration depending on the maintenance and modifications workload required. Using this approach, the Operator has been able to deliver wintertime offshore platform availability (excluding planned shutdowns) of 75.3% up to 100% (averaging 93.4%) over the three-year period 2018-2020. During this same period, all platforms were online and available to produce for 63.7% of the wintertime high demand period.

Through the Longford Gas Plant, the Bass Strait fields are connected to the Victoria and Eastern Australia Gas markets. Longford has the facilities to process and deliver gas to the domestic market. Through the Long Island Point facility, oil, condensate, propane, butane and ethane can be processed and delivered to domestic or international markets.

9.1.3.2 *Decommissioning and Restoration (D&R) Planning*

D&R planning and execution is in progress in the Bass Strait development. Currently D&R focus is on the legacy oil fields, which have ceased production, commencing with P&A of platform wells and legacy exploration wells. The Operator's D&R planning extends over the next 20 years, averaging over US$100 MM per year. D&R planning is being managed as an ongoing activity, integrated into the offshore operations planning.

9.1.3.3 *Cost Review*

GaffneyCline has reviewed cost forecasts provided by BHP covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the Bass Strait operations. GaffneyCline's review aligned the cost and production profiles and rebased all costs to a RT2022 basis. Where available, costs were checked against alternative available documentation and against historical cost levels. D&R costs were checked against the Operator's recent delivered costs, current estimates, and recent Australian experience.

Gross CAPEX for further development activities related to the Bass Strait Reserves case is estimated to be US$490 MM and gross CAPEX for development of the Contingent Resources case is estimated to be US$794 MM.

9.1.4 Contingent Resources

BHP Petroleum has a large portfolio of potential projects, but many are associated with small volumes of economically non-viable developments. Contingent Resources are assigned to four projects that are the most mature from a technical and economic viability perspective: North Turrum, Sweetlips, Wirrah and East Pilchard (**Table 9.7**).

Table 9.7: Bass Strait 2C Gross Contingent Resources as of 31 December 2021

Field	Oil and Condensate (MMBbl)	Gas (Bscf)	Development Status
Bass Strait - North Turrum Phase 3	10.3	129.0	Pending
Bass Strait - Sweetlips / Wirrah	22.3	107.2	Pending
Bass Strait - East Pilchard	3.5	40.9	Unclarified
Total	**36.1**	**277.1**	

The North Turrum project is associated with Phase 3 development, which is a five well program from the Marlin B platform: three wells in North Turrum targeting acid gas bearing Latrobe L105-400 sands and two wells in Marlin 1-4 targeting acid gas bearing Latrobe L100-L400 sands. The plan is to utilise the recently acquired CGG multi-client seismic data to optimise well placement. The development could be combined with the Turrum sand control project in order to split costs. Planned start-up is in 2024. Sweetlips (10.9 km North of Snapper) and Wirrah (18 km West of Snapper) are satellite fields of the Snapper Field. The project has been evaluated by the Operator but is currently not in the approved plan. The current development concept is to tie back these nearfield gas discoveries to the Snapper platform, similar to what was recently done in West Barracouta. Such a tieback would allow for high deliverability sweet gas to help extend plateau production. The development is technically mature, but economically uncertain. Notional start-up date is late 2025.

East Pilchard is a gas field located south-west of the Kipper Field. The proposed development concept is a single well subsea development of the Upper 3 sands, tied back to Kipper. The development has some synergy with Kipper Phase 1B drilling (1 infill well). However, compared to North Turrum, Sweetlips and Wirrah, East Pilchard is less mature and has a relatively lower economic viability. There are also technical risks associated with uncertainties associated with reservoir connectivity and thin sands, plus miss-alignment on the preferred development concept and project timing between BHP Petroleum and the Operator. Notional start-up date is in early 2026.

9.1.5 GaffneyCline's Production and Cost Valuation Profiles: Bass Strait

GaffneyCline's valuation scenario production profile for BHP Petroleum's Bass Strait gas and oil assets is given in **Figure 9.8** with the associated real term cost profiles provided in **Figure 9.9**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing fields and selected 2C resources. The aggregated MMboe Net production profile is from the BHP Petroleum interests in the eleven gas fields, four of which have oil rims, and 13 oil fields documented above which are producing along with the North Tarrum, Sweetlip, Wirrah and East Pilchard 2C Contingent resources. The Contingent Resources considered likely to proceed by GaffneyCline is based upon the review of the overall Bass Strait portfolio.

The Contingent Resource projects included in the valuation profiles have been assessed as high confidence due to several factors. These projects are currently active, as evident from the recently acquired seismic data (as discussed in section 9.1.4), and there is ample technical work available demonstrating these projects are currently being evaluated based on GaffneyCline's review. The recently completed West Barracouta development has demonstrated the technical and commercial feasibility for nearfield gas discoveries tied back to an existing platform, which is the development concept for these four Contingent Resource projects. Finally, given the mature nature of the Bass Straits asset, it would be logical for the operator to seek to develop nearby accumulations to extend the length of the plateau and the economic life of the asset. For these reasons, GaffneyCline has assessed these projects to be high confidence with a very good incremental IRR and their contingencies are therefore acceptable for valuation purposes.

The regulatory carbon cost assumption for the Bass Strait gas and oil assets is as per BHP Petroleum's below the baseline assumption for this asset group.

Figure 9.8: BHP Petroleum Net Bass Strait Gas and Oil fields Production Profile

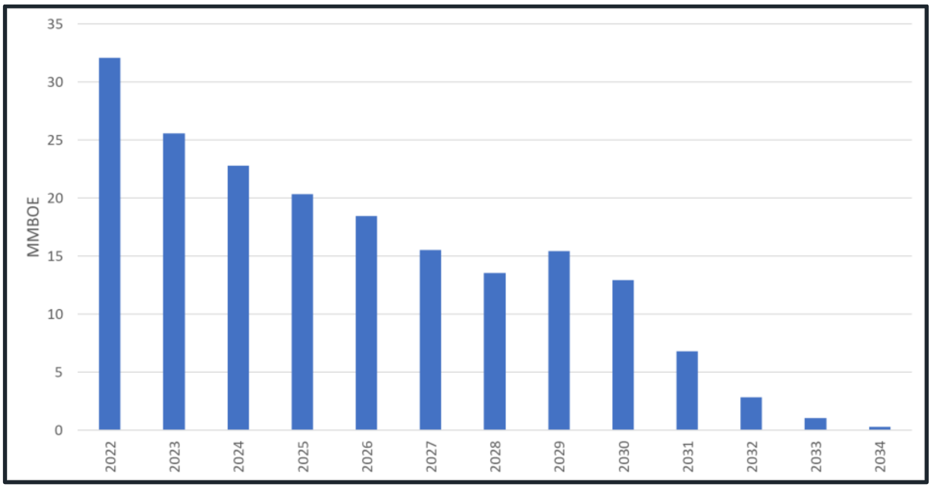
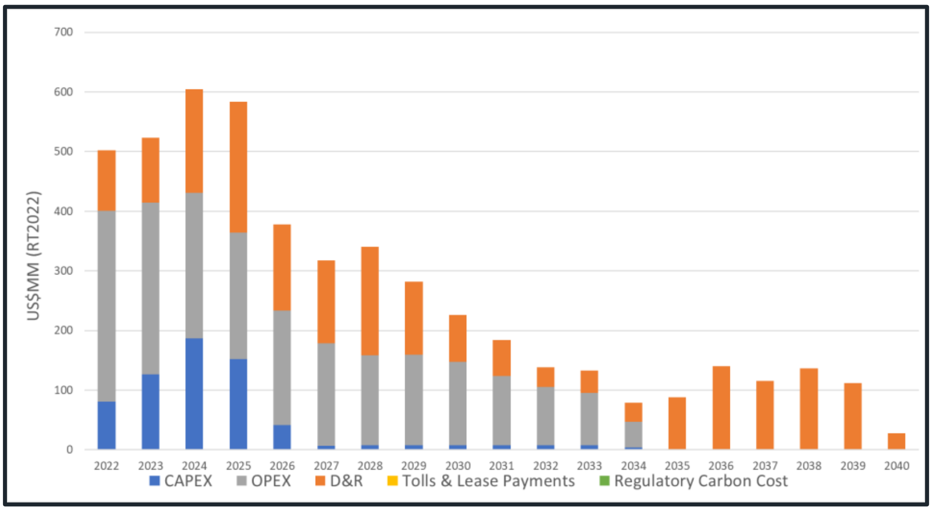


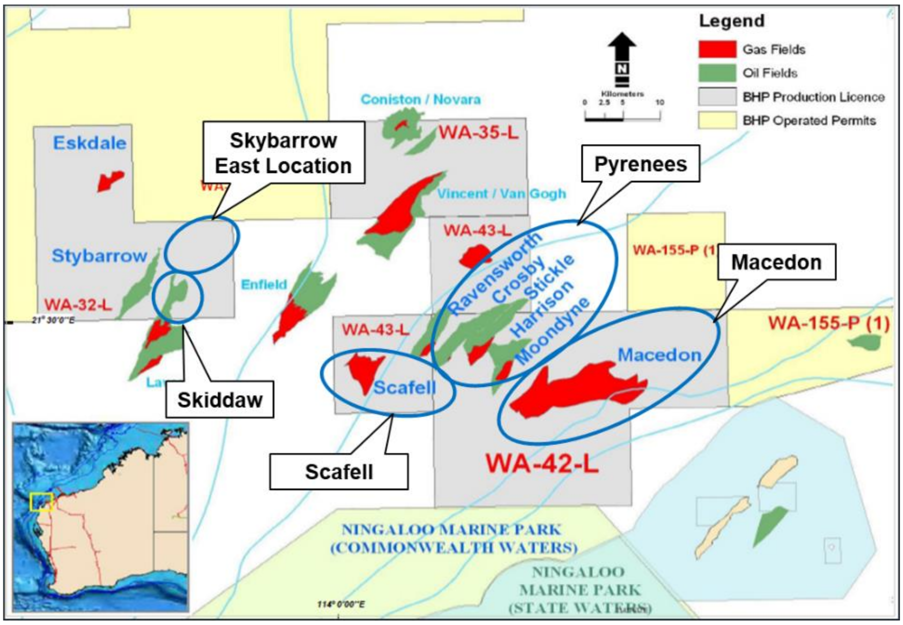
Figure 9.9: BHP Petroleum Net Bass Strait Gas and Oil Fields Cost Profile



9.2 Macedon

Macedon is a dry gas field located in Block WA-42-L in the Exmouth Sub-basin, about 40 km north of Exmouth in Western Australia in water depth of 160 to 190 m, in which BHP Petroleum has a 71.43% working interest. It has been developed with four subsea wells and gas is produced to the onshore Macedon gas plant, through a 90 km pipeline. First gas production was in 2013. **Figure 9.10** shows the locations of Macedon and other nearby fields.

Figure 9.10: Location Map of Macedon, Pyrenees, Skybarrow, Skiddaw and Scafell



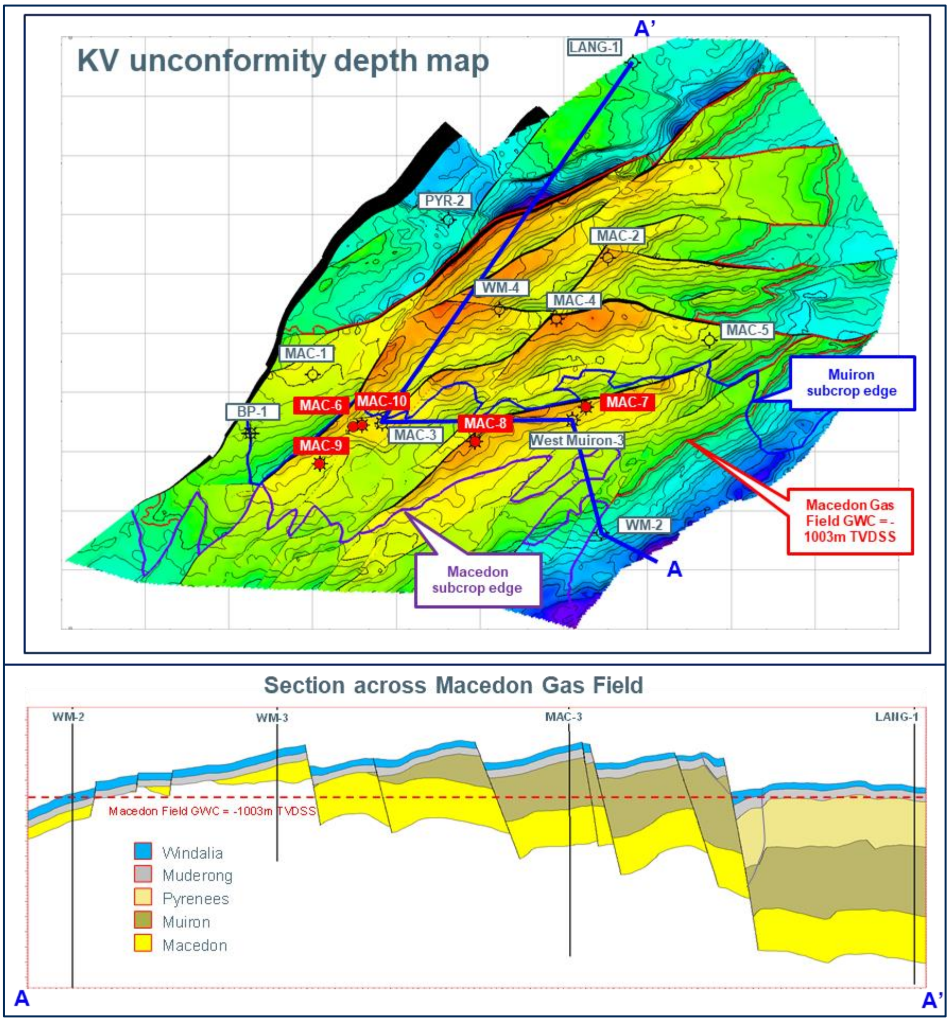
Source: BHP Petroleum

9.2.1 Field Description

Dry gas was discovered in the Macedon sandstone in 1992 by the West Muiron-3 well and the field was appraised by six wells between 1993 and 1994. Four production wells and one producer/injector well were drilled between 2009 and 2010 (the injector/producer Macedon-6 well had injected Pyrenees excess gas into Macedon and now produces Pyrenees fuel gas). The Macedon field is a large structural-stratigraphic feature consisting of several segments; notably 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, along with a cross section, is shown in **Figure 9.11**. The reservoir is a high-quality stacked slope turbidite sand, and has average NTG of 72%, porosity of 29% and 2,700 mD permeability. A secondary reservoir is provided by the Muiron member, which is a product of transgressive inner shelf or slope fan complex, and has average NTG of 35%, porosity of 23% and 60 mD permeability.

Figure 9.11: Macedon Depth Structure Map and Cross Section



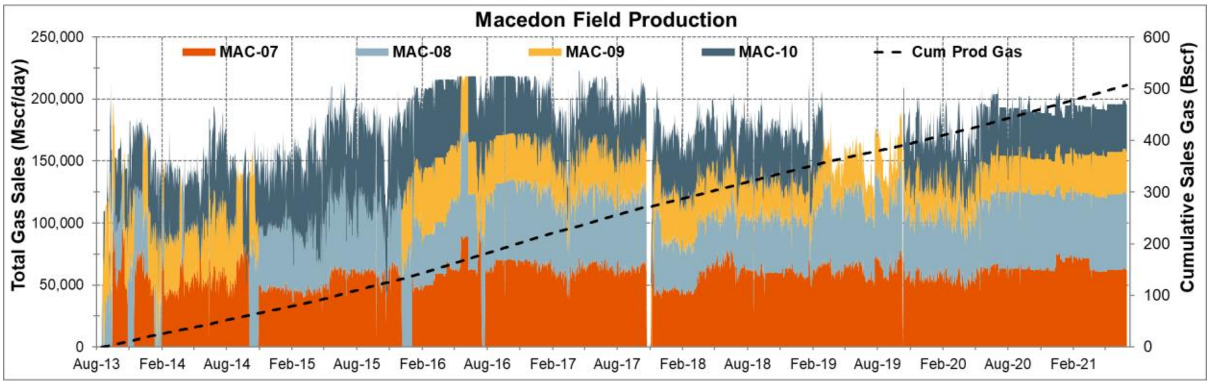
Source: BHP Ptroleum

9.2.2 Field Development and Production Forecasts

The Macedon development comprises four subsea wells (Macedon-7, 8, 9, and 10) located in the Central and Southern Field Segments, providing drainage to all segments of the reservoir. The Northern Segment does not contain a well due to its low volumes and proximity to water. However, fault-seal studies have confirmed that this segment is not structurally isolated and can be drained by the development wells in the Central segment.

Peak production of some 220 MMscfd was achieved in 2016, with current production just below 200 MMscfd (**Figure 9.12**). The total raw gas and condensate production until 30 June 2021 is 518 Bscf (507 Bscf sales gas) and 33.6 MBbl, respectively. Total fuel and flare consumption is 10.3 Bscf. Macedon fuel burn rate is approximately 3.6 MMscfd based on historical trends.

Figure 9.12: Macedon Historical Production



Source: BHP Petroleum

Due to friability of the reservoir, sand control was required, and open-hole gravel pack completions were installed in development wells. The completions provide a maximum allowable rate of 100 MMscfd per well.

GaffneyCline has reviewed the material balance (P/Z plot) provided by BHP Petroleum, including plots illustrating the history match of gas rate, bottom-hole and tubing-head pressures until mid-March 2021 and forecasts from numerical models. Overall, the technical work appears reasonable, and GaffneyCline has accepted the Low and Best estimate production forecasts prepared by BHP Petroleum for the purposes of estimating Reserves. The gross volumes are presented in **Table 9.8** and production profile depicted in **Figure 9.13**.

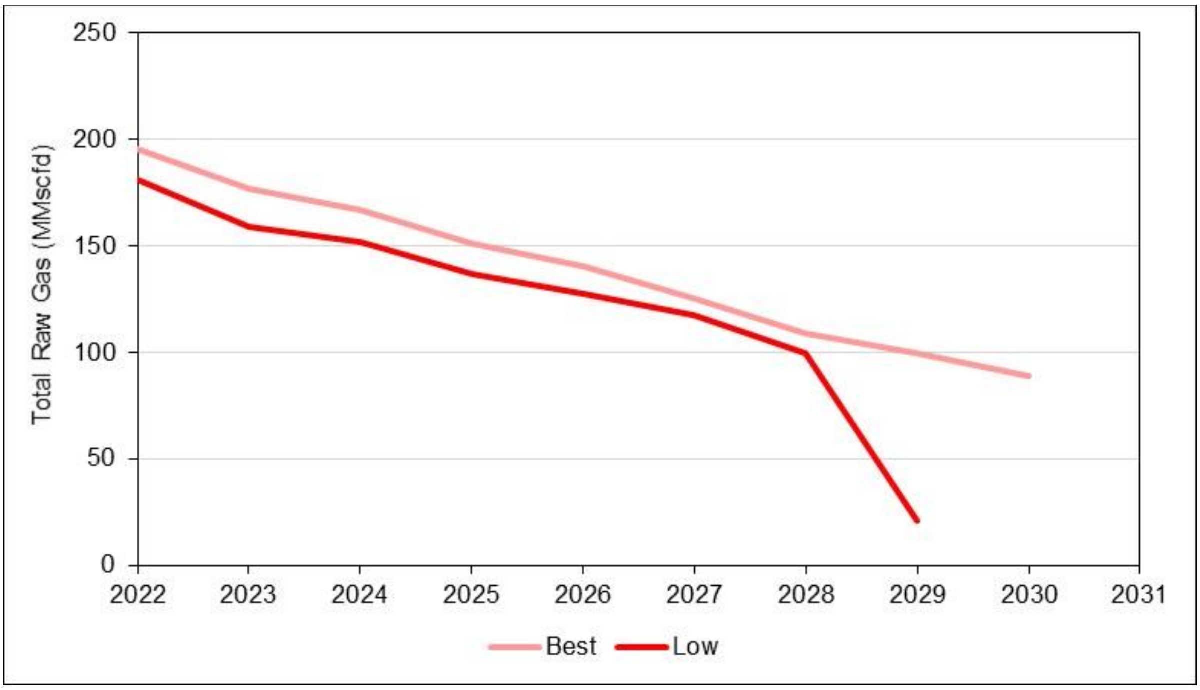
Currently, end of field life is determined by the minimum flowrate of 50 MMscfd, or the minimum arrival pressure at the Macedon plant (26 barg). A wet gas compression project is under consideration at the plant that would reduce the minimum arrival pressure to 15 bara. Additional fuel gas is supplied to the Pyrenees FPSO via the Macedon-6 well. Excess Pyrenees gas is injected into the Macedon reservoir for storage and to be recovered in the future.

Table 9.8: Macedon Low and Best Estimate Gross Volumes (Bscf)

	Low Estimate (Bscf)	Best Estimate (Bscf)
Macedon Sales Gas	339	412
Macedon Fuel Gas	10	12
Pyrenees Fuel Gas from Macedon	14	34
Total	**363**	**457**

Note: Pyrenees fuel from Macedon is not available for sale and reported herein for completeness.

Figure 9.13: Macedon Gas Production Profiles

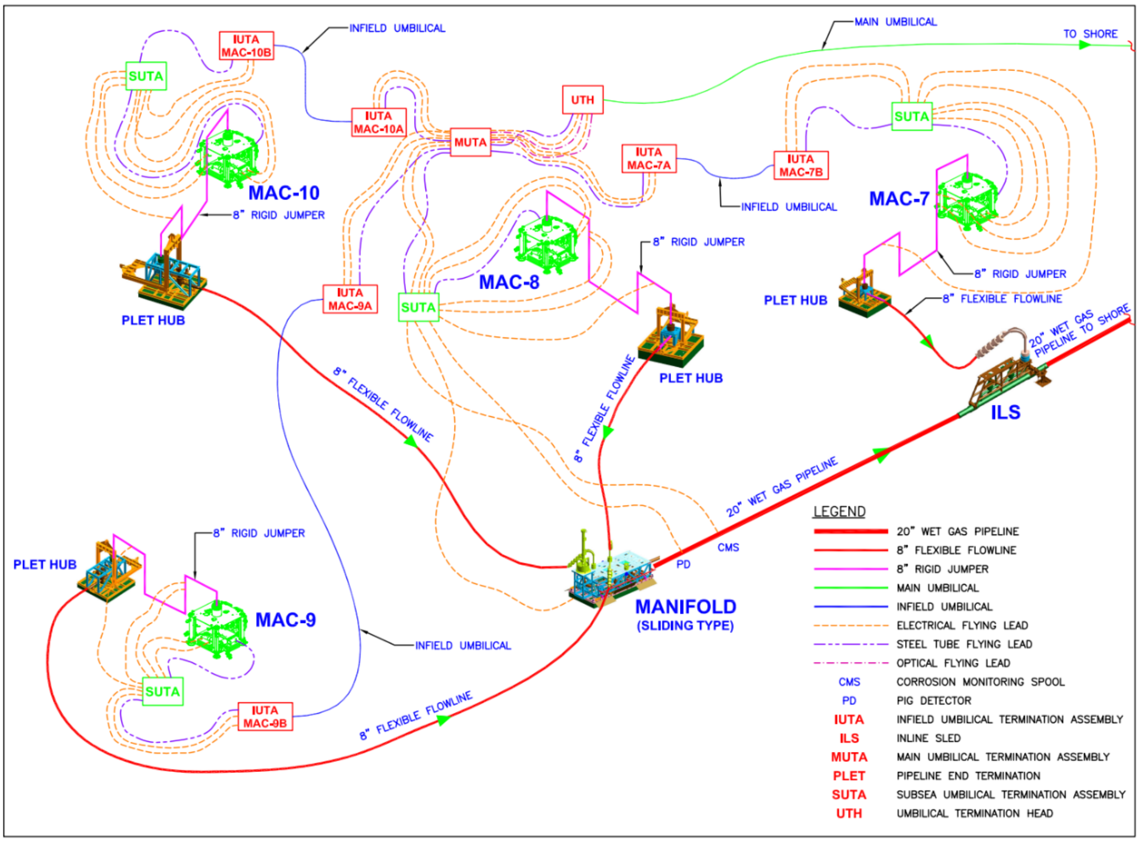


Source: GaffneyCline from BHP Petroleum Data

9.2.3 Facilities and Cost Estimate

The Macedon plant is designed to process a maximum of 220 MMscfd of gas and delivers to the Western Australia domestic gas market via the Dampier to Bunbury Natural Gas Pipeline (DBNGP). The development is designed to be a reliable supplier of gas with production availability above 95%. The Macedon offshore configuration is shown in **Figure 9.14**.

Figure 9.14: Macedon Offshore Development Layout



Source: BHP Petroleum

9.2.3.1 Facilities Operability, Integrity, and Infrastructure

The Macedon Field has been on production since August 2013 with only one full shutdown during that period (late 2017). Despite occasional problems with communications/control problems with some of the subsea wells, overall system availability has exceeded 98%.

The Macedon gas plant provides gas to the Western Australia domestic gas market, via the DBNGP.

9.2.3.2 Decommissioning and Restoration (D&R) Planning

Macedon D&R activities are planned to commence two years prior to end of field life and be carried out over a 9-year period. This is realistic, typical of current industry D&R planning, and accepted by GaffneyCline.

9.2.3.3 Cost Review

GaffneyCline has reviewed cost forecasts provided by BHP covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the Macedon operations. GaffneyCline's review aligned the cost and production profiles and rebased all costs to a RT2022 basis. Where available, costs were checked against alternative available documentation and against historical cost levels. D&R costs were checked against current estimates, and recent Australian experience.

9.2.4 Contingent Resources

BHP Petroleum's estimates of gross Contingent Resources are shown in **Table 9.9.** GaffneyCline has reviewed BHP Petroleum's analyses, including BHP Petroleum's dynamic simulation models, and has accepted BHP Petroleum's gross Contingent Resources. The Macedon Front End Compression project is the most mature, classified under PRMS as Development Pending. The Macedon Front End Compression project has been assessed by GaffneyCline as a technically mature project. It forms the basis of the Macedon field's further development for late life incremental recovery and is ranked highest in the available project opportunities order with very good economics with a plan to commence in May 2024 after FID is reached. The two infill wells are relatively immature and are classified as Development Unclarified while the Black Pearl tie-back project is Not Viable.

Table 9.9: Macedon Gross 2C Contingent Resources

Project	Development Status	Gas (Bscf)
Macedon Front End Compression	Pending	57
Muiron Infill Well	Unclarified	53
Macedon Infill Well	Unclarified	29
Black Pearl Infill Well	Not Viable	10
Total		**150**

9.2.5 GaffneyCline's Production and Cost Valuation Profiles- Macedon

GaffneyCline's valuation scenario production profile for BHP Petroleum's Macedon asset is given in **Figure 9.15** with the associated real term cost profiles provided in **Figure 9.16**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing Macedon field discussed in the previous Macedon sections**.** The Macedon Front End Compression project is also included in the valuation profile as it is the most technically mature and GaffneyCline considers the implementation as standard industry practice. The project has a very good incremental IRR also based on GaffneyCline's commercial review with the main contingency being FID.

The regulatory carbon cost assumption for the Macedon asset is as per BHP Petroleum's below baseline assumption for this asset group.

Figure 9.15: BHP Petroleum Net Macedon Production Profile

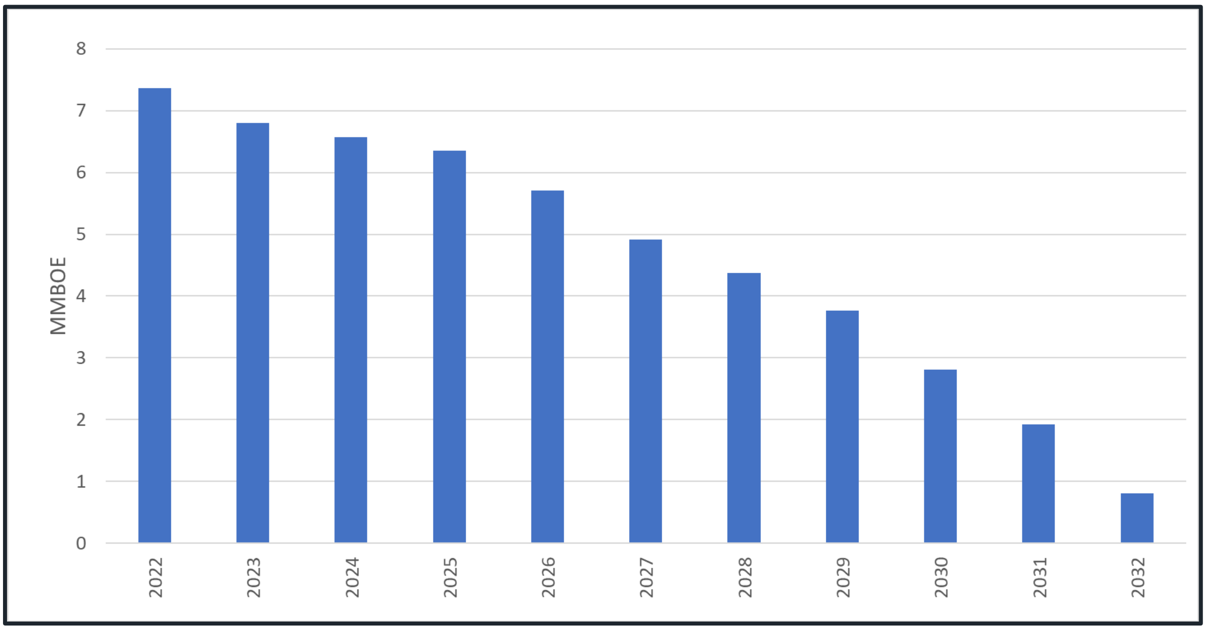
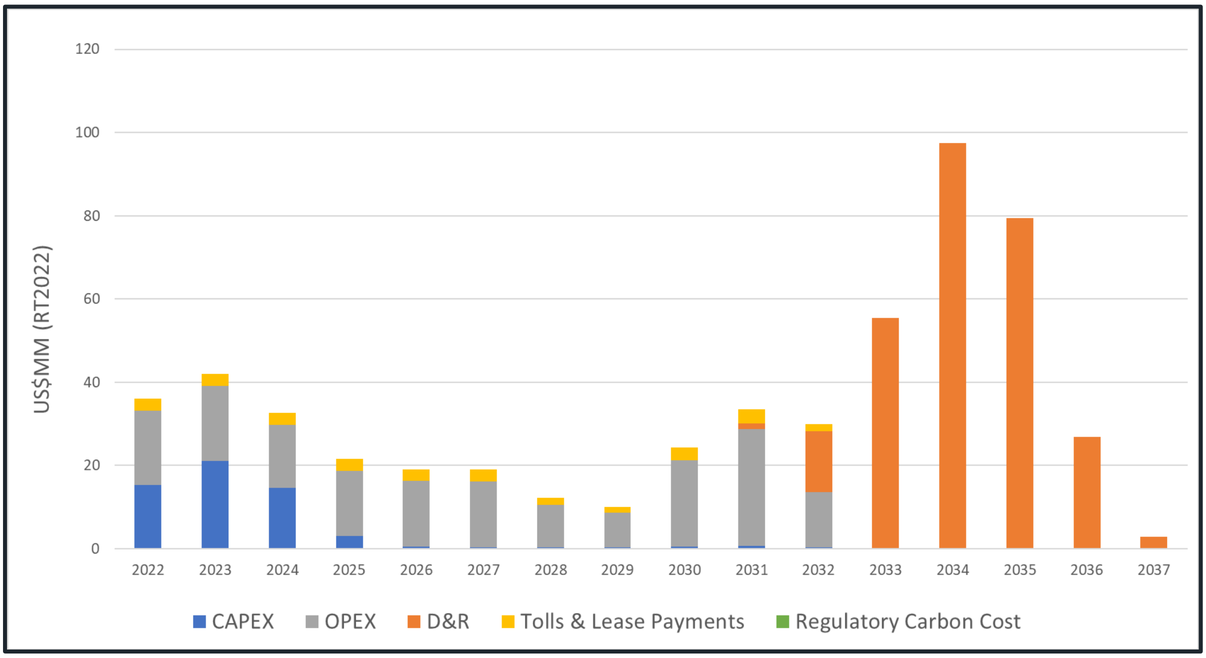


Figure 9.16: BHP Petroleum Net Macedon Cost Profile



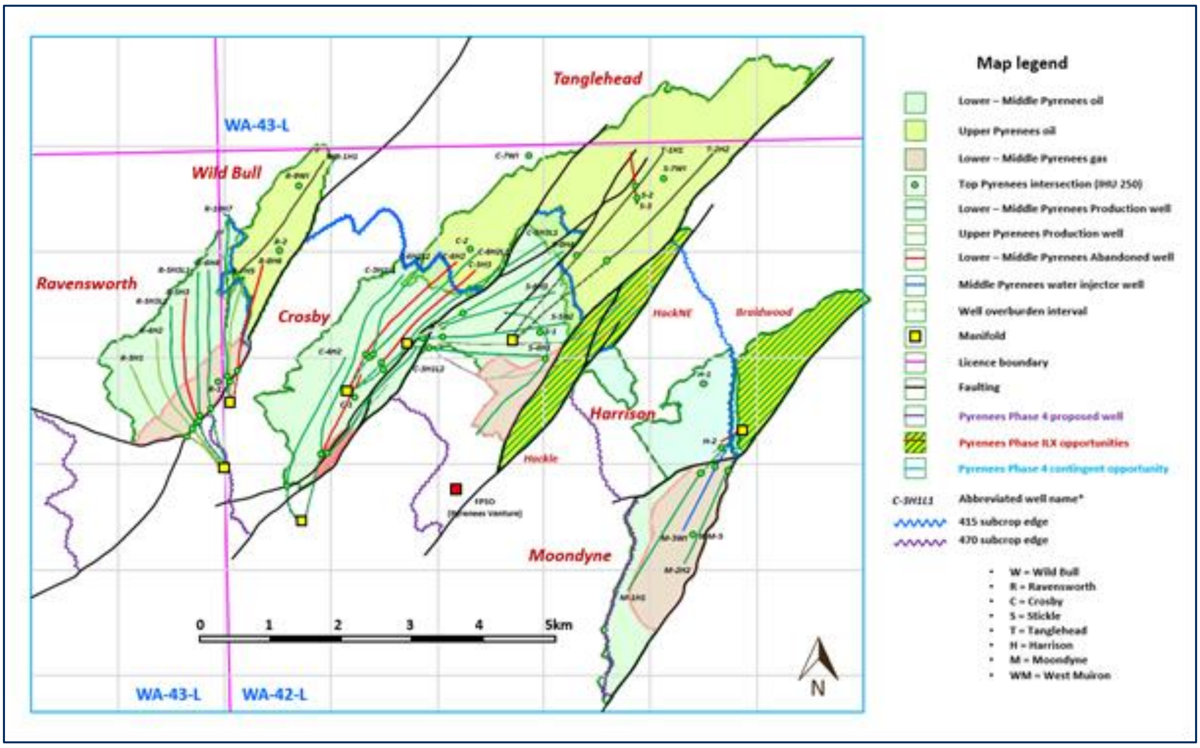
9.3 Pyrenees

The Pyrenees oil development comprises a group of fields (**Figure 9.10**) located in 200 m water depth in the Exmouth Sub-basin, 40 km NW of Exmouth in Western Australia in Blocks WA-42-L (BHP Petroleum interest 71.43%) and WA-43-L (BHP Petroleum interest 39.999%). Production commenced in 2010 and the oil is processed on the Pyrenees Venture FPSO.

9.3.1 Field Description

The asset comprises several oil accumulations trapped in a series of stair-stepping, northeast-southwest trending, fault blocks, and in dipping reservoirs truncated by an unconformity. The main fault blocks are Ravensworth, Crosby, Stickle, and Harrison, but further stratigraphic separations divided the field into seven pools (**Figure 9.17**). Oil was first encountered in the field in 1993 by West Muiron-5 well, which penetrated the Middle Pyrenees Moondyne pool. In 2003, Ravensworth-1 and Crosby-1 found oil in the respective fault blocks, followed by Stickle-1 and Harrison-1 in 2004.

Figure 9.17: Pyrenees Oil Pools and Well Locations



Source: BHP Petroleum

The Pyrenees reservoirs are the Early Cretaceous sands of the Barrow Group found at around 1,200 mss. The reservoirs have high quality, with NTG of over 90%, average porosity 28% and average permeability 4,500 mD. The sandstones are the products of progradational wave-dominated shelf margin delta, with extensive shoreface deposits. The reservoirs are divided into three groups: Lower, Middle, and Upper Pyrenees. The oil is biodegraded with 19 deg API gravity.

9.3.2 Field Development and Production Forecasts

The initial development consisted of the subsea development of Ravensworth, Crosby and Stickle oil and gas fields. Development drilling started in January 2009 and production commenced in 2010. The first infill well, STI-8H4, came online in July 2012.

Phase 2 of the development was completed during 2014 which included the development of the Upper Pyrenees (Tanglehead and Wild Bull) with first oil in January 2014 and Moondyne fields with first oil in April 2014.

The Phase 3 drilling campaign was executed during 2015 and 2016 and consisted of two new wells (STI-9H5 and RAV-10H7), one single lateral re-entry of an existing well (CRO-5H3) and three dual lateral re-entries of existing wells (RAV-5H3, CRO-6H4, and CRO-3H1).

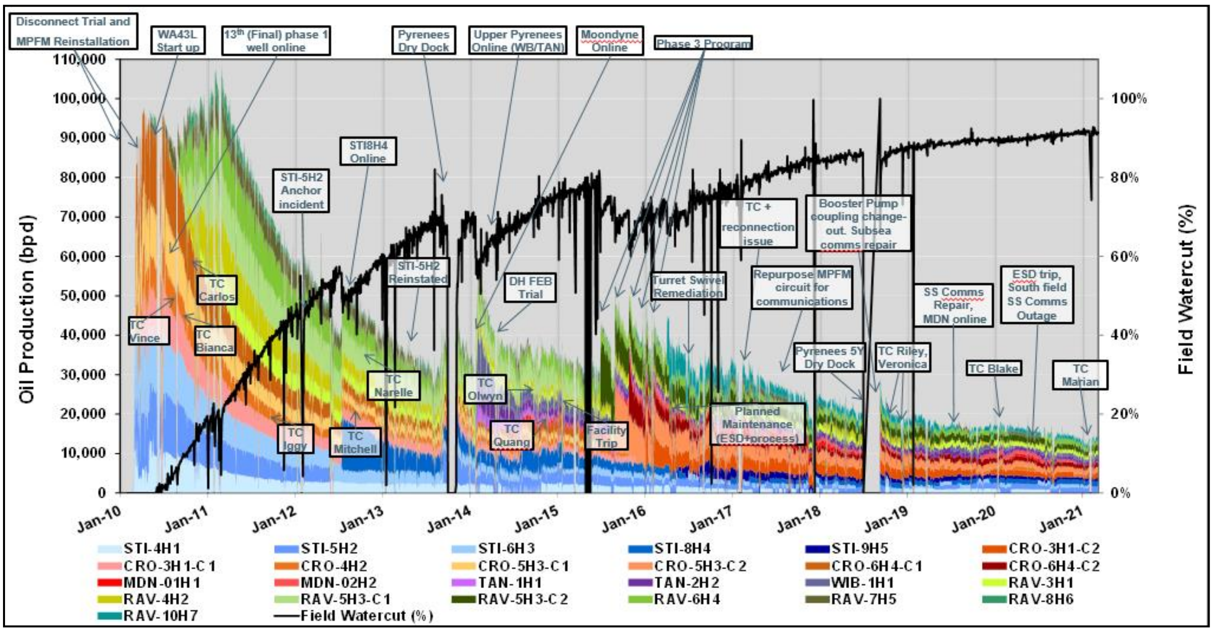
The Pyrenees development comprises the following components:

- Twenty-six subsea wells, made up of the following:
  - 21 production wells (seven in Ravensworth, four in Crosby, five in Stickle, one in Wild Bull, two in Tanglehead, and two in Moondyne).
  - Three vertical produced water disposal wells (one each in Ravensworth (failed), Crosby, and Stickle Fields).
  - One horizontal water disposal well that provides pressure support to the Moondyne field.
  - One gas injection/production well (Macedon-6) in the nearby Macedon gas field.
- Flowlines from the subsea wells to subsea manifolds, and flowlines from subsea manifolds to a Floating Production Storage and Offloading facility (FPSO).

Historical production performance on a well-by-well basis is shown in **Figure 9.18**. To date, approximately 152 MMBbl of oil has been produced at Pyrenees.

A number of characteristics affect oil recovery from the Pyrenees fields including moderately viscous oil (8 to 11 cp), thin oil columns (0 to 37 m), high permeability and high NTG sands and large active aquifer beneath most of the oil column. These attributes typically lend themselves to high field recoveries, a significant portion of which can be contained in characteristic long production “tails”. Estimates of recoverable volumes have been made by production analysis that are consistent with simulation-based estimates.

Figure 9.18: Pyrenees Production History



Source: BHP Petroleum

BHP Petroleum uses an Integrated Production Model (in the GAP software) to optimise forecasts within facility constraints. The GAP model is used by BHP Petroleum for both short and long-term forecasting. The producing wells and fields are constrained by a combination of network and facility limitations, specifically the network backpressure and facility water processing. Due to the fluid handling constraints, several wells are cycled while other wells require additional gas lift for flowline stability at the expense of other wells. It is expected these trends will continue in the future. Based on historical performance, well productivity and reservoir pressure tend to remain relatively constant over time. The Low and Base case forecast assumptions shown in **Table 9.10**.

Table 9.10: Field Life Assumption Summary

	Low Case	Best Case
Well Water Cut (WCT)	96%	Not imposed Typical 98%
End of Facility Life	FY2035	FY2035

GaffneyCline carried out a review of estimates of remaining recoverable volumes by analysing historical performance, using DCA for the main fields. Low and best estimate forecasts were generated for the period from 1 July 2021 to 31 January 2028 (BHP Petroleum low estimate economic limit) and to 30 June 2036 (end of facility life for best estimate). GaffneyCline estimated remaining oil volume for both low and best cases summary is presented in **Table 9.11.**

Pyrenees fuel gas consumption averaged around 10 MMscfd until mid-2020. Since then, fuel and flare usage has reduced to approximately 8.5 MMscfd due to compressor restaging. These reductions have been included in the fuel forecast. As Pyrenees gas caps have been blown down and oil rate reduces, the remaining produced gas volume is no longer enough to power the facility. Gas produced from the Macedon field via Macedon-6 is used to make-up the difference required.

Table 9.11: Estimated Gross Technical Remaining Recoverable Volumes by Field as of 31 December 2021

Field	Development Status	Produced Oil (MMBbl)	Remaining Recoverable Oil (MMBbl)	
			Low Estimate	Best Estimate
Crosby	Producing	43.8	5.0	9.3
Moondyne	Producing	2.7	0.9	1.2
Ravensworth	Producing	42.3	4.8	8.9
Stickle	Producing	39.5	6.0	9.8
Tanglehead	Producing	5.0	1.0	1.8
Wild Bull	Producing	3.1	0.3	0.7
Total		**136.4**	**18.0**	**31.7**

According to the WA-43-L tie-in agreement, all gas produced into the Pyrenees production network becomes the property of the WA-42-L joint venture. This affords BHP Petroleum rights to 71.43% of the total fuel gas. Fuel gas volumes incorporate the results of Phase 2 and Phase 3 drilling campaign.

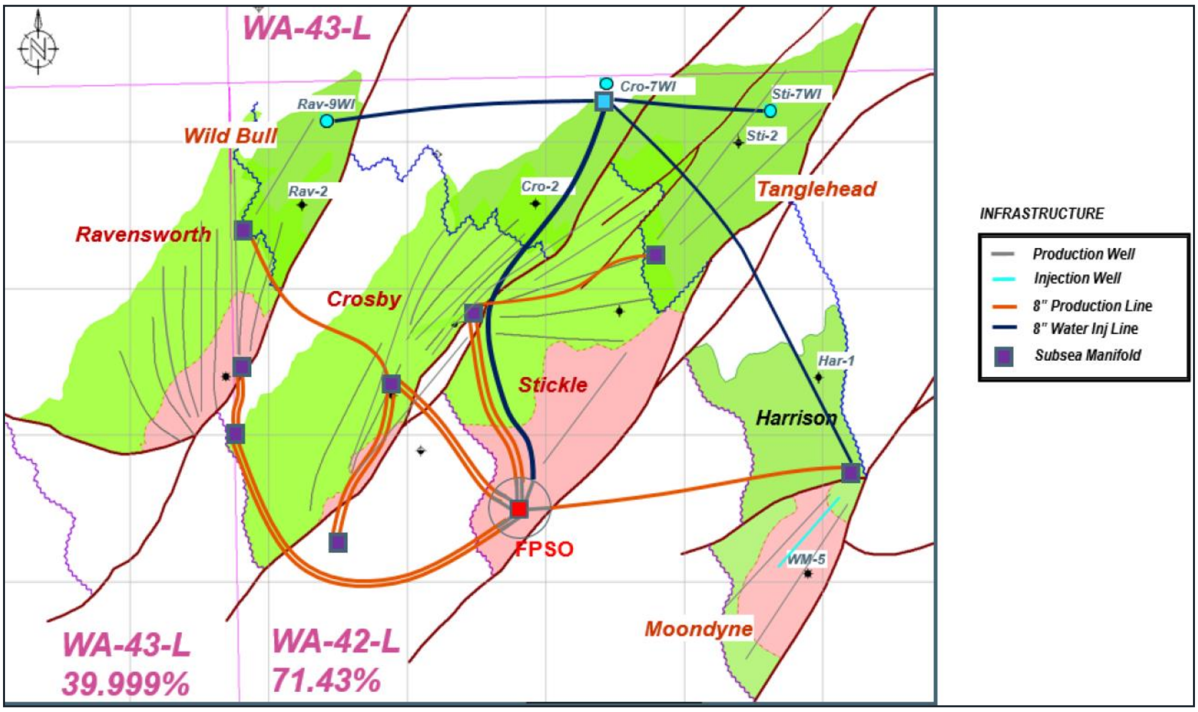
Assessment of the fuel gas component has been evaluated by using the gas production forecasts associated with each of the Low, Best and High oil production profiles. In order to generate fuel gas forecasts, flare volumes (1.5 MMscfd) were subtracted from the Pyrenees produced gas profile. Any remaining gas is booked under the Pyrenees fuel reserves entity. As Pyrenees gas caps have been blown down and oil rate reduces, this remaining produced gas volume is no longer enough to power the facility. Gas produced from the Macedon Field via Macedon-6 is used to make-up the difference required to provide the required 7 MMscfd of fuel gas. The volumes from the Macedon reservoir are booked under the Macedon entity. As Pyrenees gas production continues to decline, a higher rate of gas will be required from the Macedon gas field. In the case of the Macedon-6 well watering out before the end of Pyrenees field life, a small scope of subsea work would enable gas to flow from the Macedon field or Dampier-Bunbury Pipeline via the Macedon network back to the FPSO.

9.3.3 Facilities and Cost Estimates

The Ravensworth, Wild Bull, Crosby, Tanglehead, Stickle, Harrison, and Moondyne Fields are developed with subsea wells tied back to the Pyrenees Venture FPSO (**Figure 9.19**). Oil is exported to the buyer's vessel from the Pyrenees Venture FPSO. Gas is used as fuel or reinjected into the Macedon Field.

Since first oil in 2010, the FPSO has been regularly dry docked in 2014 and 2019, with the next scheduled dry docking expected in 2024, assuming a 5-year scheduled interval. Field production is constrained by the FPSO water handling limit, currently approximately 148 Mbwpd.

Figure 9.19: Pyrenees Venture Development Layout



Source: BHP Petroleum

9.3.3.1 Facilities Operability, Integrity, and Infrastructure

The Pyrenees development has been in production since February 2010, with 5-yearly planned dry docking for FPSO inspection and refurbishment. The subsea system has experienced problems with communications failures. At an overall system level, the Operator tracks "deferment", that is, the oil production delayed because of unplanned facilities outages. Over the last three and a half years, deferment has averaged 937 bopd, or some 5.5%. This is consistent with the Operator's planned uptime for production forecasting. The primary cause of deferment is recorded as "weather", i.e. precautionary cyclone shutdowns.

9.3.3.2 Decommissioning and Restoration (D&R) Planning

Pyrenees D&R activities are planned to commence two years prior to end of field life and be carried out over a 9-year period. This is realistic, typical of current industry D&R planning, and accepted by GaffneyCline.

9.3.3.3 Cost Review

GaffneyCline has reviewed cost forecasts provided by BHP covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the Pyrenees operations. GaffneyCline's review aligned the cost and production profiles and rebased all costs to a RT2022 basis. Where available, costs were checked against alternative available documentation and against historical cost levels. The Operator's D&R costs were adjusted in line with GaffneyCline's experience of current Australian D&R costs.

9.3.4 Contingent Resources

The 2C Contingent Resources are presented in **Table 9.12**. These are part of Phase 4 and have passed Gate 3 (Project Sanction) of BHP Petroleum's future opportunities timeline. They are currently classified as Contingent Resources Development Pending, although their migration to Reserves is imminent (subject to favourable economic evaluation). The remaining 2C Contingent Resources volumes are shown in **Table 9.13**. These are part of Pyrenees Phase 5 development plan and are not included in BHP Petroleum's five-year plan. They are at various stages of maturity as shown in **Table 9.13**, but as a group have been classified Development Unclarified.

Table 9.12: GaffneyCline Gross Contingent Resource for Pyrenees Phase 4 as of 31 December 2021

Field	Development Status	Oil (MMBbl)	Remarks
Crosby	Pending	2.7	Water Shutoff
Stickle	Pending	1.8	STI-4H1
Total		**4.5**	

Table 9.13: GaffneyCline Gross Contingent Resource for Pyrenees Phase 5 as of 31 December 2021

Field	Development Status	Oil (MMBbl)	Remarks
Crosby	Unclarified	3.0	CRO-4H2 DL
Moondyne	Not Viable	4.0	Infill Drilling
Ravensworth	On-Hold and Not Viable	3.3	RAV-8H6
Stickle	Unclarified	1.4	STI-6H1
Tanglehead	Unclarified	1.6	TAN-2H2 DL
Wild Bull	On-Hold	1.9	Wild Bull-2H2 SL
Harrison	On-Hold	3.5	HAR-3H1 TL
Total		**18.5**	

9.3.5 GaffneyCline's Production and Cost Valuation Profiles-Pyrenees

GaffneyCline's valuation scenario production profile for BHP Petroleum's Pyrenees oil assets is given in **Figure 9.20** with the associated real term cost profiles provided in **Figure 9.21**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing fields listed in the previous Pyrenees Sections up to and including Phase 4 only based on GaffneyCline's assessment of the contingencies. Phase 4 has passed the technical and commercial Gate 3 of the BHP Petroleum project sanction process. BHP Petroleum plan to migrate the volumes to Undeveloped status in FY22. The technical work for completion optimisation in the reservoir dynamic model is in progress and RFSU (Ready for Start-up) is expected to be in August 2022. Economically the project has a very good incremental IRR.

The regulatory carbon cost assumption for the Pyrenees oil assets is as per BHP Petroleum's below baseline assumption for this asset group.

Figure 9.20: BHP Petroleum Net Pyrenees Production Profile

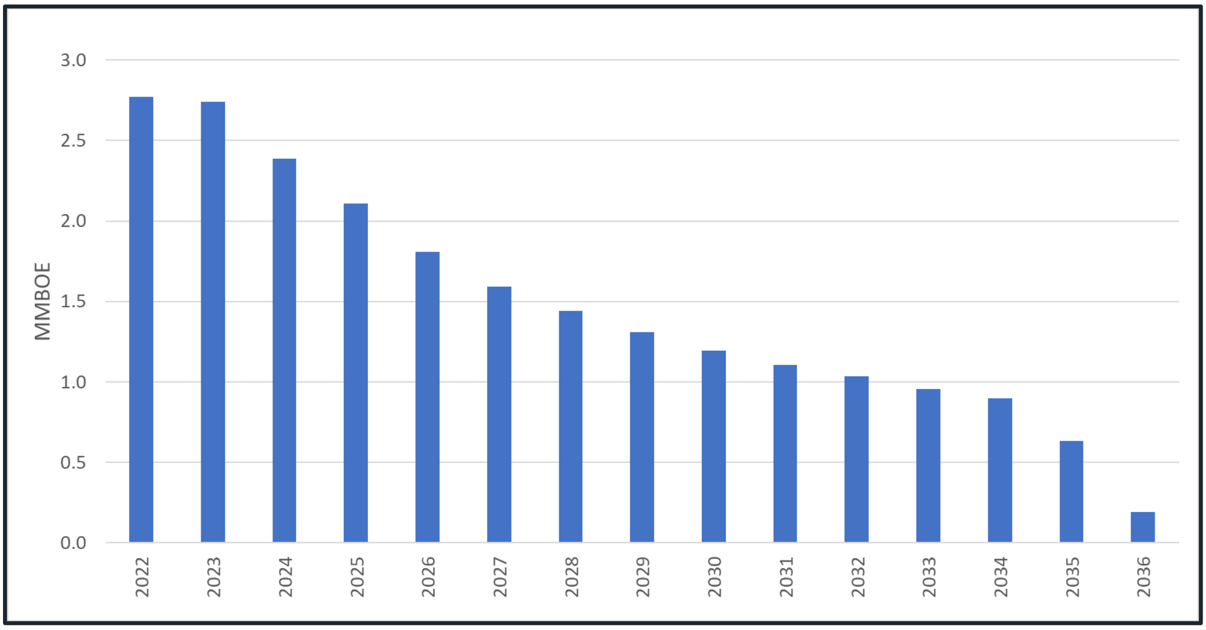
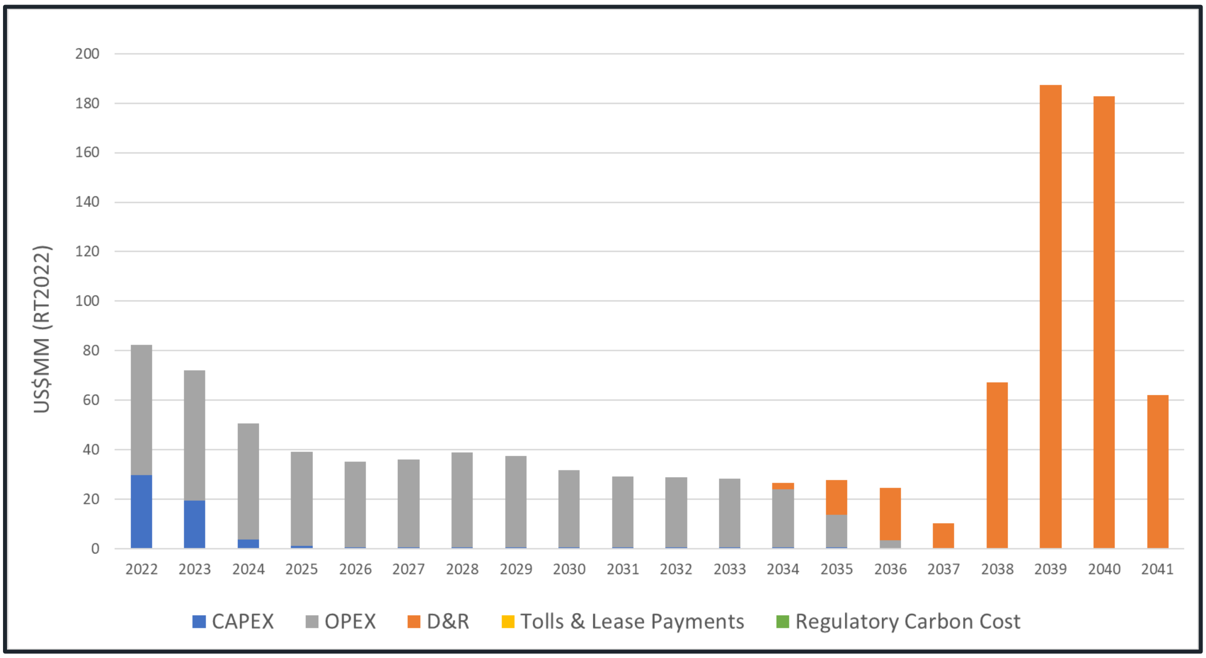


Figure 9.21: BHP Petroleum Net Pyrenees Cost Profile



9.4 Scafell

The offshore Scafell gas field is located in the NW Shelf of Australia, approximately 120 km west of Onslow and 40 km north of Exmouth within the existing Pyrenees Field production license WA-43-L (Figure 9.10). BHP Petroleum is the operator of WA-43-L with a 39.999% interest; Santos holds a 31.501% interest and Inpex a 28.500% interest. The permit forming the production lease was originally granted in September 2009. The Scafell gas field will be developed and produced under the existing production license WA-43L. Under the provisions of the Offshore Petroleum Act 2006, the duration of the license is indefinite up until no petroleum recovery operations have been carried for 5 years.

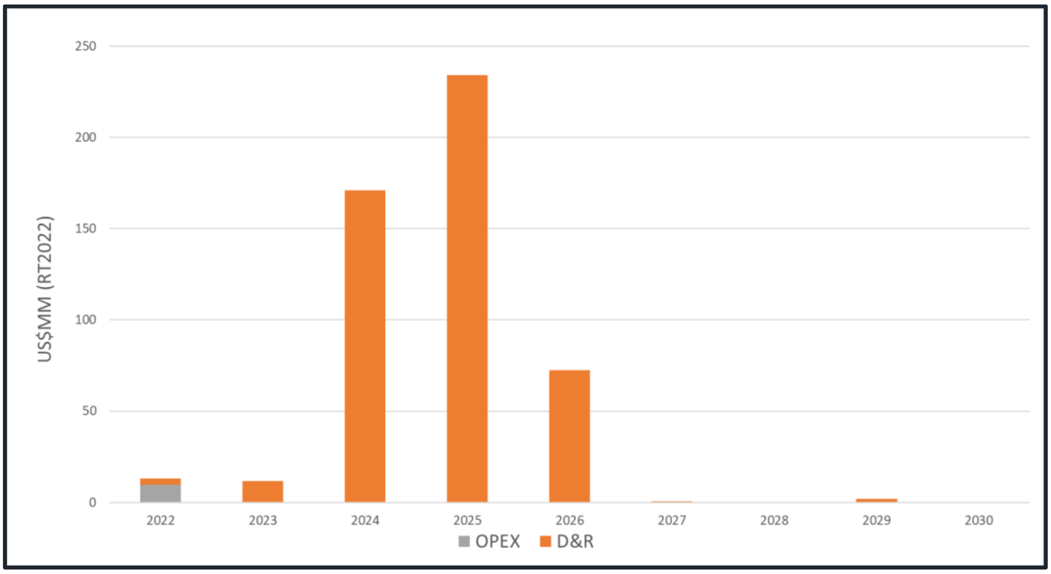
Scafell is a complex structural/stratigraphic trap approximately 3 km by 4 km in size and reservoir depth of ~1,300 to 1,500 mss in water depth of 282 m. The reservoir has excellent properties, with porosity of 25% and permeability between 300 and 1,800 mD encountered at the Scafell-1 location. Gas properties are expected to be similar to the adjacent Macedon gas field (lean and dry). Development of Scafell is planned to be a tie-back to the Macedon manifold and timing will depend on when the Macedon gas production comes off plateau or when there is an increase in WA domestic gas demand.

For Scafell, BHP Petroleum has 2C gross Contingent Resources of 94.5 Bscf (sales gas plus fuel gas for Pyrenees oil field), sub-classified as Development Not Viable. The development project has not been sanctioned and no recent progress has been made. The unitised development plan has not been finalised, and no gas contract has been signed.

9.5 Other Australian Assets

In addition to discovered and producing assets described above, BHP also have outstanding D&R obligations in respect of three fields that have ceased production, where decommissioning and restoration activities are in planning or in progress. GaffneyCline has reviewed the D&R estimates of these fields, Minerva, Griffin, and Stybarrow, and accepted or updated the costing basis in line with current industry practise (**Figure 9.22**).

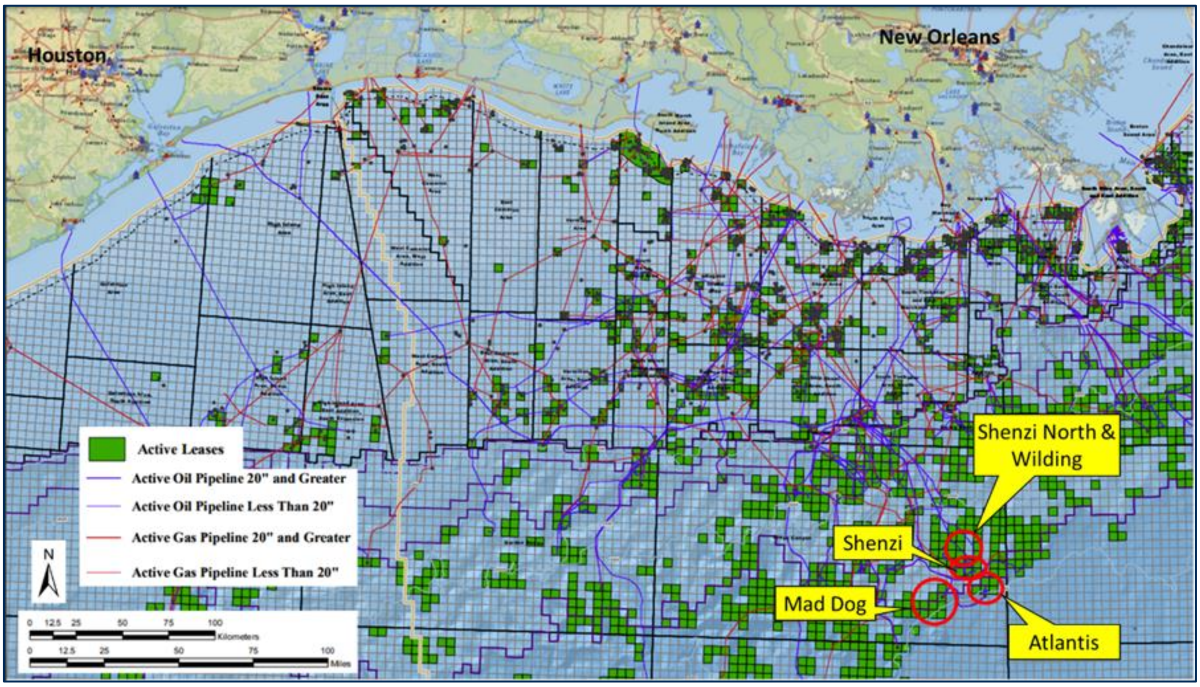
Figure 9.22: BHP Petroleum Net D&R Costs Minerva, Griffin and Stybarrow



10 BHP Petroleum United States Gulf of Mexico

BHP Petroleum has interests in four developments in close proximity in the US GOM: Shenzi, Shenzi North and Wilding, Atlantis and Mad Dog (**Figure 10.1**).

Figure 10.1: Location Map of BHP Petroleum's Assets in US GOM

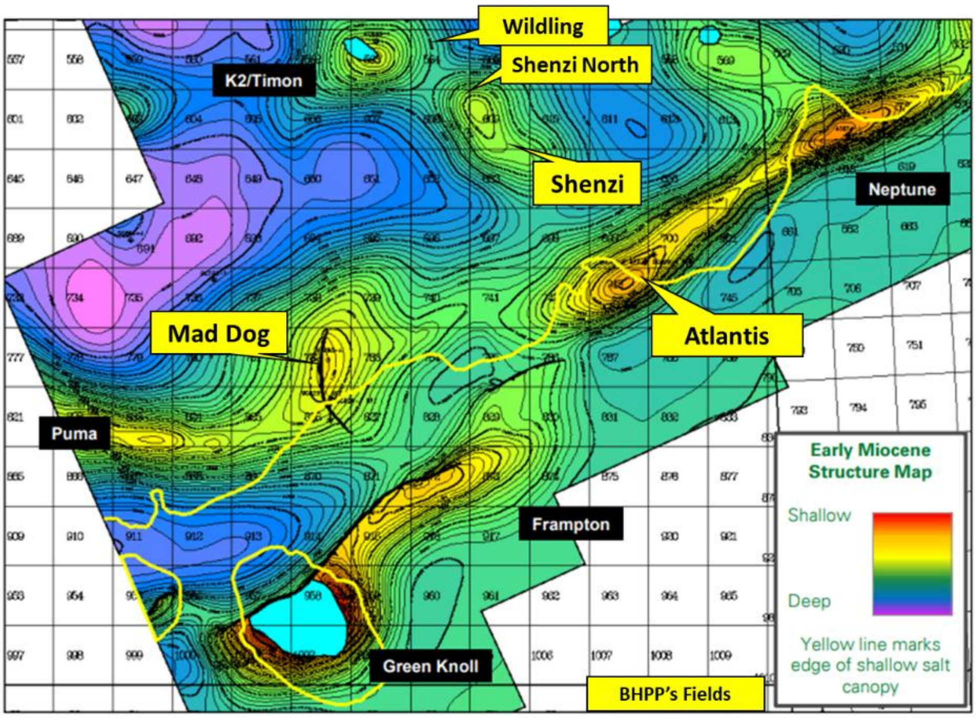


Source: Modified from BOEM (US Bureau of Ocean Energy Management (Visual-1-Active- Leases-and-Infrastructure_2.pdf as of May05, 2021)).

A depth structure map (Early Miocene) shows the relationship of the major structural highs and oil fields (**Figure 10.2**).

The dominant features are a series of SW-NE trending, elongated, high-relief structures from Green Knoll in the south, through Frampton, Atlantis and Neptune in the NE. They are primarily compressional salt-cored anticlines that trend roughly parallel to the leading edge of the shallower, overthrust (allochthonous) salt body (yellow line on map). Landward of these high-relief structures are more subtle, four-way structural closures formed primarily as drape over remnant salt-cored areas; Puma-Mad Dog in the SW and Shenzi and K2 to the north.

Figure 10.2: Early Miocene Structure Map



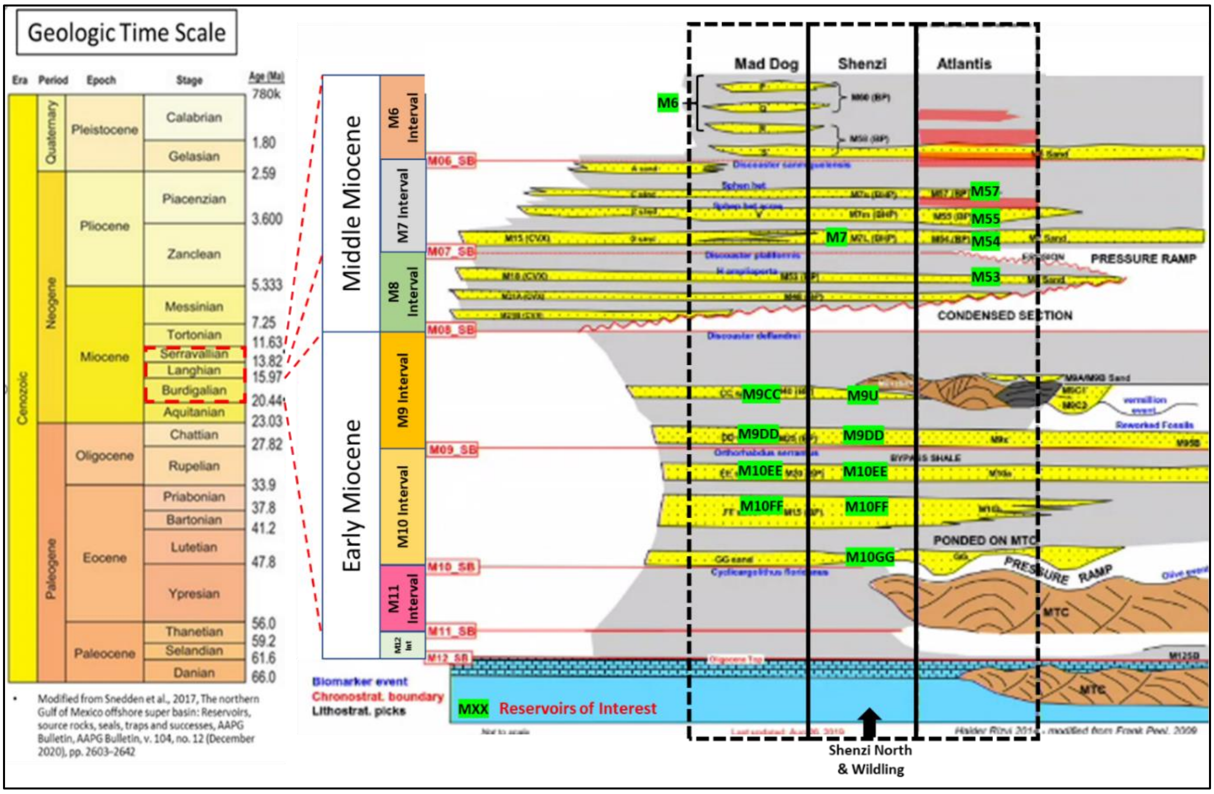
Source: Modified After: Walker, C. D., and G. A. Anderson, 2016, Simple and efficient representation of faults and fault transmissibility in a reservoir simulator: Case study from the Mad Dog Field, Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 66, p. 1109–1116. http://www.gcags.org/exploreanddiscover/2016/00177_walker_and_anderson.pdf. 2016.

Seismic interpretation, supported by drilling, has demonstrated that underlying salt was actively moving upward, and at times laterally, during the deposition of the overlying sediments. This movement most importantly affected the Miocene sands. During and after the large-scale salt movement, extensional fault movement, contemporaneous with sediment deposition, caused significant, localised sand thickness. These crestal extensional faults, and the accompanying sediment thickness variations, cause compartmentalisation seen in all the fields.

The BHP Petroleum Fields are either north of, or straddle, the southern limit of allochthonous salt (yellow line in **Figure 10.2**), therefore either the whole or a significant portion of these fields are sub-salt. The presence of the shallow salt generates problems with seismic imaging, requiring latest seismic acquisition and processing technologies to ensure optimum fault and reservoir definitions.

A generalised stratigraphic column showing the nomenclature for the BHP Petroleum fields is shown in **Figure 10.3** (Shenzi North and Wildling are similar to Shenzi). The primary reservoirs at Mad Dog, Shenzi, Shenzi North and Wildling are Early Miocene M9 and M10 deep-water turbidite fans. These sands are also present at Atlantis but are more shale-prone and are not development targets. At Atlantis, the primary reservoirs are the thick, blocky Middle Miocene M55 and M54 turbidite basin floor sheet fans. The age equivalent sand, the M7, is more channelised in Shenzi, Shenzi North and Wildling where it is a secondary reservoir target. The secondary reservoirs are Middle Miocene M57 and M53 intervals in Atlantis and the M6 in Mad Dog.

Figure 10.3: Geological Time Scale, Stratigraphic Nomenclature of BHP Petroleum's GOM Fields



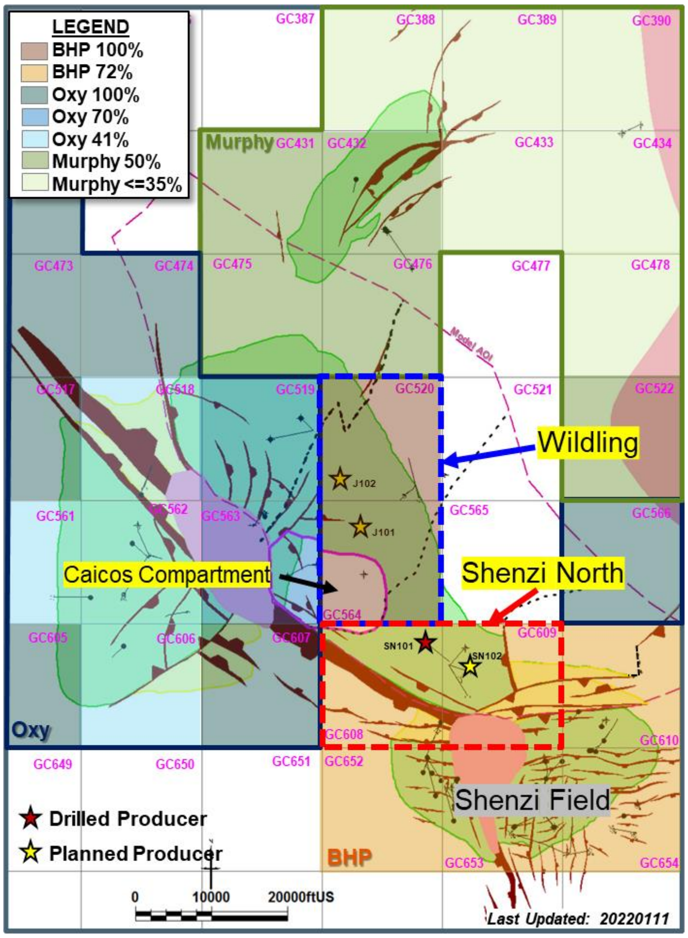
Source: GaffneyCline Modified from BHP Petroleum

BHP Petroleum has undertaken seismic interpretation, petrophysical analysis, static geological modelling, decline curve analysis and reservoir simulation for these fields, which were made available to GaffneyCline for review.

10.1 Shenzi

The Shenzi Field was discovered in 2002 in the Green Canyon area of the Gulf of Mexico in approximately 1,340 m water depth. It lies mainly in the 4-block area comprised of OCS blocks GC-610, 652, 653 and 654, and partly extends into GC 608 and 609 (**Figure 10.4**). The reservoir depths are approx. 6,700 to 8,530 mss. The field is operated by BHP Petroleum with 72% WI and Repsol holds the remaining 28% WI.

Figure 10.4: Lease Ownership Status for Shenzi, Shenzi North and Wildling



Source: BHP Petroleum

10.1.1 Field Background

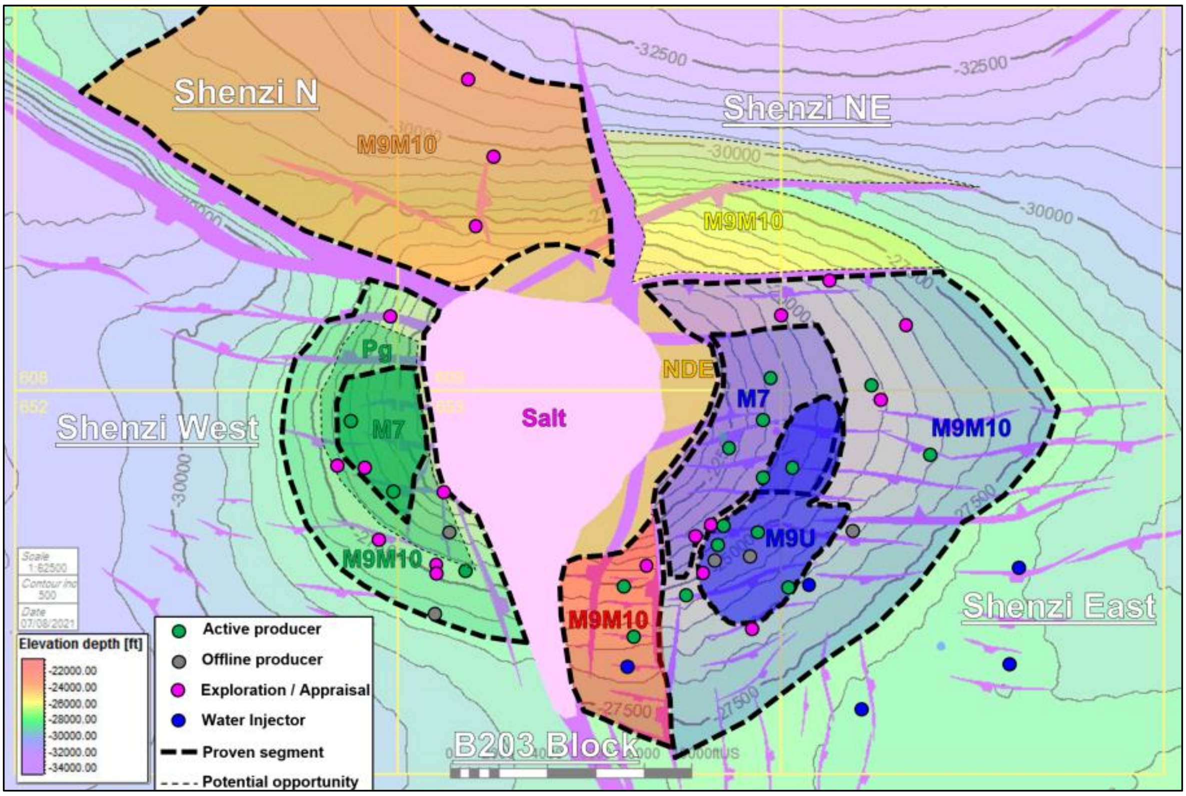
The Shenzi structure is a large, salt-cored, four-way dip closure with a series of extensional faults that radiate out from the salt core shown in pink (**Figure 10.5**). Faults and salt-welds are shown in purple.

Seismic and well information shows the Shenzi Field to be compartmentalised according to geological structure (sealing faults, salt-welds, etc.) and stratigraphy. The two largest structural compartments are found on the west (Shenzi West) and east (Shenzi East). They are separated by the salt stock and welds, each with its own oil-water contact for the primary M9/M10 reservoirs.

In the south-east, well results show a smaller structural compartment, B203. The boundaries for this block (B203 Block) are defined to the west by a large seismically defined salt feeder/weld and structural normal fault, down thrown to the west, that separates the segment from West Shenzi. It is compartmentalised to the east by structural normal faults that are mapped partially with seismic, as well as faults and missing section identified in wells and to the north by sand pinch out. The lack of pressure communication to the east is supported by pre-production pressure measurements, production history and well-based pressure gauge responses.

Outside of the Shenzi Field are two additional structural compartments; Shenzi North (located northwest of the field) and the undrilled North-eastern compartment (Shenzi NE). The Shenzi North compartment has been drilled and is included in the Greater Wildling development project (Section 10.2).

Figure 10.5: Shenzi Field Structure



Source: BHP Petroleum

In addition to the structural subdivisions, there are three stratigraphic producing intervals; one on the west side and three on the east side including the younger M9U and M7 reservoirs.

The M9U reservoir is an Early Miocene sand within the upper M9 sequence deposited as local channelised turbidite fan lobes that are highly deformed by mass transport processes. Based on well data, the M9U interval is of variable thickness and laterally discontinuous. Seismic data provide resolvable M9U reservoir edges on the western and northern parts of the structure. Over the rest of the structure, reservoir extent is determined by well control and a depositional environment model.

The M7 reservoir is a laterally extensive Middle Miocene amalgamated and channelised sheet sand complex. Well data indicate that the M7 sand thins toward the north, onto what is interpreted to be a paleo-ridge. Additionally, seismic data indicate the interval thins from the east flank toward the current structural high associated with the salt diapir.

The Shenzi Field is entirely covered by an allochthonous salt sheet resulting in a challenging seismic imaging environment. The original 3D seismic was acquired in 2002, followed by an additional acquisition in 2006 that was reprocessed in 2009 and 2014, resulting in improved interpretation that showed significant uplift in many areas, better salt definition, illumination of the east flank, and the interpretation of E-W trending reverse faults in the east flank.

In 2019, an ocean bottom node (OBN) seismic survey was acquired leading to the interpretation of new faulting regimes and building of new reservoir models. The resolution of the new OBN seismic dataset is an improvement over the previous data. Small throw faults are still difficult to identify. While the seismic resolution is improved, however, it is greater than the sand thickness (~30 m). Therefore, seismic interpretation needs to rely on mapping packages of reflections and not a single trough or peak that ties to a single sand. Assessment of lateral stratigraphic changes in the thickness of the sand bodies and delineation of slump features remain uncertain. Despite the relatively low resolution of the seismic data, the overall data quality is very good for sub-salt seismic. Overall, the resulting structure maps from seismic interpretation, tied back reasonably well to the available well data.

Well data comprising modern well logs, cores, formation pressure and fluid sample PVT data exist in the field. GaffneyCline reviewed available reservoir and fluid data. The reservoir units are predominantly clean sandstones at depths of about 6,650 to 8,670 mss, with average porosity range of 20% to 23%. The average model permeability ranges from 20 to 500 mD. Shenzi is a highly under-saturated oil field with reservoir pressures ranging from ~12,000 to ~14,900 psia and saturation pressure ~1,500 to 2,300 psia. Oil gravity is 30 to 34 °API, GOR is 250 to 550 scf/stb and viscosity is 1.1 to 1.2 cP.

10.1.2 Field Development

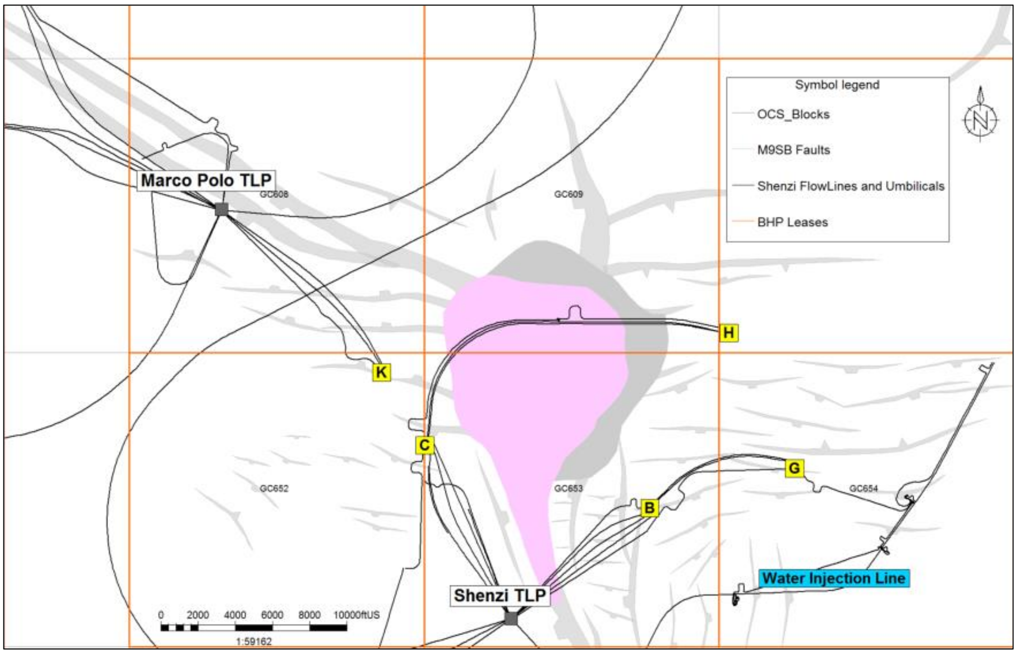
As of 31 October 2021, about 43 wells and side-tracks (excluding wells in the Shenzi North block), have been drilled in the Shenzi Field, of which twenty wells are producers and five are water injectors (**Figure 10.5**). Eighteen of the twenty development wells are tied back to the Shenzi Tension Leg Platform (TLP) via manifolds B, G, C and H, with the remaining two tied back to the Marco Polo TLP via manifold K (**Figure 10.6**).

Production started in 2007 from wells in the South-West fault block, producing to the Marco Polo production facility. Production from the other fault blocks to the Shenzi Tension Leg Platform (TLP) commenced in 2009.

The Shenzi TLP has a nameplate capacity of 100 Mbopd oil production and 125 Mbwpd water injection capacity. Gas lift capabilities are present and enabled at the B and the C manifolds. Sales oil and gas is exported through a third party operated Poseidon and CHOPS export pipeline system.

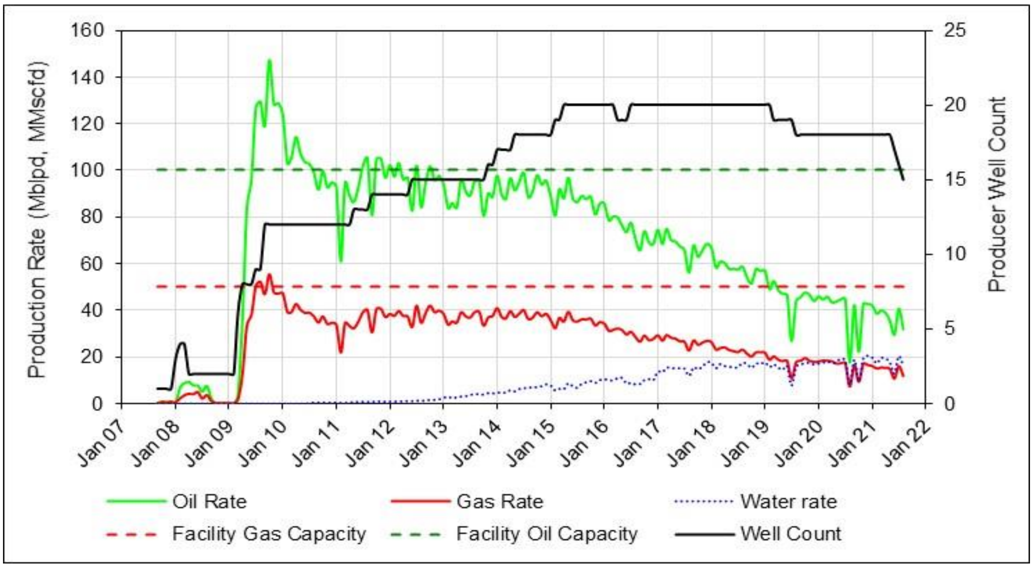
The production peaked above 100 Mbopd in 2009 but has since declined to around 42 Mbopd as of May 2021 (**Figure 10.7**). A water injection program was implemented with injection starting in May 2012. In addition, subsea multiphase pumping (SSMPP) capabilities is being implemented for the Shenzi TLP and expected to be operational in late 2022.

Figure 10.6: Shenzi Facility Overview



Source: BHP Petroleum

Figure 10.7: Shenzi Field Historical Production



Source: BHP Petroleum

Note: Facility capacity of Shenzi TLP reflected on the plot, while production is both to the Shenzi and Marco Polo TLPs

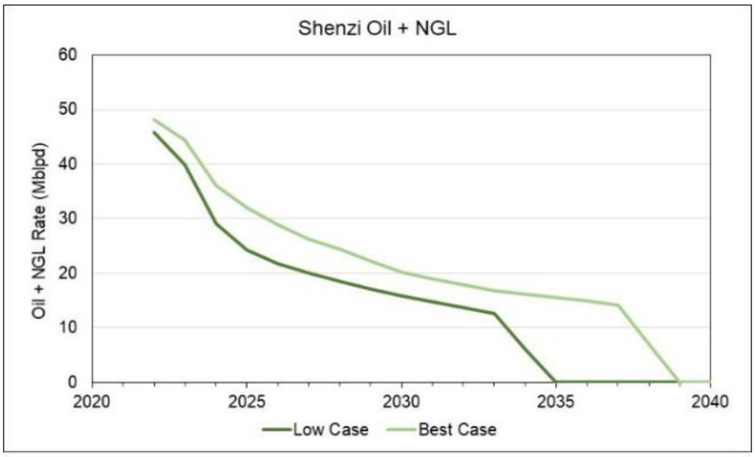
The M9/M10 sands are produced in a commingled fashion from all five zones: DD, EE12, EE, FF, and GG. The M9U and M7 reservoirs were developed as single zone frac-pack completions from stand-alone wells and have not been commingled with the M9/M10 reservoirs. The primary drive mechanism providing pressure support to production wells is aquifer influx. The East (M9/M10), and East (M9U) reservoirs have been developed with water injection for additional pressure support. The injectors have been drilled, completed and brought on stream after production had commenced. At the time of drilling, pressure depletion was observed in all the injection wells confirming connectivity to the oil producers.

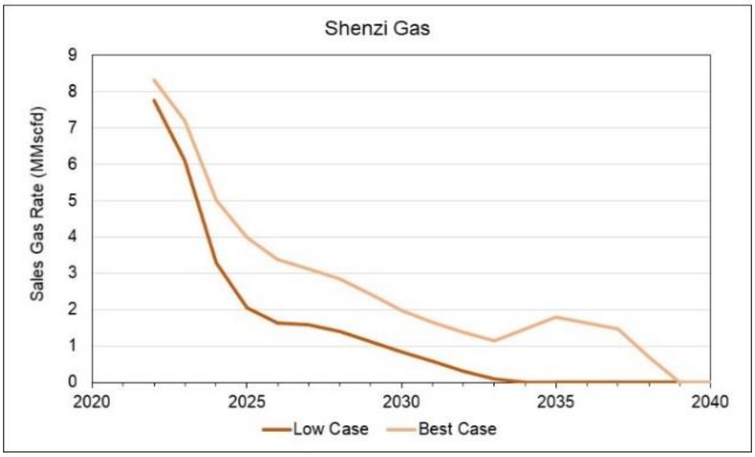
GaffneyCline reviewed the STOIIP, production forecasts and estimated recoverable volumes for the target compartments in the field from the static geological and simulation models (DCA only for the B203 block) provided by BHP Petroleum. In particular, GaffneyCline reviewed the history match of the simulation models and where possible performed decline curve analysis of existing wells with long term production history to validate the simulation results. Overall, GaffneyCline found the production forecasts from the simulation models to be reasonable.

10.1.3 Resources Estimates

Reserves in the Shenzi Field are attributed to current producing wells, two sanctioned development well side-tracks targeting the M9U compartment (with the first well put on production in 2021 and the second well expected to start producing in 2022) and the benefit of the SSMPP implementation (expected to be operational in 3Q 2022). The Low and Best Case production profiles upon which the Reserves estimates are made are shown in **Figure 10.8**.

Figure 10.8: Shenzi Production Profiles for Reserves Cases





Source: GaffneyCline from BHP Petroleum Data

Contingent Resources are associated with unsanctioned future Shenzi East M9/M10 opportunities that include conversion of an existing producer to an injector, side-track of a watered-out producer in the B203 Block to the Shenzi East Block, and an additional pair of infill vertical producer/injection wells. These opportunities are additional activities or projects to achieve incremenetal volumes from the existing producing reservoirs and are assessed using numerical simulation models. These projects do not require any additional appraisal activity. However, the evaluation of these resources is still at the early decision gate of the BHP Petroleum's project tollgate review process, hence they are captured as Contingent Resources (Development Unclarified).

BHP Petroleum has identified additional potential opportunities beyond those listed above, including future infill wells, sidetracks or workovers, and facility design life extension that might offer upside potential in the future, but for which no Contingent Resources have been attributed on the basis that they are not yet been adequately substantiated.

Estimated gross 2C Contingent Resources (Development Unclarified) for the combined group of three projects is 35 MMBbl of liquids and 9 Bscf of gas.

10.1.4 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

For the 2P Reserves, CAPEX is primarily allocated for two well sidetracks combined with the installation of a subsea multi-phase pumping system. CAPEX in the Contingent Resource case comprises of a series of well related projects to increase production, including new wells, side-tracks or well conversions. The BHP Petroleum CAPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. CAPEX for the development for the 2P Reserves cases is shown in **Table 10.1**, and CAPEX for the Contingent Resources case in **Table 10.2**.

Table 10.1: Shenzi Capital Cost Estimate – 2P

CAPEX	US$ (MM)
Development	39
Sustaining	21
Total	**59**

Note: Totals may not exactly equal the sum of individual entries due to rounding

Table 10.2: Shenzi Capital Cost Estimate – Contingent Resources

CAPEX	US$ (MM)
Development	439
Total	**439**

The OPEX estimates for the Reserves and Contingent Resources were evaluated by GaffneyCline, taking into consideration the planned activities and work programs outlined in the documentation. The total OPEX is broken down into lifting costs, processing and storage, workovers, transportation, and overhead costs. Of these cost components transportation and processing and storage are variable, proportional to the production rate.

The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX components of the total OPEX resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

For the 1P and 2P Reserves cases and the Contingent Resources case, ABEX costs have been reviewed and adopted unchanged.

10.2 Shenzi North and Wildling

The Shenzi North and Wildling oil fields, which were discovered in 2015 and 2017 respectively, make up the greater Wildling development area, located directly north of the BHP Petroleum operated Shenzi development. The Shenzi North development is focused on GC608 and GC609 while the Wildling development is focused on the GC564 and GC520 blocks in the North (**Figure 10.4**). Both Shenzi North and Wildling are operated by BHP Petroleum with working interests of 72 % and 100% respectively. Repsol holds the remaining 28% working interest in Shenzi North.

10.2.1 Field Description

The Greater Wildling discovery consists of Miocene turbidite sandstone reservoirs charged by oil originating from the Jurassic-Tithonian source rocks. The field has a large footprint with complex trap edges that are not well defined. Greater Wildling was discovered and partly appraised with the Shenzi North well, which had three side-tracks, giving a total of four reservoir penetrations. The field was further appraised with the Caicos and Wildling-2 (two penetrations) wells. The Wildling-1 well in GC521 was abandoned during drilling before reaching reservoir depth.

The original seismic interpretation of the Greater Wildling area was from a re-processed 2018 CGG 25Hz RTM (Reverse Time Migration) as well as a Kirchhoff Pre-Stack Depth Migration (PSDM) product. BHP Petroleum has recently purchased a new Ocean Bottom Nodal (OBN) seismic data set that is being integrated into new maps in the area. Seismic resolution of the new OBN seismic dataset is an improvement over the previous data, however low frequency at target depths limits vertical resolution of the seismic especially in high signal to noise areas. Furthermore, seismic character varies from well to well across the basin at the target M10U interval.

Based on pressure and fluid observations it is known that the Caicos area is isolated from both Wildling and Shenzi North areas within the main M10U horizon. Some uncertainty remains on the exact location of pressure/fluid boundaries between the wells.

The majority of the STOIIP and the expected ultimate recovery is contained within the primary target M10U reservoir sands. M10U is interpreted as being a lobe dominated system throughout most of the Greater Wildling area. The secondary reservoirs (M7, M8 and M9) are interpreted to be channelised turbidites that are aerially discontinuous and have lower net to gross compared to the M10U sand. The secondary targets are assessed to have significantly smaller volumes compared to the primary M10U reservoir.

The primary M10U formation has been found at depths of 8,200 to 9,630 mss in the development area, with average porosity of ~15% and average permeability of about 32 to 50 mD. The Greater Wildling area contains a highly under-saturated oil with reservoir pressure ~17,150 psia and saturation pressure ~1,788 psia. Oil gravity is 30 to 32 °API, GOR is 380 to 520 scf/stb and viscosity is 1.7 to 2.8 cP.

10.2.2 Field Development

The current conceptual development plan is a daisy-chained subsea tie-in to existing Shenzi production facilities and will benefit from the planned SSMPP for the Shenzi TLP. Shenzi North development comprises two producers, SN101 and SN102, in leases GC608 and GC609 respectively. Well SN101 was drilled late 2020 to early 2021. The proposed Wildling field development comprises two oil producers: Well J101 in lease GC564 and Well J102 in lease GC520.

The Shenzi North development entered Execution phase in 2021 after project sanction by BHP Petroleum in August 2021 and by Repsol in September 2021. The Wildling Field development is currently in Definition phase, with project sanction possible in late 2022, depending on the results of drilling of the appraisal/development well J101.

Both the Shenzi North and Wildling projects target areas with large STOIIP, and the expected recovery factors based on depletion drive are modest. BHP Petroleum is considering water injection as a possibility for future phases of development to improve recovery. Understanding of reservoir quality, connected volume and potential baffles gained from the production performance under depletion drive will help to plan a waterflood.

10.2.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

The Shenzi North and Wildling development plans each comprise two well subsea tiebacks to the Shenzi tension leg platform, including manifolds, high integrity pressure protection systems, and multi-phase flow meters.

BHP Petroleum's CAPEX costs for both Shenzi North and Wildling have been reviewed and appear to be credible, based on GaffneyCline's experience. CAPEX for the combined development is shown in **Table 10.3**.

Table 10.3: Shenzi North + Wildling Gross Capital Cost Estimate

CAPEX	US$ (MM)
Shenzi North Development	349
Wildling Development	650
Total	**999**

The OPEX estimates were evaluated by GaffneyCline, taking into consideration the planned activities and work programs outlined in the documentation. The total OPEX is broken down into lifting costs, processing and storage, workovers, transportation, and overhead costs. Of these cost components transportation and processing and storage are variable, proportional to the production rate.

The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX components of the total OPEX resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

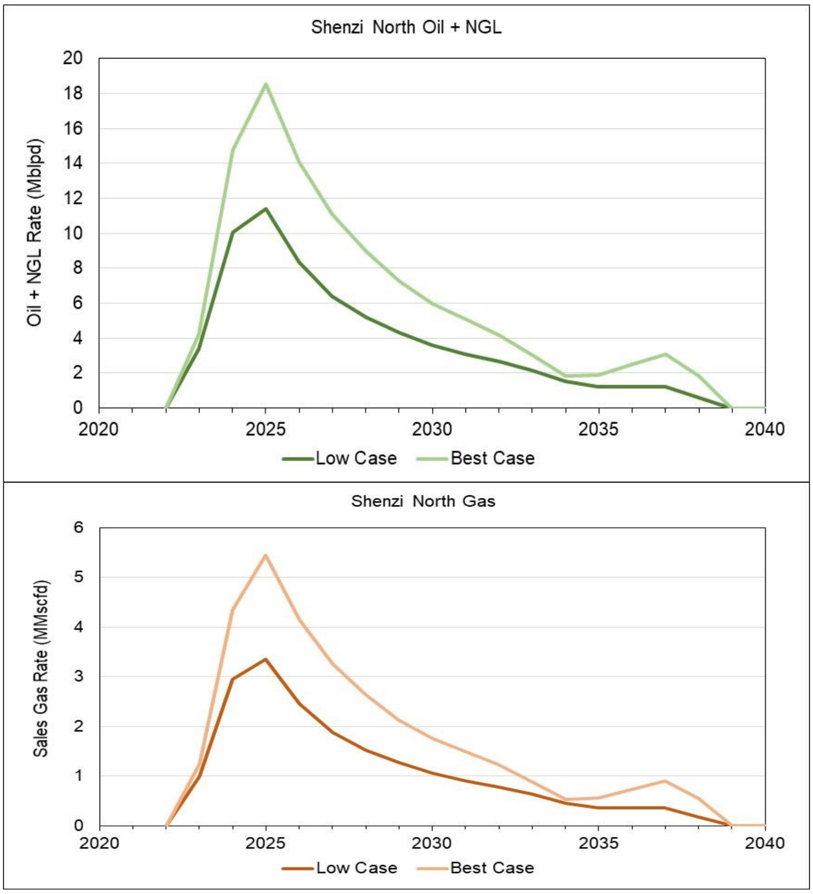
10.2.4 Resources Estimates

GaffneyCline reviewed the static geological and simulation models, sensitivity runs and analogue study that form the basis for the production forecast for the Greater Wildling development project. Both the static and simulation models reflect reasonable best effort interpretations given the limited well data over a large area and uncertainty in reservoir quality, continuity, and deliverability. In absence of actual well test and production history, oil recovery per well in the K2 field to the West and Shenzi West segment to the south have been used to assess reasonableness of the estimated recoverable volumes per well in the Greater Wildling simulation models. However, GaffneyCline notes that there is still uncertainty in these estimates since the Greater Wildling area is targeting the M10 formation at slightly deeper depths and lower porosity than the K2 and Shenzi West wells.

Reserves are attributed to two sanctioned development wells in Shenzi North: SN101 targeting the M10U and M9L reservoirs, and SN102 targeting M10U and M7U3 reservoirs. Both wells are expected to start production in 2024. The low and best Estimate production profiles upon which the Reserves estimates are made are shown in **Figure 10.9**.

Gross 2C Contingent Resources (Development Pending) of 37 MMBbl oil and 11 Bscf gas are attributed to Wildling. An appraisal/development well is planned for the Wilding field mid 2022 prior to a sanction decision end 2022. Additional Contingent Resources for water injection that are currently carried by BHP Petroleum as Development Not Viable are not reported here.

Figure 10.9: Shenzi North Production Profiles for Reserves Cases



10.2.5 GaffneyCline's Production and Cost Valuation Profiles- Shenzi/Shenzi North and Wildling

GaffneyCline's valuation scenario production profile for BHP Petroleum's Shenzi, Shenzi North and Wildling oil assets is given in **Figure 10.10** with the associated real term cost profiles provided in **Figure 10.11**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and costs are net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing Shenzi and planned Shenzi North and Wildling Fields**.**

Shenzi Contingent Resources are associated with unsanctioned future Shenzi East M9/M10 opportunities that include conversion of an existing producer to an injector, side-track of a watered-out producer in the B203 Block to the Shenzi East Block, and an additional pair of infill vertical producer/injection wells. These opportunities are additional activities or projects to achieve incremenetal volumes from the existing producing reservoirs and are assessed using numerical simulation models. These projects do not require any additional appraisal activity. However, the evaluation of these resources is still at the early decision gate of the BHP Petroleum's project tollgate review process, hence they are captured as Contingent Resources (Development Unclarified). However, GaffneyCline has assessed these volumes as appropriate for valuation purposes after review of the contingencies described above and the very good incremental IRR of the projects.

The Shenzi North development entered Execution phase in 2021 after project sanction by BHP Petroleum in August 2021 and by Repsol in September 2021 and is included in the valuation profile based on GaffneyCline's technical and commercial review.

Contingent Resources (Development Pending) are included for Wildling based on the available dynamic models provided for review and the reasonableness of the estimated recoverable volumes per well in the Greater Wildling simulation models and the incremental economics of this near-field development. The Wildling Field development is currently in Definition phase, with project sanction possible in late 2022, depending on the results of drilling of the appraisal/development well J101. GaffneyCline has reviewed these contingencies and considers the volumes appropriate for inclusion in the valuation profile.

Figure 10.10: BHP Petroleum Net Shenzi/Shenzi North and Wildling Asset Production Profile

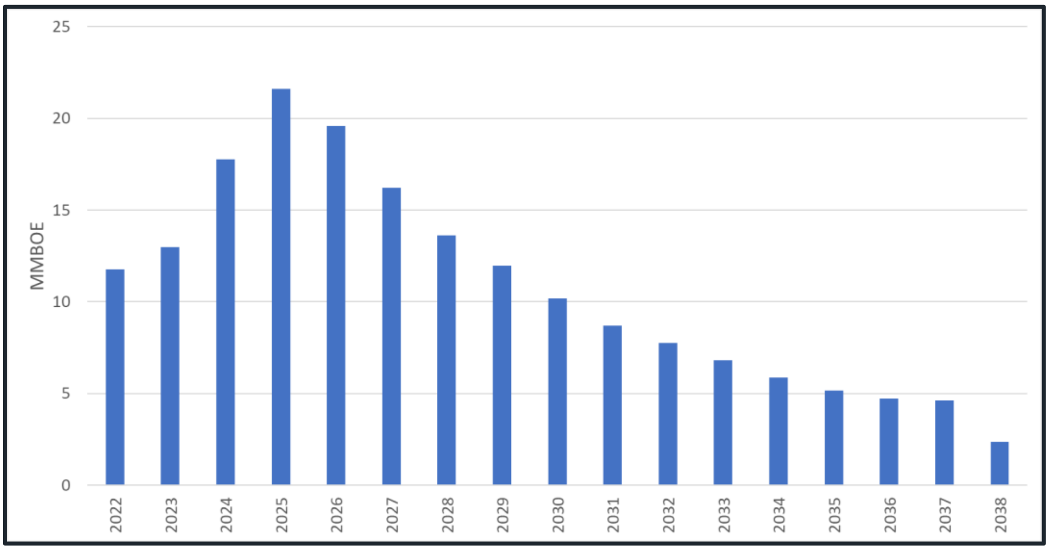
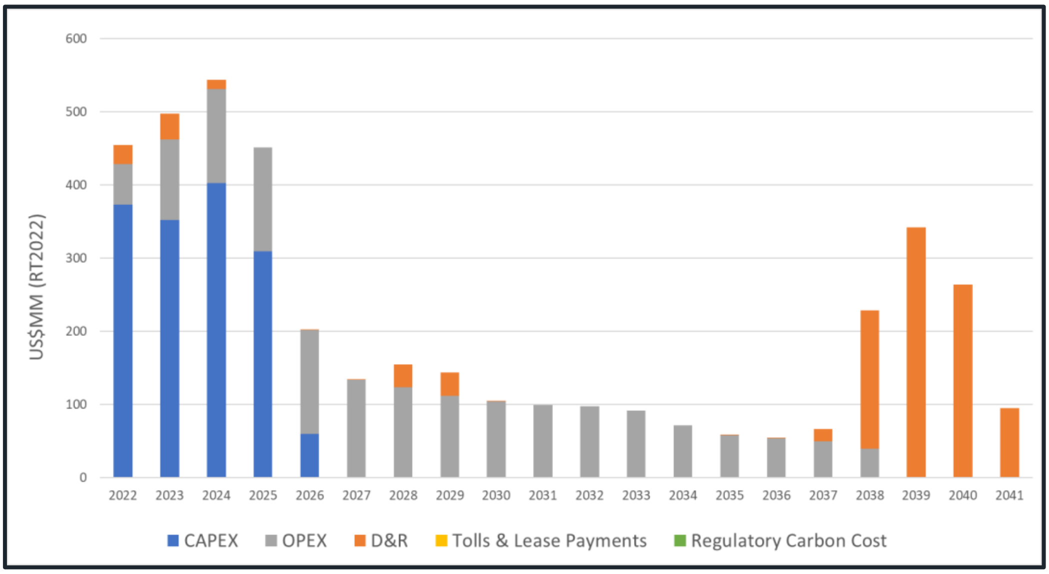


Figure 10.11: BHP Petroleum Net Shenzi/Shenzi North and Wildling Asset Cost Profile



10.3 Atlantis

The Atlantis Field was discovered in 1998 in Gulf of Mexico Green Canyon Blocks 699, 742, 743 and 744 (**Figure 10.1**) in water depths of 1,370 to 2,130 m. The field is operated by BP (WI 56%) and BHP Petroleum holds 44% WI.

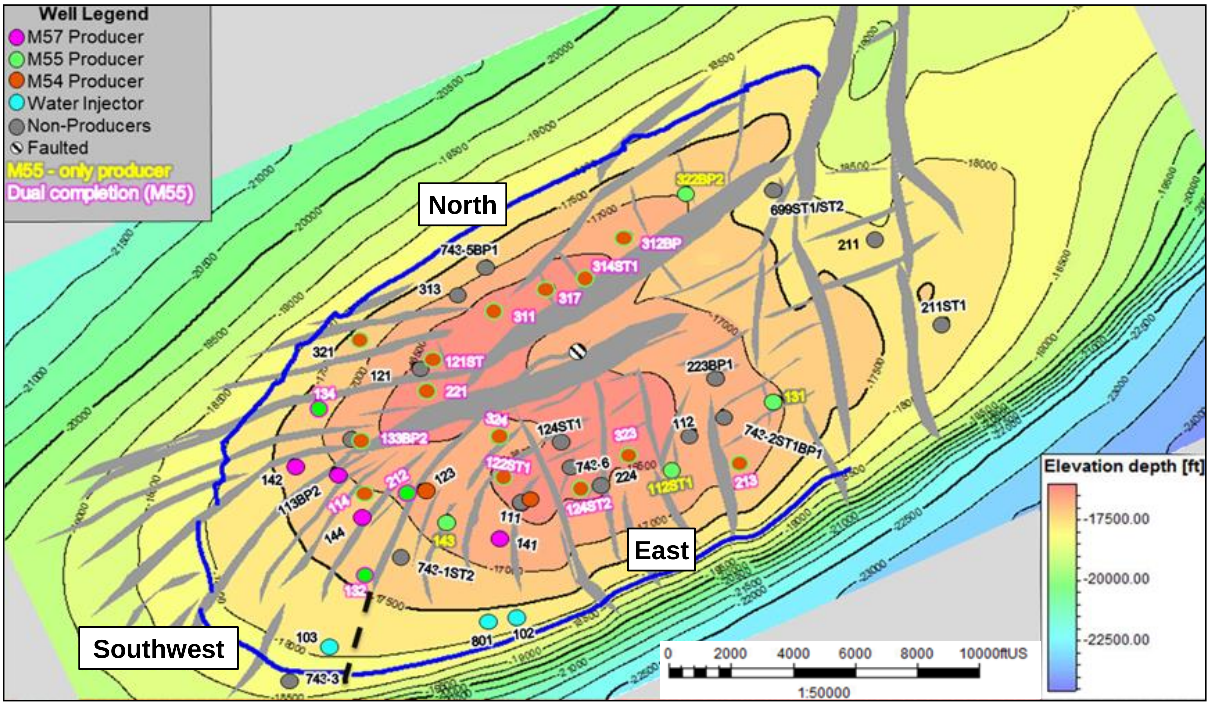
10.3.1 Field Description

The Atlantis structure is a large, southwest to northeast trending faulted anticline (**Figure 10.12**). Much of the field contains normal faults that radiate outward from the crest, subdividing the field in several structural compartments. The three major compartments are North, Southwest and East, though the field can be further subdivided into more compartments.

Atlantis straddles the southern limit of the overlying allochthonous salt in the subsurface and the resulting Sigsbee Escarpment. The salt canopy covers some 60% of the field impacting seismic quality with the best quality seismic in the south-west area of the field that is not under the salt canopy.

The original seismic dataset was a 2005-vintage rich-azimuth survey reprocessed several times to an RTM (Reverse Time Migration) as well as a Kirchhoff Pre-Stack Depth Migration (PSDM) product. Recently, new Ocean Bottom Nodal (OBN) seismic data set was acquired. The seismic had a dual purpose; first, to improve imaging of faults internal to the field to define possible flow barrier and second, for the purpose of generating 4-D (time lapse) seismic. The results of the 4-D seismic interpretation have been very beneficial in targeting future wells especially in the Southwest compartment.

Figure 10.12: Atlantis Top M55 Reservoir Structure Map



Source: BHP Petroleum

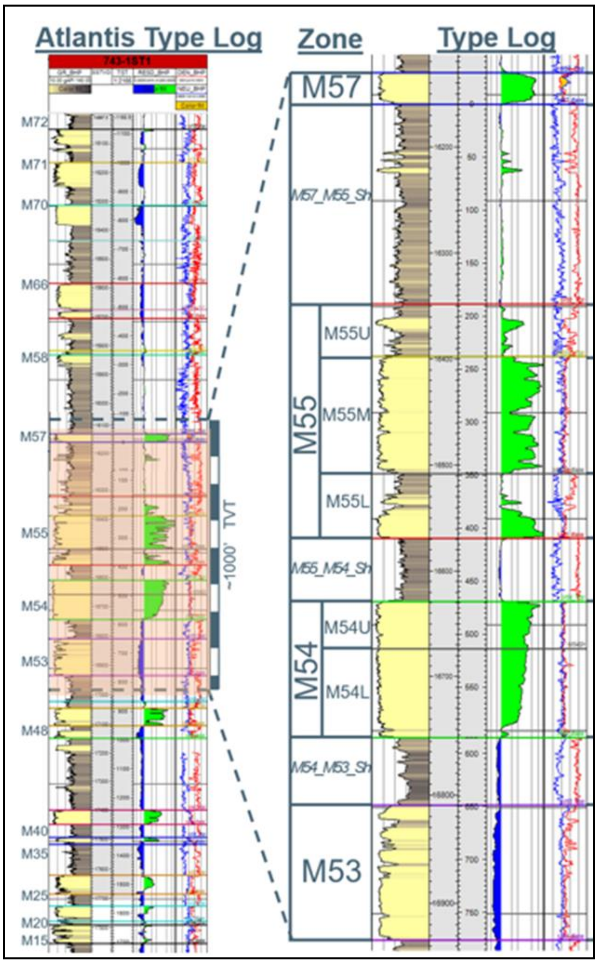
The objective intervals are the Middle Miocene age (M57, M55, M54 and M53) deep-water turbidite sandstone reservoirs encountered at depth ranging from 4,900 to 5,600 mss (**Figure 10.13**). These sands are interpreted as turbidite basin-floor sheet fans.

Other secondary reservoirs in the field are the lower Miocene (M48/M40) and deep Miocene (M35 to M15) sands that have been found to have hydrocarbons, predominately high viscosity oil that would be difficult to produce. Various gas bearing intervals have also been encountered.

MWD/LWD, wireline, static pressure, fluid data and whole cores (from some wells) have been obtained and show that sand and fluid quality are laterally consistent and predictable, unless faulted out. Well logs and core information indicate sands are high quality with average porosity of 27 to 30% and average permeability of 600 md to 850 mD.

The M54 and M55 reservoirs contain under-saturated oil while the M57 fluid has a higher bubble point oil with free gas being found in various locations in the Southwest/East section of the field. In general oil gravity range from ~25 to 31° API and oil viscosity is 1.6 cp to 2.95 cp (excluding the Lower/Deep Miocene reservoirs). The associated 'wet gas' produced with the crude oil is further processed onshore to remove natural gas liquids 'NGL' and condensate.

Figure 10.13: Atlantis Type Log



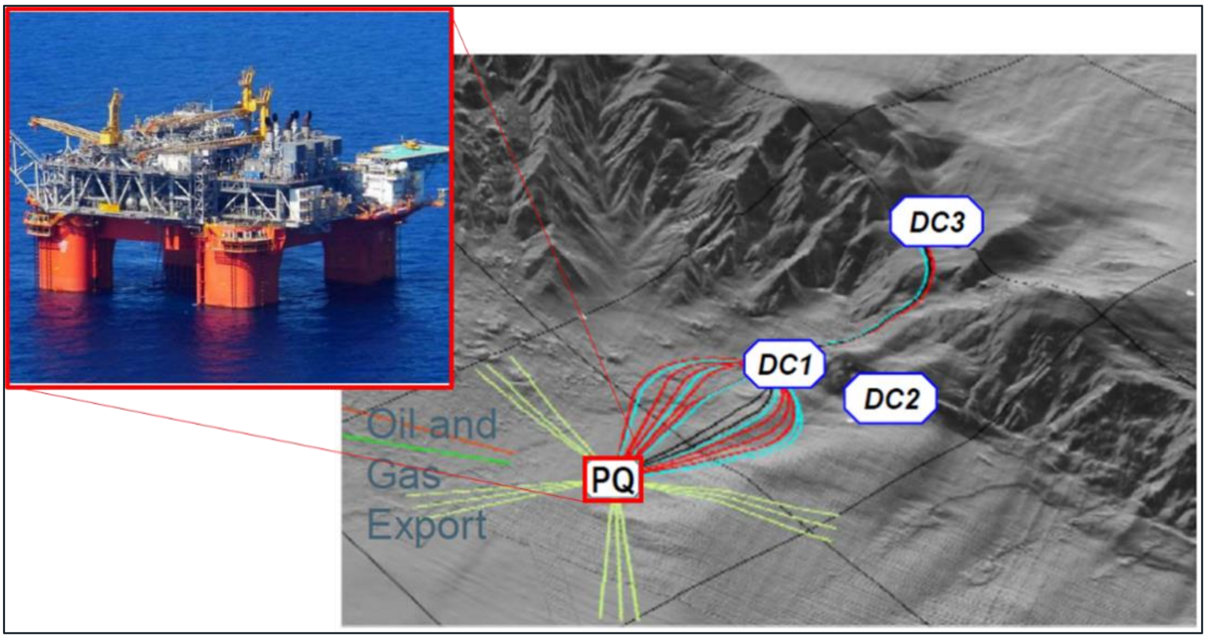
Source: BHP Petroleum

10.3.2 Field Development and Production Profiles

The Atlantis development concept comprise three drill centres that are connected to a moored semi-submersible PQ (production quarters) facility with subsea flowlines (**Figure 10.14**).

The production facility has an oil and gas production handling capacities of 200 Mbopd and 180 MMscfd respectively. The facility is also designed for produced water handling and water injection capacities of 75 Mbwpd, however current produced water handling capacity is 40 Mbwpd and current water injection capacity is 50 Mbwpd. The facility has a design life up to 2039, and there are plans to extend the life to 2047.

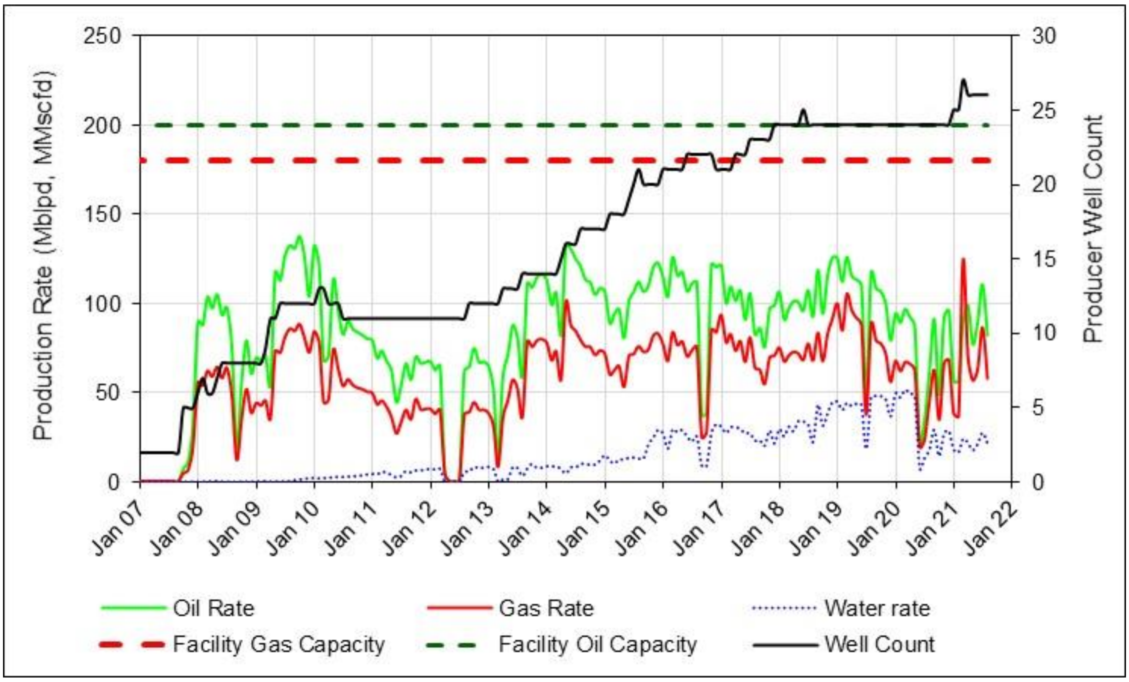
Figure 10.14: Atlantis Facility Overview



Source: BHP Petroleum

About 46 wells, including side-tracks, have been drilled in Atlantis, of which 29 are producers and three are water injectors (**Figure 10.12**); three producers and one injector are currently offline. Peak oil production of ~138 Mbopd occurred in 2009 and the production rate as of August 2021 was about 82 Mbopd (**Figure 10.15**).

Figure 10.15: Atlantis Historical Production



Source: BHP Petroleum

Oil and sales gas are exported through the Caesar and Cleopatra export pipeline system. BHP Petroleum equity is 25% in the Caesar pipeline and 22% in the Cleopatra pipeline.

The Atlantis Field has been developed in a phased approach: Phase 1 development from 2009 to 2010 and Phase 2 from 2013 to 2017. Phase 3 development was sanctioned in February 2019 and the Phase 3 drilling/completion campaign began in October 2019 (expected to end Q1 2023), consisting of eight new wells targeting one or two intervals in M54/M55/M57 and two subsea 4-well manifolds. By September 2021, five of the eight Phase 3 wells had been drilled, with three being completed and put online and two requiring sidetracks. For one of the two wells requiring a sidetrack, the target location is not yet firm and estimates of potentially recoverable volumes are currently classified as Contingent Resources. Beyond Phase 3, continuous drilling (yet to be sanctioned) is assumed until 2029 to bring online 12 additional producers and five water injectors.

There is some uncertainty in the amount of future water injection well drilling and facility expansion due to the production evidence of strong aquifer support in the North and Southwest areas of the field. BP and BHP Petroleum believe that there is potential upside to be realised from water injection in East M54/M55 and the opportunity assessment is being progressed, as well as the M57 in the Southwest. This opportunity will require an increase in water injection capacity from the current 50 Mbwpd to slightly over 113 Mbwpd.

One of the future Phase 3 wells is planned to be a dual zone M57/M55 well, and another an M57 horizontal producer. After Phase 3, the M57 may be further developed by two injectors and two producers.

The M53 reservoir is completed in the North 312 well, as the lower interval in a smart completion with the M55/54 commingled in the upper completion. The M55/M54 completion is being produced in cycles due to low reservoir energy in the area. There is opportunity to produce the M53 sand when the M55/M54 completion is shut-in. Currently, two M53 wells are carried in Contingent Resources: one dual-zone M55/M53 well in the East and one dual-zone injector in the East.

There are currently no producers in the M40 and M48 reservoirs. A Phase 3 well found oil with higher viscosity than the Middle Miocene in one of these reservoirs. There is no immediate plan to develop these reservoirs.

10.3.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation.

BHP Petroleum CAPEX costs have been reviewed for each of the 2P, and Contingent Resources cases.

For the 1P and 2P cases the CAPEX appears to be credible, based on GaffneyCline's experience of comparable scopes (**Table 10.4**).

Table 10.4: Atlantis Gross Capital Cost Estimate – 2P

US$ MM	Total
Development	290
Sustaining	334
Total	**624**

The Contingent Resources CAPEX costs comprise of a series of projects including:

- DC322ST and WIX50 – a well sidetrack plus drilling of two new injector wells to utilise the current water injection capacity;
- DC1, DC2, and DC3 expansions, involving drilling a total of eleven new producer wells; and
- MFX-SSMPP, involving the drilling of four new injectors to increase water injection capacity and installation of subsea multiphase pumps to provide artificial lift, reducing manifold pressures and accelerating production.

The BHP Petroleum CAPEX costs for each of the projects have been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments. Adjustments have been made to the CAPEX to reflect the removal of one of the four producers wells in the DC2 development (well G54), and one of the four producers wells in the DC3 development (well X54) (**Table 10.5**).

Table 10.5: Atlantis Capital Cost Estimate – Contingent Resources

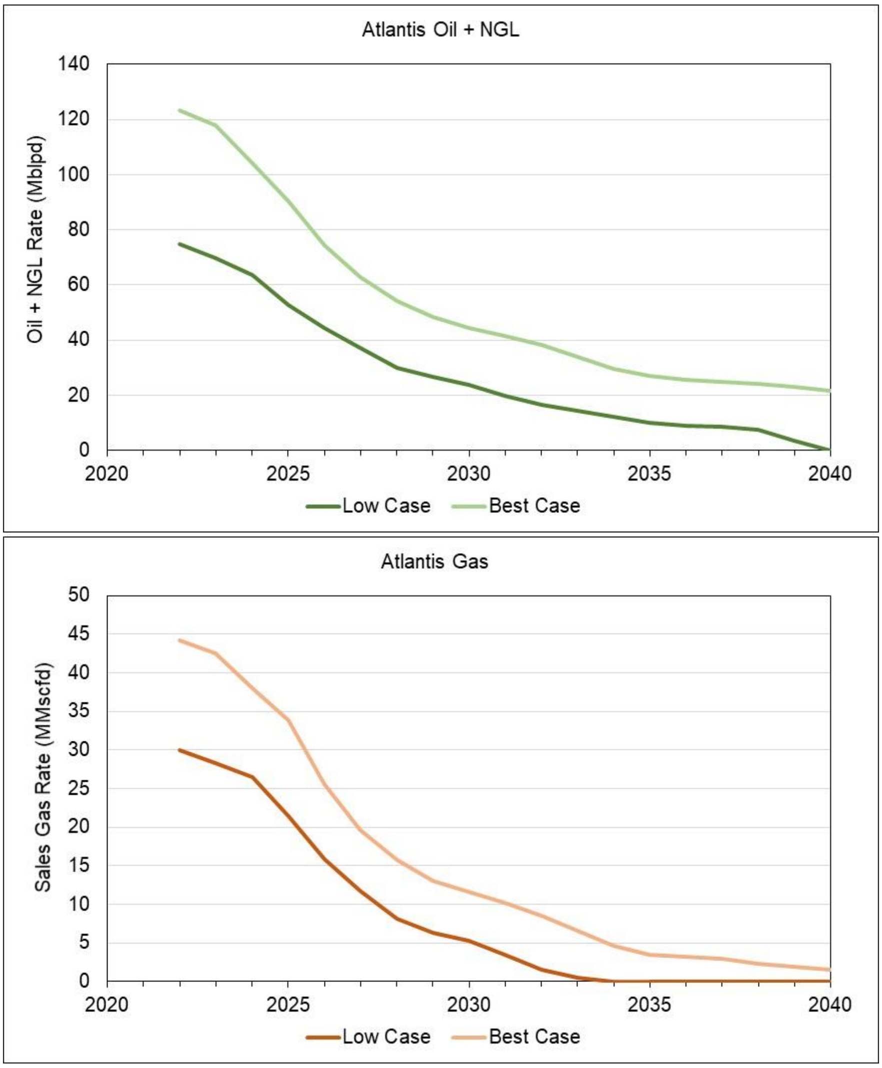
CAPEX	US$ (MM)
DC322ST and WIX50 Development	227
DC1 – Development	221
DC2 – Development	253
DC3 – Development	259
MFX - SSMPP - Development	747
Total	**1,707**

The OPEX costs provided in the economic model and supporting documentation have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted in the 2P and Contingent Resources cases to account for changes in the variable OPEX components of the OPEX costs resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

10.3.4 Resources Estimates

Reserves in Atlantis are associated with existing producing wells and approved outstanding Phase 3 wells. GaffneyCline reviewed the simulation models that form the basis for the production forecast for these activities, in particular the history match to existing wells' production and pressure data and found the models and forecasts to be reasonable. The low and best estimate production profiles upon which the Reserves estimates are made are shown in **Figure 10.16**.

Figure 10.16: Atlantis Production Profiles for Reserves Cases



Source: GaffneyCline from BHP Petroleum Data

Contingent Resources are attributed mostly to asset development projects being actively worked on, but are yet to be sanctioned (**Table 10.6**):

- One to two new water injection wells and a sidetrack of a failed producer to the central compartment targeting the M55/M53 reservoirs.
- Expansion of Drill Centre 1 with three new infill wells targeting the M57/M55/M54 reservoirs.
- Facilities expansion to incorporate subsea multiphase pumps (SSMPP) that will boost production as well as four new water injectors for the M57/M55/M54/M53 reservoirs.
- Expansion of Drill Centre 3 with four infill wells in reservoirs M55/M54.
- Expansion of Drill Centre 2 with four infill wells in reservoirs M55/M54.

The Contingent Resources projects are part of BHP Petroleum's five-year plan for the asset and target existing producing reservoirs in the field. The incremental volumes from these projects have been assessed using simulation models. The target location of these activities and resource outcomes are contingent on the performance of the existing producers and ongoing Phase 3 development, thus are subject to potential revisions. Hence most are sub-classified as Development Unclarified. BHP Petroleum have also considered some of the projects to be commercially non-viable based on their internal assessment (technical and economic assessment as of June 30, 2021). However as discussed below additional BHP Petroleum economic modelling subsequent to that assessment and GaffneyCline's review have resulted in the inclusion of these projects.

GaffneyCline reviewed the production profiles associated with these incremental activities and found most to be reasonable. However, for a variety of technical reasons, GaffneyCline made downward adjustments to the incremental volumes attributed to the G54 producer in the Southwest compartment, wells WI_Un54, X54 and Ve54 in the East compartment, and well nF54 in the North compartment.

GaffneyCline has not reported Contingent Resources for the Lower and Deep Miocene reservoirs that have been found to have high viscosity crude, or for a potential late life shallow gas development and facility design life extension beyond 2047, all of which are currently considered not viable based on their preliminary technical and economic assessment.

In Table 10.6 even though BHP Petroleum documentation assigns a Not Viable* development sub-classification for the Contingent Resources Drill Centre 2 & 3 expansion projects, GaffneyCline has assessed these projects as technically mature with a very good incremental IRR. GaffneyCline has kept the operator documented development sub-classification for consistency; however, subsequent economic models provided separately by BHP Petroleum (without updated documentation) indicate commercially viable projects consistent with GaffneyCline's assessment. Furthermore all projects listed below are part of BHP Petroleum's five-year plan with technically mature work available for assessment and economics.

Table 10.6: Atlantis Gross 2C Contingent Resources as of 31 December 2021

Project	Gross 2C Contingent Resources		Development Status
	Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Water injectors and a sidetrack producer	37.8	16.6	Unclarified
Expand Drill Centre 1 with three wells	40.0	16.1	Unclarified
SSMPP and four water injection wells	74.3	31.7	Unclarified
Expand Drill Centre 3 with four wells	22.2	10.3	Not Viable*
Expand Drill Centre 2 with four wells	26.5	12.1	Not Viable*

10.3.5 GaffneyCline's Production and Cost Valuation Profiles- Atlantis

GaffneyCline's valuation scenario production profile for BHP Petroleum's Atlantis oil asset is given in **Figure 10.17** with the associated real term cost profiles provided in **Figure 10.18**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing Atlantis field and the five planned Atlantis Contingent Resources projects documented in the previous sections. GaffneyCline has independently assessed the five Contingent Resources projects and their technical and commercial maturity and considers them appropriate for valuation as discussed in section 10.3.4. As most projects are expansion projects with additional drillable wells from existing infrastructure with very good incremental IRR assessments, GaffneyCline considers these projects appropriate for valuation. The target location of these activities and resource outcomes are contingent on the performance of the existing producers and ongoing Phase 3 development, thus are subject to potential revisions.

Figure 10.17: BHP Petroleum Net Atlantis Asset Production Profile

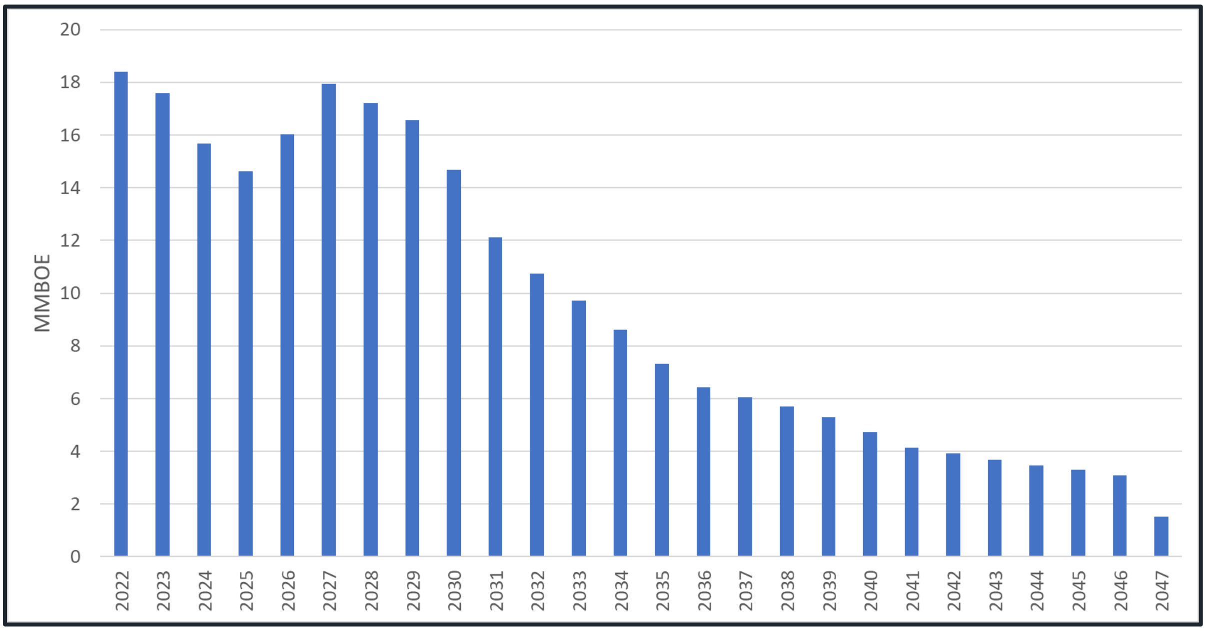
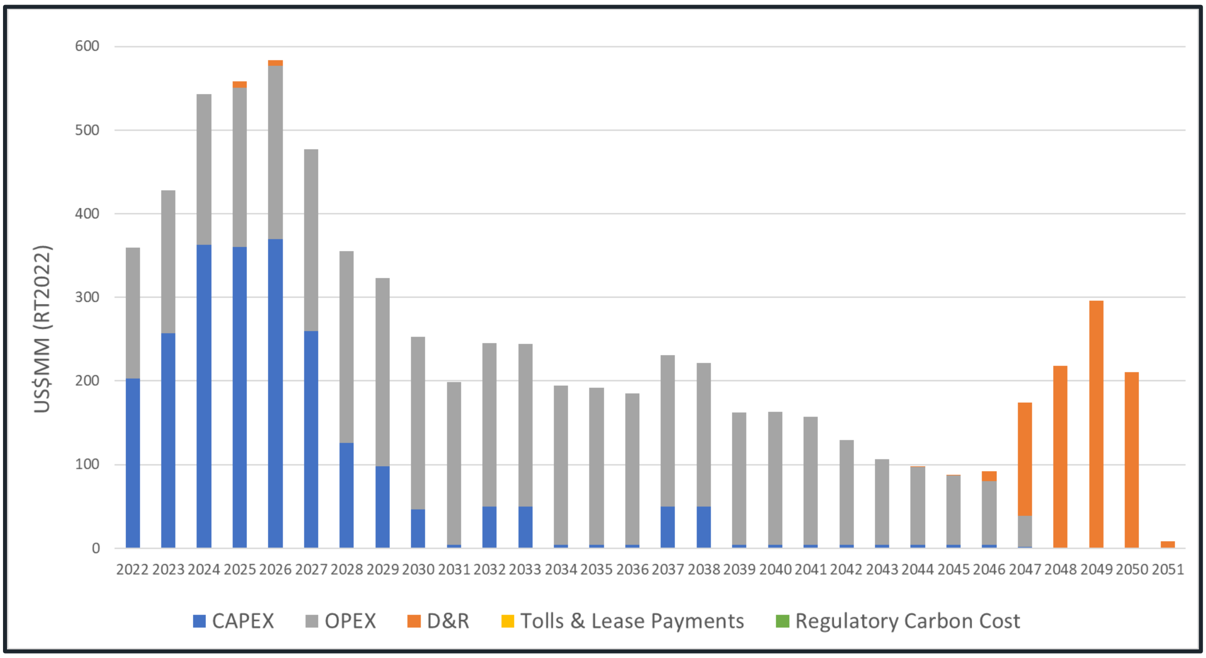


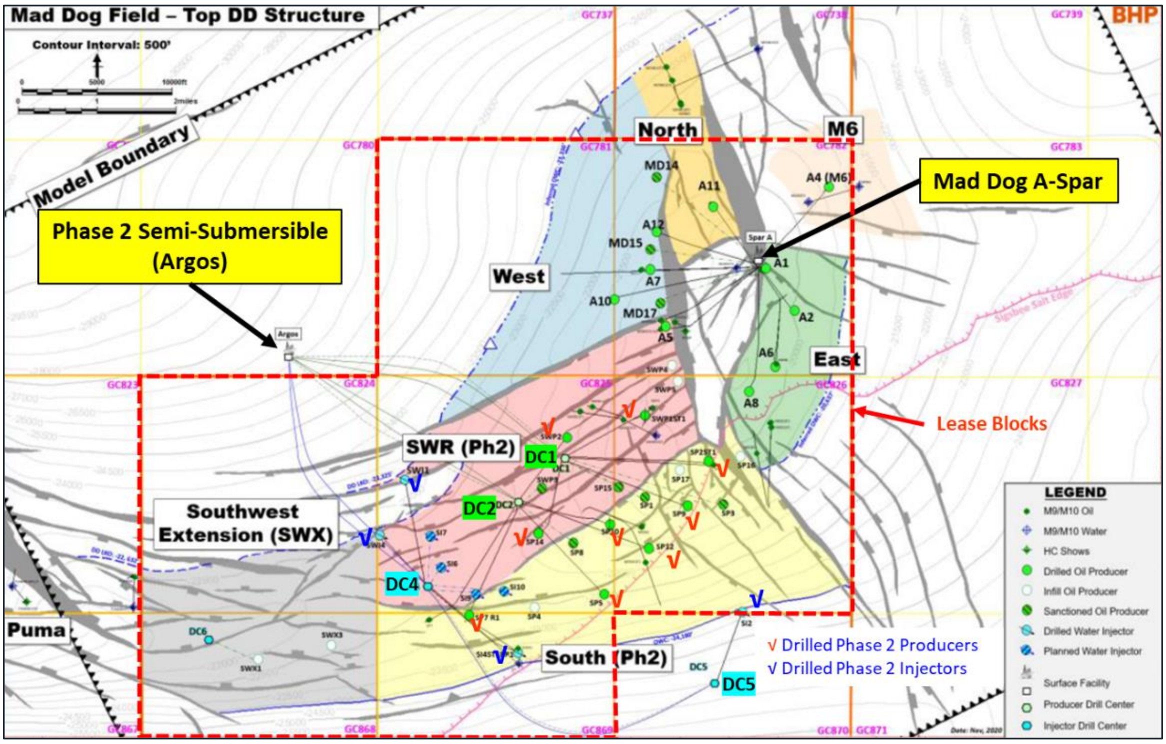
Figure 10.18: BHP Petroleum Net Atlantis Asset Cost Profile



10.4 Mad Dog

The Mad Dog Green Canyon 826 Field was discovered in 1998 in the Gulf of Mexico in approximately 1,340 m water depth (**Figure 10.1**). The Mad Dog Lease area comprises seven blocks in the Green Canyon area: GC 781, 782, 824, 825, 826, 868 and 869 (**Figure 10.19**). The field is operated by BP (WI 60.5%) and BHP Petroleum and Chevron hold 23.9% and 15.6% WI respectively. First production occurred in January 2005. There are ten producing wells (**Figure 10.19**).

Figure 10.19: Mad Dog Field Overview, Structure Map, Wells and Facility Locations



Source: BHP Petroleum

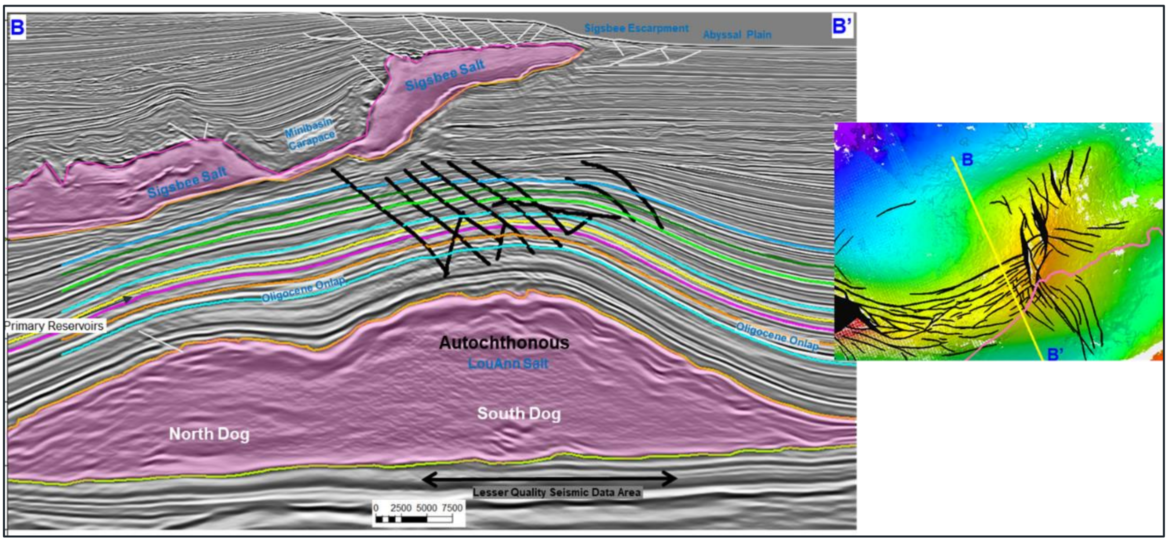
10.4.1 Field Description

The Mad Dog Field is a large, north-south trending, faulted, compressional anticline in the Western Atwater Fold Belt with oil trapped in Middle (M6) and Lower Miocene (M9/M10) turbidite reservoirs. Over 75% of the field is overlain by the Sigsbee Salt; the Sigsbee Salt limit (pink line in **Figure 10.19**) runs diagonally from SW to NE across the southern flank of the field.

The field contains a series of normal faults that radiate outward from the crest, subdividing the field into several structural compartments. The five major field compartments are East, North, West, Southwest Ridge (SWR) and South (**Figure 10.19**). The Southwest Extension (SWX) is an extension of the SWR and South compartments, though several other compartments could be interpreted.

The Mad Dog structure is supported by an autochthonous salt body (**Figure 10.20**), with associated extensional faults forming a crestal graben. Despite being at the crest of the structure, the graben area does not have trapped hydrocarbons.

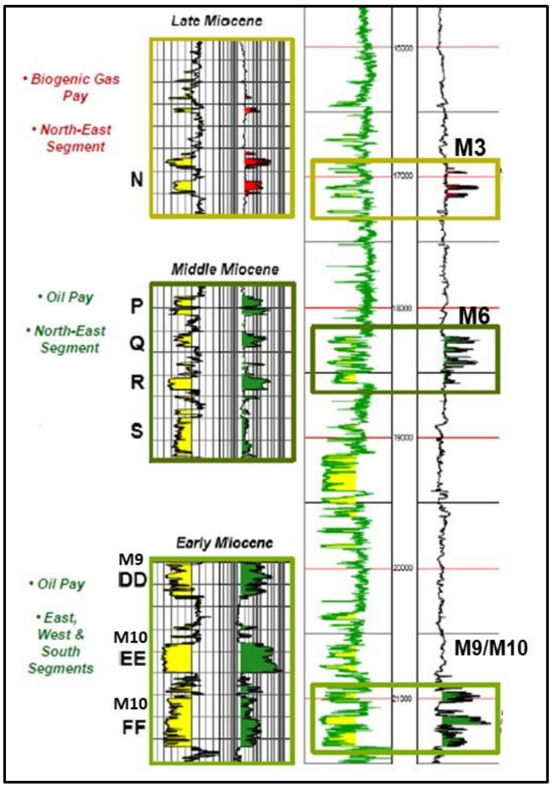
Figure 10.20: Seismic Cross section through Mad Dog



Source: BHP Petroleum

A Mad Dog type log and stratigraphic nomenclature used at Mad Dog Field is shown in **Figure 10.21**.

Figure 10.21: Mad Dog Type Log



Source: Walker, C. D., and G. A. Anderson, 2016, Simple and efficient representation of faults and fault transmissibility in a reservoir simulator: Case study from the Mad Dog Field, Gulf of Mexico: GCAGS Explore & Discover Article #00177, http://www.gcags.org/exploreand discovery/2016/00177_walker_and_Anderson.pdf Gulf Coast Association of Geological Societies.

The primary reservoirs are thick, blocky Lower Miocene (M9/M10) sands, designated as M9DD, M10EE, and M10FF. At Mad Dog individual sands are often more than 30 m thick and are stacked/amalgamated into 100 to 120 m thick sand packages with good porosity of 24% to 27% and permeability of about 500 to 650 mD. The M9/M10 reservoirs are oil bearing in the East, West, North, South-West Ridge and South segments of the structure. Some of the interbedded shales are likely to be continuous and may be flow barriers while others are limited in extent and may be flow baffles. Actual oil-water contacts (OWCs) for the Lower Miocene sands were intersected in two wells.

The Mad Dog Deep 2 well encountered an OWC in the M10 FF Sand in the south-eastern portion of the field. On the west side, an OWC was intersected in the M10 FF sands by the Mad Dog-11 down dip appraisal well. On the south side, an ODT was encountered in the Lower Miocene sands in the MDS-ST1 down dip appraisal well. The northern appraisal wells (down dip) encountered oil in the M9 and oil and water in the M10. The A-11 North graben well drilled in 2016 encountered oil all the way to the base of the M9/M10 sand.

The oil in the M9/M10 is undersaturated with oil gravity ranging from 26.5 to 33° API and oil viscosity from 2.17cP to 7.61 cP.

The M9 CC sand, Upper Miocene (M3) and Middle Miocene (M6) are minor reservoirs. Oil has been encountered in the CC and M6 and gas has been encountered in the M3 reservoir.

The most significant geological uncertainty associated with the Mad Dog Field is structural complexity (although sand quality is laterally consistent and predictable within the M9/M10 reservoirs). Faults were encountered in most of the wells drilled to date with evidence of some compartmentalisation on a field level. The issues revolve around the sealing nature of these faults, the number and location of compartments, volumes within compartments and their connectivity to the aquifer.

A wide-azimuth towed streamer (WATS) 3D seismic survey was acquired in 2004-2005 and reprocessed several times between 2006 to 2010 using different migration algorithms with the final product based on using tilted transverse isotropic (TTI) migration. Interpretation of the TTI volume currently serves as the basis for fault placement, segment definition in the field and STOIIP estimation. Subsequent seismic volumes have not been used for any resources estimates but rather used to help validate the existing TTI-based geomodel. An Ocean Bottom Nodal (OBN) 3D seismic survey was acquired between 2017 and 2019. The interpretation from this OBN data (see an example in Figure 10.20) forms the basis for a recent update to the geological model and new simulation modelling still in progress.

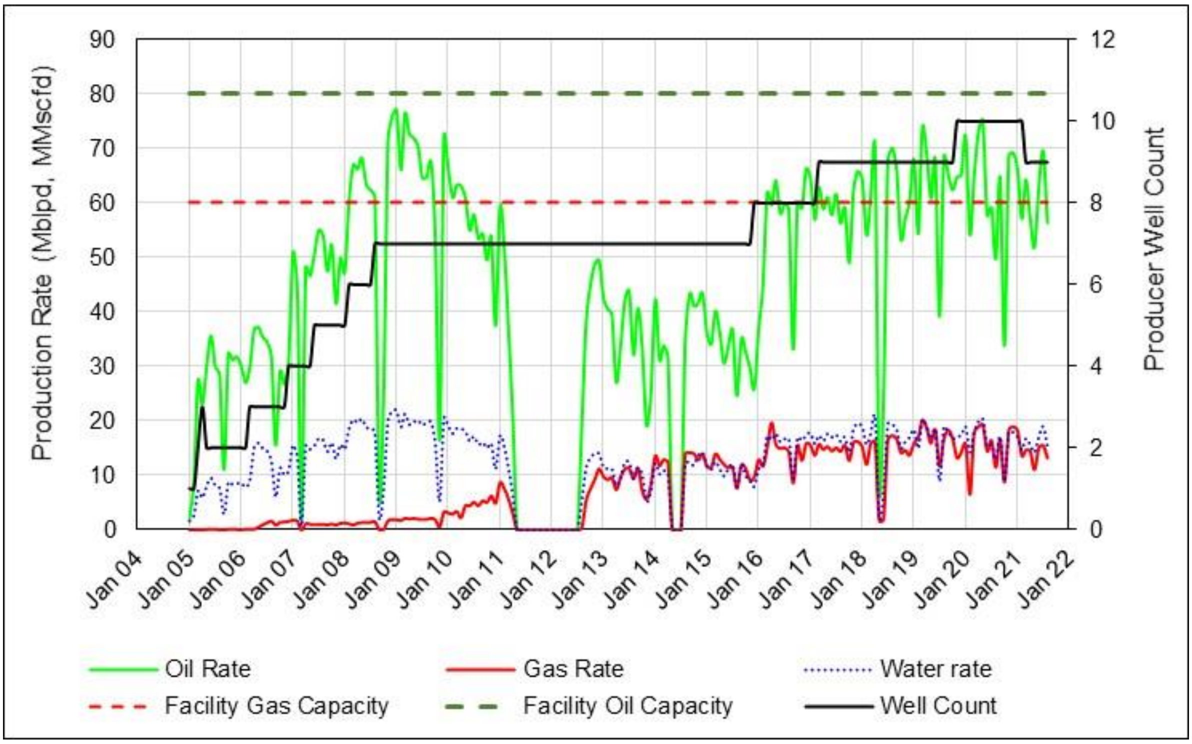
10.4.2 Field Development and Resources Estimates

The Mad Dog A-Spar facility comprises a 16-slot (capable of 13 production wells), dry-tree, floating spar hull with integrated production and drilling capabilities. It is a production quarters (PQ) truss spar host with an original nameplate capacity of 80 Mbopd (upgraded to 100 Mbopd in 2016), 40 MMscfd of gas, and 50 Mbwpd. Currently, it has no water injection capability. An 8-well gas lift manifold was set in April 2009. Mad Dog's historical production is shown in **Figure 10.22**. Current oil production rates are ~65 Mbopd, with watercut ~20%.

The design life of many of the major components of the A-Spar facility is 20 to 30 years, putting the original design life to December 2024. BP has performed several studies to quantify both the work scope and CAPEX required to extend the life of the facility to recover the significant remaining potential. BP has adopted 2045 as the end of field life for their business planning purposes.

Oil and sales gas are exported through the Caesar and Cleopatra export pipeline system. BHP Petroleum equity is 25% in the Caesar pipeline and 22% in the Cleopatra pipeline.

Figure 10.22: Mad Dog A-Spar Historical Production



Source: BHP Petroleum

The A-Spar development plan has three remaining wells to be drilled in the West Segment and two future side-track opportunities (one in the East and the other in the West Segment). Drilling operations are planned to commence in February 2022.

The Phase 2 project, currently in progress, comprises a semisubmersible floating production facility 'Argos' with a name plate capacity of 110 Mbopd and 140 Mbwpd water injection. Fourteen producers and eight water injectors are initially planned from drill centres connected to the facility via subsea flowlines. Nine producers and four injectors in the Phase 2 development plan have been drilled of which six producers and one injector have been completed. Start-up of production is planned for the second quarter of 2022.

GaffneyCline reviewed the simulation models that form the basis for production forecast of the A-Spar existing and future wells, and Phase 2 development wells, and consider them to be reasonable. In particular, GaffneyCline reviewed the quality of the calibration of the models with production and pressure data.

10.4.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation. GaffneyCline has reviewed the CAPEX provided by BHP Petroleum for each of the 1P, 2P and 2C Contingent Resources cases for Mad Dog A-Spar and Mad Dog Phase 2.

Mad Dog A-Spar

For the 1P and 2P Reserves cases costs are related to the original A Spar development (Mad Dog A-Spar Base) and to the A Spar infill programme (Mad Dog Approved).

The Contingent Resources CAPEX costs comprise of the following two projects:

- Expansion of the Phase 2 water injection to West and North segments; and
- A-Spar life extension and tie-back to Argos.

Table 10.7: Mad Dog A-Spar Capital Cost Estimate – 2P

CAPEX	US$ (MM)
Development	159
Sustaining	197
Total	**355**

Note: Totals may not exactly equal the sum of individual entries due to rounding

Table 10.8: Mad Dog A-Spar Capital Cost Estimate – Contingent Resources

CAPEX	US$ (MM)
Development	376
Total	**376**

Mad Dog Phase 2

For the 1P and 2P Reserves cases costs comprise of costs related to the second phase of development targeting the southern flank of the field with a semi-submersible floating production unit (Mad Dog Phase 2). The Contingent Resources CAPEX costs comprise of the following two projects:

- Infill drilling in the Phase 2 area; and
- Development of the South-West Extension area between Mad Dog and Puma.

The BHP Petroleum CAPEX costs for each of the projects have been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments.

Table 10.9: Mad Dog Phase 2 Capital Cost Estimate – 2P

CAPEX	US$ (MM)
Development	611
Total	**611**

Table 10.10: Mad Dog Phase 2 Capital Cost Estimate – Contingent Resources

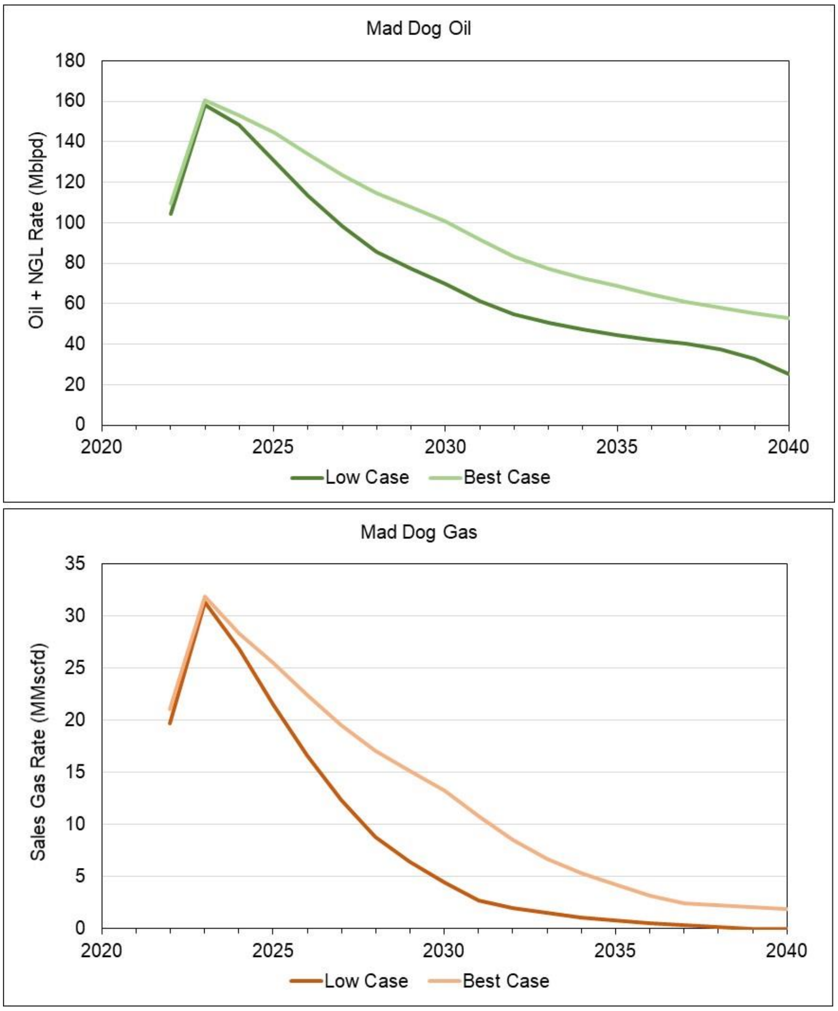
CAPEX	US$ (MM)
Development	461
Total	**461**

The OPEX costs provided in the economic model and supporting documentation have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted in the 1P, 2P and Contingent Resources cases to account for changes in the variable OPEX components of the OPEX costs resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

10.4.4 Resources Estimates

Reserves are attributed to Mad Dog for future production from existing infrastructure and wells, and for the implementation of Phase 2 with production schedule to start in 2022. The low and best estimate production profiles upon which the Reserves estimates are made are shown in **Figure 10.23**.

Figure 10.23: Mad Dog Production Profiles for Reserves Cases



Contingent Resources (**Table 10.11**) are attributed to the following future projects:

- Expansion of Phase 2 water injection system from 140 to 210 Mbwpd into the West and North Segments benefiting A-Spar recovery. Low salinity water injection is planned with the intention of enhancing oil recovery by reducing the residual oil saturation. Decision Gate 2 (end Selection Stage) is expected to be passed early in 2022.
- Development of the South-West Extension area between Mad Dog and Puma. The South-West extension area is a proved oil acculumation but is staged for development after the current Phase 2 development, hence the technical work in this area is less matured. The development strategy including decision for further appraisal drilling in this area will depend on the outcome of the current Phase 2 development.
- Infill drilling to supplement the Phase 2 wells, and contingent on the outcome of Phase 2. Three wells are provisionally included in the plan.
- Additionally, Contingent Resources are attributed to extension of the A-spar beyond 2045. The facility extension study beyond 2045 is still yet to be undertaken, hence the volumes produced to the A-Spar beyond 2045 is currently considered Contingent Resources (Development Unclarified).

Table 10.11: Mad Dog Gross 2C Contingent Resources as of 31 December 2021

Project	Gross 2C Contingent Resources		Development Status
	Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Expand Phase 2 water injection	66.7	1.6	Pending
South-West Extension	86.7	10.8	Unclarified
Phase 2 supplementary infill drilling	101.6	5.1	Unclarified
A-Spar extension	38.7	-	Unclarified

BHP Petroleum has identified additional potential opportunities beyond those listed above, which might provide upside potential in the future, but for which no Contingent Resources have been attributed on the basis that they are not yet been adequately substantiated.

10.4.5 GaffneyCline's Production and Cost Valuation Profiles- Mad Dog

GaffneyCline's valuation scenario production profile for BHP Petroleum's Mad Dog oil asset is given in **Figure 10.24** with the associated real term cost profiles provided in **Figure 10.25**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing Mad Dog Field and the four planned Mad Dog Contingent Resources projects documented in the previous sections.

GaffneyCline has independently assessed the four Contingent Resources projects and their technical and commercial maturity and considers them appropriate for valuation. As most projects are expansion projects with additional drillable wells from existing infrastructure with very good incremental IRR assessments, GaffneyCline considers these projects appropriate for valuation after consideration of the contingencies described in section 10.3.4.

Figure 10.24: BHP Petroleum Net Mad Dog Asset Production Profile

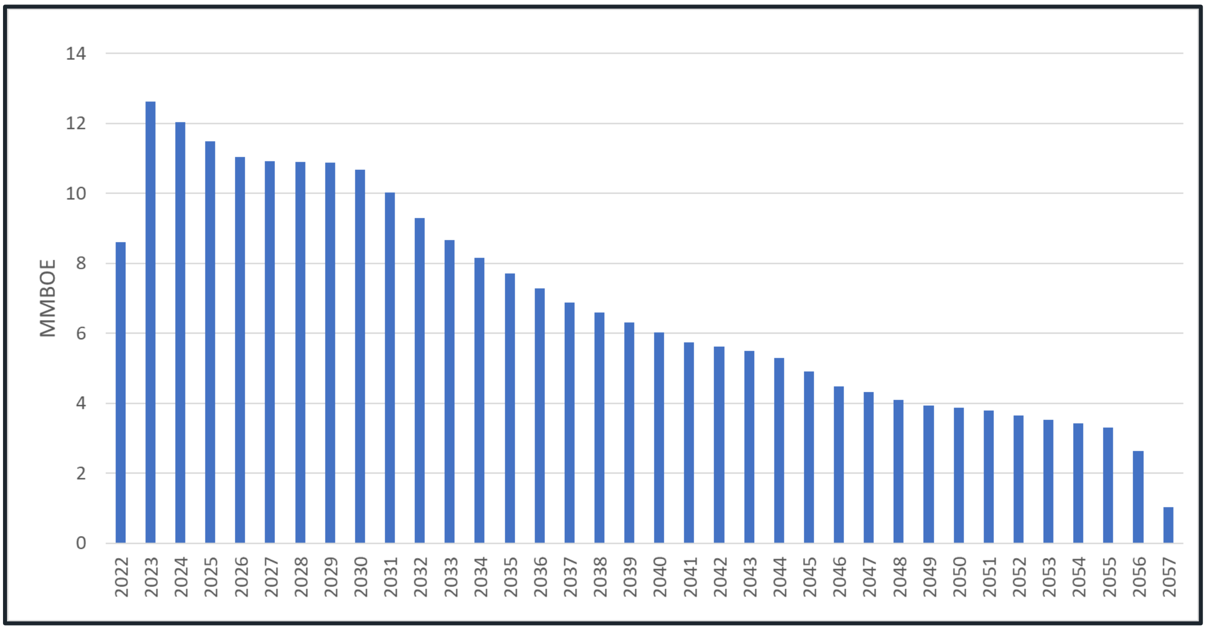
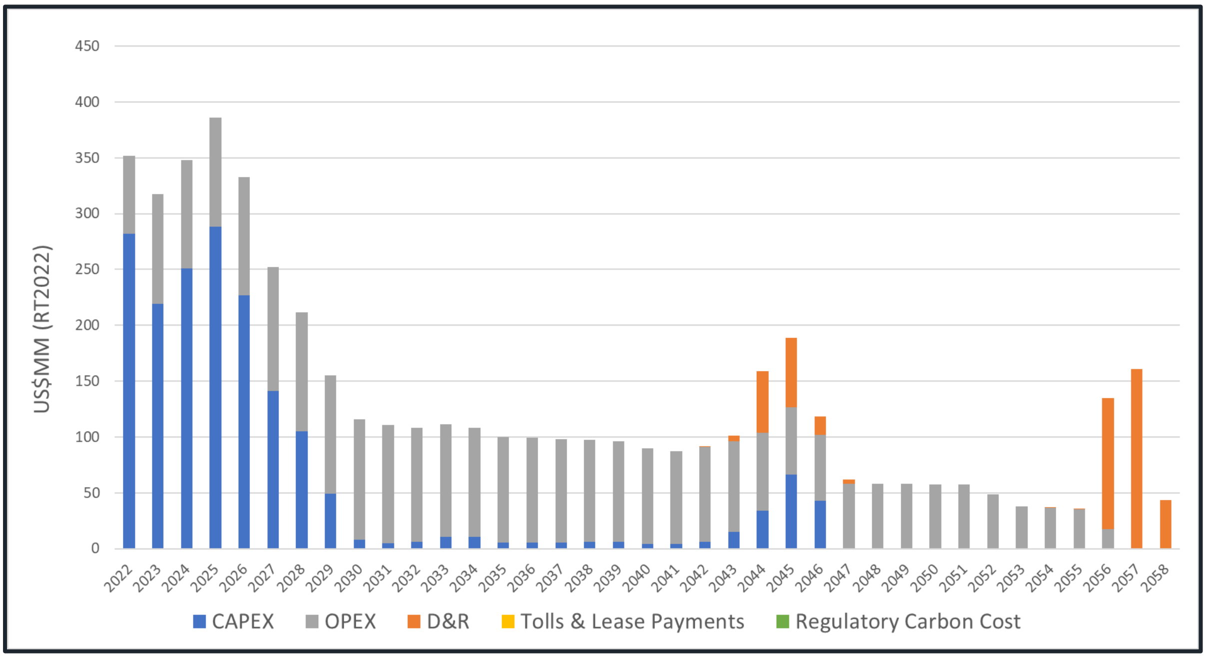


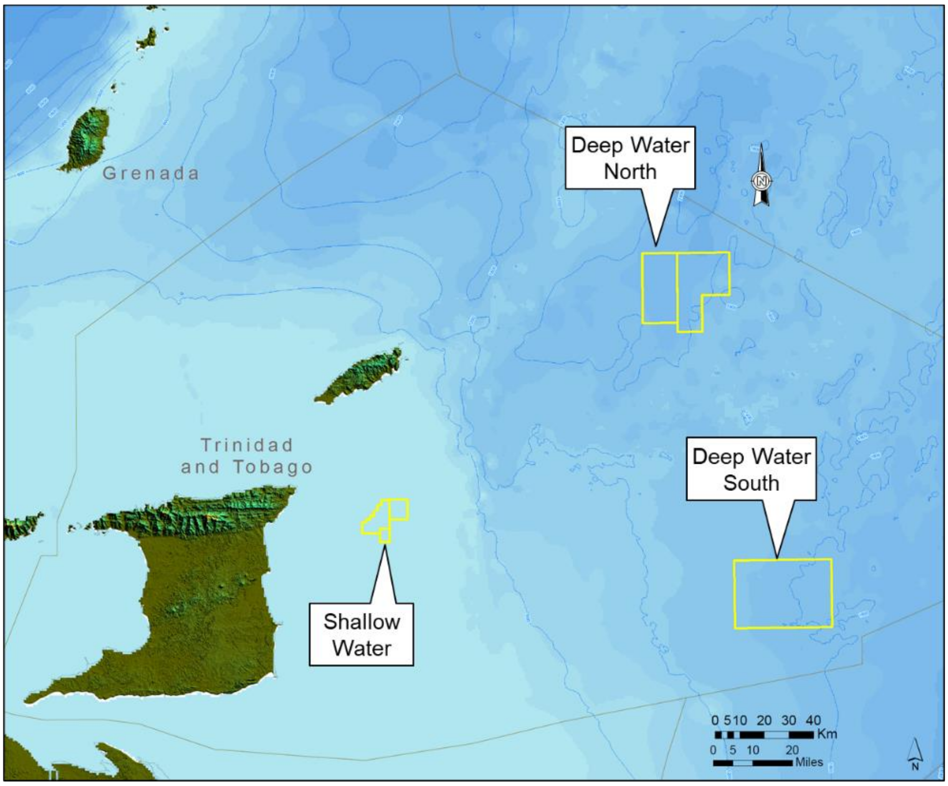
Figure 10.25: BHP Petroleum Net Mad Dog Asset Cost Profile



11 BHP Petroleum Trinidad and Tobago

BHP Petroleum holds licences in three offshore areas: Shallow Water, Deep Water North and Deep Water South (**Figure 11.1**). The Shallow Water area contains producing oil and gas assets and undeveloped discoveries of the Greater Angostura Complex. The Deep Water North area contains the multi-field Calypso gas development currently under appraisal and the Deep Water South area contains gas discoveries currently under evaluation.

Figure 11.1: Location Map of BHP Petroleum's assets Offshore Trinidad and Tobago

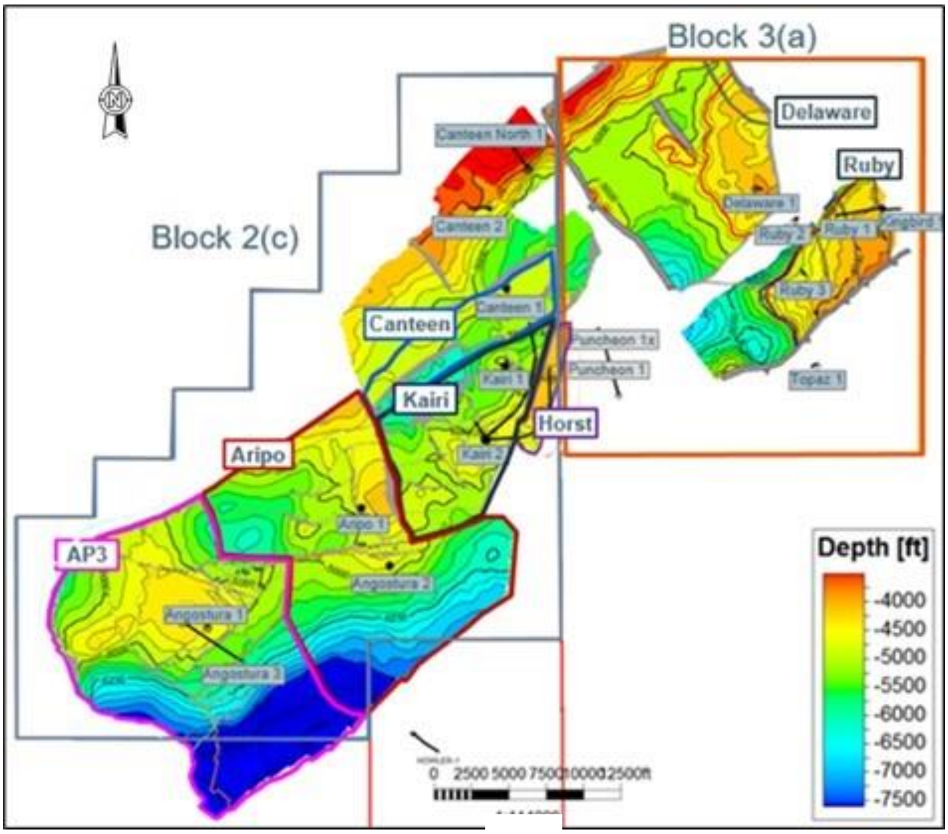


Source: BHP Petroleum

11.1 Shallow Water - Greater Angostura Complex – Block 2(c) and 3(a)

The shallow water Greater Angostura Complex comprises multiple accumulations located within Block 2(c) and Block 3(a) (**Figure 11.2**). Block 2c contains producing oil and gas assets (AP3, Aripo, Horst, Kairi and Canteen) and discoveries (Howler, Canteen North). Block 3(a) contain the Ruby (oil and gas) and Delaware (gas) fields, which came on stream in 2021. BHP Petroleum is the operator under a Production Sharing Contract (PSC) and holds a 45% working interest in the producing assets in Block 2(c) with partners National Gas Company of Trinidad and Tobago (30%) and Chaoyang (25%), and a 68.46% stake in Block 3(a) with the National Gas Company of Trinidad and Tobago as partner. BHP Petroleum has 64.3% working interest in the Howler discovery, which has been incorporated in Block 2(c) with its PSC terms, with Chaoyang as partner.

Figure 11.2: Location Map of Fields in Greater Angostura Complex



Source: BHP Petroleum

11.1.1 Field Description and Development History

The discovery well Angostura-1, intersected ~290 m of gas in Early Oligocene sands in Block 2(c) in 1999. Oil was discovered by Kairi-1 in 2001, also in Block 2(c). During the Exploration Phase of the Block 2(c) PSC, a total of four exploration and three appraisal wells were drilled, discovering significant oil and gas resources within a large, faulted structure in the same Oligocene sandstone reservoir. Oil rims in Kairi, Canteen and Horst fields have been developed and came on stream from 2005 to 2008. The Aripo and AP3 gas fields came on stream in 2011 and 2016 respectively.

During the Exploration Phase of the Block 3(a) PSC, five exploration and two appraisal wells were drilled. Gas was discovered in Delaware-1 in 2003 and oil in Ruby-1 in 2006. Declaration of Commerciality for Block 3(a) was in 2018 and development of Ruby and Delaware fields was sanctioned in 2019. Development drilling in Ruby started late in 2020 and production is to the Block 2(c) facilities. First oil production from Ruby started in May 2021 and first gas production from Delaware commenced in August 2021.

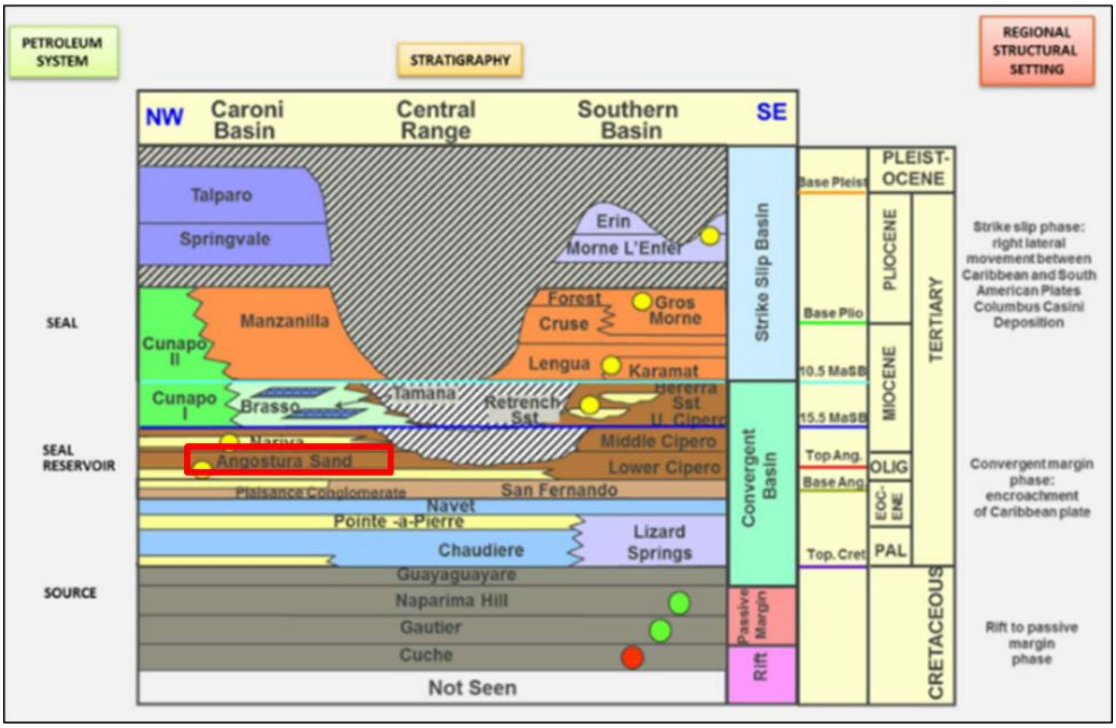
With the development of Ruby and Delaware fields in Block 3(a), the PSC for both Block 3(a) and Block 2(c) has been extended to 2031.

The broad antiformal feature of Greater Angostura is in an area with complex tectonic history and the faults in the field create an intricate structural picture. Major faults have compartmentalised the Greater Angostura structure into at least five or six separate production units. However, due to the high sand content and the large gross thickness, many of the intra-field faults are not completely sealing, but may act as partial flow barriers over the producing life of the field. Most of the tested fault blocks appear to contain different gas-oil and oil-water contacts, and between some blocks, different pressure regimes.

AP3 and Aripo have thin oil rims (11 m) with large gas caps. The Canteen-1 and Kairi compartments contain thicker, but separate, oil columns (96 and 133 m respectively) with gas caps. The Horst block has a 30 m oil rim with a large gas cap.

The fields produce from an Early to Middle Oligocene-aged sand formation named the Angostura Sandstone (**Figure 11.3**). It ranges in thickness from less than 100 m to over 450 m. The Angostura Sandstone is interpreted to be a turbidite-dominated gravity flow depositional system in the upper to mid-slope environments, either a fan delta-fed slope or a detached turbidite system, relatively close to its source area. The depositional model is described by a series of laterally coalescing, northwest derived shelf type fan deltas that are banked against a northeast-southwest trending thrust fault bordering an Oligocene ‘Northwest Trinidad High.

Figure 11.3: Stratigraphic Column of Greater Angostura Complex



Source: BHP Petroleum

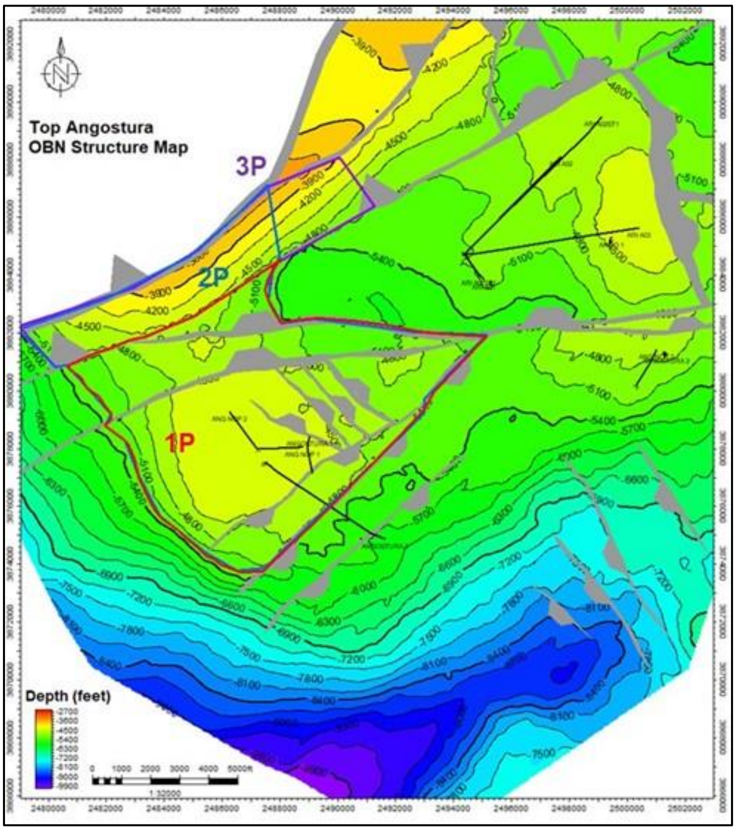
The structure was originally covered by a 3D OBC (Ocean Bottom Cable) seismic dataset obtained in 1997. The quality of these data and the complexity of the structure left a large amount of uncertainty in the mapping. Since then, several newer 3D seismic surveys (Angostura in 2001, Darien 2003, Emerald 2004) have been acquired and processed for better seismic imaging. The Angostura Field seismic survey was reprocessed and a PSDM volume was delivered in 2005 to improve resolution. In 2008 another reprocessing project was carried out utilising the latest technologies. However, imaging remained a challenge and the ability to map top and base reservoir away from well control remained difficult.

The 2018 Trinidad OBN (Ocean Bottom Node) seismic survey was designed to improve imaging to, inter alia, plan the placement of the horizontal wells of the Ruby development. Processing used Full Waveform Inversion technology and allowed for higher confidence in defining reservoir extent.

AP3 Field (Block 2c)

Six wells have been drilled in the AP3 Field. Angostura-1 was the discovery well and encountered a gas filled Angostura Sandstone interval. Angostura-2 was an appraisal well drilled northeast of the discovery well and found a gas interval that was lower in pressure than the original well and a thin oil column (11 m) with water bearing sandstone below. The Angostura-3 appraisal well was drilled between the other two previous wells and encountered a thin gas section apparently connected to the discovery well, then faulted into a water bearing sand which looks to be the Angostura-2 reservoir. As part of the AP3 project, three development wells were drilled and completed. These are currently all on production. Dynamic data show larger GIIP than estimated by mapping seismic data around the wells. Connected GIIP has been estimated using multi-tank material balance and diagnostic plots. Low and best estimate resources estimates are based on material balance and history matched reservoir simulation models respectively (**Table 11.1**).

Figure 11.4: Depth Structure Map of AP3 Field



Source: BHP Petroleum

Aripo Field (Block 2c)

Four wells have been drilled in Aripo. Aripo-1 found gas bearing Angostura Sandstone with a thin oil column and water bearing sand. Pressures suggest a possible connection between the Angostura-2 eastern area and Aripo-1. Three development wells were drilled and completed. Pressure decline due to production from the Kairi field indicates communication between these fault blocks. Over 90% of the ultimate recovery has been produced. Resources estimates are based on well performance extrapolation using 500 psi abandonment pressure (**Table 11.1**).

Kairi Field (Block 2c)

Kairi Field, discovered by Kairi-1 and appraised by Kairi-2 has been the predominant oil producing segment of the Angostura complex. To date 15 development wells have been drilled from the two wellhead platforms (excluding Kairi Horst). Eleven are horizontal or highly deviated oil producers and four are gas injection wells. Development drilling has confirmed the geologic complexity of the area. Additional faulting and different fluid contacts have been encountered in some of the wells. Low and best estimate Resource estimates are based on DCA and reservoir simulation respectively (**Table 11.1**). More than 95% of the ultimate recovery has been produced.

Canteen Field (Block 2c)

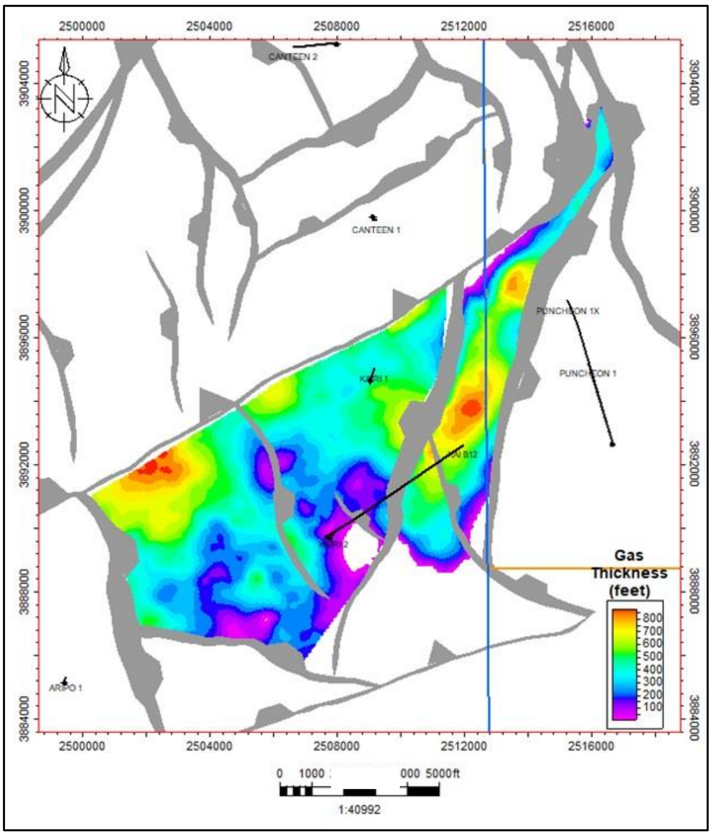
The Canteen oil accumulation was discovered by Canteen-1. Seven development wells were drilled: four horizontal oil producers and one deviated gas injection well in the main producing area of Canteen, and a gas injector to support a horizontal oil producer that was drilled into the western area. Low and best estimate Resource estimates are based on DCA and reservoir simulation respectively (**Table 11.1**). More than 97% of the estimated ultimate recovery has been produced.

Horst Field (Block 2c)

A well drilled northeast from the Kairi-A platform in 2005 to test the Kairi Horst feature failed to find the Angostura Sandstone. In 2007, a second well from Kairi-B confirmed the presence of both oil and gas in the Horst block, encountering approximately 180 m of gross gas and 30 m of gross oil in the Angostura Sandstone. Pressures measured in the well, as well as different fluid contacts, show that the Kairi Horst is in a separate reservoir compartment from the other parts of the field. The well was completed as an oil producer, but later converted to a gas injector to support a horizontal oil producer drilled in 2011, which had gas breakthrough within half a year. Both wells have produced since 2014 at high GOR and are currently producing mainly gas.

Dynamic data show larger GIIP than estimated from mapping of OBN seismic data and this is likely due to connection to the Olistostrome (**Figure 11.5**). Low and best estimate Resource estimates are based on DCA and reservoir simulation respectively (**Table 11.1**).

Figure 11.5: Hydrocarbon Pore Thickness Map of Olistostrome above Kairi and Horst Field



Source: BHP Petroleum

Resources Estimates for AP3, Aripo, Kari, Canteen and Horst

Reserves are attributed to the AP3, Aripo, Kari, Canteen and Horst Fields. Estimates of recoverable volumes shown in **Table 11.1** form the basis for the Reserves estimates.

Table 11.1: Estimates of Initially In Place and Recoverable Volumes for Angostura Projects

	Field	Initially in Place		Ultimate Recovery	
		Low	Best	Low	Best
Gas (Bscf)	AP3	560	650	459	544
	Aripo	505	518	386	406
	Kari	478	531	331	372
	Canteen	80	95	29	35
	Horst	240	280	181	217
	Block 2(c)	**1,863**	**2,074**	**1,387**	**1,574**
Liquids (MMBbl)	Kari		223	58.2	58.8
	Canteen		81	24.8	25.0
	Horst		9	0.7	0.7
	Condensate		-	0.7	0.8
	Block 2(c)		**313**	**84.4**	**85.3**

Note: Volumes exclude estimates of fuel.

Contingent Resources in the Greater Angostura Complex within Block 2(c) comprise gas in the Canteen North area (discovered by the Canteen North exploration well in 2011), the Howler area (discovered by the Howler exploration well in 2003), the Nariva age sands (gas discovered by the ANG-NOP-02 well in 2016) and additional gas production from the Canteen, Kairi, Aripo and Horst fields attributed to lowering field abandonment pressure below that currently assumed for the Reserves case.

Canteen North (Block 2c)

Canteen North was discovered in 2011 north of the oil-bearing Canteen Field. Gas was encountered in well-developed olistostrome sands with a GWC in the upper Angostura thin beds. The thin beds are interpreted as a transgressive phase of the Angostura Sandstone. The majority of GIIP is in the olistostrome sands (**Table 11.2**). Based on regional analogues and weak aquifer drive, ultimate recovery is estimated at 62 Bscf (65% recovery factor). Canteen North is one of the development opportunities in the area when gas ullage become available.

Table 11.2: Best Estimate Reservoir Properties and GIIP for Canteen North

Field / Reservoir	NTG (v/v)	Porosity (v/v)	Water Saturation	GIIP (Bscf)
Olistostrome/thin beds	0.3	0.2	0.4	77
Angostura	0.7	0.18	0.22	19

Howler Field (Block 2c)

The Howler-1 discovery well was drilled in Block 2c south of the Angostura Development Area and encountered hydrocarbons in the Naparima Hill carbonate reservoir, flowing gas during a drill-stem test (DST). After declaration of commerciality, the Howler area has been assimilated into Block 2c.

The presence of matrix porosity with enhanced permeability from fractures is the main uncertainty and it is believed that an additional appraisal well will be required.

GIIP (**Table 11.3**) and recoverable gas from the Naparima Hill Formation have been estimated probabilistically. The best case assumes effective gas reservoir to be found down to 500 m below the end-of-thrust (ET) unconformity and the gas water contact (2,545 mss) at the intersection of the Howler gas gradient and Kairi-1 water gradient. The recovery factor (75%) assumes primary depletion through a network of natural fractures enhanced with compression. Analog fields, which produce from fractured and low porosity reservoirs, indicate a wide variation in well quality and recovery per well. Recovery per well ranges from 25 to 80 Bscf.

Table 11.3: Best Estimate Reservoir Properties and GIIP for Howler Field

Field / Reservoir	NTG (v/v)	Porosity (v/v)	Water Saturation (v/v)	Permeability (mD)	GIIP (Bscf)
Naparima Hill	0.85	0.15	0.65	10	364

Significant uncertainty requires further study prior to drilling any additional appraisal wells. Recoverable volumes are classified as Contingent Resources and sub-classified as Not Viable as development is uneconomic at prevailing costs and gas prices.

Delaware Field (Block 3a)

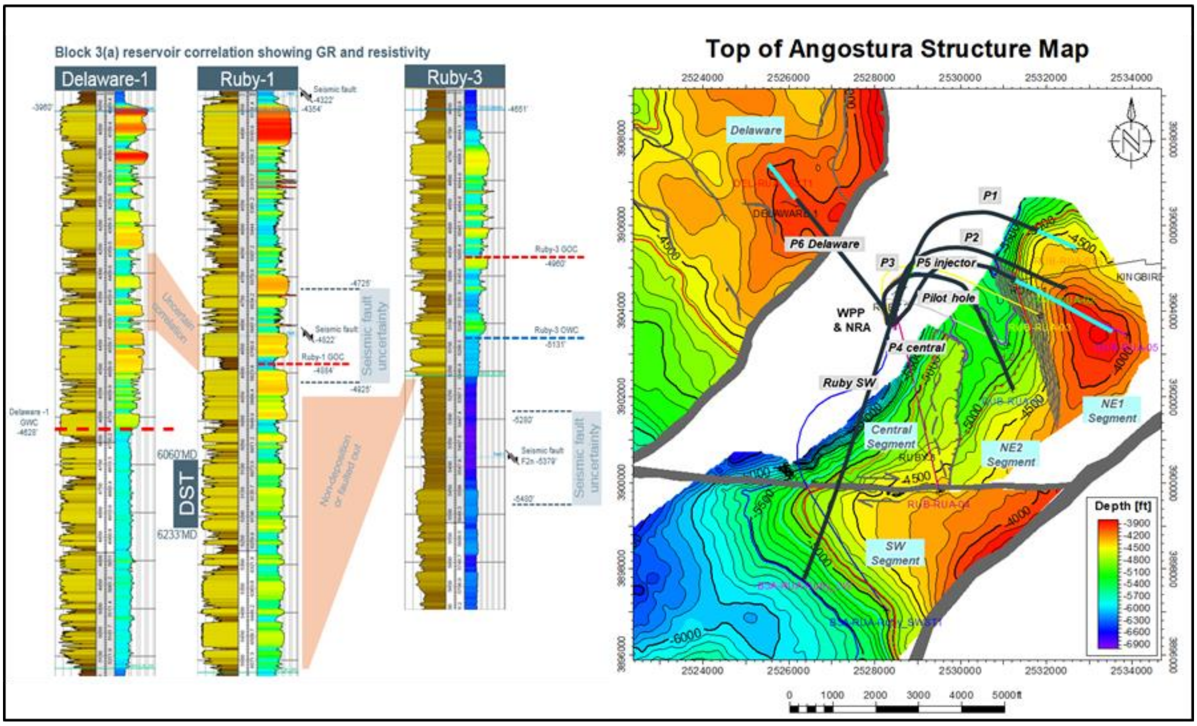
The Delaware-1 well was drilled in 2003 at the crest of the Delaware thrust sheet, which dips to the NNW (**Figure 11.6**), discovering gas. One deviated gas producer has been drilled. Resources estimates are shown in **Table 11.4**.

Ruby Field (Block 3a)

The Ruby-1 exploration (2006) and Ruby- 3 appraisal (2016) wells found oil and gas in commercial quantities. However, the Ruby-3 well found an oil-water contact and gas-oil contact shallower than the oil-down-to and gas-oil contact in the initial Ruby-1 well, indicating compartmentalization. Reservoir sand properties are good, with porosity ranging from 12 to 23% (average about 15%) and permeability ranging from tens of milli-Darcies to over 5 Darcy (average around 240 mD). The NTG ranges from 50% to 75% with average about 67%.

Development wells were drilled in 2020 and 2021. The development plan involves four horizontal wells with an injector for pressure maintenance, later followed by gas cap blow down when ullage for sales gas becomes available. Long horizontal reservoir sections (~600 m) are drilled with an orientation designed to maximise contact with stratigraphy and mitigate potential compartmentalisation risk.

Figure 11.6: Type Logs and Structure of Delaware and Ruby Fields



Source: BHP Petroleum

The pilot development well into the NE2 segment drilled in 2021 delivered unexpected results, encountering the top Angostura 120 m deeper than prognosed, with a thinner sand and FWL shallower than the lowest known hydrocarbon depth in the NE1 segment intersected by Ruby-1. The appraisal exploration well into the SW segment encountered the Angostura sandstone deeper than prognosed and water bearing.

Estimates of ultimate recovery (**Table 11.4**) are based on the new OBN seismic, results of the development wells and initial production performance.

Table 11.4: Gross Resources Estimates for Delaware and Ruby Fields

Field	Low			Best		
	HCIIP	Ultimate Recovery	RF (%)	HCIIP	Ultimate Recovery	RF (%)
Ruby oil (MMBbl)	18.5	3.2	17	25.9	4.1	16
Ruby gas (Bscf)	64.6	17.6	27	101.1	33.9	34
Delaware gas (Bscf)	56.3	23.4	42	66.3	29.9	45

11.1.2 Field Development and Production Profiles

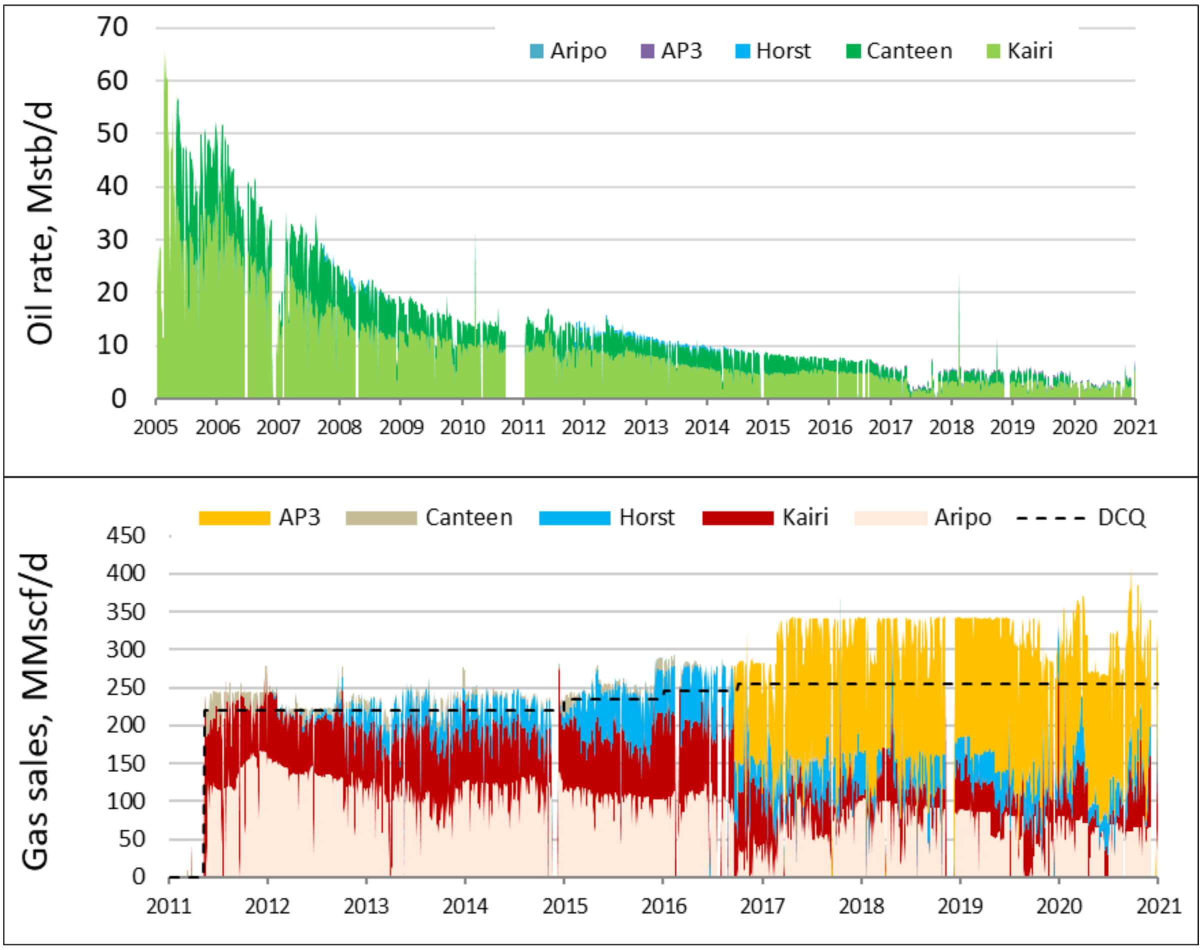
Development of the Angostura oil (Kairi, Canteen and Horst) was sanctioned in February 2003 and drilling began in October 2003, with oil production starting in January 2005 from Kairi. The oil development utilises horizontal and highly deviated producing wells and deviated gas injection wells, drilled from three fixed wellhead platforms. Produced gas is re-injection into the gas caps for pressure maintenance. In late life a gas cap blow down is planned. The wells produce to a fixed central production platform (CPP) that is bridge connected to one of the wellhead platforms. The central facility hosts living quarters, gas compression equipment for re-injection, and the production facilities necessary to deliver stabilised crude to onshore storage facilities at Galeota Point on the southeast coast of Trinidad. Oil is exported via a catenary anchor leg mooring (CALM) buoy and tanker loadings. Produced gas, less fuel requirements, is re-injected. Produced water is treated and discharged into the sea.

In August 2008, the Angostura Gas Project (AGP) was sanctioned. The development comprises three dedicated gas wells Aripo and provides additional facilities on a new gas export platform (GEP) necessary to produce, process, and deliver natural gas from the gas caps of Kairi, Canteen, Horst and Aripo to the Natural Gas Company of Trinidad and Tobago (NGC) for the domestic market. Under the sales agreement, NGC takes delivery of the gas at an offshore sales delivery point at the GEP. The gas export pipelines, export risers and associated infrastructure are owned, operated, and maintained by NGC. Development of AP3 was sanctioned in 2014 and consisted of 3 subsea gas wells tied back to GEP.

The fields are believed to have limited aquifer support. Pressure data acquired after production commenced indicate communication through the aquifer in the Greater Angostura structure. Faults appear to have low sealing capacity and although compartmentalisation causes baffling to flow, communication across faults occurs with differential pressure depletion.

As of June 2021, 31 development wells have been drilled in Block 2(c): 17 horizontal or highly deviated oil wells and eight deviated gas injection wells in Kairi, Canteen and Horst fields, and six dedicated gas producers in Aripo and AP3. Current oil production is ~3,500 bopd coming mainly from Kairi and Canteen. The AP3 and Aripo fields are currently producing the bulk of the total gas sales of ~340 MMscfd (**Figure 11.7**), with Horst, Kairi and Canteen fields contributing the remaining sales gas. The combined complex has produced an estimated 80 MMBbl of oil through June 2021 and a total of 967 Bscf of natural gas has been sold.

Figure 11.7: Historical Production from Greater Angostura Complex



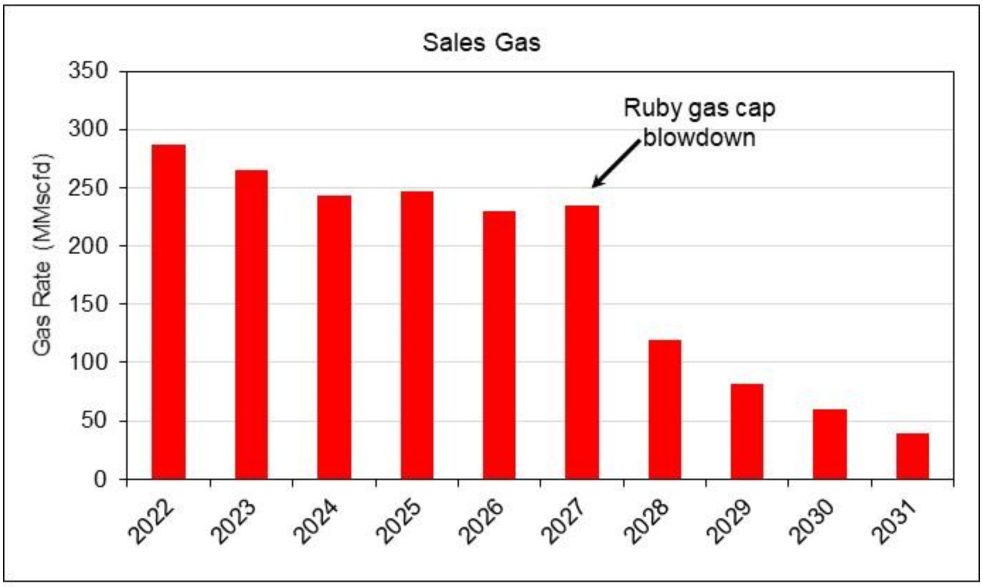
Source: BHP Petroleum

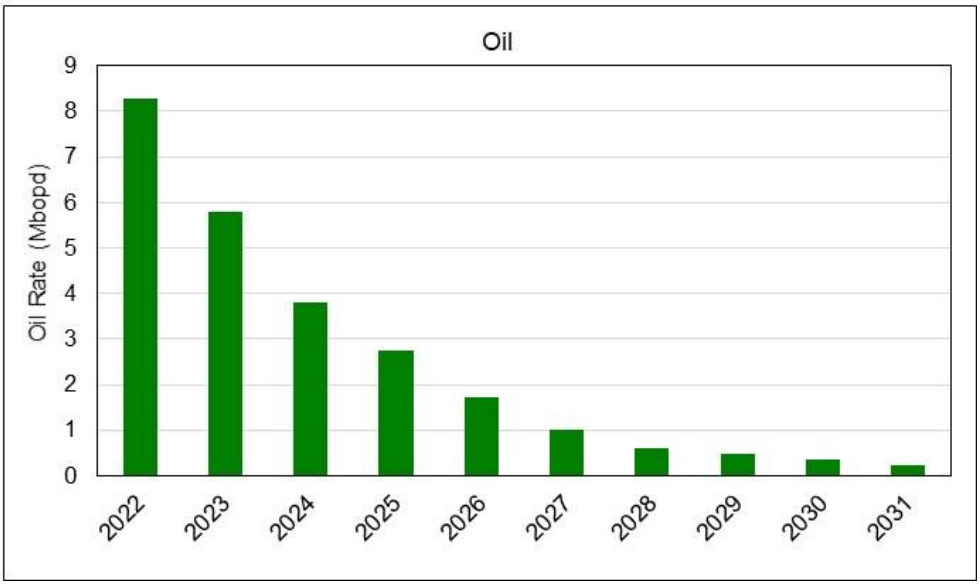
The Ruby/Delaware development of 2020 comprises six wells: four horizontal oil producers and one horizontal gas injection well in Ruby and one deviated gas producer in Delaware. Wells are drilled from a single, unmanned wellhead protector platform (WPP) tied back to the existing Block 2(c) processing facilities (CPP) via 3 flowlines: a production flowline from WPP to CPP for Ruby, an injection flowline from CPP to WPP and a production flowline from WPP to GEP for Delaware. Produced gas will be re-injected in Block 3(a) or exported as sales gas. Metering and allocation instrumentation have been installed on the CPP to distinguish new production from Block 3(a) from existing production in Block 2(c).

The nominal capacity of the processing facilities on the CPP is 100 Mbopd with a gas-handling limit of 350 MMscfd. The expected maximum current daily production rate from the field is ~6 Mbopd and 340 MMscfd of gas. All the gas that is not used for sales, fuel and flare is re-injected into the eight gas injection wells in Canteen, Kairi and Ruby. Current daily injection target is approximately 160 MMscfd.

Figure 11.8 shows overall constrained production profiles for Block 2(c) (AP3, Aripo, Horst, Canteen, Kairi Fields) and Block 3(a) (Ruby and Delaware fields) combined.

Figure 11.8: Production Profiles for Block 2(c) and Block 3(a)





Source: Based on data provided by BHP Petroleum

11.1.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

For both Block 2(c) and Block 3(a) the 2P Reserves CAPEX comprise of risk reduction and improvement capital costs, but no significant facilities CAPEX expenditure. The BHP Petroleum CAPEX costs have been reviewed and appear to be credible, and have been adopted unchanged. CAPEX for the 2P Reserves case from 31 December 2021 is shown in **Table 11.5**.

Table 11.5: Block 2(c) and Block 3(a) Capital Cost Estimate – 2P

CAPEX - US$ (MM)	Block 2(c)	Block 3(a)
Development		
Sustaining	42	26
Total	**42**	**26**

The OPEX for the 2P Reserves is broken down into fixed operating overhead costs, lifting costs and processing and storage. The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX components of the total OPEX resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles, and allocation of the total OPEX adjusted between 2(c) and 3(a) based on the relative production rates.

11.1.4 Resources Estimates

Reserves are attributed to the AP3, Aripo, Kairi, Canteen, Horst, Ruby and Delaware fields. Coupled simulation models are used to forecast performance of the Canteen, Kairi, Horst, Aripo and AP3 fields together. The forecast assumption is that 255 MMscfd will be produced from Block 2(c) leaving an ullage of 85 MMscfd for gas from Block 3(a) Ruby/Delaware fields.

Contingent Resources in Block 2(c) (**Table 11.6**) include volumes that are associated with the Canteen North and Howler discoveries and production associated with the Canteen, Kairi, Horst and Aripo Fields at lower abandonment pressure than currently assumed. In 2016, a gas discovery was made in the Nariva age sands during the drilling of the ANG-NOP-02 well. All these Contingent Resource volumes are sub-classified as Not Viable as no plans exist to mature these development opportunities.

Table 11.6: Gross 2C Contingent Resources for Block 2(c) as of 31 December 2021

Field	2C Contingent Resources	
	Gas (Bscf)	Condensate (MMBbl)
Canteen North	62	-
Howler	274	1.6
Nariva	8.7	-
Lower Abandonment Pressure	25.2	-
Total	**370**	**1.6**

11.1.5 GaffneyCline's Production and Cost Valuation Profiles-Block 2c

GaffneyCline's valuation scenario production profile for BHP Petroleum's Trinidad and Tobago Block 2c asset is given in **Figure 11.9** with the associated real term cost profiles provided in **Figure 11.10**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing Trinidad and Tobago Block 2c asset projects documented in the previous sections. Block 2c profiles contains producing oil and gas assets AP3, Aripo, Horst, Kairi and Canteen.

Figure 11.9: BHP Petroleum Net Trinidad and Tobago Block 2c Asset Production Profile

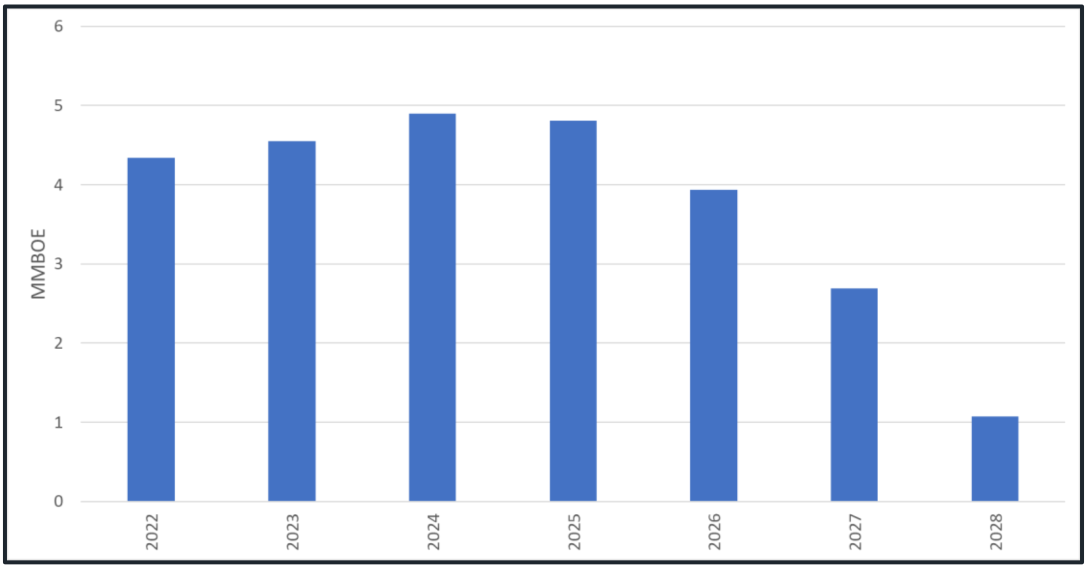
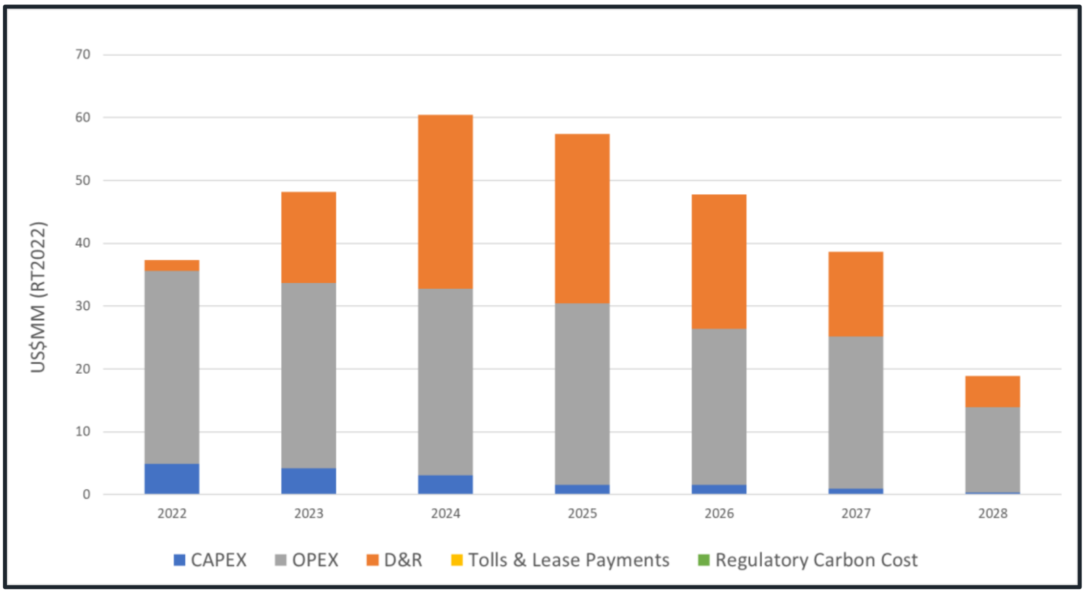


Figure 11.10: BHP Petroleum Net Trinidad and Tobago Block 2C Asset Cost Profile



11.1.6 GaffneyCline's Production and Cost Valuation Profiles-Block 3a

GaffneyCline's valuation scenario production profile for BHP Petroleum's Trinidad and Tobago Block 3a asset is given in **Figure 11.11** with the associated real term cost profiles provided in **Figure 11.12**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the remaining recoverable volumes of the producing Trinidad and Tobago Block 3a asset projects documented in the previous sections. Block 3a contain the Ruby (oil and gas) and Delaware (gas) fields, which came on stream in 2021.

Figure 11.11: BHP Petroleum Net Trinidad and Tobago Block 3a Asset Production Profile

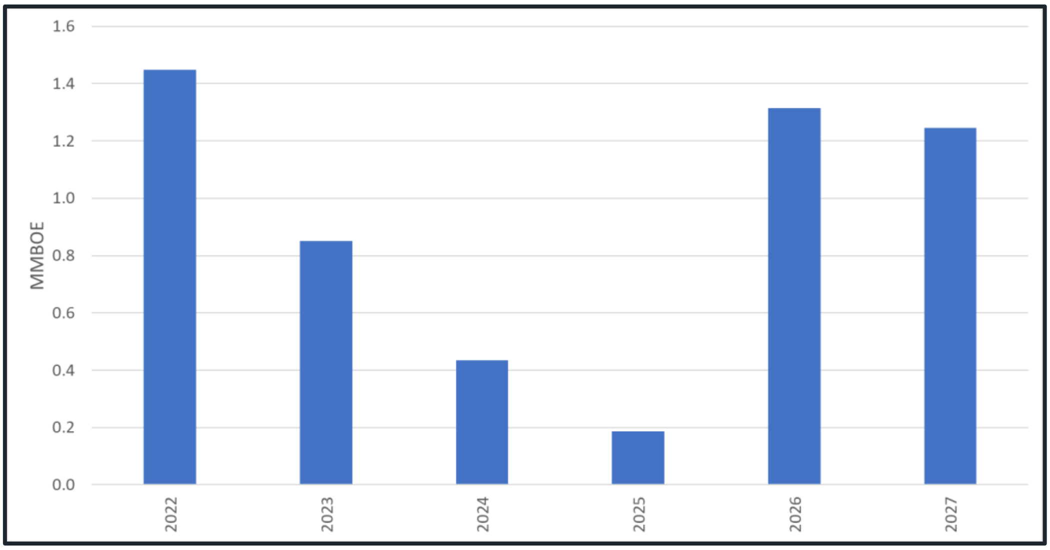
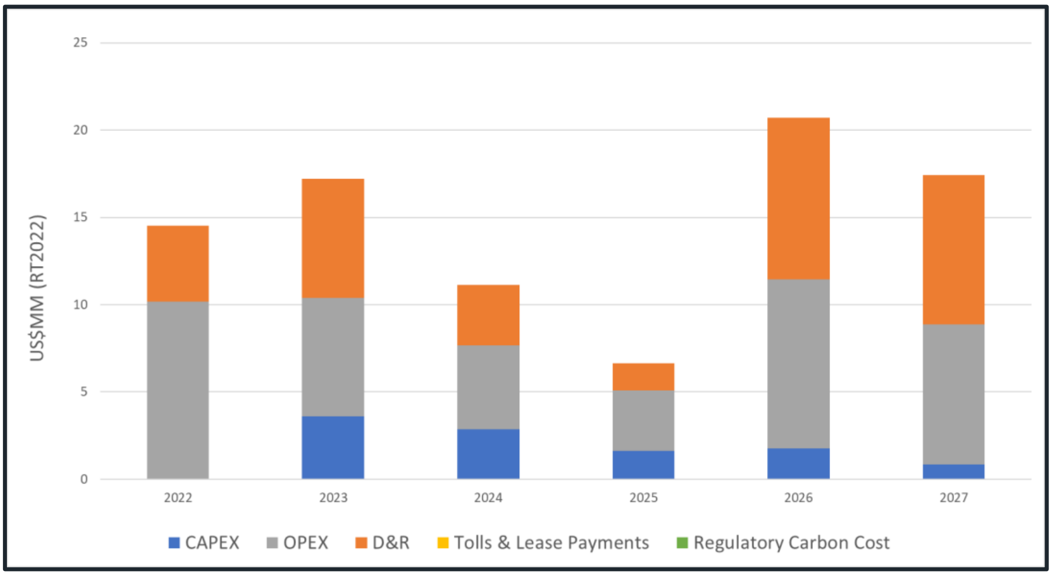


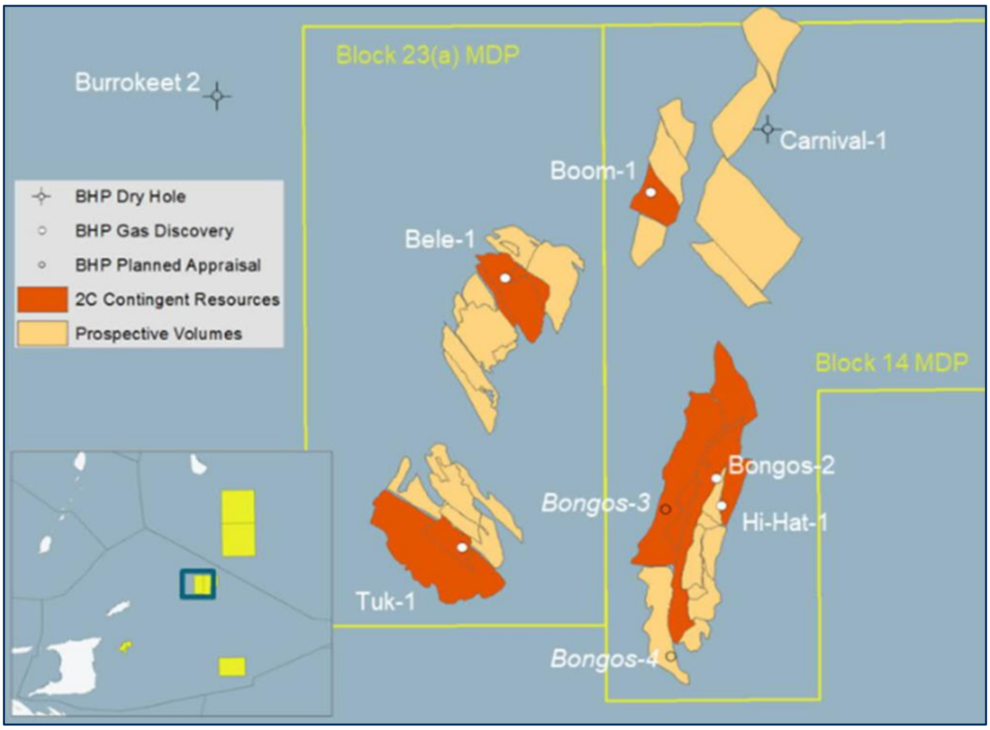
Figure 11.12: BHP Petroleum Net Trinidad and Tobago Block 3a asset Cost Profile



11.2 Deep Water North – Calypso Development

The Deep Water North area covers Blocks 23(a) and 14 (**Figure 11.13**), approximately 170 km northeast of the island of Tobago with a water depth of 2,000 m. BHP Petroleum is the operator and has a 70% working interest with BP as partner. BHP Petroleum drilled seven exploration wells and made five discoveries (Bongos, Bele, Tuk, Hi-Hat, Boom), with the Burrokeet and Carnival wells being unsuccessful. The discoveries are expected to be developed in a single development referred to as Calypso.

Figure 11.13: Location Map of Deep Water North Calypso Development



Source: BHP Petroleum

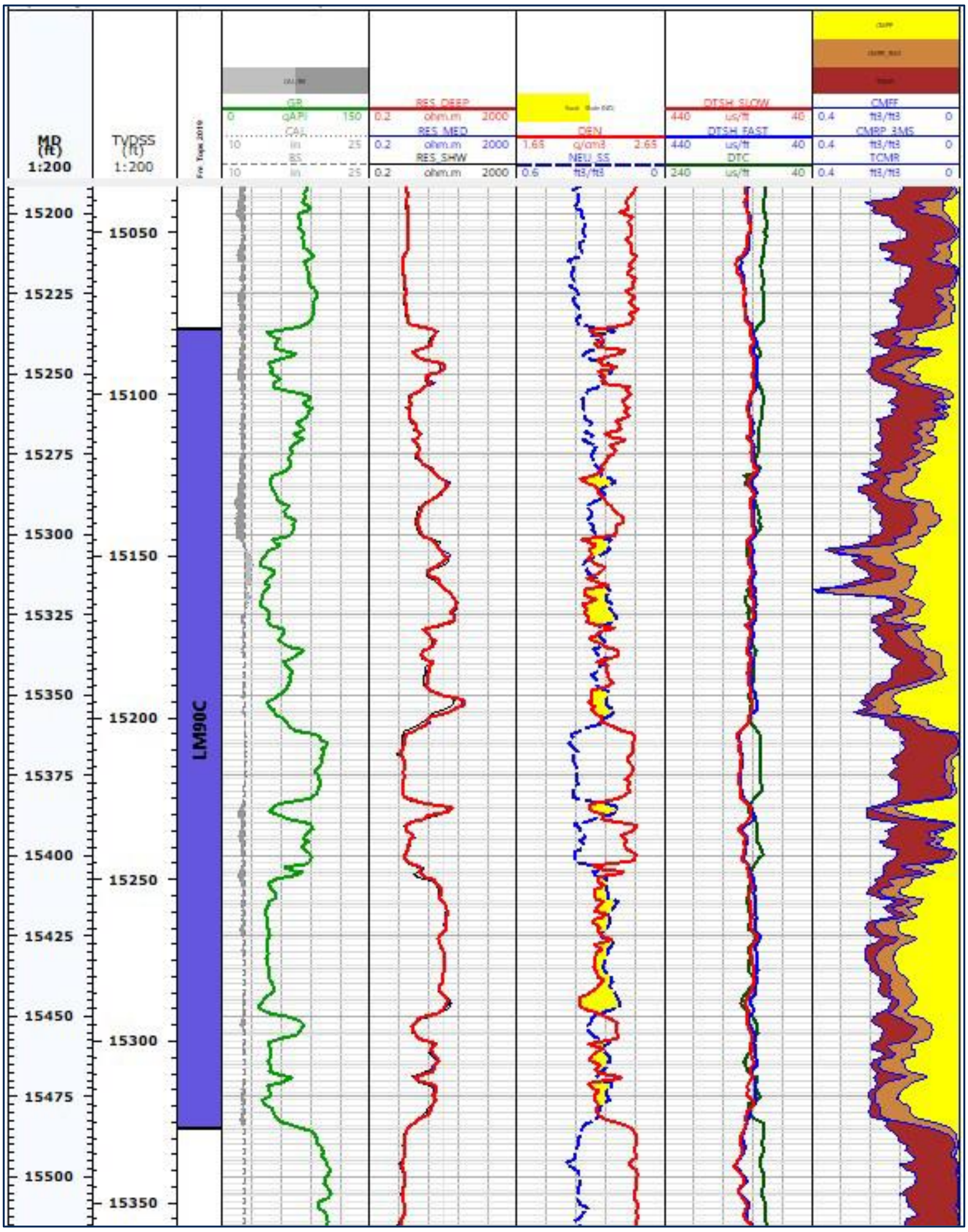
11.2.1 Field Description

Bongos was discovered in 2018 and contains thermogenic gas in a shallow PO2 and deeper LM90C reservoir. Exploration wells were drilled in 2019 in the Bele, Tuk, Hi-Hat and Boom prospects. Mixed thermogenic and biogenic gas was discovered in Bele and Tuk in the PO15 and PO2 reservoirs, and thermogenic gas was found in the PO2 reservoir in Hi-Hat and the LM97 reservoir in Boom. Two appraisal wells have been drilled in the Bongos field in 2021.

Seismic data were acquired in 2014. A complete suite of wireline logs and comprehensive set of side-wall core data, pressure and fluid samples were acquired in the exploration wells. Whole core data was collected in two side-tracks of the Bele-1 well. A type log for the Bongos LM90 sandstone reservoir is shown in (**Figure 11.14**).

Following reinterpretation of 2018 reprocessed seismic data and updated petrophysical models, static geomodels were built and used for dynamic simulation to assess resource for Bongos, Bele and Tuk. Three separate models were built (Bongos PO2, Bongos LM90C and Bele/Tuk PO15/PO2).

Figure 11.14: Composite Type Logs Bongos Field (Well Bongos 2)



Source: BHP Petroleum

The Bongos PO2 sands are interpreted to be stacked amalgamated sheet sands, likely deposited toward the margin of a channelised lobe sequence. The lower portion of the Bongos LM90C is interpreted to be stacked amalgamated sands, likely deposited toward the margin of a channelised lobe sequence. In the upper portion, the LM90C sands are interpreted to be stacked axial/off-axial channel fill sands capped by a series of levee deposits, and finally, by a mass transport complex (MTC).

The Bele and Tuk PO15 and PO2 sands are interpreted to be stacked amalgamated sheet sands, likely deposited toward the axial portion of a channelised lobe sequence. The Hi-Hat PO2.250 sand is interpreted to be an internal levee to the PO2.250/200 meandering channel. The lower and upper portions of the Boom LM97 sands are interpreted to be stacked amalgamated sands, likely deposited toward the axial portion of a channelised lobe sequence, that have been modified locally by an overlying MTC.

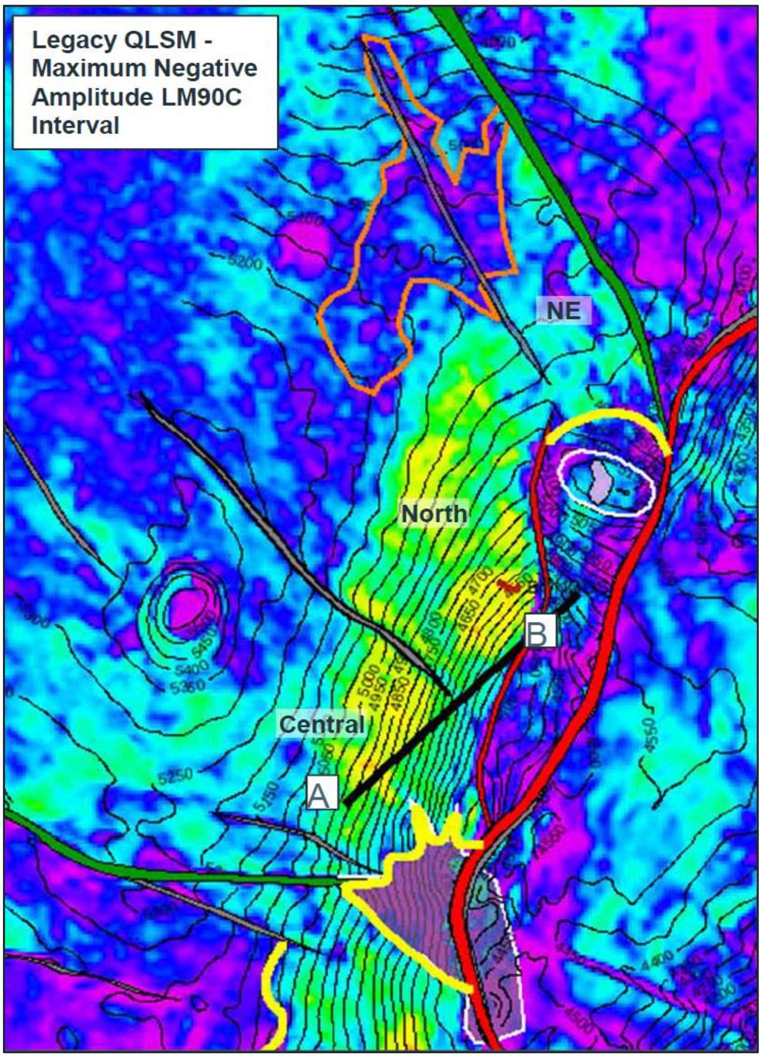
The data used for the integrated reservoir interpretation of the area entailed all available logs and the 3D seismic reprocessed 2018 full stack volume including six well penetrations, detailed well correlations, reservoir facies from log and core, and pressure information for both PO2 and LM90C reservoir sections. Seismic interpretation was used to determine the extent of hydrocarbon traps, faults and compartmentalization, gas water contacts (from combination of structural contour maps and evidence of seismic amplitude conformance), gross rock volume, geomorphology of the gross depositional environment and the approximate extent and thickness of the main reservoirs.

Average reservoir properties show high porosity of 25% or more, while permeability is variable between reservoirs and fields, with some reservoirs having low values (20 to 30 mD) while others have permeability measuring hundreds of milli-Darcies. Net reservoir varies between 30 m and 200 m.

Gas samples as well as water samples were collected during the exploration phase and PVT analysis indicates that the gas encountered in the reservoirs is dry with high methane content ranging from 96% to 99% for the shallowest reservoir (Bele PO15 at 3,350 mss) and no H_2S. The Bongos LM90C has a low condensate yield (CGR of 2 Bbl/MMscf). The reservoir pressure ranges from 5,600 psia to 10,000 psia and reservoir temperature from 137°F to 167°F.

MDT pressures from the Bongos and Boom Fields indicate pressure equilibrium at initial conditions in all wells that intersected the LM90C interval. No GWC has been encountered in the wells (GDT is 4,672 mss). The seismic derived GWC from DHI analysis (**Figure 11.15**) is 5,160 mss, which corresponds closely to a pressure derived FWL assuming gas pressure in Bongos LM90C and pressures taken in the water bearing LM90C in Boom field (FWL of 5,190 mss). This equates to a gas column of ~610 m. Appraisal well Bongos-3 encountered hydrocarbons approximately 30 m shallower than expected from seismic data and found slightly better reservoir properties. In the Bongos Field, analysis of dip closure, major faults (thrust faults, normal faults) and erosional truncation suggests that three areas of the LM90C reservoir can be distinguished (South, Central, North, and North-East) (**Figure 11.15**). However, juxtaposition of formations across faults according to interpretation of fault throw suggest that these three areas can potentially be combined into a single North Segment, considered discovered by the Bongos-2 well. Bongos-4 was drilled in the South segment and encountered hydrocarbons approximately 30 m shallower than expected from seismic data. The seismic amplitude was confirmed by the well although the extent of the anomaly to the south of the well is smaller than the mapped closure.

Figure 11.15: Bongos LM90C Regions

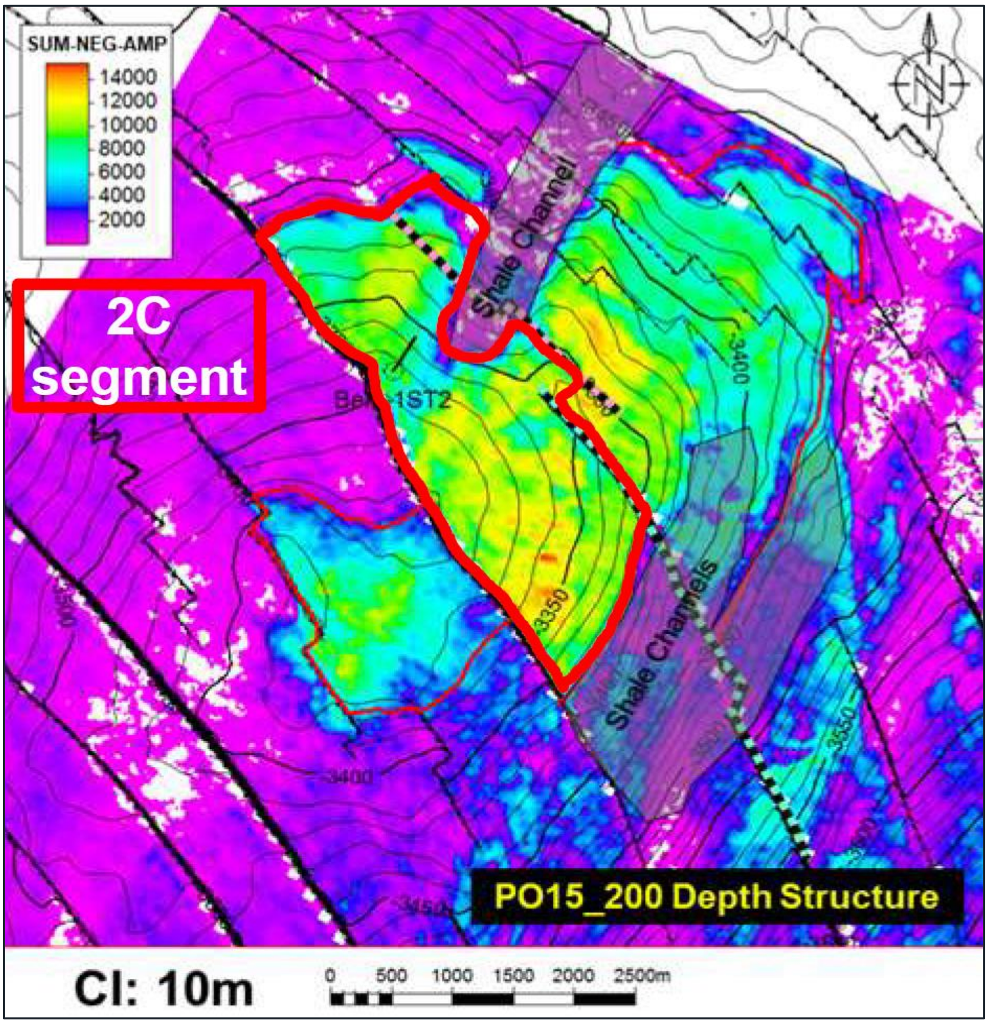


Source: BHP Petroleum

The 200 and 300/400 zones in the PO2 sand of the Bongos field are not in pressure equilibrium and no GWC has been encountered (GDTs are 3,795 mss and 3,909 mss respectively). The seismic derived GWCs are 3,974 mss and 4,000 mss respectively resulting in gas columns of ~213 m and 120 m. The extent of the interpreted 200 and 300 zone accumulations are bounded by dip closure, stratigraphic truncation, and the major thrust fault. The 200 zone is divided into two segments based on seismic. Based on the seismic derived GWCs, it can be concluded that the aquifers from LM90C and PO2 are not connected (2,500 psi pressure offset) in the Bongos Field.

In the Bele Field, the three gas bearing zones in the PO15 sand are in pressure equilibrium at initial conditions. The main compartment penetrated by well Bele-1 is bounded by faults, a shale channel and the GWC evidenced by seismic conformance (**Figure 11.16**). A GWC has been encountered in Bele-1 well in the PO2 sand, zone 300 at 3,776 mss and corresponds well with the MDT derived FWL. The 100, 200 and 300 zones in the PO2 sand are in pressure equilibrium but the water bearing zone 400 is not in pressure equilibrium and MDT pressures show a 25 psi offset. The main compartment is bounded by sealing faults and the GWC.

Figure 11.16: Bele PO15 Discovered Polygons

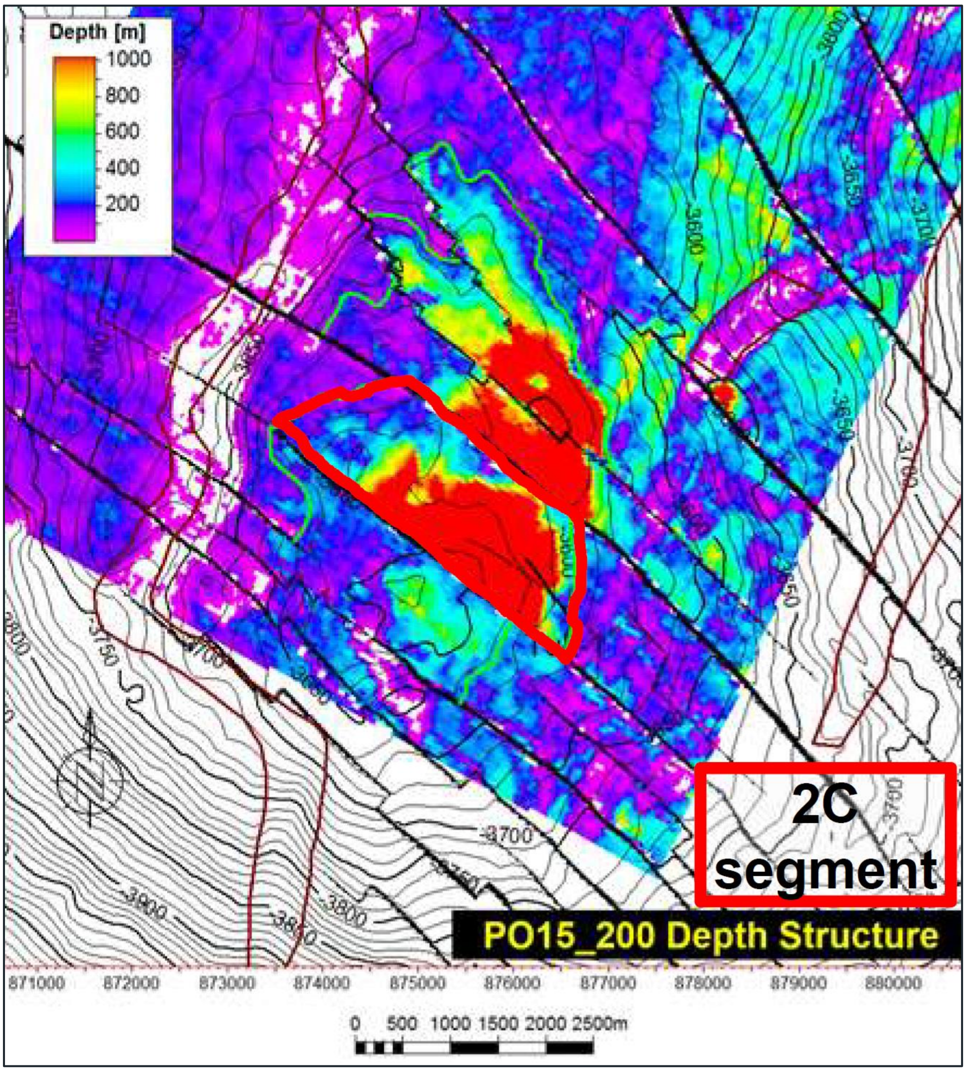


Source: BHP Petroleum

In the Tuk Field a GWC has been encountered in the PO15 sand zone 200 at 3,600 mss and this corresponds well with the MDT derived FWL. MDT pressures in the 300 zone indicate a slight offset of 3 psi from the 200 zone and it is likely, but not certain, that they are in pressure equilibrium. Based on DHI analysis, two compartments are distinguished, bounded by the GWC and faults. Only the southern block has been penetrated by a well (discovered), whereas the northern block is prospective (**Figure 11.17**).

The PO2.200 and PO2.300 are both gas bearing sands. Thin laminated sands were found in the upper section of the 200 zone. The PO2.400 is interpreted as a gas bearing shaly sand with a GWC at 4,238 mss. MDT pressures indicate that zone 200 and 300 are in pressure equilibrium, whereas zone 400 shows a 40 psi offset when a seismic derived GWC is assumed for the 200/300 zone. The southern and northern area are separated by a sealing fault (**Figure 11.17**). The southern segment is interpreted to have a shared GWC across faults based on DHI analysis.

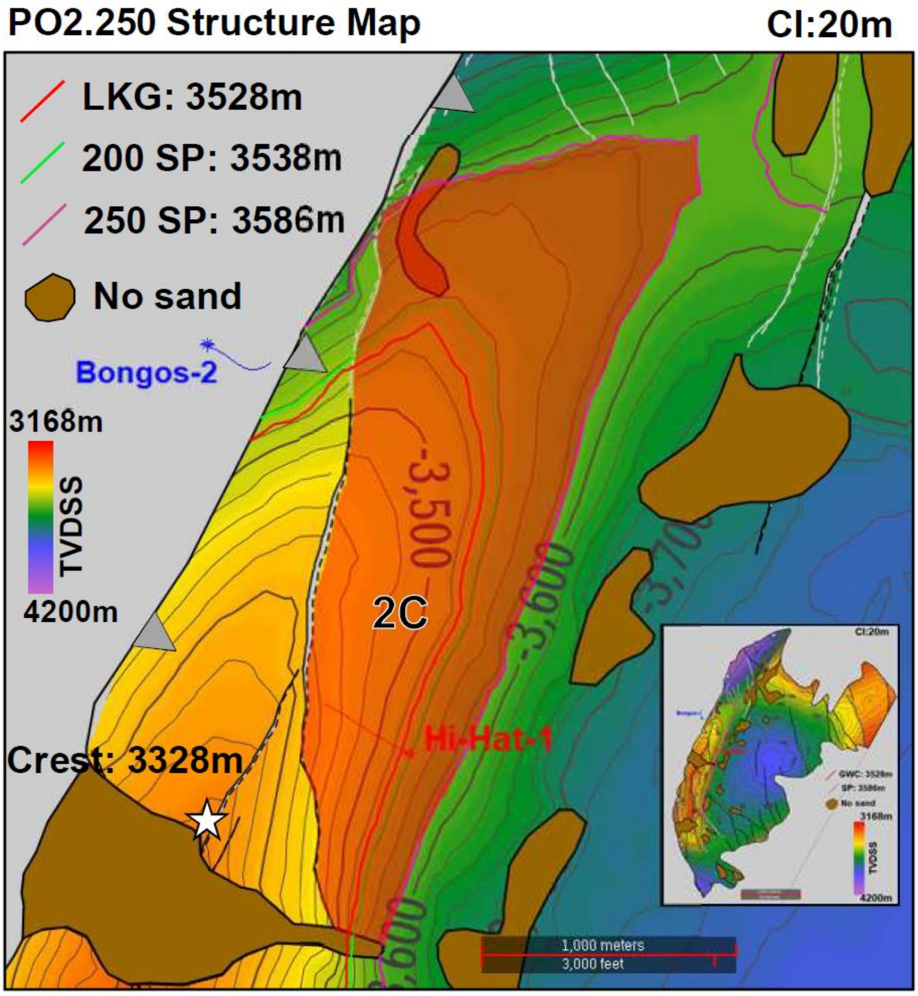
Figure 11.17: Tuk PO15 Discovered Polygons



Source: BHP Petroleum

The Hi-Hat structure is a stratigraphic trap created by overlying younger channels, limited to the west by the major thrust fault separating Bongos from Hi-Hat (**Figure 11.18**), and with a downdip limit defined as the structural spill point of the PO2.250 sand. Gas was found to the base of the PO2.250 sand and PO2.300 was fully water bearing. A FWL of 3,528 mss is inferred from MDT pressures, which is the same depth as the base of the PO2.250 sand. However, the GWC in the PO2.250 sand is interpreted to be controlled by the present-day structural spill point of the northern Hi-Hat PO2.250 segment (3,586 mss).

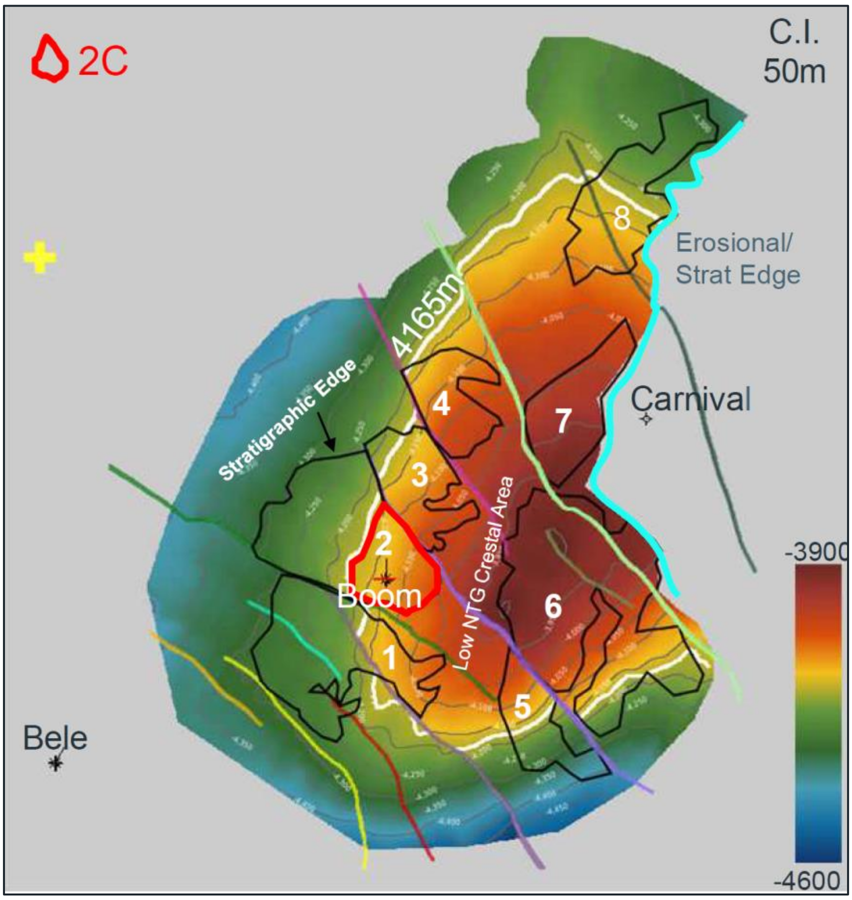
Figure 11.18: Hi-Hat PO2.250 Structure



Source: BHP Petroleum

A GWC was encountered in Boom-1 well close to the base of the LM97 lower sand at 4,165 mss. MDT pressure indicate that the upper and lower sand lobes are in pressure equilibrium. One valid pressure was taken in the water at the base of LM97 lower sand, supporting the observed GWC. Seismic interpretation shows that the Boom structure is compartmentalised, bounded by faults, the GWC, a stratigraphic edge, a low NTG crestal area due to stratigraphic pinch-out, and an erosional/stratigraphic edge in the NE (LM97 not present in Carnival well). E-W connectivity is unlikely (**Figure 11.19**).

Figure 11.19: Boom LM97 Structure



Source: BHP Petroleum

GIIP has been estimated using static models (Bongos, Bele and Tuk) or probabilistic (GeoX software) models (Boom and Hi-Hat) built from the comprehensive seismic and drilling derived dataset acquired to date. Best estimates of GIIP have been made for the compartments and reservoirs that have been intersected by exploration/appraisal wells and are therefore considered discovered.

11.2.2 Field Development Plan

A semi-submersible FPU centrally located between the Bele, Bongos and Tuk Fields, with a production capacity of 800 MMscfd gas, 4 Mbwpd of produced water and arrival pressure of 600 psi is one of the development concepts under consideration and has been used to estimate recoverable volumes. Wells will be produced via a daisy chain to the FPU. Gas export options including a pipeline to shore and selling to the Trinidad and Tobago domestic market and to LNG export are being considered.

The FPU development concept assumes 16 wells in the Bongos LM90C, Bele and Tuk reservoirs with single zone completions. Ten of these development wells are in penetrated and discovered fault blocks (Contingent Resources Unclarified) and six wells in adjacent un-penetrated blocks (Prospective Resources). Currently, the discovered Bongos PO2, Boom and Hi-Hat reservoirs are excluded from the FPU development concept. BHP Petroleum is currently anticipating a possible start-up date for Calypso area development in the late 2020s.

11.2.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

Overall CAPEX is subdivided into each of the main development items comprising wells, facilities and pipelines. Each of these CAPEX elements has been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments. CAPEX is shown in **Table 11.7**.

Table 11.7: Calypso Gross CAPEX Estimates

CAPEX	US$ (MM)
Appraisal Wells	145
Development Wells	1,527
Facilities	2,461
Pipelines	548
Total	**4,681**

The overall annual OPEX estimate for the development has been reviewed by GaffneyCline, taking into consideration the planned development. The OPEX profiles have been adjusted in the Contingent case to account for changes in the expected variable OPEX components of the overall OPEX resulting from differences between the BHP Petroleum production profiles compared with the GaffneyCline profiles.

11.2.4 Resources Estimates

Recoverable volumes for discovered and prospective reservoirs selected for development in Bongos, Bele and Tuk (**Table 11.8**) were estimated based on dynamic simulation models. For Hi-Hat and Boom, which are not currently included in the FPU concept, recovery factors were derived using type curves from Bele and Bongos, adjusted for permeability and pressure differences.

Estimated recovery factors ranging from 44% to 71% are comparable to those of fields with analogous reservoir connectivity and moderate aquifer support. The recovery factor in Bele PO15 (44%) is lower than the other fields because only one well is assumed for a connected GIIP of 437 Bscf. The ultimate recovery per well is in the range 100 to 600 Bscf, except for the development well in Hi-Hat (18 Bscf).

The following Resources are attributed:

- Gas Contingent Resources are attributed to the discovered reservoirs that are included in the development and will be penetrated by at least one development well. Gross 2C Contingent Resources: 3,692 Bscf of gas (Development Unclarified).
- Gas Contingent Resources are attributed to the discovered reservoirs that are not currently included in the development. Gross 2C Contingent Resources: 418 Bscf of gas (Development Not Viable).
- Gas Prospective Resources are attributed to low-risk prospects that are provisionally included in the development concept. Gross 2U Prospective Resources: 1,024 Bscf of gas.

Besides the "high graded" Prospective Resources that are included in the provisional development plan, numerous other prospective targets have been identified in the area which offer upside potential.

Following the drilling of the two appraisal wells in 2021 volumes in the Bongos South block are now considered discovered and preliminary results of the appraisal wells have been included in the estimation of their Contingent Resources.

Further technical evaluations and feasibility studies are planned to mature the Calypso development.

Table 11.8: GIIP and Recoverable Volumes for Calypso Reservoirs as of 31 December 2021

Field / Reservoir	Block	GIIP (Bscf)	No. of Development Wells (Base Case)	Gross Recoverable Gas (Bscf)	Classification
Bongos PO2	N	460	-	281	Contingent Not Viable
Bongos LM90C	C, N, NE	2,543	3	1,761	Contingent Unclarified
	S	966	1	601	Contingent Unclarified
Bele PO15	Main	437	1	193	Contingent Unclarified
	NE	455	1	194	Prospective
Bele PO2	Main	306	1	176	Contingent Unclarified
	NE	174	1	89	Prospective
	SW (D)	366	1	315	Prospective
	SW (F)	213	1	148	Prospective
Tuk PO15	S	124	1	86	Contingent Unclarified
Tuk PO2	S	1,228	3	875	Contingent Unclarified
	N	471	2	278	Prospective
Hi-Hat PO2		29	-	18	Contingent Not Viable
Boom LM97	2	188	-	119	Contingent Not Viable
Base Case Total (Contingent)			**10**	**3,692**	**Contingent Unclarified**
Base Case Total (Prospective)			**6**	**1,024**	**Prospective**
Other Contingent Total			**-**	**418**	**Contingent Not Viable**

11.2.5 GaffneyCline's Production and Cost Valuation Profiles-Calypso

GaffneyCline's valuation scenario production profile for BHP Petroleum's Trinidad and Tobago Calypso asset is given in **Figure 11.20** with the associated real term cost profiles provided in **Figure 11.21**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the recoverable volumes of the defined development project documented in the previous sections**.** The base case FPU development profile assumes 16 wells in the Bongos LM90C, Bele and Tuk reservoirs with single zone completions. Ten of these development wells are in penetrated and discovered fault blocks (Contingent Resources Unclarified) and six wells in adjacent un-penetrated blocks (Prospective Resources). Risk assessment for valuation is discussed in section 11.2.6. Technical and commercial contingencies are also discussed that impact the project Chance of Development.

Figure 11.20: BHP Petroleum Net Trinidad and Tobago Calypso Asset Production Profile

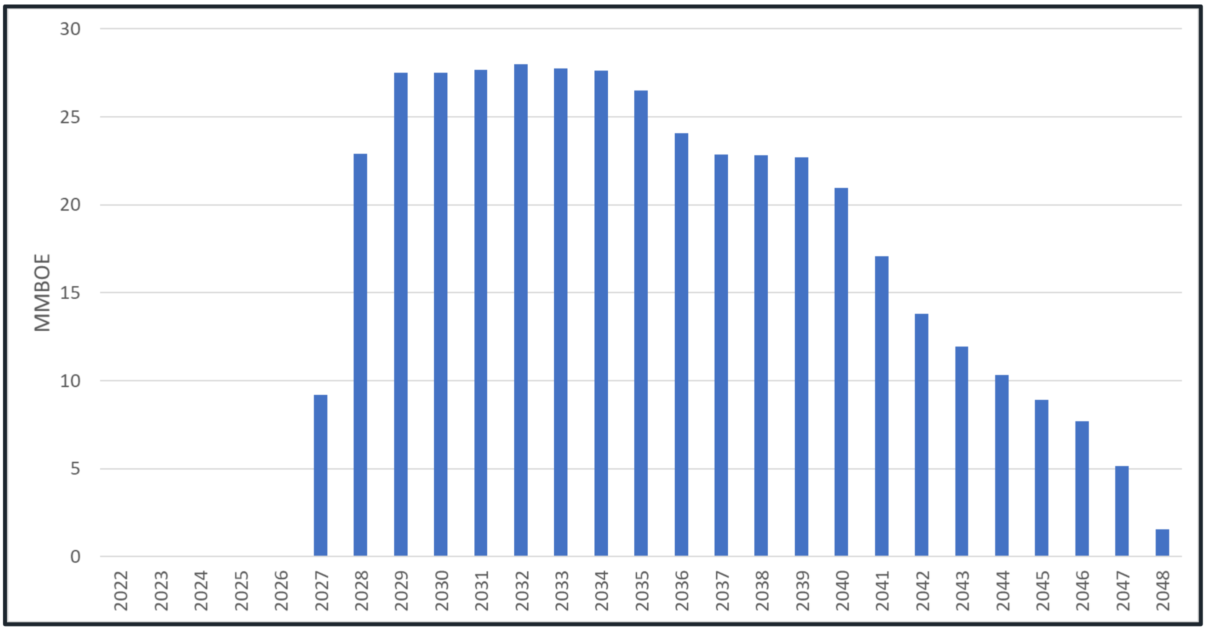
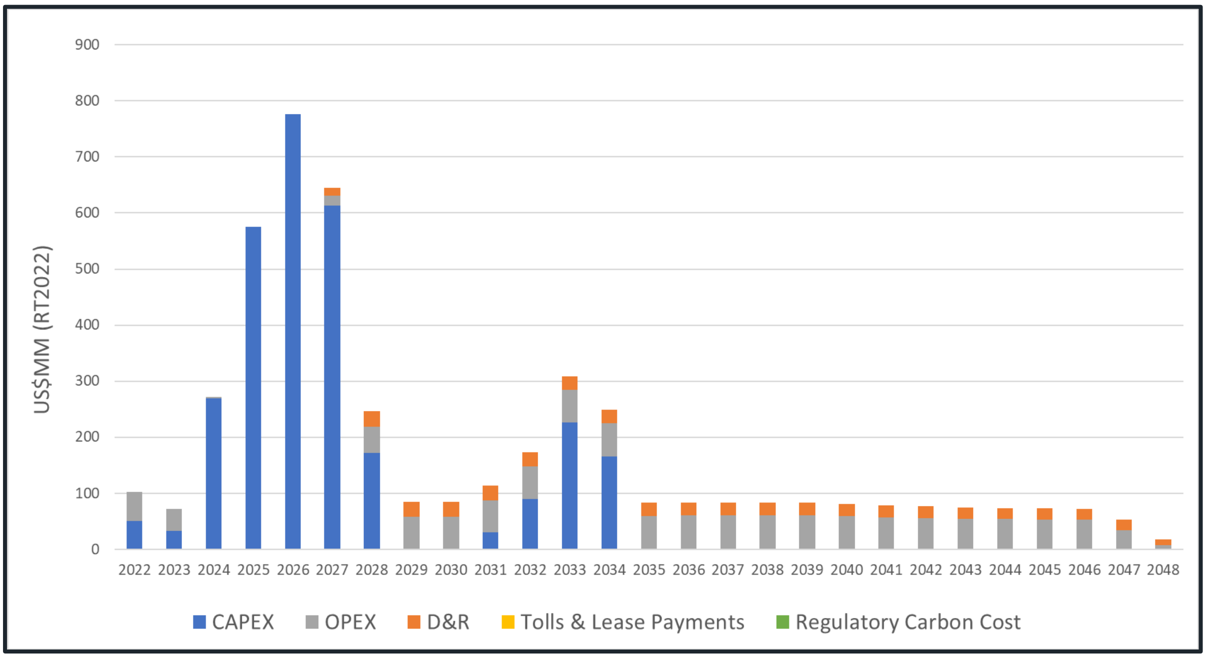


Figure 11.21: BHP Petroleum Net Trinidad and Tobago Calypso asset Cost Profile



11.2.6 Calypso Asset Chance of Development

The classification status of the Calypso Project is Contingent Resources - Development Unclarified.

The base case development of Bongos LM90C, Bele and Tuk fields has passed Gate 0 in BHP Petroleum's Stage Gate Process (project has been initiated and moved into Assessment Phase / Feasibility Phase). The project is actively being worked and two appraisal wells were drilled in 2021 into the Bongos field with positive results (the GWC in the main block was confirmed and gas was discovered in the southern block). Sufficient gas has been discovered in the area to enable a stand-alone hub development. No further exploration/appraisal wells are planned/envisaged by BHP Petroleum.

The base case development includes risked development wells into adjacent (prospective) faults blocks, which have a high chance of being gas bearing (>85%) based on seismic evidence. The base case for only the discovered volumes in Bongos LM90C, Bele and Tuk fields is marginal (10 wells, 3.7 Tscf gross recoverable gas, NPV~0). The base case development including six additional (risked) development wells adds 0.9 Tscf recovery and yields a positive NPV. There is more upside by including Bongos PO2, Boom and Hi-Hat fields in the development, which would add 1.1 Tcsf risked recovery for the additional seven wells (Full Development Case).

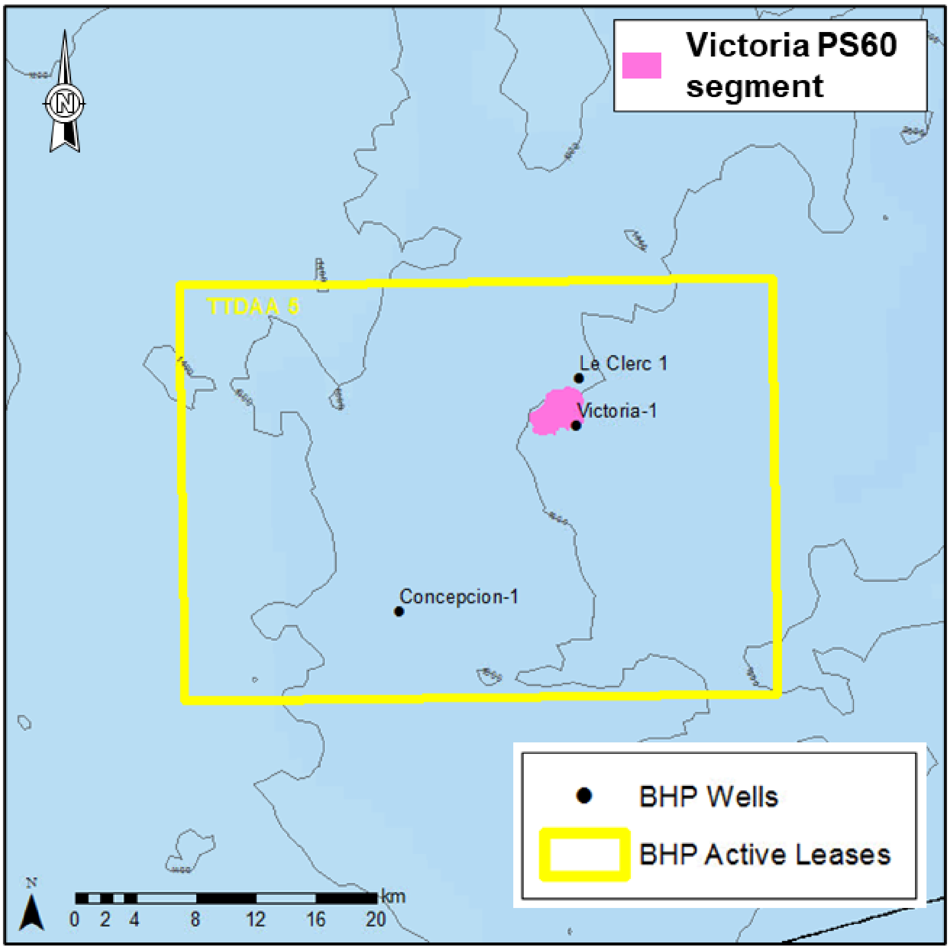
The gas is 97-99% methane with low CO_2 content (<0.15%) and no H_2S.

Based on above considerations Gaffney Cline recommends a 70% chance on development for Calypso for KPMG's valuation analysis.

11.3 Deep Water South – Magellan Development

The Deep-Water South area, also called Magellan, covers Block TTDAA 5. BHP Petroleum signed a PSC in 2013 for exploration in TTDAA5, approximately 200 km east of the island of Trinidad with water depth of 1,800 m (**Figure 11.22**). BHP Petroleum is operator and has a 65% working interest with Shell as partner (BG farmed-in in 2014 and BG was later acquired by Shell). BHP Petroleum made two discoveries with exploration wells Victoria-1 and LeClerc-1, whereas the Concepcion-1 exploration well was unsuccessful.

Figure 11.22: Location Map of the Victoria and LeClerc Discoveries, TTDAA Block 5



Source: BHP Petroleum

11.3.1 Field Description

LeClerc was discovered in 2016 and encountered dry biogenic gas in the Pliocene PO20 and PO2 reservoirs. In 2018 an exploration well was drilled in Victoria Prospect and encountered dry biogenic gas in the Pleistocene PS60 reservoir and found low residual gas saturations in the deeper PS54 and PO94 sands. The Pliocene is characterised mostly by deep water turbidites and basin floor fan systems, while the Pleistocene comprises leveed-channel and channelised lobe complexes.

A complete suite of wireline logs, MDT pressure data and fluid samples were acquired in the exploration wells. Side-wall core data were acquired in LeClerc-1 and whole core data was collected in Victoria-1. BHP Petroleum acquired a proprietary narrow-azimuth 3D seismic survey over the Trinidad and Tobago TTDAA-5 and TTDAA-6 licenses area in 2014 and a Pre-Stack Depth Migration (PSDM) was completed in 2015. Subsequent reprocessing of the data in 2017 provided an improved velocity model and imaging. Coloured-inversion (CI) and fluid volumes were produced from the 2017 PSDM to aid in structural interpretation and predict the presence of hydrocarbons.

Interpretation from seismic data as well as the GWC penetrated in the Victoria-1 well form the basis of the segment definition and GIIP estimates (2017 reprocessed data was not used for resource estimates). Top and base horizons for the reservoirs were mapped on the reflectivity and CI volumes and were used to define the segment definition of the reservoirs. Amplitude extractions performed on the CI and fluid volumes were used to determine the sand extents and the GWC's for each reservoir.

Type logs for the PS60 reservoir (**Figure 11.23**), PO20 and PO2 (**Figure 11.24**) show the sands to be blocky and good quality. Average reservoir properties are good, with porosities of 20 to 30% or more, and permeability up to several hundred milli-Darcies.

The Victoria PS60 reservoir is at a depth of ~2,500 mss, with pressure of ~3,790 psi and temperature of ~73 degF. The LeClerc PO20 and PO2 reservoirs are deeper, at ~4,020 mss and ~4,640 mss respectively, with pressures of ~7,410 and 7,980 psi and temperatures of ~149 and ~173 degF.

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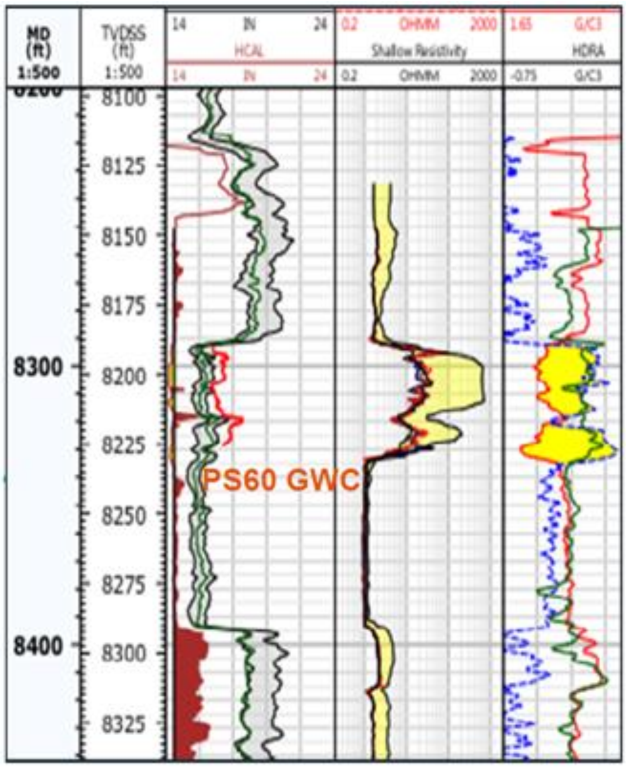
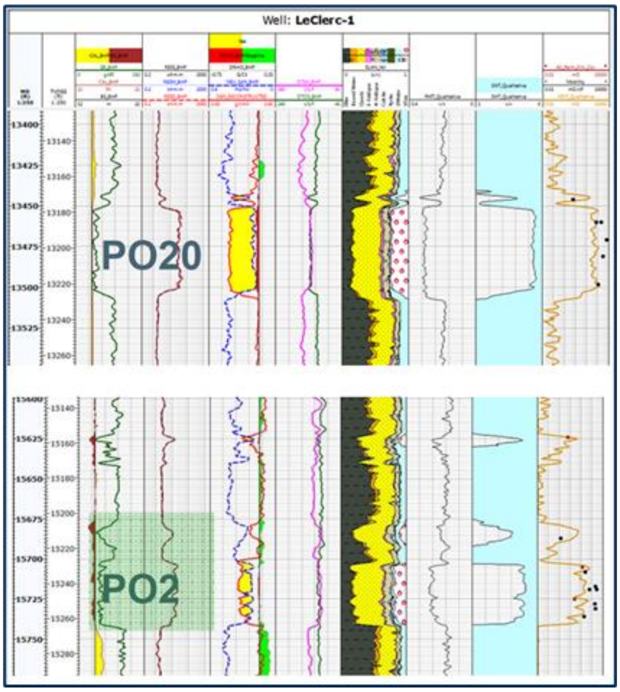
Figure 11.23: Composite Type Log Victoria PS60



Source: BHP Petroleum

Figure 11.24: Composite Type Log of LeClerc PO20 and PO2 Reservoirs

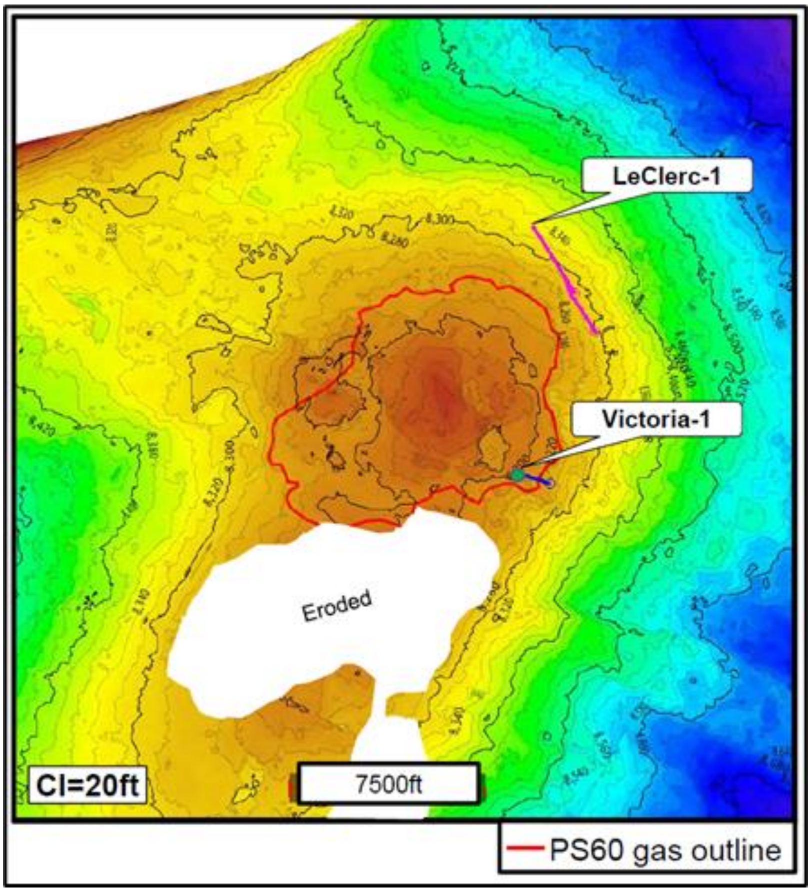


Source: BHP Petroleum

Multiple gas samples (both wells) and water samples (Victoria-1) were collected, and PVT analysis indicates that the gas encountered in the reservoirs is dry with high methane content of 99% and no H_2S. Water salinity in Victoria PS60 is 34,000 ppm.

The Victoria-1 well penetrated the gas water contact in the PS60 at a depth 2,508 mss, a depth supported by the interpretation of MDT pressures. The gross rock volume is defined by the structural closure of the gas water contact and top surface of the PS60 as defined by the seismic interpretation (**Figure 11.25**). The contact conforms to structure except for the southeast quadrant which is interpreted to be eroded and the northwest quadrant which is interpreted to be a stratigraphic edge.

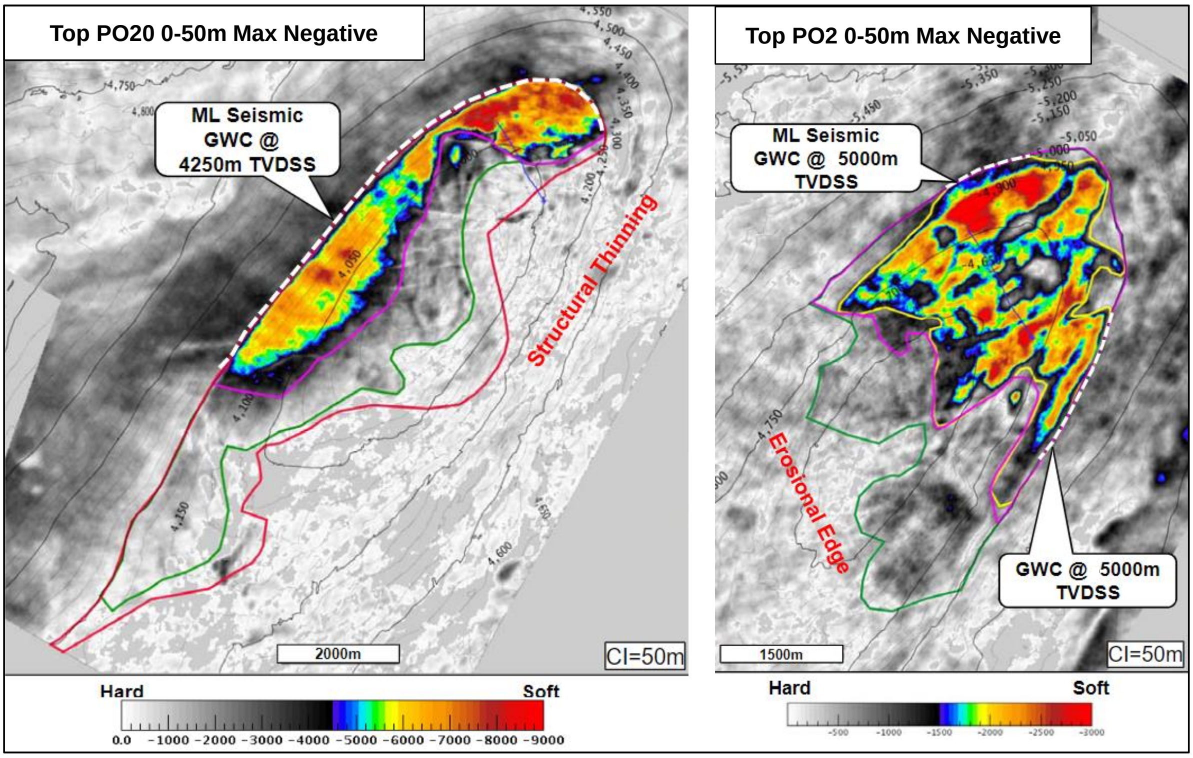
Figure 11.25: Victoria Top Structure and Seismic Amplitude Map PS60



Source: BHP Petroleum

In the LeClerc Field the PO20 and PO2 sands were found fully gas bearing and no GWC has been encountered. However, the structure is well imaged and both reservoirs have distinct, depth conforming seismic amplitude shutoffs (**Figure 11.26**), which give an indication of the GWC.

Figure 11.26: LeClerc PO20 and PO2 Seismic Amplitude Map



Source: BHP Petroleum

11.3.2 Conceptual Field Development Plan

Current development concepts under consideration involve subsea wells at LeClerc and Victoria tied back to a semi-submersible host in deep water with export line to shore or tied back to a host platform or directly to shore (~250 km). Currently, discovered volumes are below the threshold for economic development and are sub-classified as Development Not Viable.

11.3.3 Resources Estimates

Based on the seismic interpretations of the basin, it is likely that the aquifers are active and large. Recovery factors have been estimated using analytical methods on the assumption that the drive mechanism would be a combination of aquifer influx and pressure depletion. This approach takes account of reservoir swept by water encroachment, the trapped residual gas saturation and pressure behind the flood front, abandonment pressure in depleted un-swept gas zones and reservoir connectivity. Recovery factor ranges from 48% to 59% (**Table 11.9**) are reasonable and comparable to the lower end of the range for analogue fields with moderate to strong aquifer support. LeClerc PO2 sand is expected to have a lower connectivity than LeClerc PO20 and Victoria PS60. The Victoria recovery factor is lower than LeClerc PO20 as the PS60 reservoir is much shallower with lower reservoir pressure. Further, a tie-back development will have higher abandonment pressures than deep water development with a stand-alone host.

Total gross gas 2C Contingent Resources (Development Not Viable) of 482 Bscf have been attributed to the discoveries.

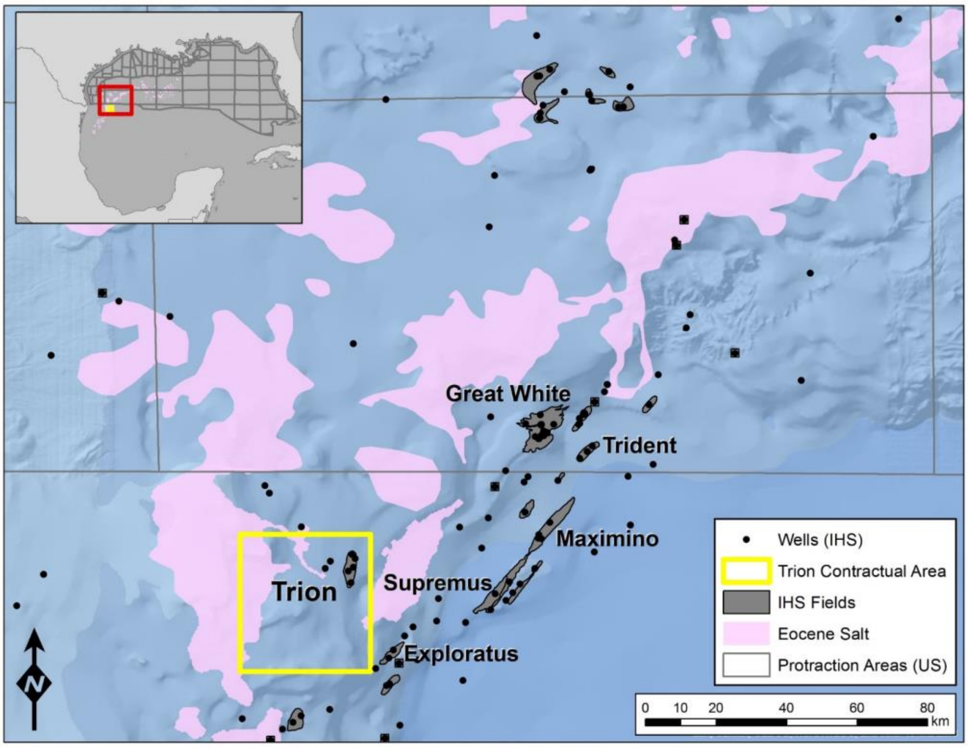
Table 11.9: Estimated GIIP and Gross 2C Contingent Resources for LeClerc and Victoria as of 31 December 2021

Field / Reservoir	GIIP (Bscf)	Recovery Factor	2C Gas Contingent Resources (Bscf)
LeClerc PO20	391	59%	231
LeClerc PO2	194	48%	94
Victoria PS60	313	50%	157
Magellan Total	**898**		**482**

12 BHP Petroleum Mexico

BHP Petroleum holds a 60% participating interest in the Trion Contractual Area (AE-0092 and AE-0093) located in the deep-water Gulf of Mexico offshore Mexico and is also the operator. PEMEX Exploration & Production Mexico holds the remaining 40% interest (**Figure 12.1**). The initial lease terms run to March 2052 with potential for lease extensions pending government approval.

Figure 12.1: Location Map of Trion Field



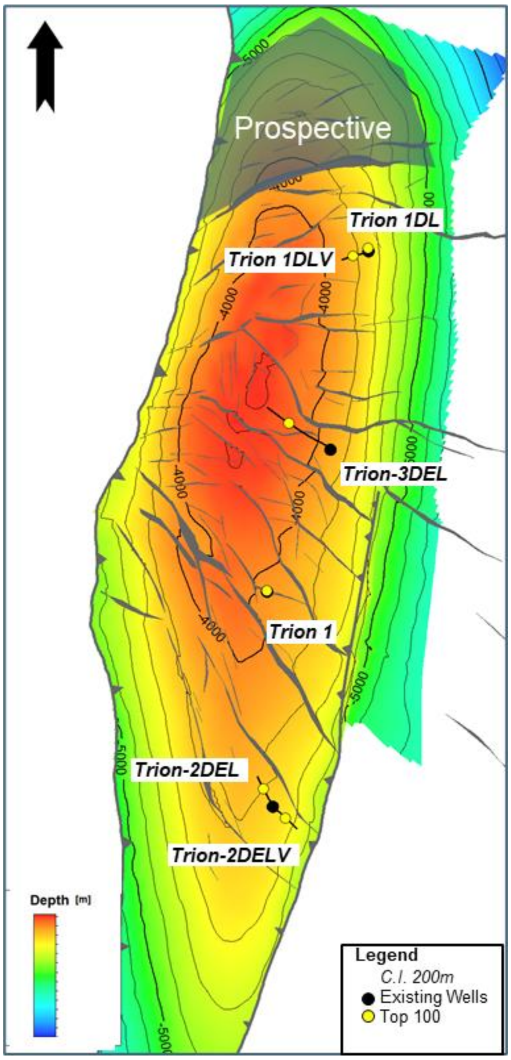
Source: BHP Petroleum

12.1 Trion

12.1.1 Field Background

Trion was discovered by Pemex in 2012 with the Trion -1 exploration well (**Figure 12.2**) in water depth of ~2,500 m. Pemex appraised the field with well Trion-1DL and side-track Trion-1DLV. BHP Petroleum appraised the field further with wells Trion-2DEL and side-track Trion-2DELV, and with Trion-3DEL. Two Eocene age reservoirs have been delineated; the overlying 100 Fan, which contains the bulk of the oil, and 350 Fan. The four wells provide good coverage of the field in a north to south direction, but are all located east of the central line, and provide little data on east-west variation in reservoir presence and quality, which is based on interpretation of the 3D seismic data. The majority of the estimated resources are on the east side of the field with limited development expected on the west side.

Figure 12.2: Depth Structure Map of Top 100 Fan



Source: BHP Petroleum

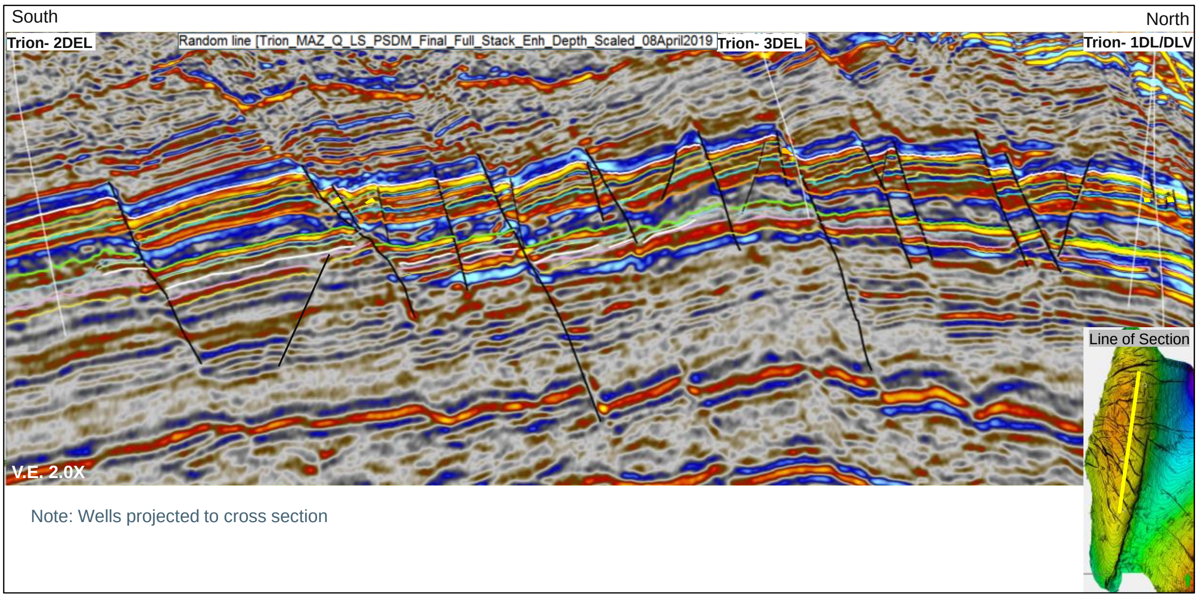
A comprehensive suite of wireline logs has been acquired in all wells. Whole cores were obtained in Trion-1, Trion-1DL and Trion-2DEL/V, and sidewall cores were recovered from Trion-1, Trion-2DEL/V and Trion-3DEL. A DST was carried out in Trion-1DLV, "mini-DSTs" using a dual packer configuration were carried out in Trion-1, and Interval Pressure Transient Testing (IPTT), using a Saturn tool (Saturn 3D Radial Probe) was carried out in Trion-2DEL/V and Trion-3DEL. A comprehensive set of fluid samples has been acquired.

Three dimensional seismic surveys were acquired in 2012 (wide azimuth) and in 2017 (wide and narrow azimuth). A multi-azimuth reprocessing project of these two datasets was undertaken in 2019. In 2020-2021 a 3D ocean bottom node (OBN) survey was acquired, which has greatly enhanced definition in the crest and west of the structure where seismic imaging had previously been poorer due to a shallow anomaly. BHP Petroleum is still in the process of interpreting the OBN dataset and it is likely that the information will lead to refinements of the development plan, although the focus of the development is on the eastern side of the structure where good seismic data existed prior to the OBN.

Seismic and well data have been used to map the Trion structure and seismic attributes have been used to condition the interpretation of the 100 Fan and 350 Fan reservoirs. Each survey has improved the knowledge and understanding of the reservoirs, allowing the distribution of lithology, porosity and fluids within the reservoir interval to be enhanced. The top and base of each of the reservoir units can be seismically mapped and these surfaces are key to the reservoir model.

The Trion discovery is a north-south oriented anticline bounded to the east and west by reverse faults and is mapped as dip closed to the north and south. The anticline formed due to compressional forces and the movement of nearby salt. The structure is internally faulted (**Figure 12.3**) and the dominant fault direction is NNW-SSE. Some faults are interpreted to compartmentalise both reservoirs, giving rise to multiple fluid contacts, while others might potentially create baffles to flow.

Figure 12.3: Seismic Section Showing Reservoir Architecture



Source: BHP Petroleum

BHP Petroleum has identified a prospect (Trion North Prospect) at the northern end of the Trion Field. This is, in essence, the northern “nose” of the anticline that contains the Trion discovery. It is considered a prospect as the fault that separates it from the field area is large and potentially offsets the 100 Fan and 350 Fan reservoir intervals. The seismic attributes seen in the field are also present in the Trion North Prospect; however, their development is less well defined and the conformance with structure poorer. BHP Petroleum interprets these differences being the effect of velocity issues in this part of the structure.

The 100 Fan is further subdivided into three sandstone units, the upper, middle and lower lobes, separated by shales. The 350 Fan does not have such clear subdivisions. At the crest of the structure, the depth of the 100 Fan is ~3,800 mss and that of the 350 Fan is approximately 3,950 mss.

The reservoirs are interpreted as deepwater sandstones deposited as lobe complexes with a SW–NE trend. Seismic data have been used to condition the distribution of facies and porosity in the static model. The sandstones are thick with average net thickness from well intersections of 77 m for the 100 Fan and 35 m for the 350 Fan. Average well porosities are also high at 29% and 25% for the 100 Fan and 350 Fan respectively and permeabilities are moderate, at 162 and 42 mD (**Table 12.1**).

Table 12.1: Trion Petrophysical Property Averages from Wells

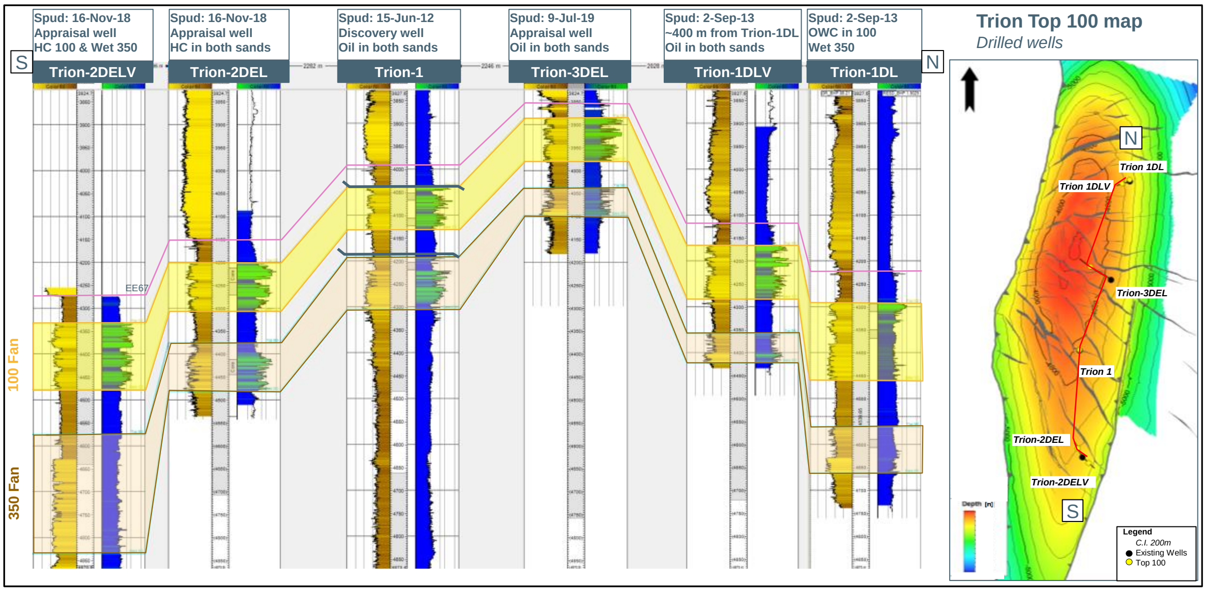
Property	100 Fan	350 Fan
Gross thickness (m)	116	92
Net thickness (m)	77	35
NTG ratio	66%	36%
Porosity	29%	25%
Water saturation	42%	39%
Permeability (md)	162	42

The reservoir structure has considerable relief with an oil column of more than 700 m in the 100 Fan (**Figure 12.4**). Reservoir pressure ranges from 6,400 to 7,100 psia in the 100 Fan and from 6,600 to 7,300 in the 350 Fan. Reservoir temperature varies in depth from 130 to 175 degF. High structural relief favours recovery by waterflooding and gas injection, the recovery mechanisms of choice.

During the DST of Trion-1DLV, a 19 m interval out of a gross thickness of 86 m was perforated. The DST was carried out under sub-optimal conditions with large string size causing unstable flow, high skin (10) caused by completion method and intermittent weather disruptions. Nonetheless, interpretation of the available data showed no barrier within the 365 m radius of investigation and permeability of approximately 74 mD.

Formation pressures measured in several wells have shown the likelihood of compartmentalisation of the reservoirs. The overall interpretation, which BHP Petroleum has used in its reference case model and is reasonable, is that barriers are present in the 350 Fan between Trion-2DEL/V and Trion-1 and between Trion-1DLV and Trion-3DEL, and that similar barriers might be present in the 100 Fan. It is also possible that there are more compartments in the field, and BHP Petroleum has taken this into consideration for well planning.

Figure 12.4: Cross Section Across Trion Structure



Source: BHP Petroleum

Within the 100 Fan, all wells had ODTs, except Trion-1DL, which intersected an OWC at 4,335 mss, supported by pressure data and petrophysical interpretation. Within the 350 Fan, Trion-1DL and Trion-2DELV intersected water bearing formation and all other wells had ODTs, except Trion-1DLV, which might have intersected an OWC at its base, at 4,487 mss, a depth that is supported by extrapolation of pressure gradients. Extrapolation of pressure gradients in Trion-2DEL/V implies an OWC at 4,578 mss.

BHP Petroleum has relied on seismic evidence for identifying fluid contacts, supported by petrophysics and interpretation of pressure gradients. The field has been divided into seven regions with different fluid contacts based largely on seismic attribute evidence. In the 100 Fan, the OWC is interpreted to vary between 4,368 and 4,510 mss and in the 350 Fan, between 4,450 and 4,578 mss.

No free gas has yet been intersected, but oil properties suggest the likely presence of a gas cap in the 350 Fan, with a GOC interpreted at 3,962 mss in the Trion-1DL/V area and 4,017 mss elsewhere. Oil samples from the 100 Fan suggest that the saturation pressure of the oil in this reservoir is less than the pressure projected at the crest of the structure and hence that the presence of a gas cap is unlikely.

The 100 Fan and 350 Fan have significantly different fluid properties and oil samples also show vertical and horizontal variation in composition within the reservoirs. In the 100 Fan the API density decreases with increasing depth from 26 to 17 °API while in the 350 Fan the API density decreases from 34 to 22 °API. Within the 350 Fan, oil properties in the Trion-1 DL/V area differ from those elsewhere, with the oil being apparently higher API and lower viscosity, although the fluid samples from this region were contaminated and less reliable (**Table 12.2**).

Table 12.2: Trion Oil Properties

Depth Location	100 Fan			350 Fan			350 Fan at Trion-1DL/V		
	GOR (scf/stb)	Bo (rb/stb)	Visc. (cP)	GOR (scf/stb)	Bo (rb/stb)	Visc. (cP)	GOR (scf/stb)	Bo (rb/stb)	Visc. (cP)
At GOC	1,300	1.54	0.7	1,550	1.65	0.4	1,900	1.82	0.2
At OWC	350	1.14	7.0	500	1.21	4.4	1,000	1.44	0.7
Average	770	1.31	2.3	1,040	1.43	1.2	1,480	1.64	0.4

12.1.2 Field Development Plan and Production Profiles

The depletion plan for Trion is an edge waterflood with crestal gas injection focused on the eastern flank of the elongated structure where the oil is interpreted to be concentrated in good quality reservoir. The high relief of the structure offers benefits for sweep efficiency from displacing fluids due to gravity effects. The field is compartmentalised although the extent of the compartmentalisation is not yet fully understood. Many semi-parallel faults are clearly interpreted on seismic data extending from the crest of the structure towards the OWC. The fault pattern divides the elongated field into reasonably well-defined segments on the eastern flank. BHP Petroleum's approach is therefore to position a water injector and producer pair of wells in each compartment, as far as possible. This means each potential compartment is developed semi-independently and this approach goes some way to mitigate the potentially adverse effects of compartmentalisation.

The field will be developed with subsea wells tied back to a floating production unit (FPU). Stabilised crude will be sent to a floating storage and offloading facility (FSO) for export via tanker. Artificial lift will be with riser-based gas lift. The facility capacities are shown in **Table 12.3**.

Table 12.3: Trion Facilities Specifications

Item	Description/Capacity
Nameplate oil capacity (Mbopd)	100
Dry oil uplift	20%
Produced gas handling capacity (MMscfd)	145
Gas injection capacity (MMscfd)	133
Produced water handling (Mbwpd)	60 expandable to 90
Water injection capacity (Mbwpd)	140
Production uptime	92%
Water injection uptime	80%
Gas injection uptime	97%
Facility design life	30 years

The field will be developed in three phases with a total of fourteen production wells, ten water injection wells and three crestal gas injection wells. The production and water injection wells planned for each phase are shown in **Table 12.4** and the proposed well locations are shown in **Figure 12.5**. Note that two of these wells (producer "A" and water injector "Z") are located in the northern extremity of the field, in a compartment which is interpreted to be separated from the main field by a fault with significant throw and is therefore considered prospective (i.e. undiscovered). Oil potentially recoverable from this compartment are not reported as Contingent Resources.

All the wells will be completed in the 100 Fan and a subset (11 of 14 producers, seven of ten water injectors and all three gas injectors) will have dual completions in both the 100 Fan and 350 Fan. The producers and gas injectors will be fitted with downhole flow control (DHFC) devises that will allow selective shutting-off of individual reservoirs. The water injection wells will not be fitted with DHFC devices.

On 19 December 2021 BHP announced that it had filed with the National Hydrocarbons Commission (CNH) a Declaration of Commerciality (DoC) in respect of the Trion discovery area. The DoC confirms that BHP and PEMEX consider the Trion discovery area to be commercial subject to and in accordance with the terms of the License. On 5 August 2021, the BHP Board approved US$258 million in capital expenditure to move the Trion project into the Front End Engineering Design (FEED) phase.

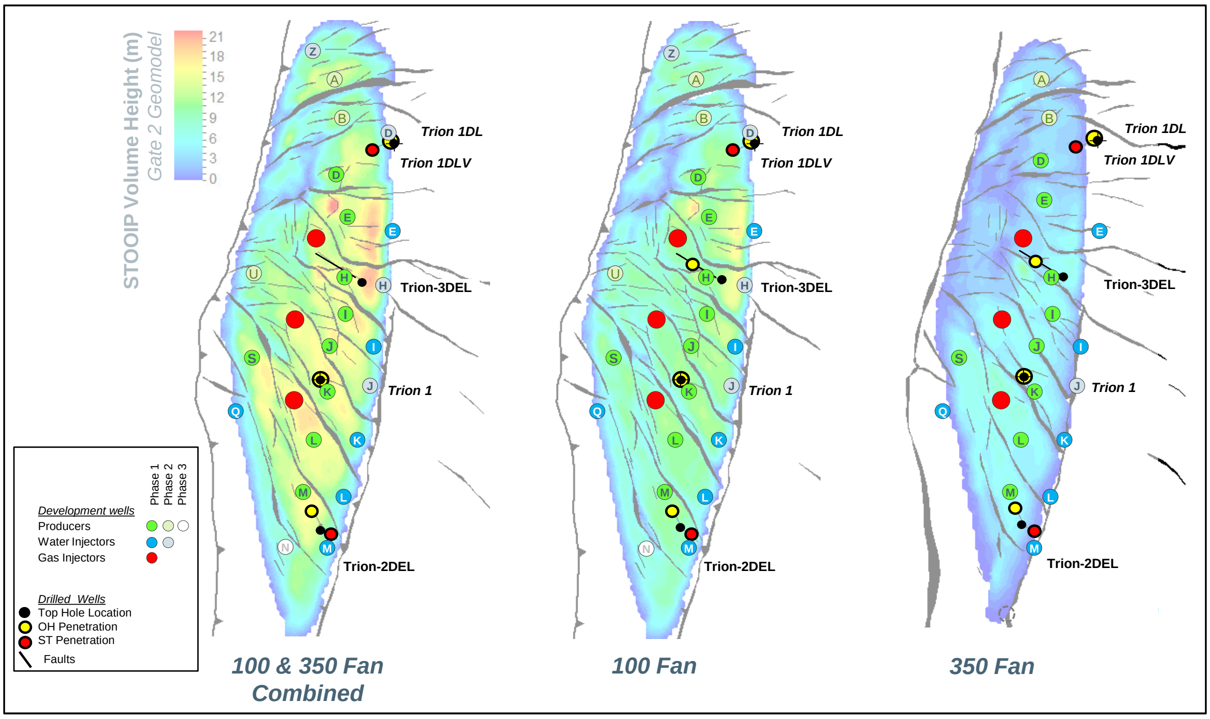
Production start-up is expected to occur late in 2026 (FY2027), taking into account the current schedule. Phase 1 drilling will include pre-drilled wells and drilling through the ramp-up period. Phase 2 drilling will commence approximately two years after start-up and phase 3 will commence approximately eight years after start-up.

Table 12.4: Trion Development Phases and Wells

Phase 1		Phase 2		Phase 3	
Producers	Water Injectors	Producers	Water Injectors	Producers	Water Injectors
D			D		
E	E				
H			H		
I	I				
J			J		
K	K				
L	L				
M	M				
S	Q				
		A	Z		
		B			
		U			
				F	
				N	
9	**6**	**3**	**4**	**2**	**0**

Notes:
1. Wells A and Z are in a prospective (undiscovered) region.
2. In addition to the wells shown here, three crestal gas injectors will be drilled in the crest of the structure and completed in both fans.

Figure 12.5: Development Wells for Trion



Source: BHP Petroleum

The gas injection wells are intended to re-inject all produced gas as far as possible for pressure maintenance. Gas that cannot be injected will be exported via pipeline. The gas export volumes estimated by BHP Petroleum from the dynamic simulation model are dependent upon the simulator's projection of GOR, and re-injection capacity, both of which are sensitive to the assumptions and controls imposed in the simulation model. The gas export pipeline route has not yet been finalised although there are options to tie into existing infrastructure. Estimates of sales gas volumes are small, but an export option is an integral part of the development to avoid oil production becoming constrained by gas injection limitations.

BHP Petroleum has carried out dynamic simulation studies including an uncertainty analysis for development planning and has provided GaffneyCline with a "reference case" model which forms the basis for BHP Petroleum's Field Development Plan. GaffneyCline has reviewed the dynamic model and found it suitable to underpin 2C Contingent Resources estimates.

Estimates of recoverable oil volumes are shown in **Table 12.6**. Note that the volumes in these tables exclude the undiscovered (prospective) area in the north of the field, which could contain ~100 MMBbl of STOIIP, of which ~26 MMBbl of incremental oil could be recovered if the proposed wells (A and Z) successfully meet their objectives.

12.1.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

The BHP Petroleum CAPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments. Adjustments have been made for the Contingent Resources to reflect the removal of producer well "A" and water injector well "Z" which are both considered prospective and not included in the Contingent Resources. A development well capex of US$200 MM across 2028-2030 to account for two prospective infill wells is added on top of contingent resources CAPEX in the table below for the valuation profiles.

CAPEX (from 2022 onwards) for the Contingent Resources case is shown in **Table 12.5**.

Table 12.5: Trion Capital Cost Estimate – Contingent Resources

Item	Total CAPEX (US$ MM)
Exploration Wells	80
Development Wells	2,226
Facilities	4,159
Pipelines	141
BHP Petroleum	24
Total	**6,630**

The OPEX estimates for the development were evaluated by GaffneyCline, taking into consideration the development scope, planned activities and work programs outlined in the documentation. The total OPEX is broken down into fixed (asset management, maintenance, FPSO lease) and variable (US$/Bbl or US$/MCF) elements.

The variable elements are calculated based on the production using fixed rates of US$0.20/Bbl and US$0.05/MCF for oil and gas respectively.

The OPEX costs provided in the economic model and supporting documentation have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted in the Contingent case to account for changes in the variable OPEX components of the OPEX costs resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

For the Contingent Resources ABEX figures provided by BHP Petroleum have been reviewed and adopted unchanged.

12.1.4 Resources Estimates

The gross volume of oil estimated to be recoverable from the discovered part of the field prior to expiration of the primary licence term in 2052 is 428 MMBbl (**Table 12.6**), classified as 2C Contingent Resources Development Pending. The volume of gas expected to be produced and used as fuel (consumed in operations, CiO) during the licence period is estimated at 99 Bscf.

Additionally, estimates of sales volumes of gas prior to expiration of the primary licence term in 2052 of approximately 32 Bscf have been classified as 2C Contingent Resources Development Pending. These sales gas estimates are based on surplus produced gas that cannot be injected, as forecast by the simulator. They are dependent on a variety of sensitive reservoir performance parameters in the dynamic simulation model and are thus uncertain. There is no formal sales agreement to cover these volumes, although it is understood that gas demand in Mexico is such that gas sales are low risk. Gas sales volumes shown in **Table 12.6** are small.

Further volumes of oil potentially recoverable after licence expiry (43 MMBbl) and potential sales gas from the gas cap blowdown (176 Bscf) are reported as Contingent Resources Development Unclarified. The volume of CiO gas estimated to be produced and consumed after licence expiry is 42 Bscf.

Table 12.6: Trion Hydrocarbons Initially in Place and Recoverable Gross Volumes as of 31 December 2021

Item	Formation	Quantity
STOIIP in discovered area (MMBbl)	100 Fan	1,003
	350 Fan	365
	Total	**1,368**
Solution GIIP (approximate) (Bscf)	100 Fan	772
	350 Fan	385
	Total	**1,158**
GIIP in gas cap (Bscf)	350 Fan	42
Oil recovered within licence period to 2052 (MMBbl)	Field	**428**
Recovery factor at licence expiry (2052)	Field	31%
Ultimate oil recovery (nominally in 2066) (MMBbl)	Field	471
Ultimate recovery factor (nominally in 2066)	Field	34%
Oil recovered after licence expiry (MMBbl)	Field	**43**

12.1.5 GaffneyCline's Production and Cost Valuation Profiles- Trion

GaffneyCline's valuation scenario production profile for BHP Petroleum's Trion asset is given in **Figure 12.6** with the associated real term cost profiles provided in **Figure 12.7**. All final sales products are converted to MMboe before aggregation utilising conversion factors documented in **Appendix IV**. Volumes and Costs are Net to BHP Petroleum as per the data and information provided to GaffneyCline. The valuation production and cost profiles provided to KPMG Corporate Finance are based on the best estimates of the recoverable volumes of the defined development project documented in section 12.1.3. Risk assessment for valuation is discussed in section 12.1.6. Technical and commercial contingencies are also discussed that impact the project Chance of Development.

Gaffney Cline

Figure 12.6: BHP Petroleum Net Trion Asset Production Profile

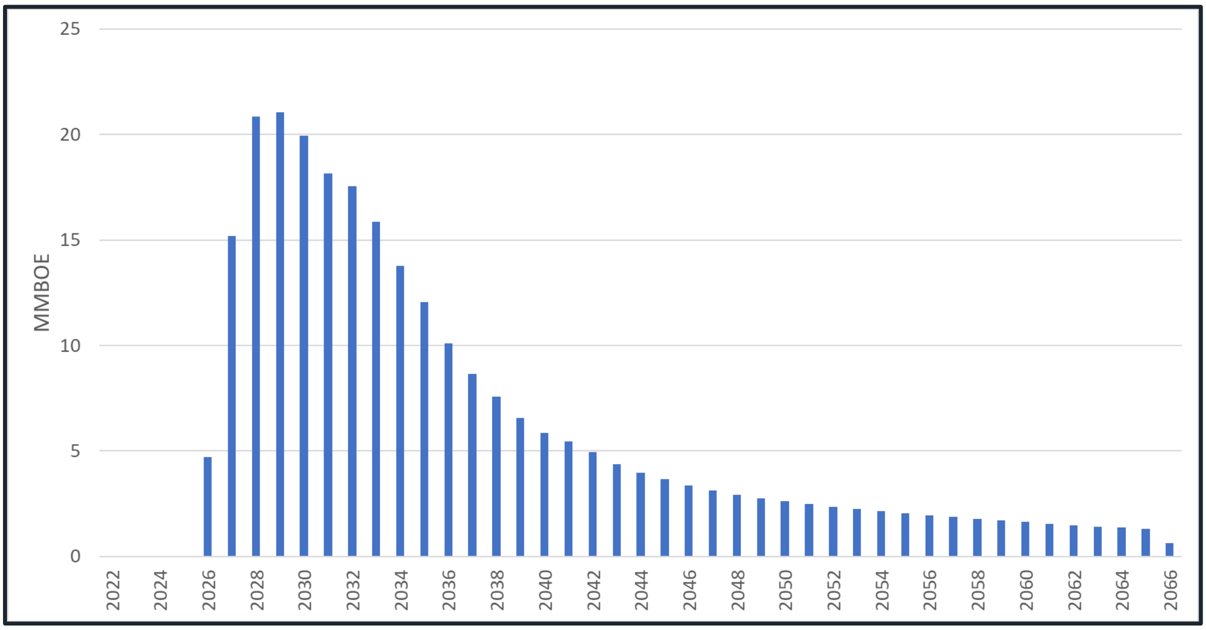
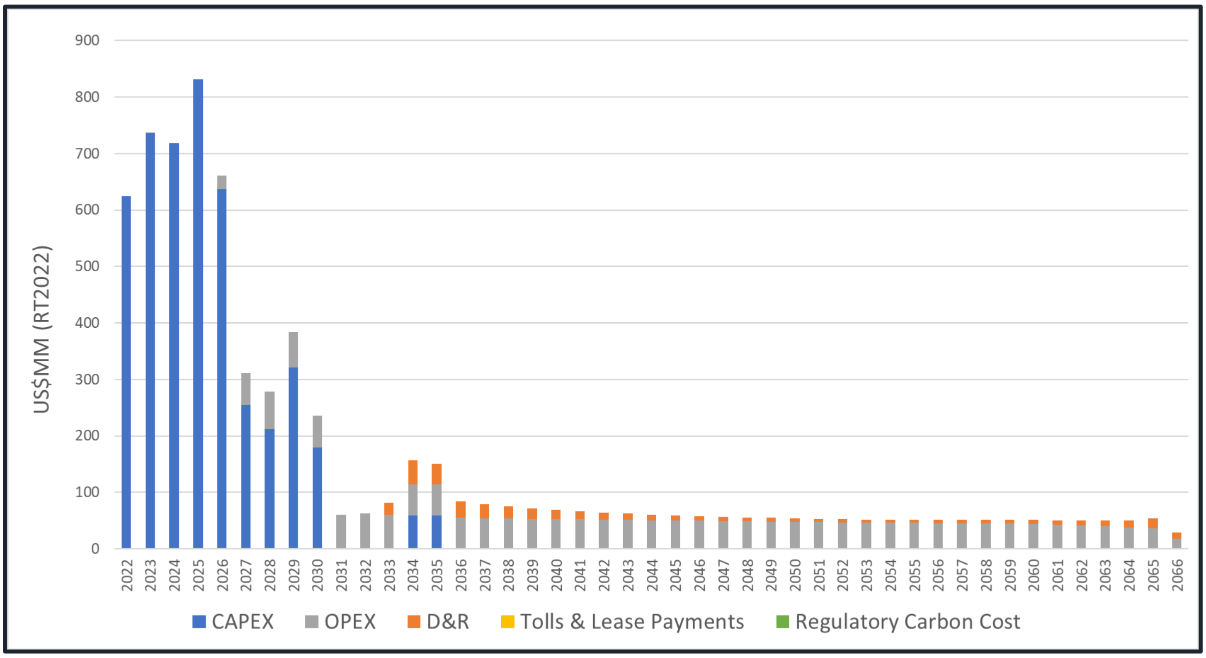


Figure 12.7: BHP Petroleum Net Trion asset Cost Profile



12.1.6 Trion Asset Chance of Development

Volumes of oil and gas estimated to be potentially recoverable from the Trion Field through the implementation of BHP Petroleum's development plan are classified as Contingent Resources - Development Pending. The project has passed decision Gate 2 (end of Select phase) and is currently in Definition phase undergoing front end engineering design. Decision Gate 3 is expected to be achieved in 2022 when the project will transition to the Execution phase and volumes of oil and gas would be considered for reclassification as Reserves.

The undeveloped Trion Field has been adequately appraised by four wells (including the discovery well), two of which have side-tracks, resulting in six reservoir penetrations. A comprehensive exploration and appraisal dataset has been acquired, including wireline logs, whole and sidewall cores and pressure transient testing. Several seismic datasets have been acquired, processed and reprocessed and these, together with latest 3D ocean bottom node survey, acquired in 2020-2021 have allowed detailed imaging and interpretation of the reservoir structure and distribution of hydrocarbons. The good dataset has facilitated the modelling of the reservoir and aided the development planning, which is progressing well.

The development plan comprises subsea wells (fourteen production, ten water injection and three gas injection) tied back to a floating production unit (FPU). Stabilised crude will be sent to a floating storage and offloading facility (FSO) for export via tanker

On 19 December 2021 BHP Petroleum announced that it had filed with the National Hydrocarbons Commission (CNH) a Declaration of Commerciality (DoC) in respect of the Trion discovery area. The DoC confirms that BHP Petroleum and PEMEX consider the Trion discovery area to be commercial subject to and in accordance with the terms of the Licence. On 5th August 2021, the BHP Petroleum Board approved US$258 MM in capital expenditure to move the Trion project into the Front End Engineering Design (FEED) phase. (As announced on BHP's website).

Considering the above, GaffneyCline recommends a 90% chance of development applied to all the Trion Contingent Resources for KPMG's valuation analysis.

13 BHP Petroleum Global Exploration Portfolio

BHP Petroleum's global exploration portfolio consists of assets in Mexico, Trinidad and Tobago, Canada, Australia and USA. These prospects range from near field opportunities in Mexico, Trinidad and Tobago, Australia and the USA to stand-alone exploration projects in the USA and Canada.

All of the prospects discussed here could potentially be drilled within the next five (5) years; additional prospectivity with no planned drilling has been excluded from the assessment.

BHP Petroleum has identified two gas prospects with 2U (Best estimate) Prospective Resources varying between 85 and 300 Bscf and Chance of Geologic Success (P_g) between 85% and 90%, plus eleven oil prospects with 2U Prospective Resources varying between 4.4 and 440 MMBbl and P_g between 11% and 90%.

GaffneyCline has reviewed the prospects mentioned above. This review has broadly confirmed the assessments by the BHP Petroleum, although GaffneyCline has modified both the Prospective Resource estimates and P_g where it deems it to be required. No further details are provided here as they are deemed to be commercially sensitive.

13.1 Recommended Value Range for BHP Petroleum's Exploration Assets

BHP Petroleum provided detailed assumptions for exploration valuations for nine prospects using the EMV methodology. Four of these prospects are in the USA GOM. One in Mexico, two in Canada and two in Australia. BHP has indicated that the names and details of the prospects are commercially sensitive.

Trinidad and Tobago prospects are valued along with the Calypso asset best case and the Mexico Trion North prospect is valued along with the Trion best case.

The GaffneyCline calculated EMV range is positive for only four prospects with an aggregated EMV range of US$190 MM to US$436 MM.

BHP Petroleum did not share their internal EMV evaluation with GaffneyCline but negative EMV values could still be explained due to the different discount rate assumptions, P50 volume and GCoS adjustments by GaffneyCline.

GaffneyCline's recommended value range is **US$190 MM** to **US$436 MM** for BHP Petroleum's exploration assets for KPMG's consideration.

14 Economic Assessment for Reserves (Economic Limit Test)

GaffneyCline has conducted an economic assessment of Woodside and BHP Petroleum assets in order to derive the economic limit for production, the Net Entitlement Reserves and the Net Present Values (NPVs) associated with the 1P and 2P Reserves cases. The assessments are based upon GaffneyCline's understanding of the fiscal terms governing these assets and the various economic and commercial assumptions described herein.

Additionally, GaffneyCline performed economic limit tests with KPMG provided oil and gas prices and macro-economic assumptions. This resulted in no changes to economic limits.

14.1 Assumptions and Inputs

14.1.1 Macro-Economic Assumptions

- Effective date of the economic analysis is 31 December 2021.
- CAPEX, OPEX and D&R costs are in US$ 2022 real terms, then escalated 2% p.a. from 2023

14.1.2 Oil and Gas Pricing Scenarios

GaffneyCline's price scenario for 1Q 2022, shown in **Table 14.1**, has been used as the reference price for global benchmarks in the economic analysis.

Table 14.1: GaffneyCline 1Q 2022 Price Scenario for Global Price Benchmarks

Year	Brent Crude (US$/Bbl)	West Texas Intermediate (US$/Bbl)	Henry Hub Gas (US$/MM Btu)
2022	75.92	72.69	3.78
2023	71.00	66.91	3.42
2024	70.00	66.00	3.20
2025	71.40	67.32	3.26
2026+	+2% per annum	+2% per annum	+2% per annum

14.1.3 Realised Product Prices

GaffneyCline estimated product price differentials based on 2021 actual realised prices provided by Woodside and BHP Petroleum. For contracted prices where applicable, GaffneyCline reviewed pricing information made available by Woodside and BHP Petroleum and accepted them to be reasonable. Details of pricing are not included as they are confidential.

15 Fiscal Regimes and Modelling Assumptions

15.1 Woodside Australia

Woodside's Australian petroleum projects are subject to the Petroleum Resource Rent Tax (PRRT) Fiscal Regime. Fiscal terms are summarised as below:

- Excise duty is applicable to oil and condensate produced from the North West Shelf Fields. A royalty regime also applies to production from the North West Shelf Fields.
- PRRT is applied at 40% of taxable profits derived from hydrocarbon production. PRRT payments are deductible for income tax purposes. The tax applies to profits derived from a petroleum project and not to the value or volume of production as with royalty and excise regimes. Deductions are available for all allowable expenditures and uplifts are applied to the carried-forward expenditure to ensure that PRRT taxes the economic rent generated from a petroleum project in a financial year.
- PRRT Payable is calculated as follows:
  - PRRT Payable = Taxable Profit x PRRT Rate (40%);
  - Taxable Profit = Assessable Receipts – Deductible Expenditures;
  - Assessable Receipts include petroleum receipts, tolling receipts, exploration recovery receipts, property receipts, miscellaneous compensation receipts, employee amenities receipts, incidental production receipts;
  - Expenditures are deductible in the year they are incurred. Expenditures include general project expenditures, exploration expenditure or closing-down expenditures;
  - General project expenditures consist of costs incurred in carrying out or providing the operations, facilities and other activities in relation to an oil and gas project;
  - Exploration expenditure is cost incurred in the exploration for oil and gas in an eligible exploration or recovery area;
  - Closing-down expenditure related to abandonment and decommissioning costs; and
  - Expenditures that are excluded are financing costs, dividend payments, acquisition costs, private overriding royalties, income tax and GST payments, indirect administration costs.
- Depreciation of historical CAPEX for each asset has been provided by Woodside.
- Applicable income tax rate of 30%.

15.2 Woodside Sangomar (Senegal)

Woodside holds 82% working interest in the Sangomar field in Senegal which operates under a Production Sharing Contract (PSC). The key elements of the PSC fiscal regime are as follows:

- Max Cost Recovery is 75% of Production Revenue.

- Recoverable Costs comprise OPEX, FPSO and Pipeline CAPEX depreciation (10 years SL basis), all other Post-FID Development CAPEX depreciation (5 years SL basis), Pre-FID CAPEX on an expensed basis, Abandonment Provision payments, Training Fees, Surface rentals, Local Element Contribution and Customs Duty. Unrecovered costs can be carried forward indefinitely.
- Profit Oil (Production Revenue minus Cost Recovery) is split between Contractor and Government by production tranches as shown in **Table 15.1**.

Table 15.1: Profit Oil Split for Sangomar

Tranche	Production in MBbl/day	Government Profit Share %
Tranche 1	0 – 50	15%
Tranche 2	50 – 100	20%
Tranche 3	100 – 150	25%
Tranche 4	150 – 200	30%
Tranche 5	> 200	

- Abandonment Provision payments must be paid into an escrow account at the earliest of 6 years before economic limit or date at which 70% of recoverable reserves have been produced.
- Other Levies and Payments:
  1. Local Economic Contribution comprises Contribution on Value Added (CVA) and Contribution on Rental Value (CRV).
  2. CVA is calculated as 1% PSC revenue minus operating expenditure.
  3. CRV is calculated on the rental value of the hull of the FPSO.
  4. Customs Duty is levied at 2.3% of imported value of the FPSO during the development phase.
  5. Surface rentals are calculated at US$15/sq.km contract area annually. Annual Training Fee payable is US$0.4 MM.
- Corporate Income Tax (CIT) is payable at 33% of Taxable Income. Deductions to calculate taxable income is subdivided into those that have a 3-year limit on loss carry-forward (such as pre-FID CAPEX, OPEX, ABEX provision payments, Training fees, Surface rentals, LEC and Customs Duty) and Deductions with unlimited carry forward (such as post-FID CAPEX).
- Branch Profit Tax (BPT) at the rate of 10% is payable on the CIT taxable income net of CIT.
- Future contingent payments related to transactions with Cairn Energy and FAR Limited, opening balances and depreciation schedules of CAPEX already placed in service were included in asset evaluation based on economic models provided by Woodside.

15.3 BHP Petroleum Australia

BHP Petroleum's Australia assets are governed under the Petroleum Resource Rent Tax (PRRT) Fiscal Regime, the terms of which are summarised in Section 15.1.

Depreciation of historical CAPEX for each asset has been provided by BHP Petroleum.

The following information supplied by BHP Petroleum has also been used in the economic analysis:

- Contracted gas prices and annual contracted volumes;
- Balances for calculating depreciation for income tax and PRRT;
- Revenues and costs related to the pipeline tariff in Bass Strait and Macedon;
- Hydrocarbon product prices – no historical product prices have been provided to verify any differentials to the benchmark crude prices such as Brent or WTI; and
- PRRT and tax credit related to future abandonment costs.

15.4 BHP Petroleum US Gulf of Mexico

Key terms of the US Gulf of Mexico fiscal regime are as follows:

- The US Gulf of Mexico assets follows a simple royalty/tax regime with the governmental take comprising of royalty and the standard corporation tax. BHP Petroleum Working Interest and Royalty rates of each asset used for the assessment are shown in **Table 15.2**.
- Expenditure. Opening balances, cost depletion and other depreciation balance calculations have been made available by BHP Petroleum.
- Note that Corporate Tax has no impact on ELT calculations.
- Licences are expected to be renewed until the economic limit of the asset is reached.

Table 15.2: BHP US Gulf of Mexico Assets Working Interest and Royalty Rates

Asset	Working Interest	Royalty Rate	Effective Royalty Rate
Shenzi	72.00%	[1]12.50%	10.58%
Atlantis	44.00%	12.50%	12.50%
Mad Dog	23.90%	12.70%	12.70%

Notes:

1. Shenzi is made up of 5 blocks and royalty relief of up to 87.5 MMBOE of production is applicable per block. Two blocks have exhausted the royalty relief and the remaining 3 blocks are not expected to reach relief limit within the evaluation period. The effective royalty is the weighted average royalty of the five blocks and is based on data shared by BHP.
2. Mad Dog Royalty rate is the average of blocks with 12.5% and 18.75% rates with an effective rate of 12.702%

15.5 BHP Petroleum Trinidad and Tobago(T&T) Assets

BHP Petroleum's Trinidad and Tobago assets comprise of Block 2(c) and Block 3(a). BHP Petroleum holds a 45% working interest position in the Block 2(c) production sharing contract (PSC) and a 68.46% working interest position in the Block 3(a) PSC. Net interests are determined by the terms of the PSC for each block and may vary from the working interest.

Actual terms are excluded due to confidentiality.

Appendix I
SPE PRMS Definitions & Guidelines

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 ([2])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

[2] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/Sub-Class	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

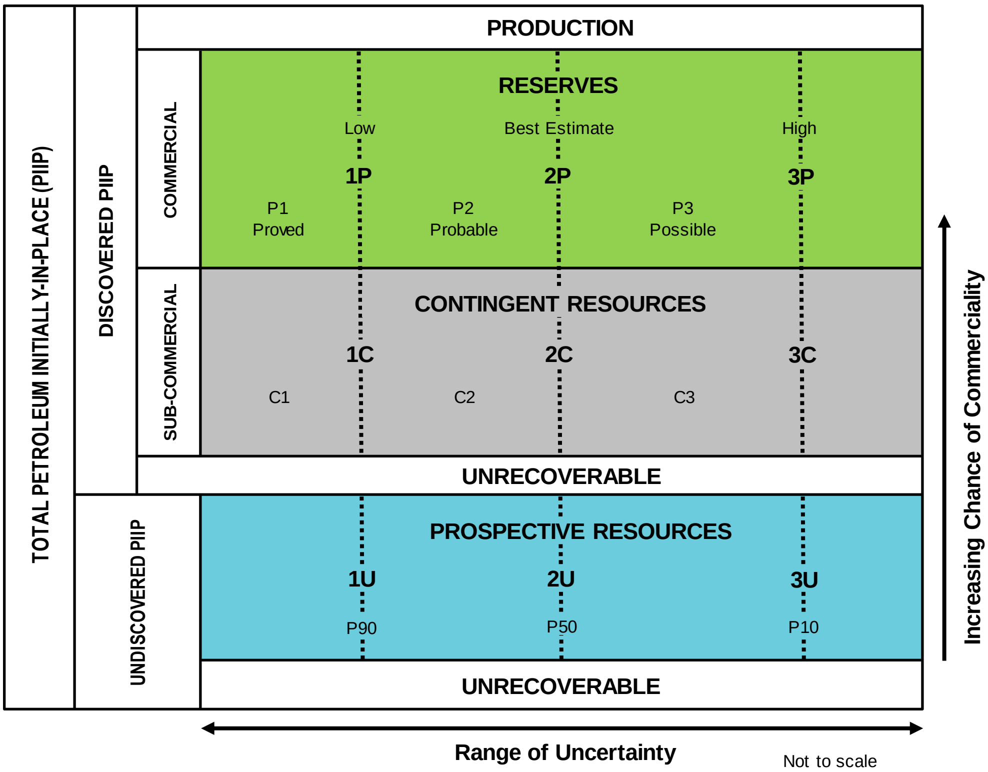
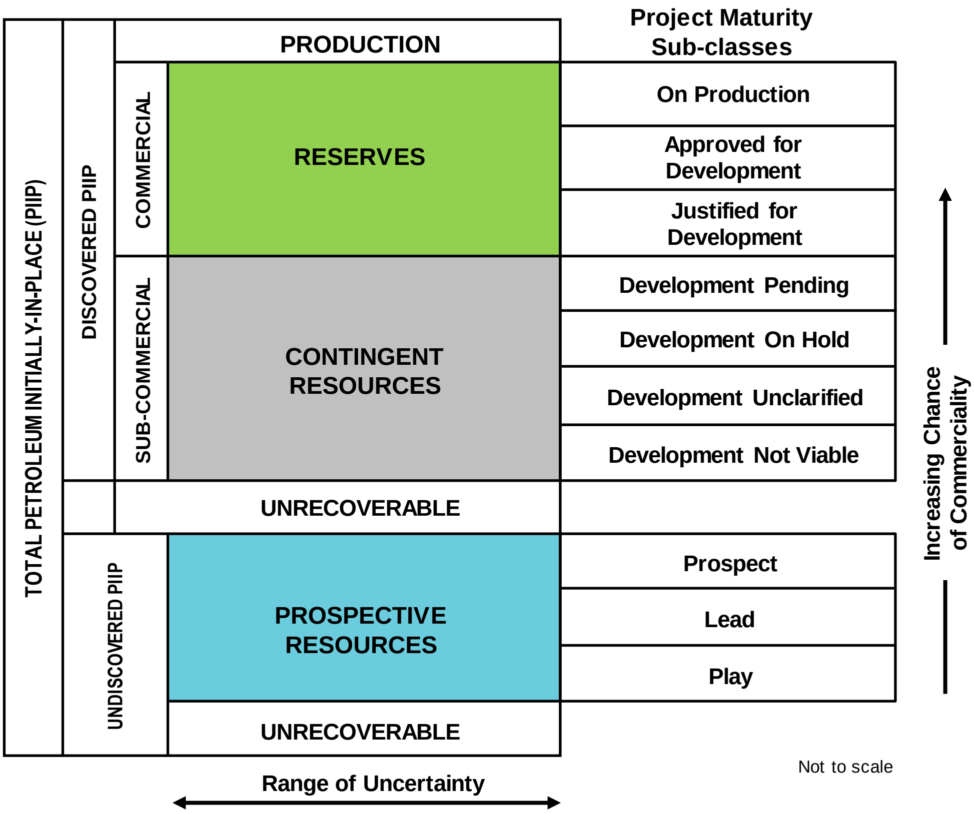


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



Appendix II
Glossary

Gaffney Cline

GLOSSARY

Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment expenditure
ACQ	Annual contract quantity
API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus offset
B	Billion (10^9)
Bbl	Barrels
/Bbl	Per barrel
BBbl	Billion barrels
bcpd	Barrels of condensate per day
BHP	Bottom hole pressure
blpd	Barrels of liquid per day
Bm^3	Billion cubic metres
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
BOP	Blow out preventer
bopd	Barrels oil per day
bpd	Barrels per day
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
BS&W	Bottom sediment and water
BTU	British thermal units
bwpd	Barrels of water per day
°C	Degrees Celsius
CAPEX	Capital expenditure
CBM	Coal bed methane
cf	Standard cubic feet
cfd	Standard cubic feet per day
CIIP	Condensate initially in place
CGR	Condensate to gas ratio
cm	Centimetres
CMM	Coal mine methane
CO_2	Carbon dioxide
cP	Centipoise (a measure of viscosity)
CSG	Coal seam gas
CT	Corporation tax
DCQ	Daily contract quantity
Dev	Developed
DHI	Direct hydrocarbon indicator
DST	Drill stem test
E&A	Exploration & appraisal
E&P	Exploration and production
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement interest
EIA	Environmental impact assessment
ELT	Economic limit test
EMV	Expected monetary value
EoFL	End of Field Life

EOR	Enhanced oil recovery
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FPSO	Floating production, storage and offloading vessel
FSO	Floating storage and offloading vessel
ft	Foot/feet
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GTL	Gas to liquids
GWC	Gas water contact
HCIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment
HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
KB	Kelly bushing
kJ	Kilojoules (one thousand Joules)
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas
LKH	Lowest known hydrocarbons
LKO	Lowest known oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)

MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
mg/l	milligrams per litre
MIMI	Japan Australia LNG (MIMI) Pty Ltd (a 50-50 joint venture between Mitsubishi Corporation and Mitsui & Co/ Ltd)
MJ	Megajoules (one million Joules)
Mm^3	Thousand cubic metres
Mm^3d	Thousand cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
mss	Metres subsea
MW	Megawatt
MWD	Measuring while drilling
MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
NGL	Natural gas liquids
N_2	Nitrogen
NOK	Norwegian krone
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OBM	Oil based mud
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
Pa	Pascal (metric measurement of pressure)
P&A	Plugged and abandoned
PD	Proved developed
PDP	Proved developed producing
%	Percentage
PI	Productivity index
PJ	Petajoules (10^{15} Joules)
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSC / PSA	Production sharing contract / Production sharing agreement
PSDM	Post stack depth migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved undeveloped
PVT	Pressure volume temperature
P10	Value with a 10% probability of being exceeded
P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded

RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
RT2022	Real Terms 2022
RUB	Russian Rouble
R_w	Resistivity of water
SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRP	Sucker rod pump
ss	Subsea
ST	Side track
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
S_w	Water saturation
t	Tonnes
TD	Total depth
te	Tonnes equivalent
THP	Tubing head pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical committee meeting
TOC	Total organic carbon
TOP	Take or pay
tpd	Tonnes per day
TVD	True vertical depth
TVDss	True vertical depth subsea
Undev	Undeveloped
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
VSP	Vertical seismic profiling
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)

Appendix III
Consumed in Operations (Reserves)

Although the PRMS recommends that Reserves be sales quantities, it does allow volumes of hydrocarbons forecast to be consumed in operations (CiO) as fuel during the production of Reserves, upstream of the reference point at whch Reserves are reported, to be classified as Reserves, provided they are reported separately from sales volumes.

Woodside and BHP Petroleum customarily report CiO volumes differently. For integrated gas projects involving both an upstream component (the production facilities) and a downstream processing component (e.g. an LNG plant), Woodside reports only the downstream CiO volumes as Reserves, while BHP Petroleum reports both the upstream and downstream CiO volumes as Reserves.

Table AIII.1 shows total CiO Reserves for each asset for both companies, split into upstream and downstream components for Woodside, to facilitate comparison with prior annual reporting.

Table AIII.1: Summary of Working Interest CiO Gas Reserves as of 31 December 2021

(a) Woodside CiO Gas

Country	Asset	CiO Gas Reserves (Bscf)					
		Proved			Proved plus Probable		
		Up-stream	Down-stream	Total	Up-stream	Down-stream	Total
Australia	North West Shelf	23	77	**99**	24	100	**124**
	Wheatstone LNG (Brunello & Julimar)	23	96	**119**	35	149	**185**
	Pluto LNG	105	127	**233**	142	150	**292**
	Scarborough LNG	128	506	**634**	199	782	**980**
	Greater Enfield	21	0	**21**	24	0	**24**
Senegal	Sangomar	51	0	**51**	54	0	**54**
Total		**351**	**806**	**1,157**	**478**	**1,181**	**1,659**

(b) BHP Petroleum CiO Gas

Country	Asset	Total CiO Gas Reserves (Bscf)	
		Proved	Proved plus Probable
Australia	North West Shelf	101	127
	Bass Strait	47	57
	Macedon	16	31
	Pyrenees	0	0
	Scarborough LNG	228	353
US GOM	Shenzi	17	21
	Shenzi North	0	0
	Atlantis	16	42
	Mad Dog	28	36
Trinidad & Tobago	Angostura/Ruby	9	11
Total		**462**	**677**

Notes:
1. CiO Reserves net to company are the company's net working interest of total fuel used.
2. Totals may not exactly equal the sum of the individual entries due to rounding.
3. Woodside's estimates of downstream CiO are based on heating values per component whereas GaffneyCline has utilised average heating values for this reconciliation process.

Appendix IV
boe Conversion Values

KPMG Financial Advisory Services (Australia) Pty Ltd
March 2022

Energy Equivalent Conversion Factors

The following energy equivalent conversion factors have been used to convert the sales products to boe equivalent valuation production profiles for the Australian Assets of Woodside and BHP Petroleum. For BHP Petroleum assets outside Australia, a 6000 scf = 1 boe conversion is used. Note GaffneyCline has not utilised boe conversions for any technical or valuation work and is simply utilising the conversion factors to display aggregate valuation production profiles.

Table AIV: boe Conversion values for Australian Assets

Final Product	Unit of Measurement	boe Equivalent
Crude Oil	**Bbl**	1
Domestic Gas	**GJ**	0.1636
LNG	**MMBTU**	0.1724
LPG	**Tonnes**	8.1876
Condensate	**Bbl**	1

Part Two – KPMG FAS Corporate Finance Financial Services Guide

KPMG

KPMG Financial Advisory Services (Australia) Pty Ltd

ABN 43 007 363 215
Australian Financial Services Licence No. 246901

Financial Services Guide

Dated April 2022

What is a Financial Services Guide (FSG)?

This FSG is designed to help you to decide whether to use any of the general financial product advice provided by **KPMG Financial Advisory Services (Australia) Pty Ltd (KPMG FAS) ABN 43 007 363 215**, Australian Financial Services Licence Number 246901 (of which KPMG Corporate Finance is a division). Jason Hughes is an authorised representative of KPMG FAS, authorised representative number 404183, Bill Allen is an authorised representative of KPMG FAS, authorised representative number 405336 and Sean Collins is an authorised representative of KPMG FAS, authorised representative number 404189 (**Authorised Representatives**).

This FSG includes information about:

- KPMG FAS and its Authorised Representatives and how they can be contacted;
- The services KPMG FAS and its Authorised Representatives are authorised to provide;
- How KPMG FAS and its Authorised Representatives are paid;
- Any relevant associations or relationships of KPMG FAS and its Authorised Representatives;
- How complaints are dealt with as well as information about internal and external dispute resolution systems and how you can access them; and
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- Eligible international emissions units, to retail and wholesale clients.

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KPMG FAS has been engaged by Woodside Petroleum Ltd (**Woodside** or **the Client**) to provide general financial product advice in the form of a Report to be included in Woodside's Explanatory Memorandum (**Explanatory Memorandum**) to be sent to Woodside securityholders pursuant to the share sale agreement with BHP Group Limited (**BHP**) announced by Woodside on 22 November 2021 under which Woodside and BHP will combine their respective oil and gas portfolios by way of an all-stock merger (**the Proposed Transaction**).

You have not engaged KPMG FAS or the Authorised Representatives directly but have received a copy of the Report because you have been provided with a copy of the Explanatory Memorandum. Neither KPMG FAS nor the Authorised Representatives are acting for any person other than the Client.

KPMG FAS and the Authorised Representatives are responsible and accountable to you for ensuring that there is a reasonable basis for the conclusions in the Report.

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KPMG entities have provided a range of services to the Client and to BHP for which professional fees are received. Over the past two years professional fees of approximately $4.6 million have been received from the Client and approximately $12.7 million from BHP respectively. None of those services have related to the Proposed Transaction or alternatives to the Proposed Transaction. These fees are not material to the KPMG in terms of value. Accordingly, we do not consider that these receipt of these fees impairs our independence.

No individual involved in the preparation of this Report holds a substantial interest in, or is a substantial creditor of, the Client or has other material financial interests in the Proposed transaction. A KPMG employee involved in the preparation of the report holds an interest in 38 shares in BHP. These shares are not material to the employee in terms of value. Accordingly, we do not consider that the employee's interest in these shares impairs our independence.

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If you have a complaint, please let KPMG FAS or the Authorised Representatives know. Complaints can be sent in writing to The Complaints Officer, KPMG, GPO Box 2291U, Melbourne, VIC 3000 or via email (AU-FM-AFSL-COMPLAINT@kpmg.com.au). If you have difficulty in putting your complaint in writing, please telephone the Complaints Officer on (03) 9288 5555 and they will assist you in documenting your complaint.

We will acknowledge receipt of your complaint, in writing, within 1 business day or as soon as practicable.

Following an investigation of your complaint, you will receive a written response within 30 calendar days. If KPMG FAS is unable to resolve your complaint within 30 calendar days, we will let you know the reasons for the delay and advise you of your right to refer the matter to the Australian Financial Complaints Authority (**AFCA**).

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Further details about AFCA are available at the AFCA website www.afca.org.au or by contacting them directly at:

Address: Australian Financial Complaints Authority Limited, GPO Box 3, Melbourne Victoria 3001
Telephone: 1800 931 678

Email:

The Australian Securities and Investments Commission also has a freecall infoline on 1300 300 630 which you may use to obtain information about your rights.

Compensation arrangements

KPMG FAS has professional indemnity insurance cover in accordance with section 912B of the *Corporations Act 2001(Cth)*.

Contact details

You may contact KPMG FAS or the Authorised Representatives using the below contact details:

KPMG Corporate Finance (a division of KPMG Financial Advisory Services (Australia) Pty Ltd)
Level 38, International Towers Three
300 Barangaroo Avenue

Sydney NSW 2000

PO Box H67
Australia Square
NSW 1213
Telephone: (02) 9335 7621
Facsimile: (02) 9335 7001

Jason Hughes/Bill Allen/Sean Collins

C/O KPMG
PO Box H67
Australia Square
NSW 1213

Telephone: (02) 9335 7621
Facsimile: (02) 9335 7001

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