Independent Technical Specialists Report on the Petroleum Properties of AWE Limited

January 2018

decisions with confidence

Table of contents

List of figures

List of tables

1. Executive Summary

The Directors
AWE Limited
Level 12, 100 Pacific Highway,
North Sydney, 2060

Mr Andrea De Cian
Grant Thornton Corporate Finance Ltd
Level 17, 303 Kent Street
Sydney NSW 2000

19 February 2018

Dear Directors and Independent Expert,

Independent Technical Specialist's Report on the Petroleum Assets of AWE Limited

Grant Thornton Corporate Finance ("Grant Thornton") has been appointed by the Directors of AWE Limited ("AWE") as the Independent Expert in relation to the proposed Mitsui takeover (the "Proposed Transaction").

To assist Grant Thornton in preparing its Independent Expert Report in relation to the Proposed Transaction, Grant Thornton has provided instructions to RISC Advisory Pty Ltd ("RISC") to prepare this document an Independent Technical Specialist's Report in relation to the petroleum assets of AWE.

The Technical Report documents our review of the petroleum reserves, resources and associated development schedules, production and cost forecasts. We have audited the estimates provided by AWE and made such adjustments that in our judgement were necessary to provide a reasonable assessment and reflect current information. We prepared scenarios for valuation of the properties by Grant Thornton. This report also provides a description and economic analysis to assist Grant Thornton with their valuation of AWE's AAL discovery and the exploration properties which form part of the Proposed Transaction.

Reserves and contingent resources

The estimated 2P reserves and 2C contingent resource volumes net to AWE as at 31 December 2017 are shown in Table 1-1 and Table 1-2, respectively. Reserves and resources have been evaluated in accordance with PRMS Guidelines.

Table 1-1: 2P reserves net to AWE as at 31/12/2017

Category	Area/Project	Gas	LPG	Cond.	Developed	Undeveloped	Total
		PJ	ktonne	MMbbl	MMboe	MMboe	MMboe
2P	**Otway** - Casino Gas Project	32.8	-	0.02	5.5	-	5.5
	Bass Basin – Yolla	27.3	76.0	0.91	4.9	1.4	6.3
	Perth Basin – Waitsia, Beharra Springs	418.2	-	0.09	6.9	62.9	69.8
	Total 2P	**478**	**76.0**	**1.0**	**17.3**	**64.3**	**81.6**

Table 1-2: 2C contingent resources net to AWE as at 31/12/2017

Category	Area/Project	Gas	LPG	Cond.	Oil	Total
		PJ	kT	MMbbl	MMbbl	MMboe
2C	**Otway** - Casino Gas Project	7.4	-	0.07	-	1.30
	Bass Basin – Trefoil et al	112.5	394.4	6.53	0.72	30.55
	Perth Basin - Waitsia and Corybas	241.3	-	2.01	-	42.23
	Indonesia - Ande Ande Lumut	-	-	-	46.5	46.50
	Total 2C	**361**	**394**	**8.6**	**47.2**	**120.6**

Notes to tables:

1. A combination of probabilistic and deterministic methods have been used.
2. Reserves and contingent resources have been aggregated arithmetically.
3. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated as sales quantities net of fuel and flare.
4. All the above reserves and contingent resources are considered conventional.
5. PJ means one petajoule (10^{15} joules).
6. ktonne is one thousand metric tonnes.
7. MMbbl is one million barrels. One barrel is 158.99 litres.
8. MMboe is one million barrels of oil equivalent. Conversion factors used to evaluate gas equivalent quantities are LPG 11.6 BOE/tonne, condensate 1.0 BOE/bbl, oil 1.0 BOE/bbl and sales gas 6.0 PJ/MMboe.
9. The contingent resources have not been risked to reflect the chance of development
10. The Ande Ande Lumut contingent resources are held under a PSC with entitlement to cost and profit oil.

RISC has prepared sales gas and condensate production forecasts associated with the 2P reserves and Waitsia 2C Contingent Resources as shown in Figure 1-1.

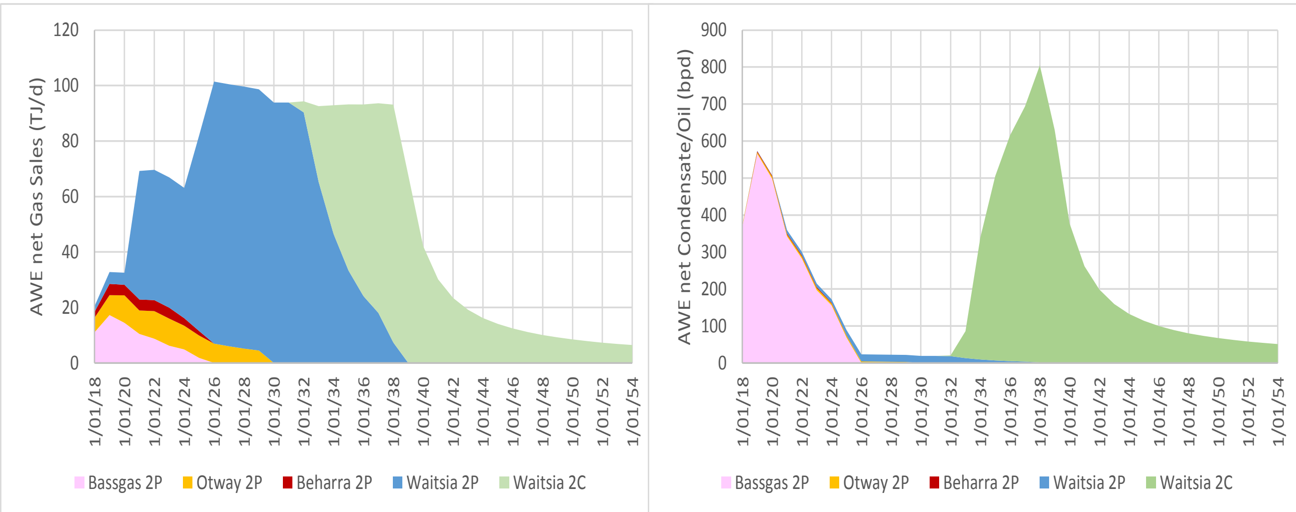


Figure 1-1: AWE Net 2P and Waitsia 2C gas sales and condensate production forecast

The Waitsia project in the Perth Basin has AWE's largest reserves and contingent resources. Production commenced from the Stage 1A development at rates of up to 10 TJ/d in August 2016. Stage 2 development is planned to complete the development in the high deliverability Kingia and High Cliff Sandstone (HCSS) reservoirs. AWE is planning a final investment decision (FID) on the 100 TJ/d Stage 2 project in 2018 and to commence production in 2020. RISC has developed Waitsia production and cost forecasts for the following four development scenarios:

1. Development of 1P reserves through the planned 100 TJ/d facility;
2. Development of 2P reserves through the planned 100 TJ/d facility;
3. Development of 2P reserves through the 100 TJ/d facility expanded to 200 TJ/d after 3-4 years;
4. Development of 2P + unrisked 2C resources with the expanded 200 TJ/d facility.

RISC estimate that expansion of the 100 TJ/d facility to 200 TJ/d after 3-4 years is likely as gas demand increases and recommend this as the base case evaluation scenario.

The Contingent Resources shown for the Waitsia Stage 3 project are from lower deliverability reservoirs in the High Cliff Sandstone, IRCM and Dongara Sandstone. The higher CGR estimated in the Dongara results in greater condensate production than in the Waitsia Phase-1A and Phase-2 Kingia/HCSS development. RISC has estimated larger contingent resources in the IRCM and Dongara than AWE. We estimate Waitsia Contingent Resources to have a 25% chance of progressing to commercial development. The risks are dependent on the ability to extract hydrocarbons in commercial quantities employing horizontal wells and/or fracture stimulation technology and favourable gas prices. The Contingent Resources are not risk adjusted. A discussion on the risks is provided in our report.

The Henry-3 development well is planned for the Casino project and the JV is pursuing opportunities to transfer processing of Casino gas to an alternative processing facility (location confidential) in calendar year 2019 to increase reserves and extend the field life.

AWE is also evaluating the development potential of the AAL field in Indonesia and the Trefoil field in the Bass Basin. At this point, there is no firm commitment or schedule for the development of these projects. Potential production from these less mature contingent projects is not included in Figure 1-1.

Table 1-3 shows AWE's net operating and minor capital expenditure for the financial year 2017 (actual) and forecast expenditure for financial years 2018 and 2019. This covers the costs for ongoing operations and minor capital expenditure in the producing fields.

Table 1-3: AWE Net Producing Field Operating Expenditure and minor Capital FY2017 to FY2019 A$ million

Project	Cost Type	FY2017 Actual	FY2018 Forecast	FY2019 Forecast
Otway – Casino Gas Project	Operating	0.8	1.8	1.2
	Capital	1.2	10.5	19.5
Bass Basin – Yolla & Trefoil	Operating	19.9	21.8	22.9
	Capital	15.4	3.4	2.8
Perth Basin – Waitsia and Beharra Springs[1]	Operating	9.5	8.8	7.1
	Capital	18.9	27.8	61.8
Total	**Operating**	**30.2**	**32.4**	**31.2**
	Capital	**35.5**	**41.7**	**84.1**

Table 1-4 below summarises the estimated net future cumulative expenditure on the Waitsia, Corybas and AAL contingent resource projects from 31 December 2017, as well as abandonment and rehabilitation expenditure on all developments.

Table 1-4: AWE Net Future Capital and Operating Cumulative Expenditure from 31 December 2017 (A$ million, 2018 RT)

	Capital Costs	Operating Costs	Abandonment Costs
Otway – Casino Gas Project	35.1	49.1	32.5
Bass Basin – Yolla & Trefoil	11.8	123.3	48.0
Perth Basin – Waitsia and Beharra Springs Reserves[2]	434.4[#1]	250.8	146.8
Waitsia Contingent Resources	306.5	307.4	29.0
Corybas Contingent Resources	59.1	38.3	1.6
Ande Ande Lumut Contingent Resources	409.4	1,194.8	56.6
Total	**1,256**	**1,964**	**315**
#1: Includes A$270 million to progress Waitsia Stage-2 project to first gas in 2020. Remainder largely Waitsia Stage-2 post start-up.			

Details of the costs and production profiles associated with the development and production of these resources are included in our report.

[1] Includes ongoing operational and abandonment and rehabilitation spend for decommissioned assets in the Perth basin.

[2] Includes ongoing operational and abandonment and rehabilitation spend for decommissioned assets in the Perth basin.

Comparable Transaction Analysis of Ande Ande Lumut Contingent Resources

RISC has used comparable transactions to assist Grant Thornton with their valuation of the AAL field in Indonesia.

The transactions reviewed have been limited to a contingent resource oil dominated resource base in PSC regimes post 2014 after the oil price crash. In our opinion earlier transactions will provided an overly optimistic view of value compared to the current market.

Since 2014, there have been a relatively limited number of oil dominated contingent resource transactions in PSC regimes. We have used SE Asian and African transactions to provide an indicative range. Our analysis indicates a range of unit values as indicated in Table 1-5.

Based on a 2023 start up, the estimated oil recovery to the end of the PSC term in 2034 is approximately 79 MMbbl gross. The analysis supports a valuation for AWE's 50% interest in AAL in the range A$40 to 79 million with a mid-range value of A$59 million. These values are exclusive of the free carry.

Table 1-5: AAL Comparable Transaction Analysis – A$ million net to AWE

	Low	Mid	High
Unit Value A$/bbl	1.0	1.5	2.0
Value A$million	40	59	79

The Local Government has an option to take a 10% participation in the AAL development, reducing AWE's interest from 50 to 45%. They would either pay their own way as a JV partner or more likely have their share of development costs carried by the other JV parties who would then retain the cost recovery. Such Government participation is common in PSCs in the area, and incorporated in the transaction values discussed. Therefore, in this analysis AWE's 50% PSC interest has not been reduced to 45% due to potential Government participation.

AWE has a US$88 million carry on AAL development costs from the Santos acquisition. However, this carry has the risk of delaying development as development may be sub-economic for Santos while it is economic for AWE. This carry has some value to AWE that is not incorporated into the value in Table 1-5.

Exploration value

RISC has used a number of methods to assist Grant Thornton with their valuation of AWE's exploration and appraisal properties. We considered comparable farm-out transactions in the current market and existing work program commitments in the AWE exploration portfolio. The resulting low, best and high case values indicated by this analysis for exploration properties in AWE's portfolio are shown in Table 1-6.

A range of values is typically estimated for individual assets. While acquirers of the individual permits could value individual assets at either end of the value range, it is unlikely that potential buyers of the exploration asset portfolio would value all of the assets at either the arithmetically summed low or arithmetically summed high totals.

Their own assessments of individual permits will span the low, best or high outcomes based on factors including: their strategic objectives and region or geological basin focus; assessment of an asset's prospectivity and associated geological risks; the fiscal and regulatory framework applicable to the asset; accessibility of commercialisation routes, including markets and infrastructure, for each asset; equity interests, operator capability and joint venture partners in each asset.

RISC accounts for the portfolio effects by estimating the low and high values of the portfolio of exploration assets at an estimated one standard deviation from the total mid value of the portfolio. There may be further adjustments required to the range based on judgement taking into account the specifics of the portfolio and market.

Adjusting for portfolio effects, RISC's economic analysis indicates a value range on the AWE exploration assets of between A$11.5 million and A$26.0 million.

Details of the analysis shown in Table 1-6 are contained in our report.

Table 1-6: Economic Analysis of AWE's exploration portfolio, A$ million net to AWE

Project area	Low (A$ million)	Mid (A$ million)	High (A$ million)
Perth Basin	3.1	6.3	11.9
Otway Basin	0	12.5	12.5
Carnarvon Basin	-1.5	0	4.0
Onshore Taranaki Basin	0	0	2.5
West Natuna	0	0	12.5
Total Arithmetic Addition	**1.6**	**18.8**	**43.4**
Total Portfolio	**11.5**	**18.8**	**26.0**

2. Introduction

2.1. Description of the petroleum properties

AWE has a portfolio of producing gas properties in the Perth, Otway and Bass Basins in Australia, undeveloped oil in the Northwest Natuna PSC, Indonesia and exploration tenements in the prospective Perth, Otway, Carnarvon and Taranaki basins Figure 2-1.

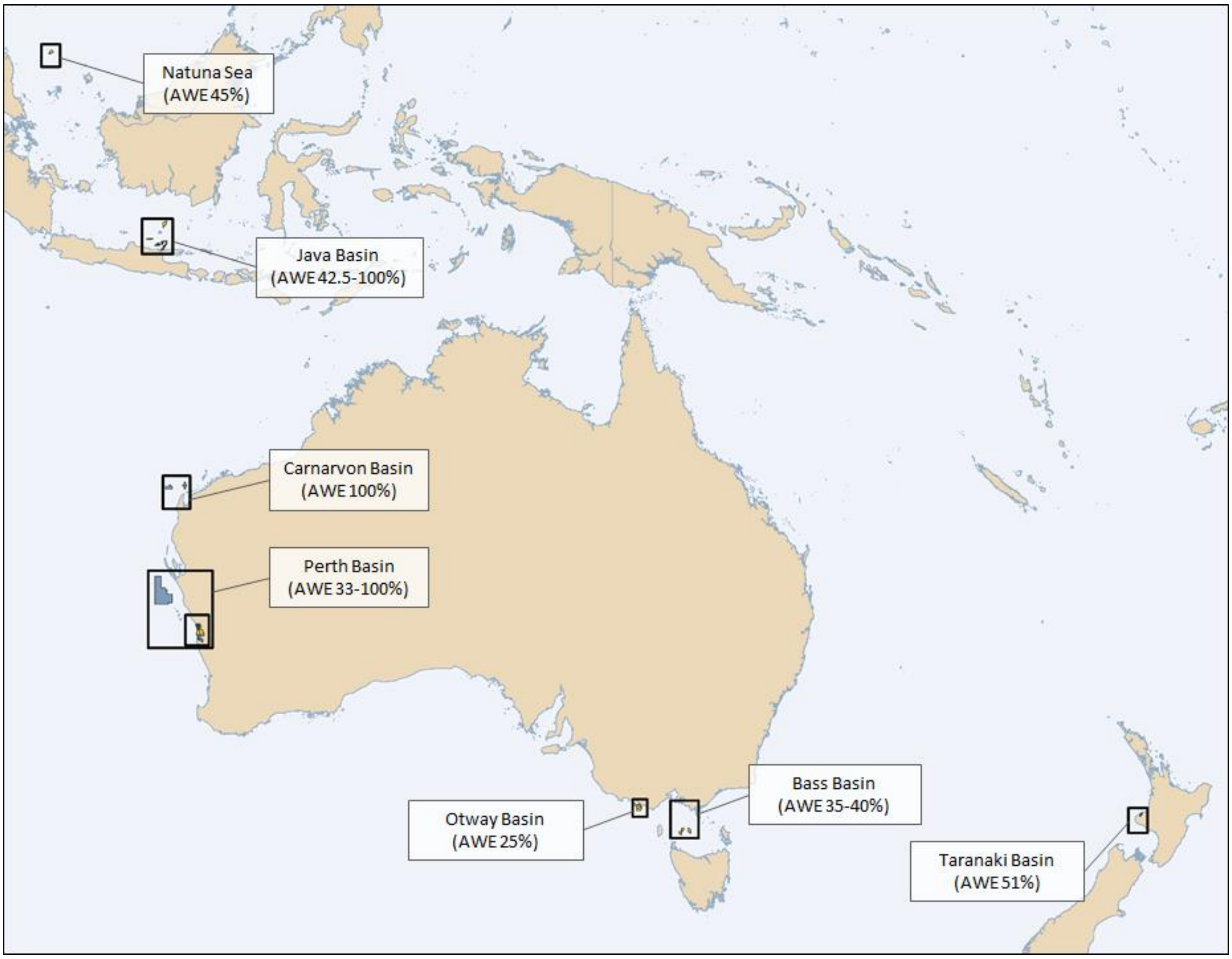


Figure 2-1: Location map for AWE's petroleum tenements

AWE's working interest in the permits ranges from 25% to 100%. Details of the tenements are contained in Table 7-1 and Table 7-2 at the end of this report.

The producing and undeveloped assets which AWE holds are:

- Waitsia Gas Project permits L1, L2 (50% and operator);
- Beharra Springs Gas Project permit L11 (33% non-operated interest)
- Casino Gas Project, permits VIC/L24, VIC/L30 (25% non-operated interest);
- Bass Gas Project, Permit T/L1 (35% non-operated interest) and associated Bass Basin retention leases;

- Ande Ande Lumut oil field in the Northwest Natuna PSC, Indonesia (50%, non-operated interest).

AWE's active gas fields[3] have been producing to the East Coast gas markets since 2006 and the West Coast gas markets since 1991 (Figure 2-2). The Casino and Bass Gas projects also produce appreciable volumes of condensate and LPG, however the Perth Basin assets produce predominantly dry gas. Gross cumulative gas production for the active fields estimated to 31 December 2017 is 575 PJ of gas, 475 ktonne of LPG and 6.9 MMbbl of condensate (Table 2-1).

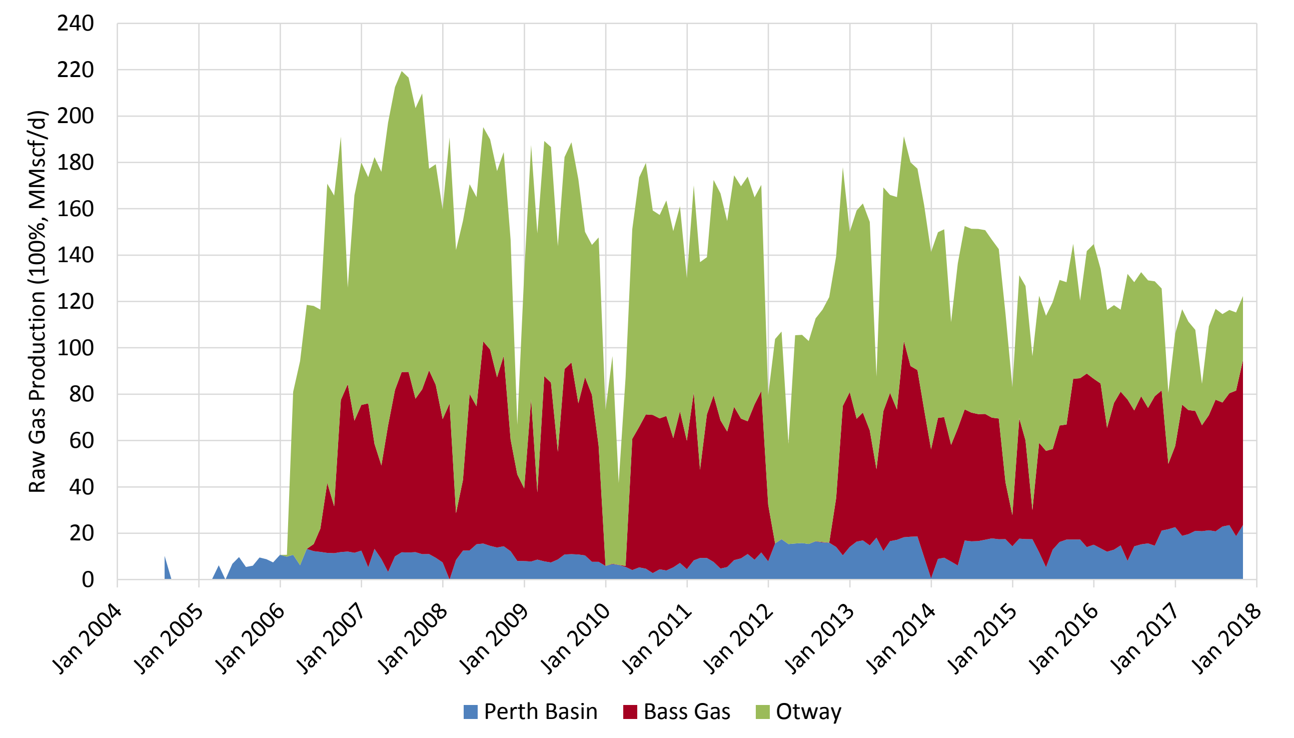


Figure 2-2: AWE's Perth Basin, Otway Basin and Bass Basin Gross Historical Gas Production

Table 2-1: AWE's Perth Basin, Otway Basin and Bass Basin Gross Production to 31 December 2017

Field	Gross Cumulative Production to 31 Dec 2017			
	Gas PJ	Condensate MMbbl	LPG ktonne	Total MMBOE
Perth Basin Fields	42.4	0.0	0.0	7.1
Casino Gas Project	357.9	0.3	0.0	59.9
Bass Gas Project	174.4	6.6	474.6	41.2
Total	574.7	6.9	474.6	108.2

[3] The data shown for the Perth Basin excludes currently shut in fields such as Woodada, Corybas, XAGGS and Apium which there are no firm plans for further production. Production prior to 2004 not shown.

2.2. Terms of reference and basis of assessment

2.2.1. Terms of reference

This assignment has been conducted under the terms of our engagement with AWE dated 13 December 2017 and under the direction of Independent Expert, Grant Thornton. RISC's terms of reference are:

- A review of the technical assumptions underlying the future cash flows of the producing assets including resource and reserve estimation, production volumes, operating expenses, capital costs and other environmental and infrastructure considerations. RISC will advise Grant Thornton Corporate Finance on the reasonableness of these assumptions for valuation purpose and prepare various sensitivity/scenario cases;
- Valuation assessment of the exploration potential not included in the valuation assessment of the producing assets;
- Preparation of the Technical Report for inclusion in the Independent Expert's Report. The Technical Specialist's Report is to be addressed to Grant Thornton.

2.2.2. Basis of assessment

The data and information used in the preparation of this report were provided by AWE supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation on the basis of a review and audit of existing interpretations and assessments as supplied making adjustments that in our judgment were necessary. Our assessment for the producing assets is based on production data up to dates ranging from 31 October to 31 December 2017 and where necessary, has been extrapolated to 31 December 2017 for reserves reporting purposes.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System (PRMS)[4].

We have reviewed the production forecasts, development plans and costs prepared by AWE. The reserves presented in this report are based on long term mid-case oil and gas price projections provided by Grant Thornton of 5.0 – 5.5 A$/GJ real 2018 for WA gas, A$8 – A$9/GJ real 2018 for East Cost gas, 65 – 70 US$/bbl for oil in 2023 increasing with inflation. The long term exchange rates used was 0.75 to 0.80 USD/A$.

Unless otherwise stated, all resources presented in this report are gross (100%) quantities with an effective date of 31 December 2017. Unless otherwise stated, all costs are in A$ real terms with a reference date of 31 December 2017 (RT2018).

2.2.3. Exploration evaluation

A range of oil and gas industry accepted practices can be used to estimate the value of exploration assets and these are discussed below. To assist Grant Thornton with their valuation, RISC has collated the relevant data and information for the alternative valuation methods.

The VALMIN Code defines Value as the amount of money (or the cash equivalent of some other consideration) determined by the Expert in accordance with the provisions of the VALMIN Code for which the Mineral or Petroleum Asset or Security should change hands on the Valuation Date in an open and

[4] SPE/WPC/AAPG/SPEE 2007 Petroleum Resources Management System

unrestricted market between a willing buyer and a willing seller in an "arm's length" transaction, with each party acting knowledgeably, prudently and without compulsion.

Note that in this report, RISC in some instances uses mean or average values for prospective resources. The use of mean resource values is not permitted under ASX rules and should not be used in place of the permitted low, best and high estimates for ASX compliant resource statements. However, RISC's report is not intended to be an Australian Securities Exchange (ASX) compliant prospective resource disclosure. The purpose of using mean or average values is that in our opinion, where used, they may be more appropriate for estimating the fair market value of the exploration portfolio.

2.2.3.1. Comparable transaction metrics

The Value of exploration properties can be estimated using recent comparable transactions. Such transactions may provide relevant metrics such as Value per unit of reserves, contingent or prospective resources, and price paid per unit area of the permit or % interest. The VALMIN Code advises Value must also take into account risk and premium or discount relating to market, strategic or other considerations.

This method has been developed for the AAL project contingent resources.

2.2.3.2. Farm-in promotion factors

An estimate of value can be based on an estimation of the share of future costs likely to be borne by a notional farmee under prevailing market conditions. A premium or promotion factor may be paid by the farmee. The promotion factor is defined as the ratio of the proportion of the activity being paid for and the amount of equity being earned.

The nominal permit value is defined as the amount spent by the farmee divided by the interest earned. The premium value for the permit is the difference between the nominal value and the equity share of the cost of the activity divided by the equity interest being earned.

The premium or promotion factor will be dependent upon the perceived prospectivity of the property, competition and general market conditions. The premium value is equivalent to the farmee paying the farmor a cash amount in return for the acquisition of the interest in the permit and is the fair market value.

Farm-in transactions may have several stages. For example, a farmee may acquire an initial interest by committing to a future cost in the first stage of the transaction, but has an option to acquire an additional interest or interests in return to committing to funding a further work programme or programmes.

Farm-in agreements can also include re-imbursement of past costs and bonus payments once certain milestones are achieved, for example declaration of commerciality, or achieving threshold reserves volumes. Depending on their conditionality, such future payments may contribute to value. However, they may need to be adjusted for the time value of money and probability of occurring.

This method has been developed for selected exploration assets.

2.2.3.3. Work programme

The costs of a future work programme may also be used to estimate value. The work programme valuation relies on the assumption that unless there is evidence to the contrary the permit is worth what a company will spend on it. This method is relevant for permits in the early stages of exploration and for expenditure which is firmly committed as part of a venture budget or as agreed with the government as a condition of holding the permit. There may need to be an adjustment for risk and the time value of money.

This method has been developed for selected exploration assets.

2.2.3.4. Expected monetary value (EMV)

EMV is calculated as the success case NPV times the probability of success less the NPV of failure multiplied by the probability of failure. The EMV method provides a more representative estimate of value in areas with a statistically significant number of mature prospects within proven commercial hydrocarbon provinces where the chance of success and volumes can be assessed with a reasonable degree of predictability. EMVs may require discounting to estimate market value depending upon project maturity and uncertainty.

The EMV valuation can also be used as a relative measure for ranking exploration prospects within a portfolio to make drilling decisions, assessing commercial potential and to demonstrate the commercial attractiveness of a permit, which may influence a buyer or seller.

2.2.3.5. Market factors

Since the latter part of 2014, oil prices have substantially declined from around the US$100/bbl to under US$30/bbl in January 2016. They have since recovered somewhat and are trading near US$65/bbl at the time of writing this report (Figure 2-3). AWE's share price has tracked the oil price closely prior to the proposed transaction.

Figure 2-3: Brent oil price and AWE share price 2014-2017

Prior to the oil price decline, interest in exploration valuations was high and farm-in promotes of 2 or greater were being seen for quality acreage with large investment programs. Since then, there has been a paucity of transactions and anecdotally, RISC has identified that buyers are seeking farm-in promotes at or just above ground floor level.

In response to the market factors, our experience has been that oil and gas companies have slashed their exploration budgets and the value of exploration companies has declined significantly, although there are some signs that with the stabilisation and partial recovery in prices, exploration activity is beginning to improve. Figure 2-4 shows the change in market capitalisation[5] for selected ASX listed oil and gas companies with an exploration bias with conventional portfolios from October 2014 to December 2017. Out of the 24 companies evaluated, 6 have de-listed or have been suspended (not shown in Figure 2-4), 6 have increased their market capitalisation and the remaining 12 companies have shown significant reductions[6], averaging approximately 45% of their 2014 value (100% being equivalent to the 2014 value).

Consequently, it is to be expected that unless there are special circumstances, market factors will result in significant reduction in the value of oil and gas exploration portfolios since October 2014.

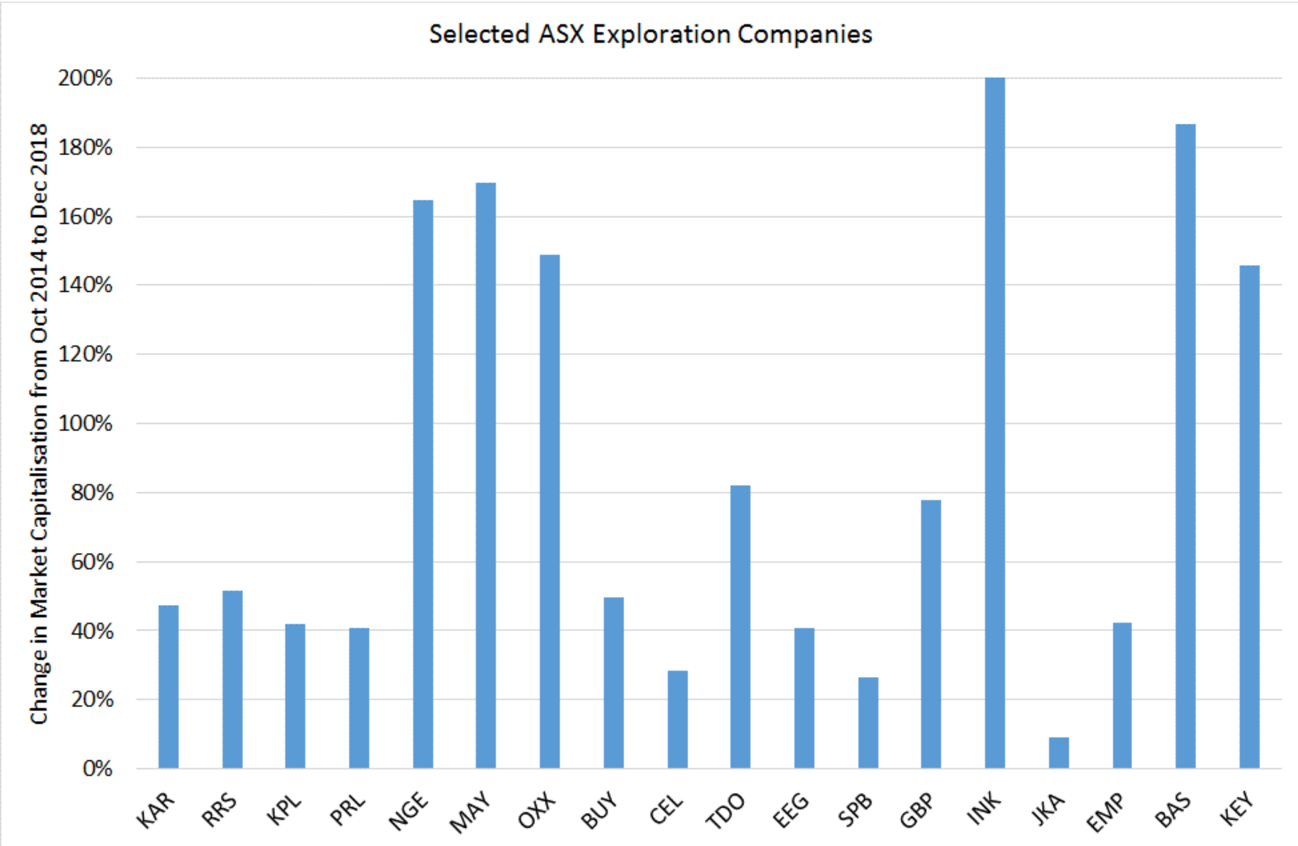


Figure 2-4: December 2018 Market Capitalisation compared to Oct 2014 for selected ASX listed exploration companies

[5] Enterprise value is calculated as the market capitalization plus debt, minority interest and preferred shares, minus total cash and cash equivalents.
[6] The scale of the vertical axis is been truncated at 200% to improve its readability.

3. Geological overview

3.1. Perth Basin

The following summary of the regional geology of the Perth Basin is reproduced from Geoscience Australia's website[7] which is recommended as a useful reference source.

The Perth Basin is a north to north-northwest trending, onshore and offshore sedimentary basin extending about 1,300 km along the southwestern margin of the Australian continent. This is a large (172,300 km^2), structurally complex basin that formed during the separation of Australia and Greater India in the Permian to Early Cretaceous. It includes a significant onshore component and extends offshore to the edge of continental crust in water depths of up to 4,500 m.

The structural architecture of the Perth Basin is the product of rifting during the Permian, Late Triassic to Early Jurassic and Middle Jurassic to Early Cretaceous, superimposed over pre-existing basement terrains. Extension during the Permian produced a series of deep (up to 15 km), north-south trending rift basins (Bunbury Trough and Dandaragan Trough) along the western margin of the Yilgarn Craton. The Abrolhos Sub-basin represents a northwestern branch of the Permian rift system formed along the southwestern margin of the Northampton Complex, which is separated from the Dandaragan Trough by an intra-basin high represented by the Beagle Ridge, Dongara Terrace and Greenough Shelf, Figure 3-1.

[7] http://www.ga.gov.au/scientific-topics/energy/province-sedimentary-basin-geology/petroleum/offshore-southwest-australia/perth-basin

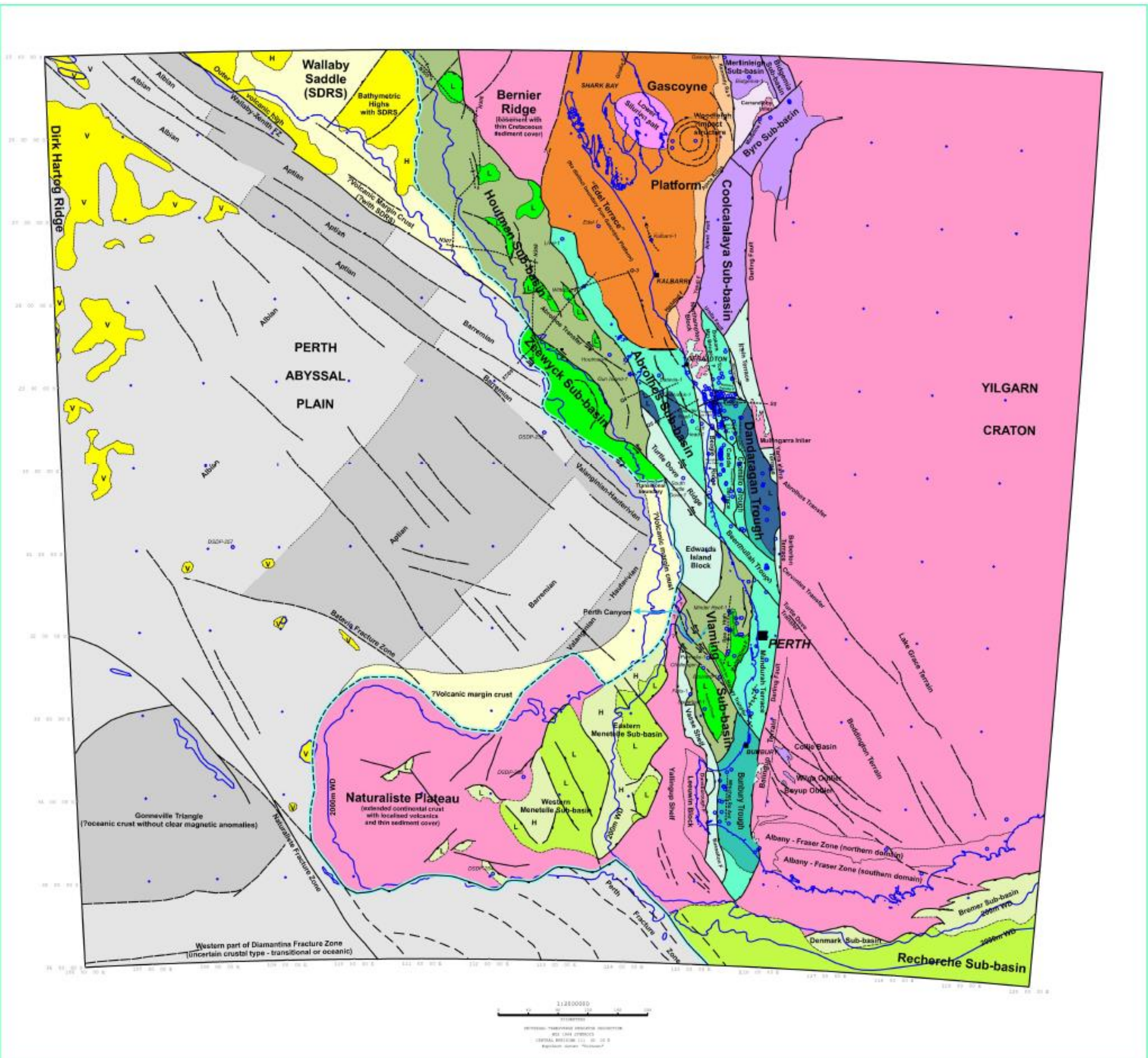


Figure 3-1: Regional setting and structural elements map for the Perth Basin (© Commonwealth of Australia (Geoscience Australia) 2014)

The Houtman Sub-basin is a major depocentre for Triassic and Jurassic sedimentary rocks that formed as a westward thickening sag basin across a hinge zone during the Middle Triassic to Middle Jurassic, and was extensively faulted during Late Jurassic to Early Cretaceous rifting. The Vlaming Sub-basin is the major Middle Jurassic to Early Cretaceous rift basin in the Perth Basin and is characterised along its northern extent by a very large and deep half graben that dips to the west. The footwall block of this half graben consists of a series of shallow tilted fault blocks containing mainly Permian and older strata from the Edward's Island Block.

Breakup during the Early Cretaceous (Valanginian) was associated with widespread inversion, erosion, strike-slip tectonics and volcanism, which significantly modified the structural architecture of the Perth Basin.

The stratigraphy and petroleum system elements of the Perth Basin developed during the tectonic evolution of the basin and vary significantly from north to south. Refer to Figure 3-2 which is a stratigraphic column applicable for the North Perth Basin and relevant to AWE's petroleum permits. Initial rifting established a series of Permian to Early Triassic depocentres for fluvial and marine siliciclastics with minor carbonates and coals in the north, while in the south fluvial siliciclastics and coals dominated. These Permian and Early Triassic-age rift-sag deposits are associated with the major petroleum system in the North Perth Basin, particularly the Kockatea Shale which forms an important oil source rock and regional seal to underlying reservoirs.

Sandstone reservoirs relevant to AWE's permits are:

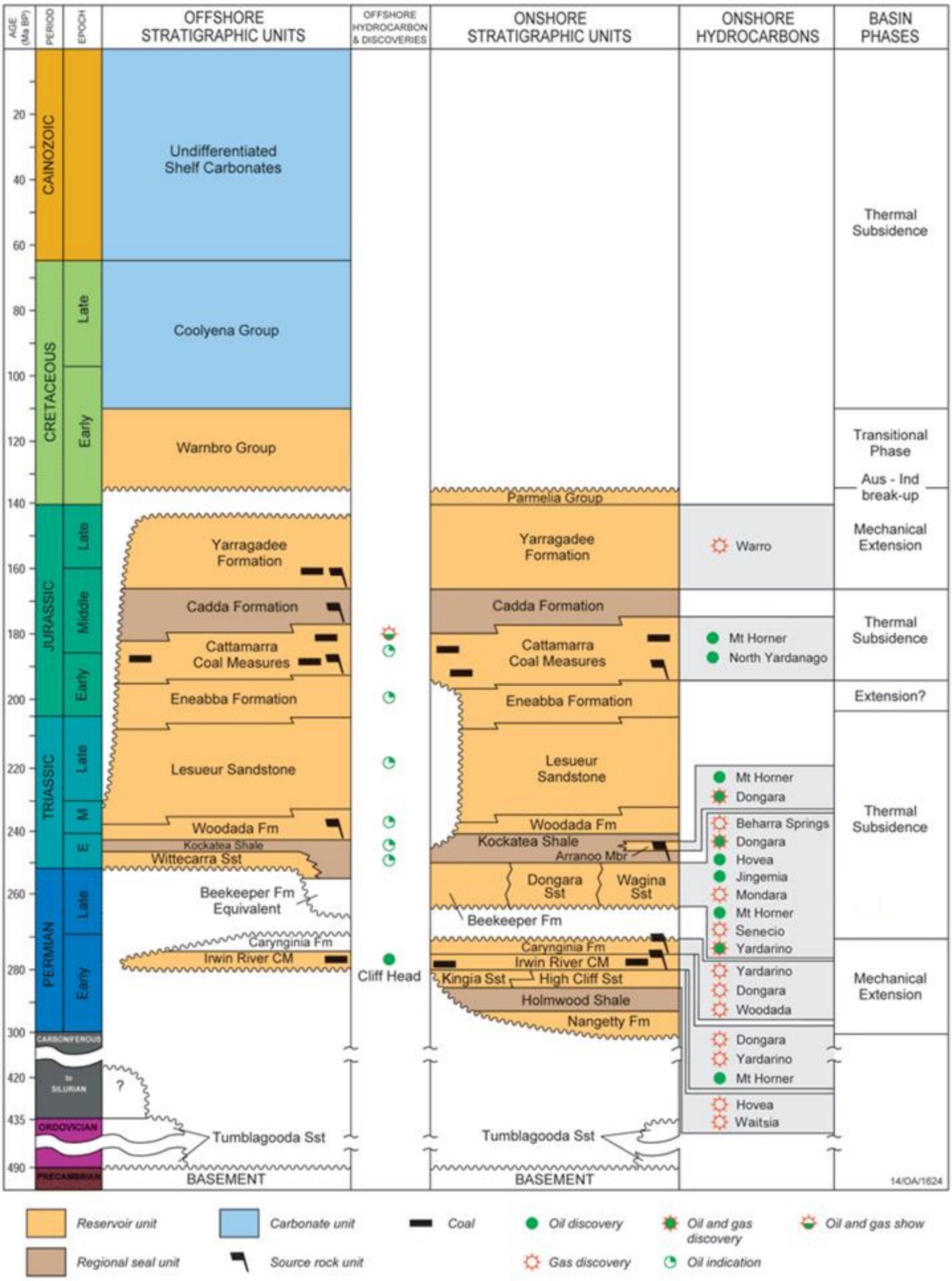
- Waitsia-Senecio Area: Early Permian Kingia Sandstone, High Cliff Sandstone and Irwin River Coal Measures (IRCM); the late Permian Dongara Sandstone;
- Beharra Springs/Redback Terraces/Tarantula: Late Permian Wagina Formation;

Prospective shale gas targets are the Early Permian Carynginia Formation and the Triassic Kockatea Shale (Hovea Member).

A second phase of rifting in the Late Triassic and Early Jurassic was associated with widespread fluvial and deltaic deposits, including a thick succession of siliciclastics and coals (Cattamarra Coal Measures), which are overlain by Middle Jurassic marine shales (Cadda Formation) in the north Perth Basin.

It is uncertain which petroleum system elements are associated with the Zeewyck Sub-basin. However, it may contain Middle Jurassic to Early Cretaceous age source rocks. Late Cretaceous and Tertiary sedimentation has occurred under stable passive margin conditions and produced a thin cover of predominantly marine carbonates. Potential traps include tilted fault blocks, anticlines, compressional rollovers and structural/stratigraphic traps.

Northern Perth Basin Stratigraphy



Stratigraphy, petroleum systems elements, and major basin phases of the Northern Perth Basin.

Figure 3-2: North Perth Basin stratigraphic column (© Commonwealth of Australia (Geoscience Australia) 2017)

The exploration status of the Perth Basin varies from sub-mature in the northern onshore area and immature to frontier in most offshore areas.

Initial exploration for hydrocarbons in the Perth Basin began in the late 1940s with an onshore field survey and evaluation of water drilling commissioned by Ampol and Richfield Oil companies and gravity surveys by the Bureau of Mineral Resources.

The onshore portion has had approximately 130 exploration wells drilled. Approximately 70 wells have been drilled in the vicinity of AWE's permits and these provide a reasonable database for reservoir characterisation and resource estimation.

Offshore exploration began in 1965. The most significant offshore discovery to date is the Cliff Head oil field located on the Beagle Ridge just east of the Abrolhos Sub-basin. Oil is produced from Permian reservoirs that are sealed by the Kockatea Shale.

3.2. Otway Basin

The Otway Basin is part of the Southern Rift System, the passive margin rift basin that formed as a product of the rifting of Australia from Antarctica during the breakup of the supercontinent Gondwana. It is situated in SW Victoria and SE South Australia, covering 150 000 km^2, 80% of which is offshore (Figure 3-3). There are two major depocentres (the onshore and shallow Inner Otway Basin, and the deeper water Morum, Nelson and Torquay Sub-basins). These were filled principally by siliciclastic and carbonate sediment during the Cretaceous Period (Figure 3-3)[8].

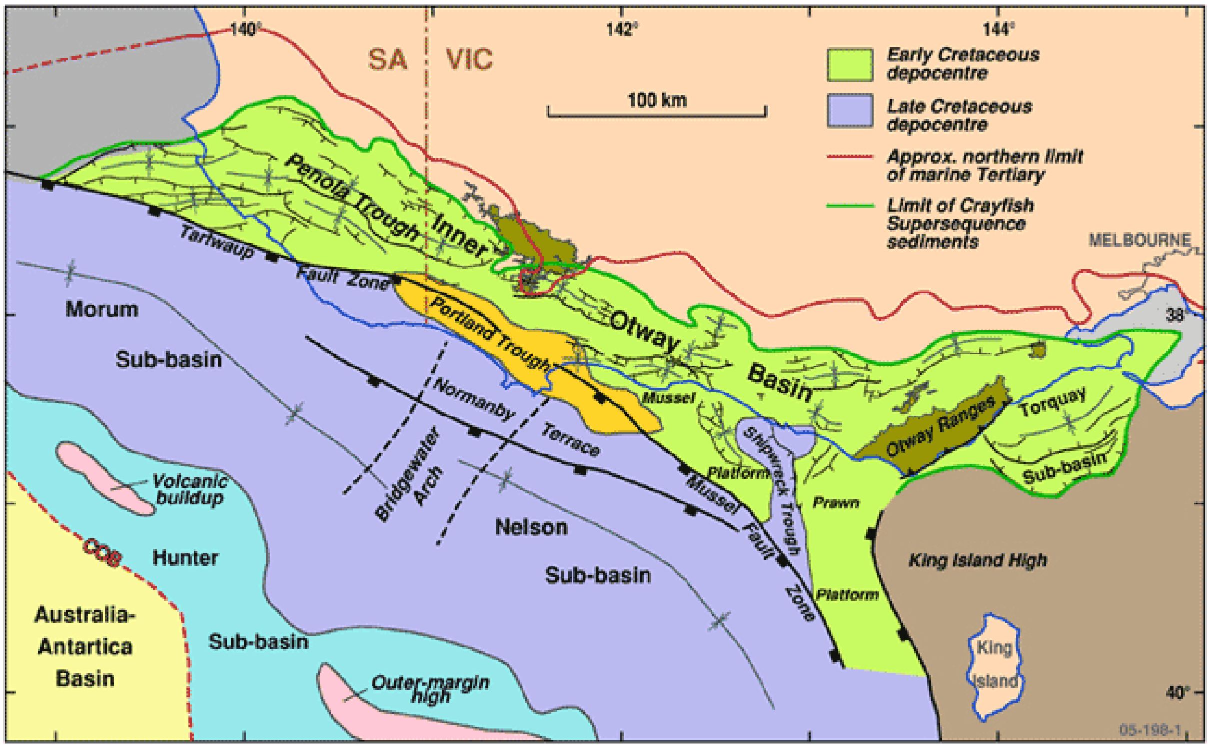


Figure 3-3: Tectonic element map for Otway Basin[8]

Petroleum occurrences are attributed to the Austral Petroleum Supersystem. The best reservoir is the Pretty Hill Formation, which exhibits 25% porosity and over 1000 mD permeability in the Katnook field. The Pretty

[8] Geoscience Australia, Regional Geology of the Otway Basin. Offshore Petroleum Exploration Release, 2015.

Hill Formation is a braided fluvial sandstone, which is overlain by the sealing fluviolacustrine shales of the Laira Formation. Structures are steep sided, east-west trending, faulted anticlines, where Pretty Hill Formation has been juxtaposed against Laira Formation. Other good reservoir rocks are the Windemere, Waare, Flaxman and intra-Belfast units. In the Windemere unit, traps are unfaulted, low relief domes, sealed by overlying silts and shales of the Eumeralla Formation. Source rocks for the systems are the Casterton and Laira Formations (Figure 3-4).

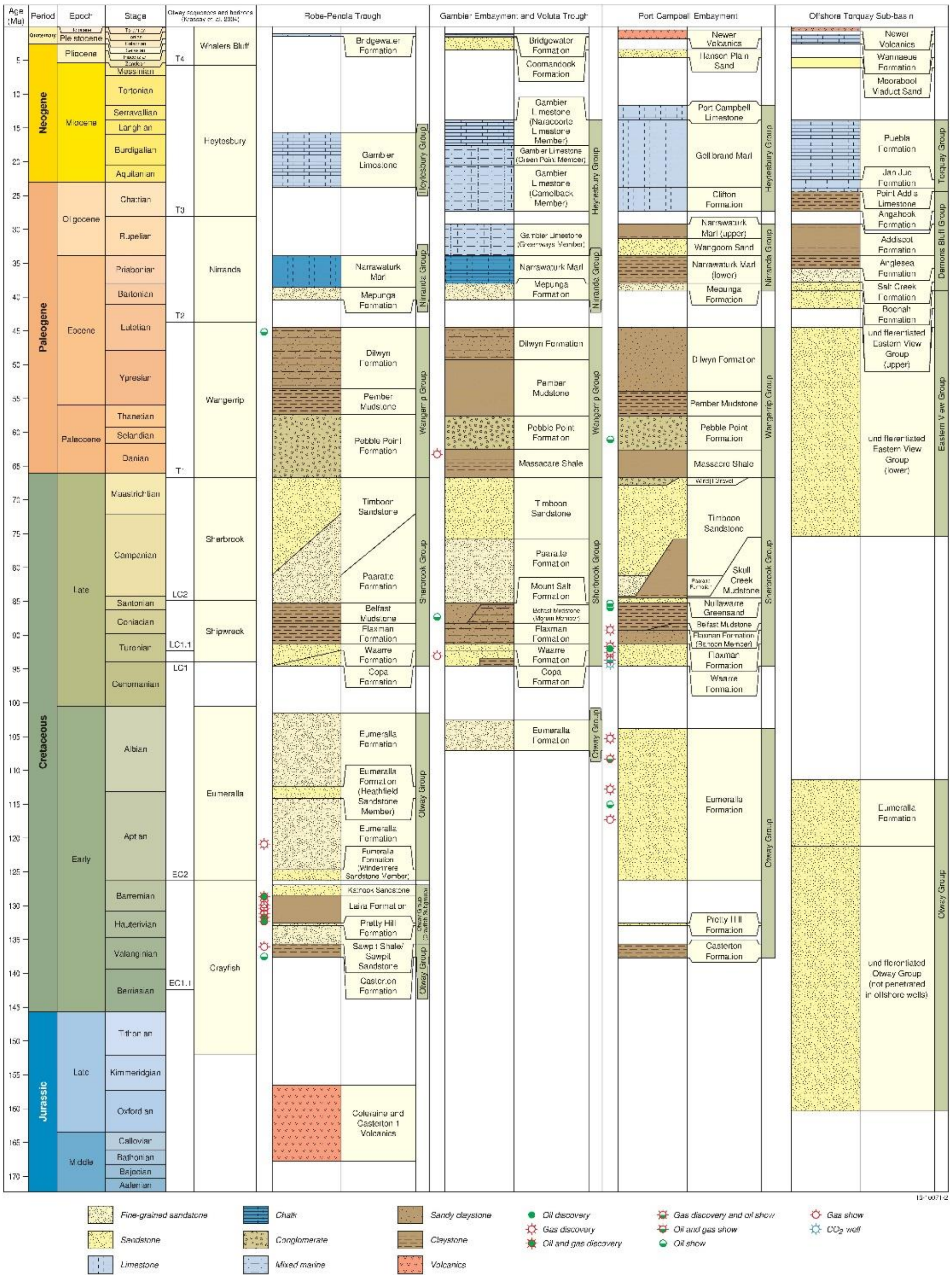


Figure 3-4: Otway Basin stratigraphic column (Commonwealth of Australia (Geoscience Australia) 2017)

The basin has been explored since the 1980s, with the first commercial gas discovery in 1987. This was the Katnook Field, which was followed by the Ladbroke field in 1989. More recently there has been exploration success in the Shipwreck Trough with the discovery of the Casino gas field in 2002 by Strike Energy. This was followed by further discoveries in Henry and Netherby which together with Casino form the Casino Gas Project. In the early nineties, BHP drilled the Minerva and La Bella fields. Between 1999 and 2005, Woodside discovered the Geographe, Thlyacine, Halladale and Black Watch gas fields. In addition, Origin Energy recorded a discovery in their Speculant 1 well in 2014.

3.3. Bass Basin

The Bass Basin is a moderately explored Cretaceous to Cainozoic intra-cratonic rift basin on Australia's south-eastern margin, underlying the shallow seabed between Tasmania and the Victorian mainland (Figure 3-6) The basin contains proven commercial reserves of gas and condensate that are producing (Yolla Gas Field, AWE's non-operated Bass Gas Project). Other discoveries in the basin include the White Ibis, Bass, Trefoil, Rockhopper and Pelican fields. To date, the wells drilled have targeted Upper Cretaceous to Middle Eocene reservoirs within fault blocks and anticlinal structures. The targeted succession comprises interbedded fluvio-deltaic and lacustrine sandstones, siltstones and shales. The principal source rocks in the Bass Basin are interbedded coals (ranging from 5 to 25 m thick) and lacustrine shales of early Palaeogene age. Geochemical analyses show these source rocks have generated liquid and gaseous hydrocarbons, with the coals being the dominant source of the liquids. Igneous rocks are common throughout the basin as sills and flows, often associated with large rift faults and accommodation zones [9]

The Bass Basin is one of a series of sedimentary basins that were formed in response to rifting during the Late Jurassic to Early Cretaceous between Australia and Antarctica. The Bass Basin covers approximately 65,000 km^2 and water depths range from 30 to 90 m. The Bass Basin is a failed intra-cratonic rift basin with structural features which highlight three separate phases of evolution: 1) initial northeast-southwest extension during the early Cretaceous, 2) Late Cretaceous to Pliocene thermal subsidence and 3) Miocene compression[10].

The rifting created a series of northwest-southeast oriented grabens offset by associated east-west wrench movement. The Pelican, Yolla and Cormorant Troughs comprise the major depocentres in the Bass Basin. The Trefoil structure is located on the flanks of the Yolla Trough. These depocentres are fault-bounded half-grabens that progressively developed via growth faulting during the active rifting and thermal subsidence phases of basin evolution. The dominant structural trend in the basin is northwest-southeast, highlighted by the orientation of the major faults and troughs.

[9] Geoscience Australia Record 2003/19 Petroleum Geology of the Bass Basin
[10] Trefoil-2 Well Completion Report

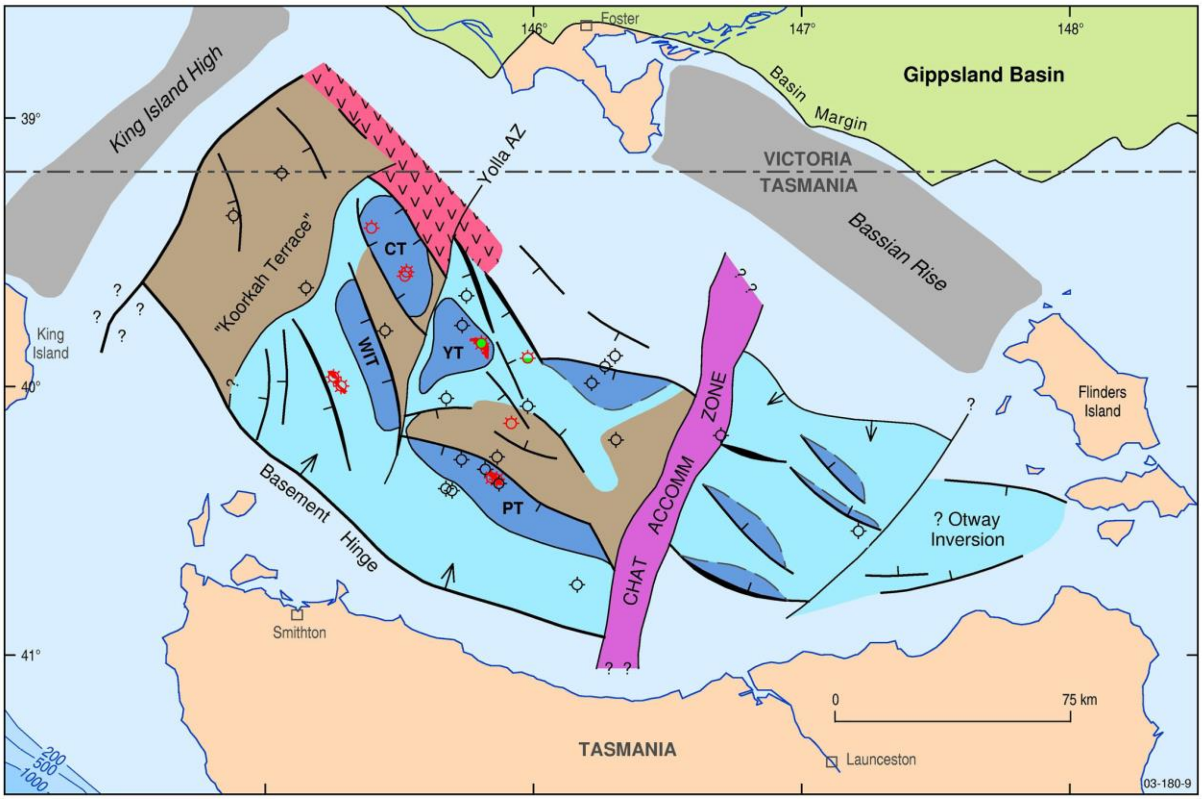


Figure 3-5: Regional map showing the location of tectonic elements and generalised basement fault trends in the Bass Basin (Source - Geoscience Australia Record 2003/19)

The stratigraphic succession in the Bass Basin comprises sediments ranging in age from Early Cretaceous to Recent (Figure 3-6).

The Early Cretaceous Otway Group rests unconformably on pre-rift Palaeozoic black shales and quartzites and consists of clastic, volcaniclastic, fluvial and deltaic sediments ranging from coarse-grained sandstone to shale and coal. The Otway Group was deposited as a very thick sequence of sediments (C.australiensis to C.paradoxus) that have been intersected in the Bass Basin at only one locale, Durroon-1, in the extreme southeast[11].

Localised uplift and erosion then occurred on the basin margins as the initial rifting phase subsided (Middle Cretaceous). The Otway Drift phase then began along the southern margin of Australia, which was largely contemporaneous with the start of the Tasman Rifting event on the eastern edge of the southern margin. This recommenced rifting in the Bass Basin, which resulted in deposition of the prospective Early Cretaceous to Late Eocene Eastern View Coal Measures (EVCM), comprise a thick succession of sandstone, siltstone, shale and coal, deposited primarily within fluvial, deltaic and lacustrine depositional environments. Seismic data suggests that the EVCM is over 4000 m thick in the Troughs. The EVCM thins markedly towards the basin margins and exhibits both onlap onto basement and erosional truncation. In a broad sense, the EVCM can be divided into three sequences separated by erosional unconformities. The middle sequence was penetrated in Bass 1, Yolla 1 and 2, amongst others, and contains the major gas accumulations in the discoveries. This sequence is bounded at the base by the N. senectus unconformity and at the top by the upper M. diversus unconformity.

[11] Trefoil-2 Well Completion Report

The Lower Eastern View Coal Measures (EVCM) depositional sequence was deposited from Cenomanian to Santonian times (A.distocarinatus to N.senectus). These units have only been intersected in Durroon 1 in the southeast of the Bass Basin and are equivalent to the Golden Beach Group in the Gippsland Basin.

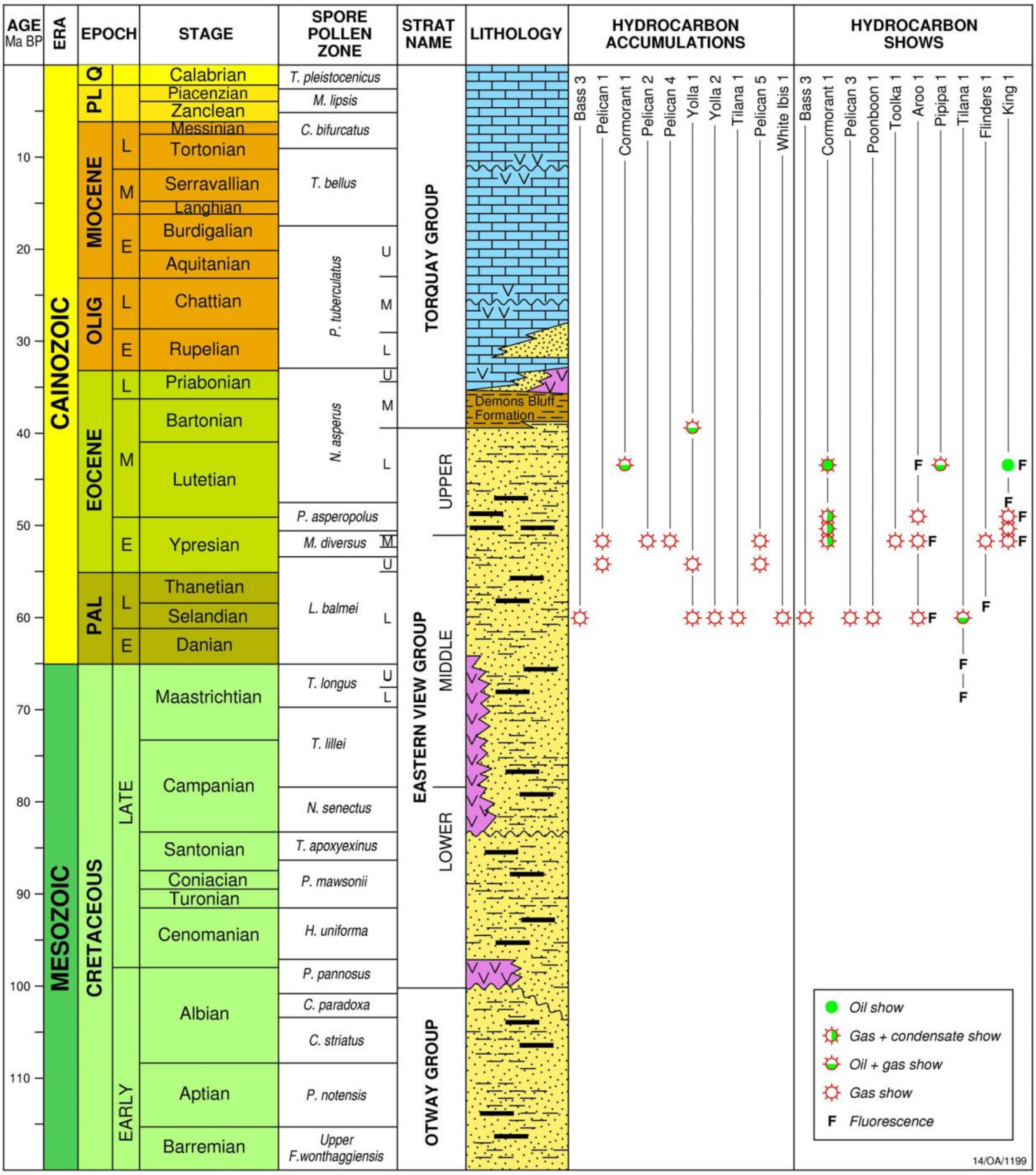


Figure 3-6: Generalised stratigraphy of the Bass Basin (after Lennon et al., 1999), including hydrocarbon accumulations and shows

An angular unconformity is identified over localised highs on the basin margins at the top of the N.senectus zone. The boundary is marked in places by significant volcanism, similar to that observed in the Gippsland Basin. This event signals the termination of Tasman rifting, which was followed by sea floor spreading in conjunction with the already active drift in the Otway region. During this time, thermal subsidence dominated throughout the basin and thick, ubiquitous deposition of the Late Cretaceous to Paleocene Lower EVCM occurred (T.lilliei to Lower M.diversus/P.asperopolus).

The EVCM has been intersected in numerous wells in the basin, identifying it as a continuous sequence of late low stand sediments grading through a transgressive systems tract and finally capped by high stand sediments. Environments are gradational both laterally and temporally from alluvial through fluvio-deltaic and nearshore to deeper restricted lacustrine. Primary sediment input to the basin was from the south east with minor localised input also deposited transversely from the flanks of the troughs. Extensive coal measures dominate the sedimentary sequence in the southeast of the basin (Pelican Trough) with increasingly thicker homogeneous shale units occurring through the Yolla and Cormorant Troughs.

The top of the middle EVCM is identified by localised uplift and inversion of the pre-existing sedimentary sequence, caused by mild regional compression. The effects of this uplift are variable with the degree of erosion extending from the Mid M.diversus through to the P.asperopolus in places.

The Eocene upper EVCM (Mid M.diversus/P.asperopolus to Mid N.asperus) was then deposited under a regime of slower subsidence, resulting in more widespread, highly variable facies development. Fluctuating conditions of alluvial, fluvio-deltaic and shallow marine processes resulted in more extensive deposition of coal dominated sediments. A regional marine transgression then occurred, resulting in the basin-wide deposition of the Demons Bluff, the base of which is marked by a locally very thick transgressive sand.

Conformably overlying the EVCM is the Late Eocene Demon’s Bluff Formation. Lithologically this unit consists of a basal sequence of fine-grained carbonaceous shale and siltstone deposited in an open marine environment. The unit has an average thickness over the basin of approximately 120 m, but thins toward the basin margins. The Demon’s Bluff Formation provides a regional top seal to hydrocarbons reservoired in the top-most sandstone units of the EVCM as demonstrated in Yolla 1.

3.4. Carnarvon Basin

The Northwest Shelf area was initially part of an extensive Palaeozoic to Triassic rift basin. During the Jurassic and Early Cretaceous a series of rift basins and platforms developed along the northwest shelf as a result of the continental break-up of Gondwanaland. Four discrete sub-basins evolved during that period, these being the Barrow Sub-basin, the Dampier Sub-basin, the Exmouth Sub-basin, and the Beagle Sub-basin (Figure 3-7).

The Palaeozoic-Recent Northern Carnarvon Basin is a large, mainly offshore, basin on the northwest shelf of Australia, which is Australia's premier hydrocarbon province. The major basin faults trend north or northeast and define a series of structural highs and sub-basins. The basin developed during four successive periods of extension and thermal subsidence. The first phase, Silurian to Permian, developed as a series of intracratonic basins during the breakup of Gondwana along the western margin of Australia. Subsequent Early Jurassic extension initiated the four main depocentres - the Exmouth, Barrow, Dampier and Beagle Sub-basins. A third extension phase in the Middle Jurassic resulted in the seafloor spreading in the Argo Abyssal Plain to the north and the fourth Tithonian-Valanginian rifting phase culminated in the creation of the Gascoyne-Cuvier abyssal plains to the west and south. The extensive deep-water (800 - 3000 m) Exmouth Plateau forms a bathymetric plateau outboard of the main depocentres and developed in response to thermal sag after Valanginian breakup.

The main depocentres contain up to 15 km of sedimentary infill. Triassic to Early Cretaceous deposition is dominantly siliciclastic deltaic to marine, whereas slope and shelfal marls and carbonates dominate the Mid-Cretaceous to Cainozoic section. The carbonate-rich sediments were deposited as a series of northwestward prograding wedges as the region continued to cool and subside. This resulted in deep burial of the underlying Mesozoic source and reservoir sequences in the inboard part of the basin.

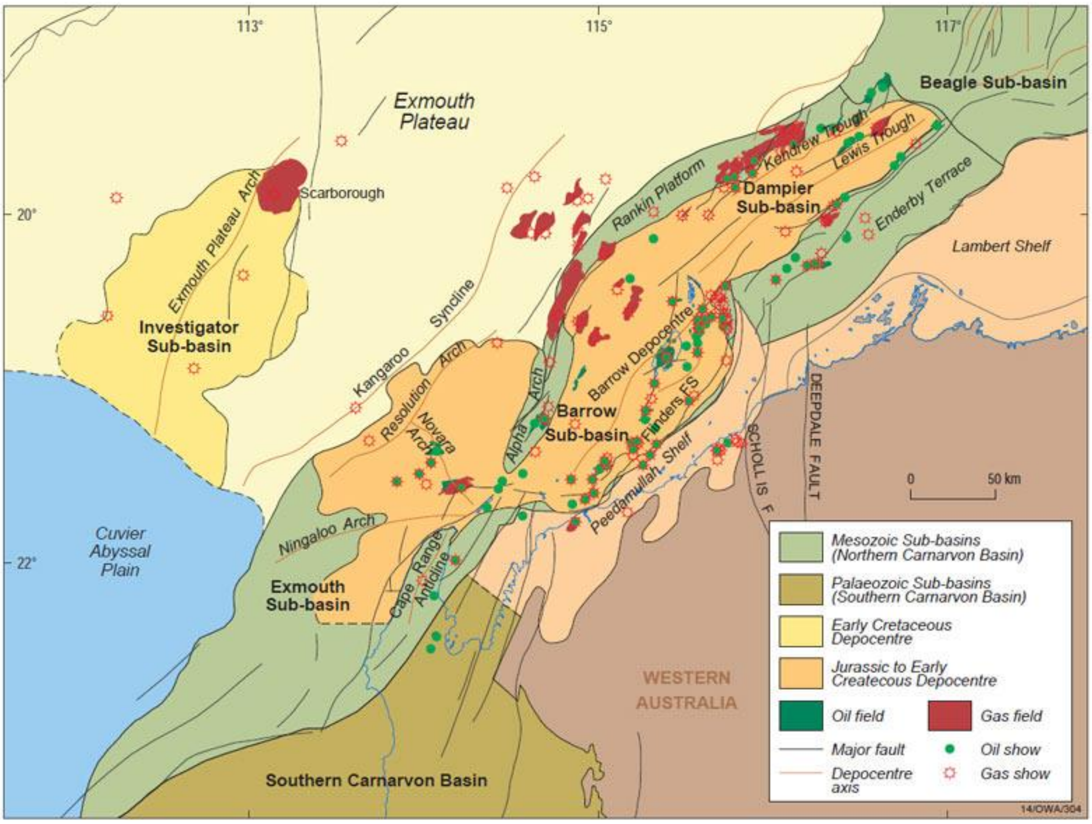


Figure 3-7: Sub basin layout of the North West Shelf area

Almost all the hydrocarbon resources in the basin are reservoired within the Upper Triassic, Jurassic and Lower Cretaceous sandstones beneath the regional Early Cretaceous seal.

The Lower Triassic section in the Carnarvon Basin is marked by a regional marine transgression that represents the sag phase of a previous Paleozoic rift cycle. The marine Locker Shale unconformably overlies the Permian section and grades upwards into the Middle-Upper Triassic Mungaroo Formation (Figure 3-8). The Mungaroo Formation was deposited in a broad, low relief, rapidly subsiding fluvio-deltaic coastal plain that extended across the Exmouth Plateau. During marine transgression in the latest Triassic (Rhaetian), carbonate patch reefs developed on the Wombat Plateau and probably extended across the northern- and western-central parts of the Exmouth Plateau, while marls, siltstones and thin sandstones (Brigadier Formation) were deposited elsewhere.

As rifting proceeded between Australia and Greater India, several faulting episodes occurred in the Jurassic. In the Pliensbachian, rifting inboard of the Exmouth Plateau formed the Exmouth, Barrow and Dampier sub-basins. Several kilometres of marine Jurassic sediments, equivalent to condensed sections on the central Exmouth Plateau (Dingo Claystone equivalents), were deposited in these troughs. Major rift-fault movement occurred in the Callovian with oceanic crust created in the Argo Abyssal Plain in the late Oxfordian, and in the Gascoyne and Cuvier abyssal plains in the Valanginian.

During the Late Jurassic in the eastern Exmouth Sub-basin, sandy shelfal facies were deposited within restricted shallow depocentres (including the Oxfordian Jansz Sandstone reservoir at the supergiant Io-Jansz gas accumulation). In the Early Cretaceous the Barrow Group delta prograded northward across the southern portion of the plateau to form a major sediment lobe with the shelf edge arced through or near the Investigator-1 and Zeepard-1 well locations. A distal claystone equivalent (Forestier Claystone) was deposited to the north of the delta lobe. Barrow Group basin floor fans form the reservoir at the Scarborough gas field.

As the newly formed oceanic crust of the Argo, Gascoyne and Cuvier abyssal plains rapidly subsided, the area was progressively transgressed throughout the Cretaceous by shallow marine mudstone (Muderong Shale) and siltstone (Gearle Siltstone), mid-outer shelf marl and chalk (Toolonga Calcilutite), and finally Cenozoic bathyal chalk and ooze.

The Triassic sedimentary succession has proven potential for mature source facies, including possible organic-rich units in the lower Triassic (marine locker shale equivalents) and upper Triassic (deltaic Mungaroo Formation facies and marine equivalents). The upper Jurassic Dingo Claystone is the principal source for oil in the Exmouth sub-basin. Migration of gas through the area has been proven by the presence of several accumulations to the north, including Spar and Gorgon. Hydrocarbon generation from the gas-prone Mungaroo formation system and older Triassic source rocks presumably occurred in the Exmouth sub-basin during the Jurassic with the deposition of kilometres of dingo claystone and other sediments in the main depocentre.

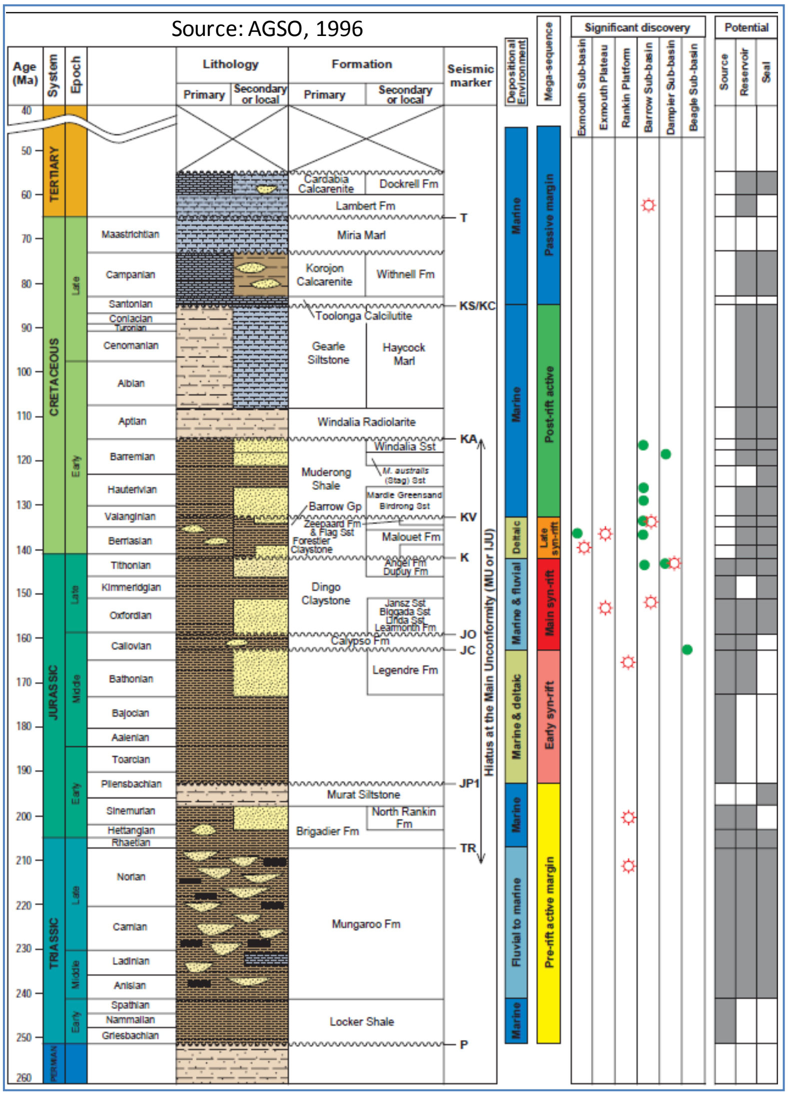


Figure 3-8: Regional Stratigraphy of the Northern Carnarvon Basin

3.5. Taranaki Basin

The Taranaki Basin which covers 330,000 km^2, mostly offshore, to the west of New Zealand's North Island (Figure 3-9)[12], was initiated by rifting at the onset of the breakup of Gondwana in the late Jurassic period. Terrestrial conglomerates and delta facies rocks of the Taranaki Delta and Rakopi formations were deposited, along with shallow marine sands of the North Cape formation (Figure 3-10). To the south east of the basin, the North Cape Formation is overlain by sandstones of the Farewell, Kaimiro and Mangahewa formations, all successfully tested reservoirs. After seafloor spreading began in the Late Cretaceous, a thick sequence of mudstone and shales were deposited as the Turi formation – a good seal for the North Cape reservoirs below. By the Oligocene, sedimentation was carbonate dominated, resulting in the deposition of marl as the Tikorangi Formation. Subduction in northern New Zealand, which initiated in the Neogene, resulted in uplift and erosion associated with volcanic activity. Terrestrial clastics were deposited as sandstone in turbidites close to shore in the southeast coastal area and some volcanicalstics. Reservoir rocks are sealed by the shales and muds of the Manganui Formation. Plays are dominantly structural, with companies mostly targeting

[12] New Zealand Petroleum and Minerals, 2013, New Zealand Petroleum Basins, Part 1.

anticlinal or four-way dip closures. Structures were produced by the Late Cretaceous rifting, followed by Miocene compression, trapping hydrocarbons at all stratigraphic levels. Half graben fill, submarine fans, buried volcanic complexes and diagenetic trap plays have also been tested.

All of New Zealand's oil and gas is produced from the Taranaki Basin. In 2013, the basin was producing 460 MMscf/day of natural gas, and 55,000 bbl/day of oil[12]. Significant offshore producing fields are Pohokura and Kupe (gas-condensate), Maui (gas-condensate and oil), Tui and Maari-Manaia (oil). Onshore, the significant producing fields are Mangahewa and Kapuni (gas) and McKee (gas and oil). Over 400 wells have been drilled, which have predominantly targeted structures on the continental shelf; deeper water areas remain unexplored.

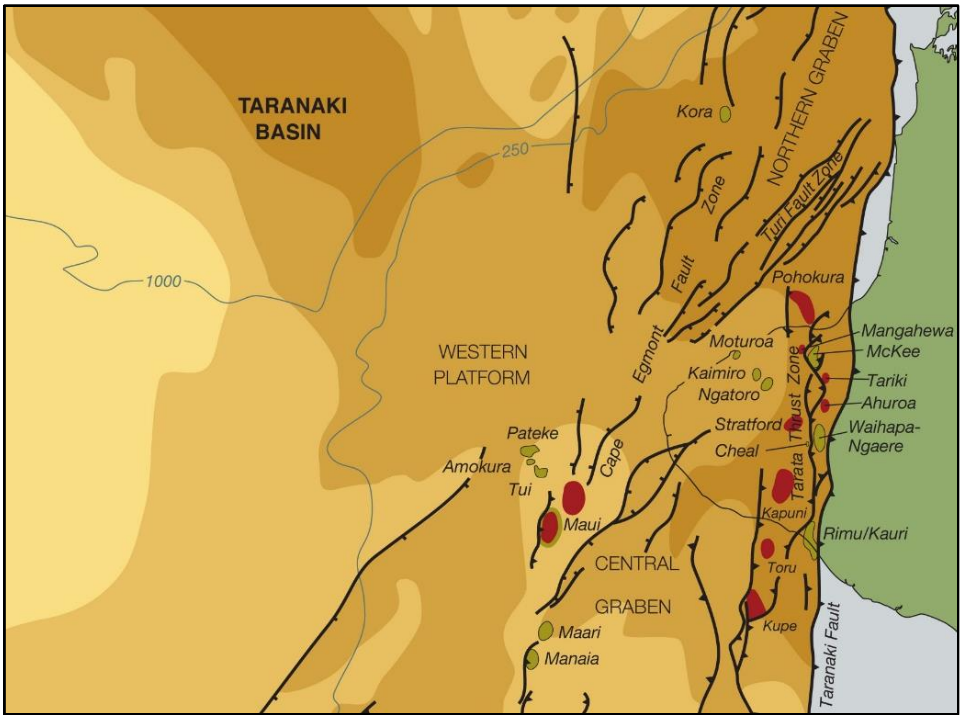


Figure 3-9: Location map for the Taranaki Basin[12]

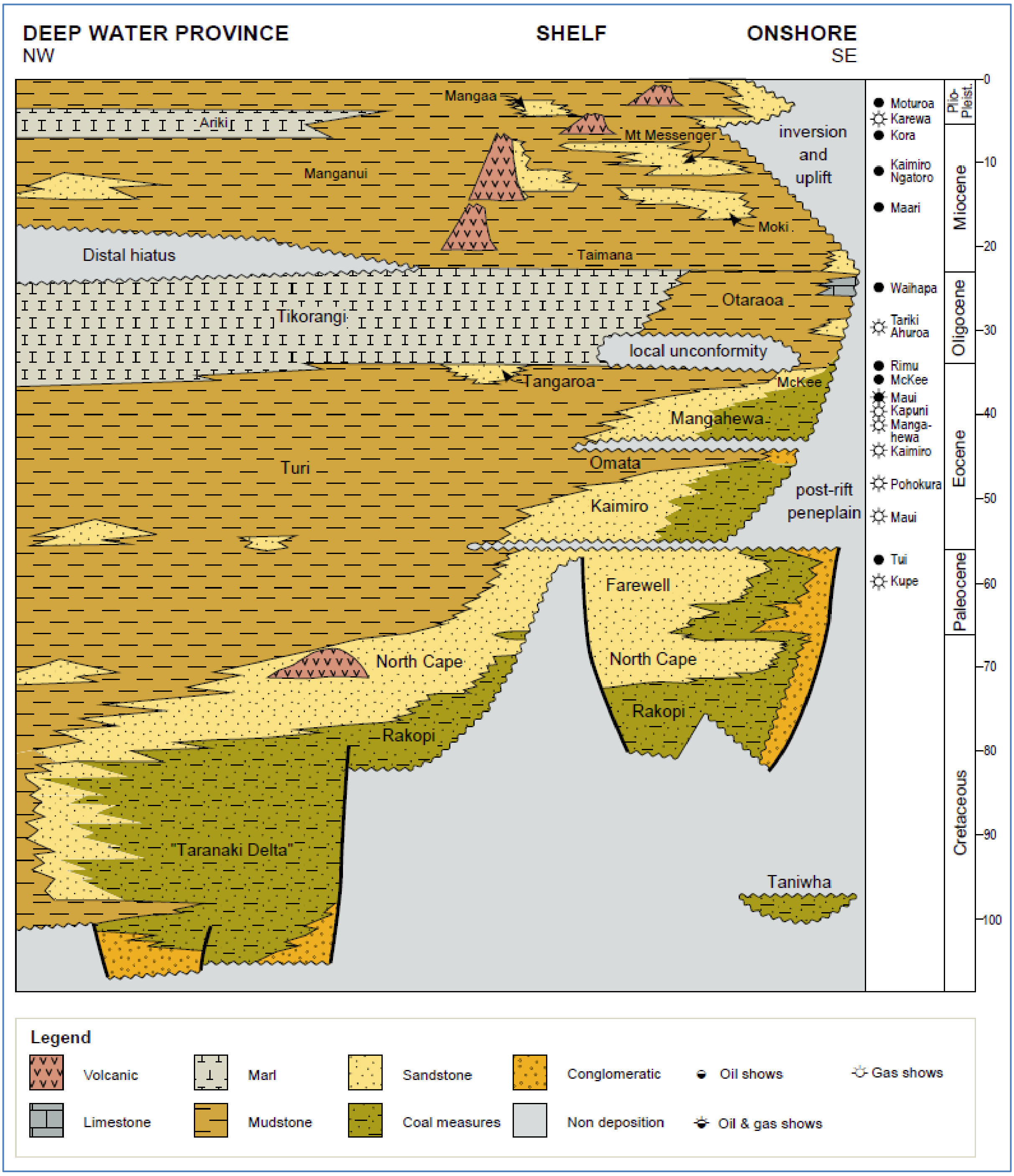


Figure 3-10: Generalised stratigraphy of the Taranaki Basin[12]

3.6. West Natuna Basin

To the west of Natuna Island lie two intensely faulted basins: the northeast-southwest trending West Natuna Basin and the east-west trending Penyu Basin. Structurally, the West Natuna Basin belongs to the Sundaland, the cratonic core of Southeast Asia, and is enclosed by a series of fault-bounded basement highs including the Khorat Swell to the north, the Natuna arch to the east, parts of the Sunda Craton to the south, and a transition into the Malay Basin to the west (Figure 3-11).[13]

The West Natuna Basin is generally considered as originating from a rift or a pull-apart basin. It is characterised by a series of small east-west orientated depocentres with intervening basement ridges that formed during Paleogene rifting. Many half-graben depocentres in the basin experienced significant contraction during the late Oligocene and Miocene, leading to the formation of "Sunda Folds" (Figure 3-12).

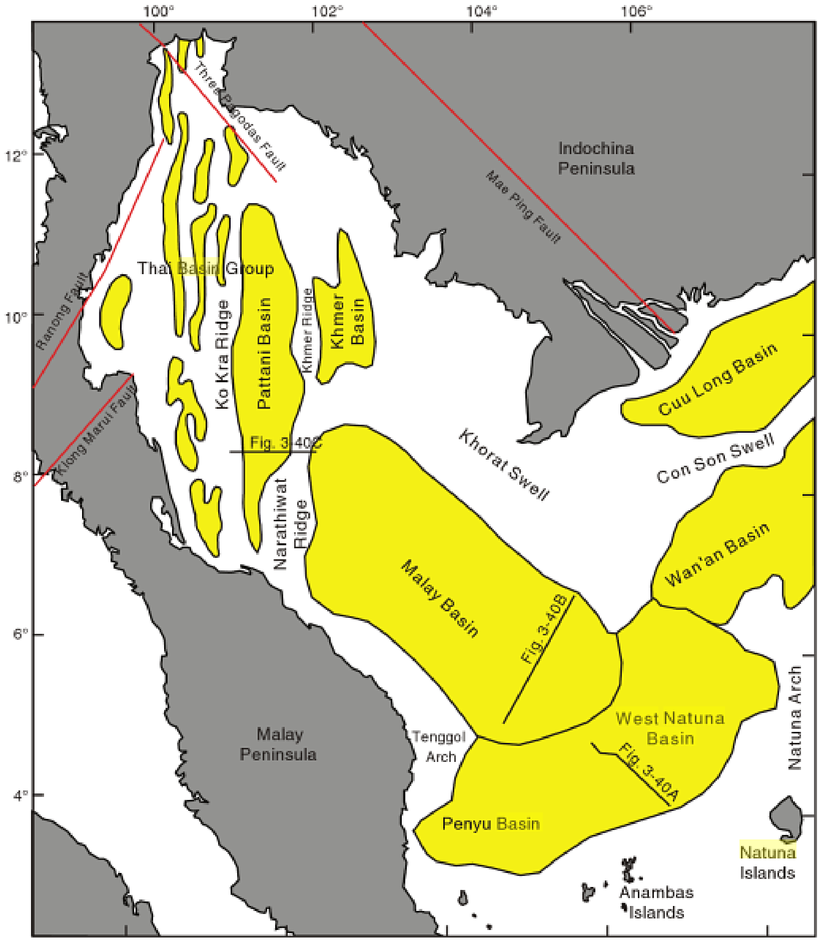


Figure 3-11: Location of the West Natuna Basin

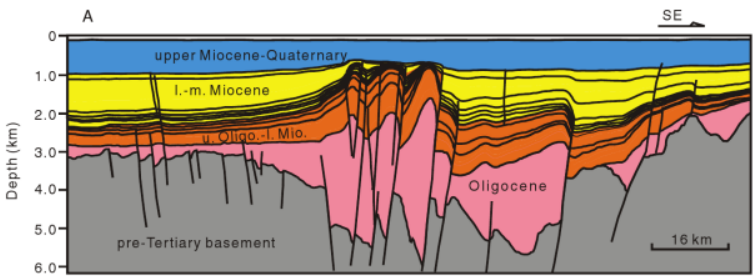


Figure 3-12: Section through West Natuna Basin

[13] The South China Sea: Paleoceanography and Sedimentology

Underlying the clastic sequence of the West Natuna basin is Mesozoic basement of Sundaland, comprising intrusive acidic-type igneous rocks. The West Natuna basin commenced development as a rift basin. It was initially filled by locally derived sediments via short drainage systems from the Khorat Swell, Natuna arch, and Sunda shelf. Alluvial fans, braided fluvial channels, fan deltas and lacustrine shales were confined to the grabens and half grabens. The grabens formed a linked chain with lakes forming in the grabens with insufficient sediment to fill them to spill, but with water flowing through these graben systems.

Grabens on the basin margin filled with coarse clastics and did not develop lakes or consequently source rocks. Those in the basin centre were more likely to contain lakes and develop source rocks, such as the Benua shale The West Natuna Basin experienced a series of extensional events that altered the accommodation space history, causing uplift and sediment by-pass on the footwall or a rapid creation of space on the hanging wall. Such events are evident at the Upper Lama, Base Lower Gabus, Intra Lower Gabus and Base Upper Gabus sequence boundaries.

During Lower Gabus time, large fluvial channels continued to pass from the Malay Basin through the West Natuna basin and on their way to the Nam Con Son basin and the South China Sea. Once the graben topography was drowned, post-rift thermal subsidence coupled with a sediment supply rate insufficient to fill the accommodation space resulted in lakes and the accumulation of the lacustrine Keras shale (Figure 3-13).

The oil discovery in the Ande Ande Lumut structure suggests a proven working petroleum system. Exploration has traditionally focused in West Natuna basin on clastics reservoirs, usually of the Oligocene Gabus formation, sourced from Eocene-Oligocene lacustrine shales with hydrocarbon trapped in structures associated with a Middle Miocene period of inversion.

The Ande Ande Lumut structure is an exception where hydrocarbon trapped in a gentle broad basement draped anticline. The widely distributed Gabus formation consists of fluvial fine to medium grained sandstones interbedded with silty shales, forming a primary exploration target in the basin. The overlying Barat Formation consists of dark grey and brown claystone, as well as clean sandstones (Udang Formation).

Upper Gabus sandstones are associated with widespread alluvial and fluvial settings. More deltaic marginal marine influences are thought possible within the upper part of the section especially to the north and northeast of the West Natuna basin. Beds are generally less than 10 m in thickness and are stacked in aggrading, retrograding and prograding sequences.

Porosity and permeability has not been as affected by burial as have underlying units. In the AAL wells the formation is divided by Premier into three sandstone units K, G1 and G2.

Seismic attributes don't appear to shed light on the morphology and depositional setting of the K-sand. However, attributes from the G-sand level show fluvial morphology with varying channel widths.

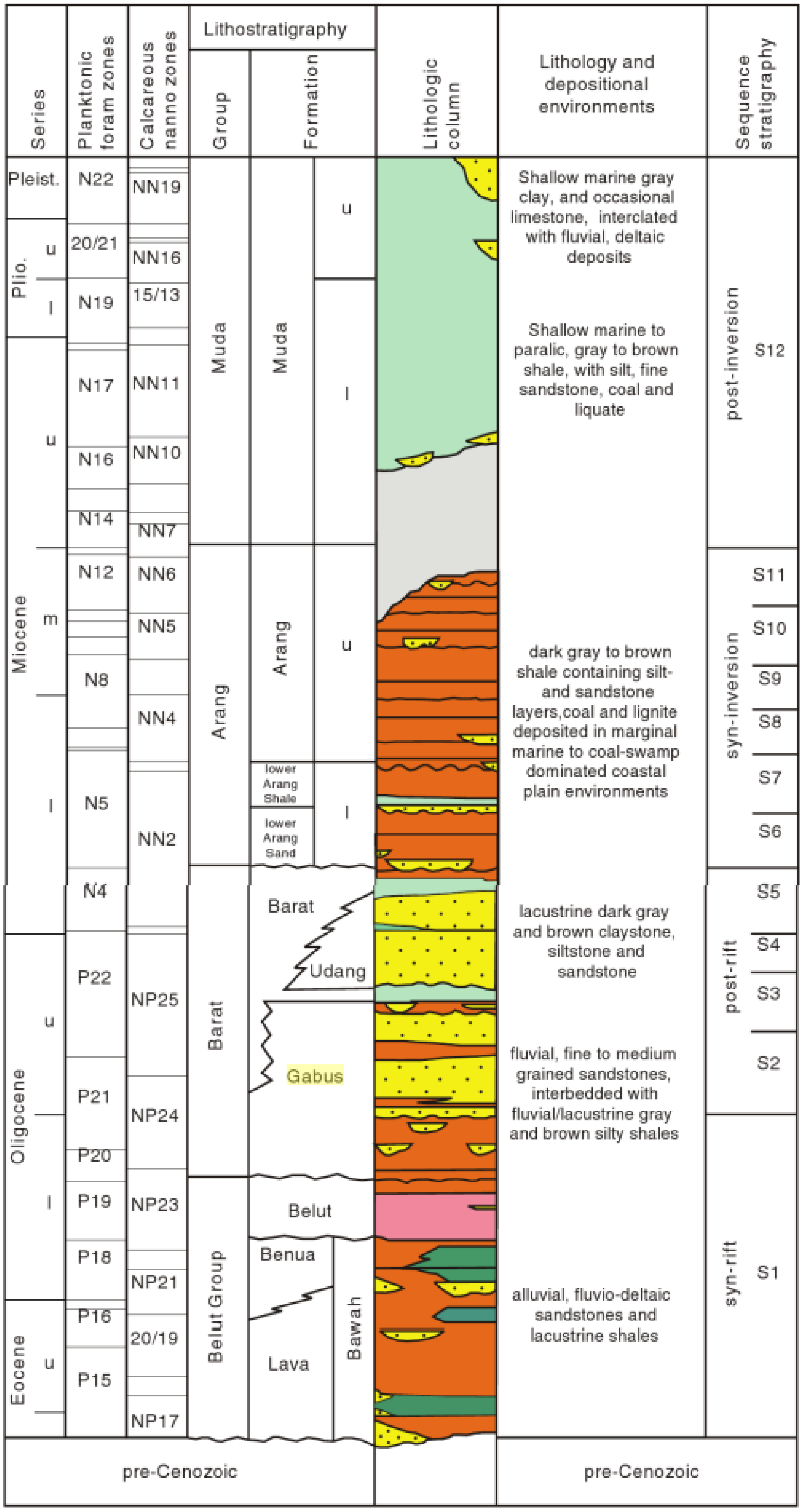


Figure 3-13: Generalised Stratigraphy, West Natuna Basin

4. Producing and production pending properties

4.1. Perth Basin

AWE's offshore and onshore Perth Basin include AWE and Beach Energy operated fields and associated facilities (Figure 4-1). AWE's interests range from 33% to 100%. Produced gas is processed at the Beach Energy operated Beharra Springs gas plant and the AWE Operated Xyris gas plant (Figure 4-2).

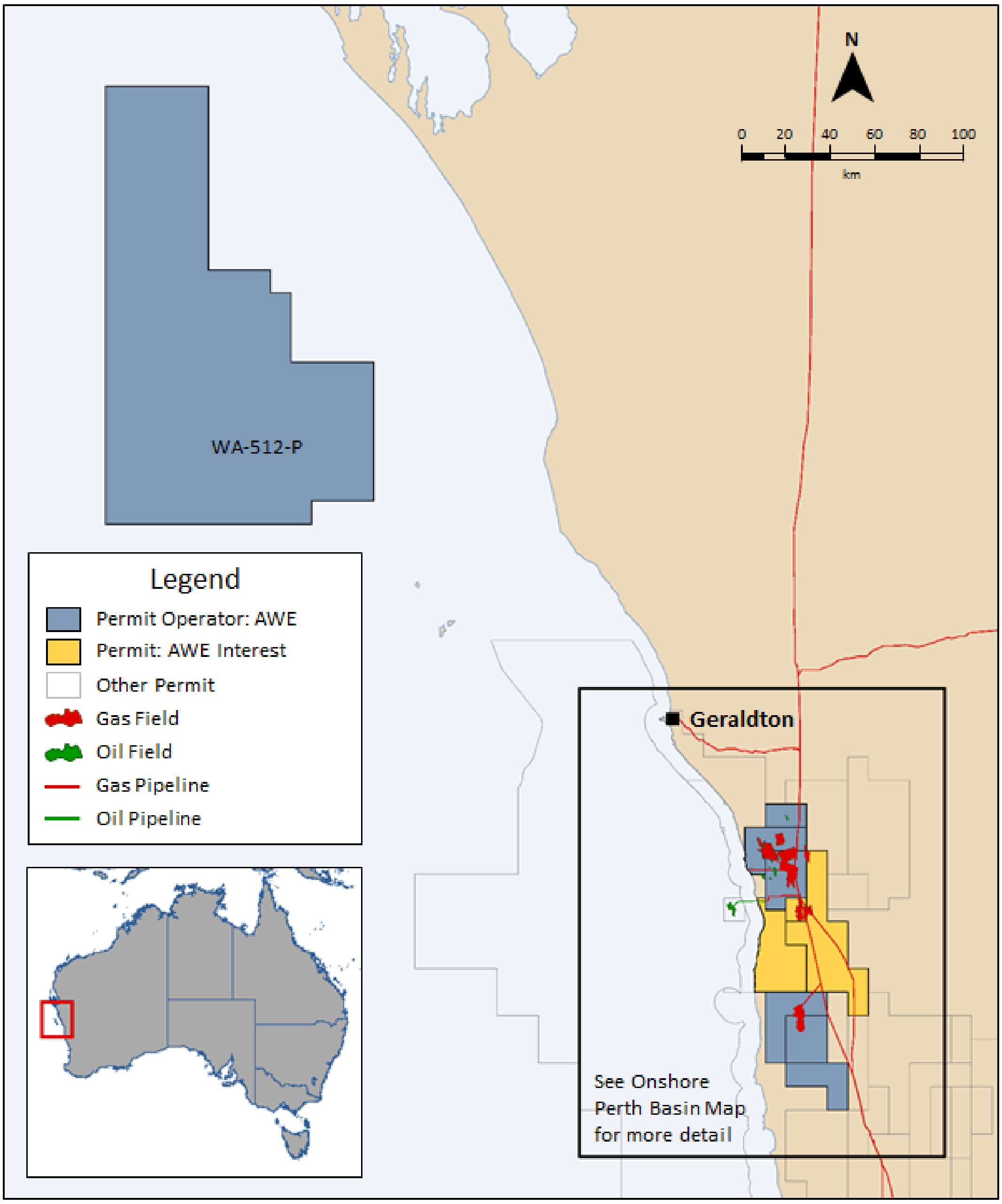


Figure 4-1: Location Map - AWE Onshore and Offshore Perth Basin Oil and Gas Properties

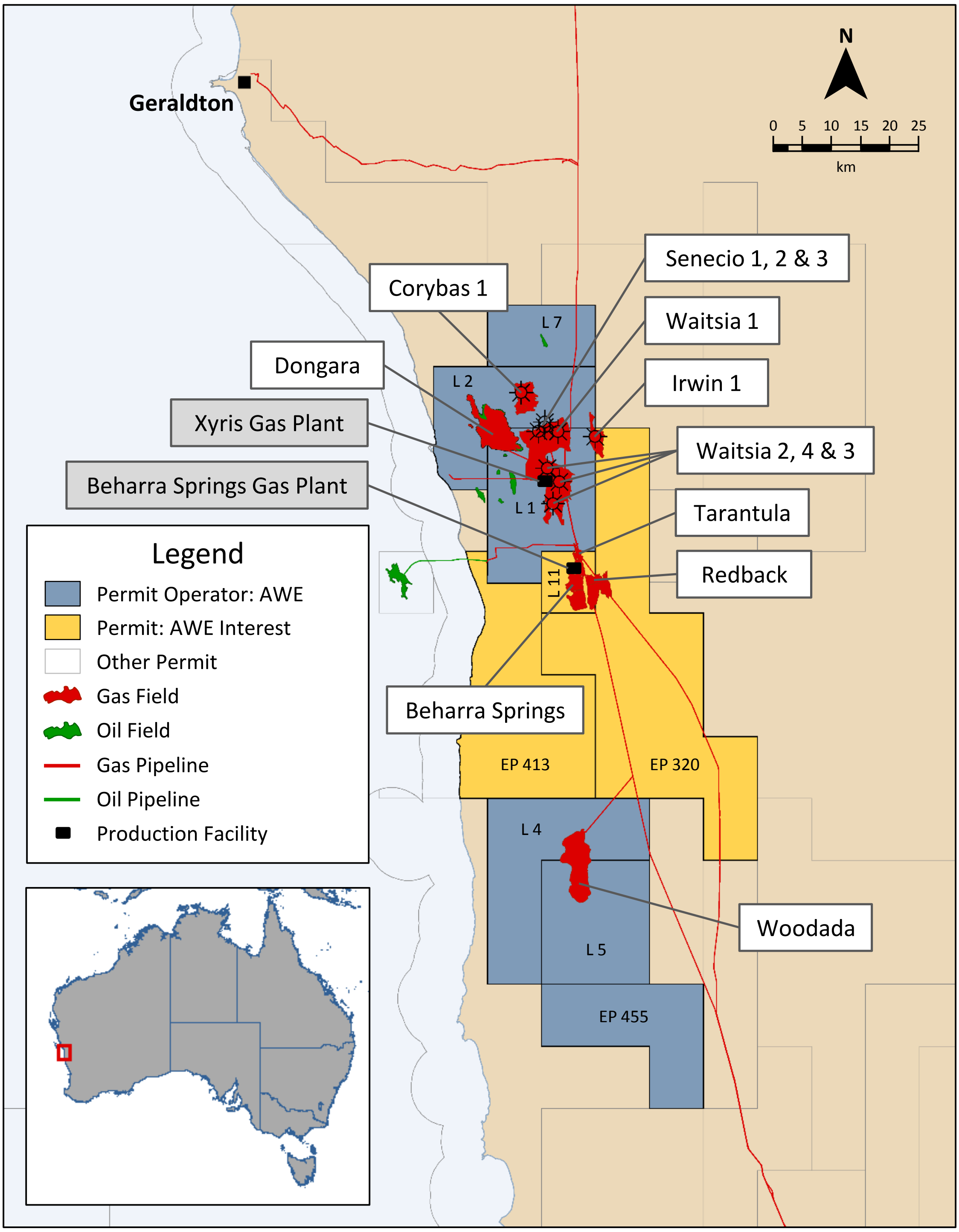


Figure 4-2: Location Map - AWE Onshore Perth Basin Oil and Gas Properties

Details of AWE's equity within the Perth Basin production licences and exploration are shown in Table 7-1 and Table 7-2.

4.1.1. Waitsia Gas Project

4.1.1.1. Introduction

The Waitsia Gas Project (WGP) is located approximately 300 km north of Perth in the North Perth Basin (Figure 4-2). AWE is operator with an interest of 50%. Gas in the region had been discovered by a number of wells that drilled and tested the Dongara and IRCM reservoirs. However, in Waitsia higher productivity gas was also discoverer in the deeper Kingia and High Cliff Sandstone, which opens up a new play in the region.

Exploration well Senecio 1 was drilled in 2005 and intersected a gas column in the Dongara Sandstone. The Senecio 2 appraisal well was sidetracked from Senecio 1 in November 2005 and flowed gas at rates up to 1 MMscf/d from the Dongara but the rate declined due to low permeability of the reservoir. In August 2011 Senecio 2 was worked over for a small hydraulic fracture stimulation treatment. The well was later successfully fracced in 2012 over a 5 m interval and achieved a stabilized gas rate of 1.35 MMscf/d.

Corybas 1 was drilled in 2005 and flowed gas from the IRCM. It is located in the northern fault block adjacent to the Senecio fault block of the WGP area. In 2009, AWE fracture stimulated the IRCM in Corybas 1 and in April 2010 the well was connected to the Dongara processing facility and began producing at initial rates over 4 MMscf/d and by the end of October 2010 the well was producing at a rate of 1.2 MMscf/d. The well is currently shut-in.

In September 2014, gas was discovered in the underlying Kingia and High Cliff Sandstones in the Senecio 3 well. Wells Senecio 1 and 2 were terminated before reaching these deeper Formations.

A flow testing program of the Senecio 3 well was completed in March 2015. The testing program was designed to determine gas flow rates from the Kingia and High Cliff gas reservoirs and to collect gas samples for analysis. During the second stage of testing, an average flow rate of 12.3 MMscf/d was measured from the Kingia Sandstone over five hours at the end of the 18 hour clean up flow period. This result confirmed the Kingia as a conventional reservoir capable of producing gas at commercial rates. An unstimulated test of the High Cliff flowed gas at 0.3 MMscf/d. Untested gas shows were reported in the IRCM.

Exploration and appraisal of the area continued in March 2015 with the exploration well Irwin 1 which straddles the EP320/L1 boundary, 22.7 km east of Dongara. Irwin 1 was designed to test the gas potential of the Dongara Sandstone, Wagina Sandstone, Caryginia Shale, Irwin River Coal Measures (IRCM), Kingia Sandstone and High Cliff Sandstone. The well encountered good oil and gas shows in the Dongara Sandstone with downhole samples taken. The IRCM is also interpreted to be gas saturated but was not tested. Although the Kingia Sandstone was water bearing it is interpreted to have high porosity and permeability from wireline logs and pressure testing data.

Appraisal of the Waitsia area continued in June 2015 with the drilling of the Waitsia 1 well located approximately 17 km east of Dongara and was flow tested. The first zone tested was the deeper High Cliff Sandstone which was perforated over a 23.5 m interval. The zone flowed gas at an average rate of 24.7 MMscf/d, on a 60/64 inch choke at approximately 1330 psig flowing well head pressure over a 1 hour period. A second flow test was performed on the Kingia Sandstone over a 15 m perforated interval. After an 8 hour combined clean-up and well test period, the well flowed gas at an average rate and pressure of 25.7 MMscf/d and 1530 psig, again constrained by tubing size, on a 56/64 inch choke for approximately a one hour period.

The Waitsia 2 appraisal well was drilled approximately 16 km southeast of Dongara within the Xyris volumetric compartment and was completed in July 2015. Core data and elevated gas shows confirmed gas in the Kingia and High Cliff Sandstones as well as the Caryginia Shale and IRCM. Waitsia-2 was perforated over a 42 m gross interval within the Kingia sandstone. The well was suspended. In November 2017, following clean up, the well flowed gas at an average gas rate of 39.5 MMscf/d[14] on an 80/64 inch choke at 1,315 psig flowing well head pressure over a 2.1 hour period before being beaned back for a longer term flow test.

In May and June 2017, the Waitsia-3 appraisal well was drilled. It encountered a gas column in excess of a 150m across the IRCM, Kingia and HCSS reservoirs. The gas column in the higher quality Kingia reservoir was 51.7 m with a net pay of 21.3 m. The gas has total inert gas content of about 7.2%, with a CO_2 content of about 6.8%. Gas bearing sands were also encountered in the HCSS, however these appear tight. Waitsia-3 tested with rates of 49.5 MMscf/d over a 42 m gross Kingia interval for a two hour period[15] before being beaned back for a longer term flow test.

Waitsia-4 was drilled in July-August 2017 confirming the eastern extension of the field with strong gas shows over a 150 gross interval of IRCM, Kingia and HCSS reservoirs. The HCSS reservoir was very tight. The gas had total inerts content of about 5.31%, with a CO_2 content of about 4.8%. Waitsa-4 was perforated over a 50 m Kingia interval and flowed at a maximum rate of 89.6 MMscf/d[16] on a 96/64 inch choke at approximately 2,395 psig flowing well head pressure over a 23 minute period before being produced at lower rates in a longer term flow test.

No GWC was intersected in either Waitsia-3 or Waitsia-4 wells, however a GWC is interpreted at 3525 mSS from pressure data, which is consistent with Waitsia-2. The Senecio-3 and Waitsia-1 wells have an inferred GWC of 3350 mSS.

The effect of the Waitsia-3 and -4 well results were to transfer contingent resources in the Kingia reservoir from Blocks D, E and F to the reserves classification and upgrade the gas volumes due to the thicker reservoir which was encountered.

The Waitsia gas field top Kingia structure map is shown in Figure 4-3.

[14] AWE ASX Announcement, 10 November 2017
[15] AWE ASX Announcement, 23 October 2017
[16] AWE, ASX Announcement 22 November 2017

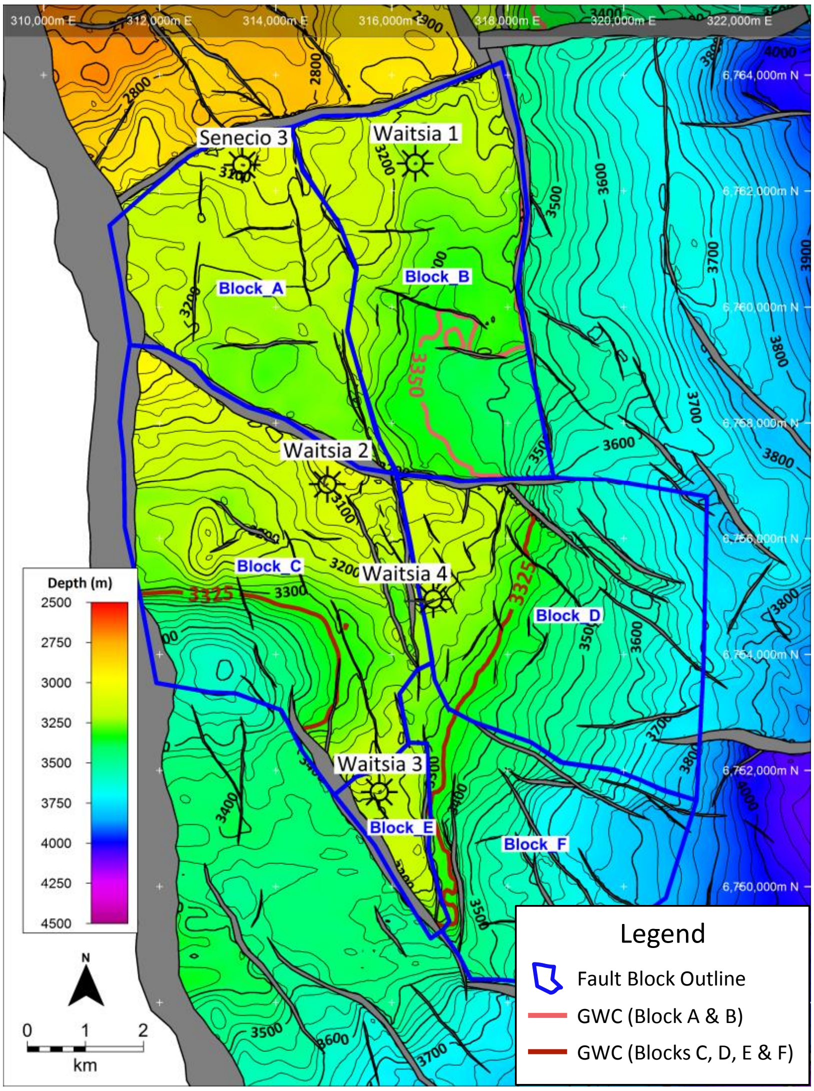


Figure 4-3: Waitsia Field Top Kingia Structure Map and Fault Block Polygons

Commercial production commenced with the Stage 1A project in August 2016 from the Waitsia-1 and Senecio-3 wells producing to the Xyris gas plant delivering gas under contract to Alinta Energy. The gas is blended in the pipeline with Beharra Springs gas to manage the CO_2 limit in the sales gas which is approximately 5 mole%. Production has been alternating from the Senecio 3 Kingia reservoir and Waitsia 1 HCSS while the operator gathers pressure and flow data to confirm connected volumes. Production in 2017 to 31 December 2017 has averaged 8.0 MMscf/d gross gas (8.4 TJ/d sales) from the two wells (Figure 4-4). Senecio-3 was shut-in in November due to reduced nominations from Alinta. As at 31 December 2017, both wells were reported to be producing at a combined rate of 9.6 TJ/d.

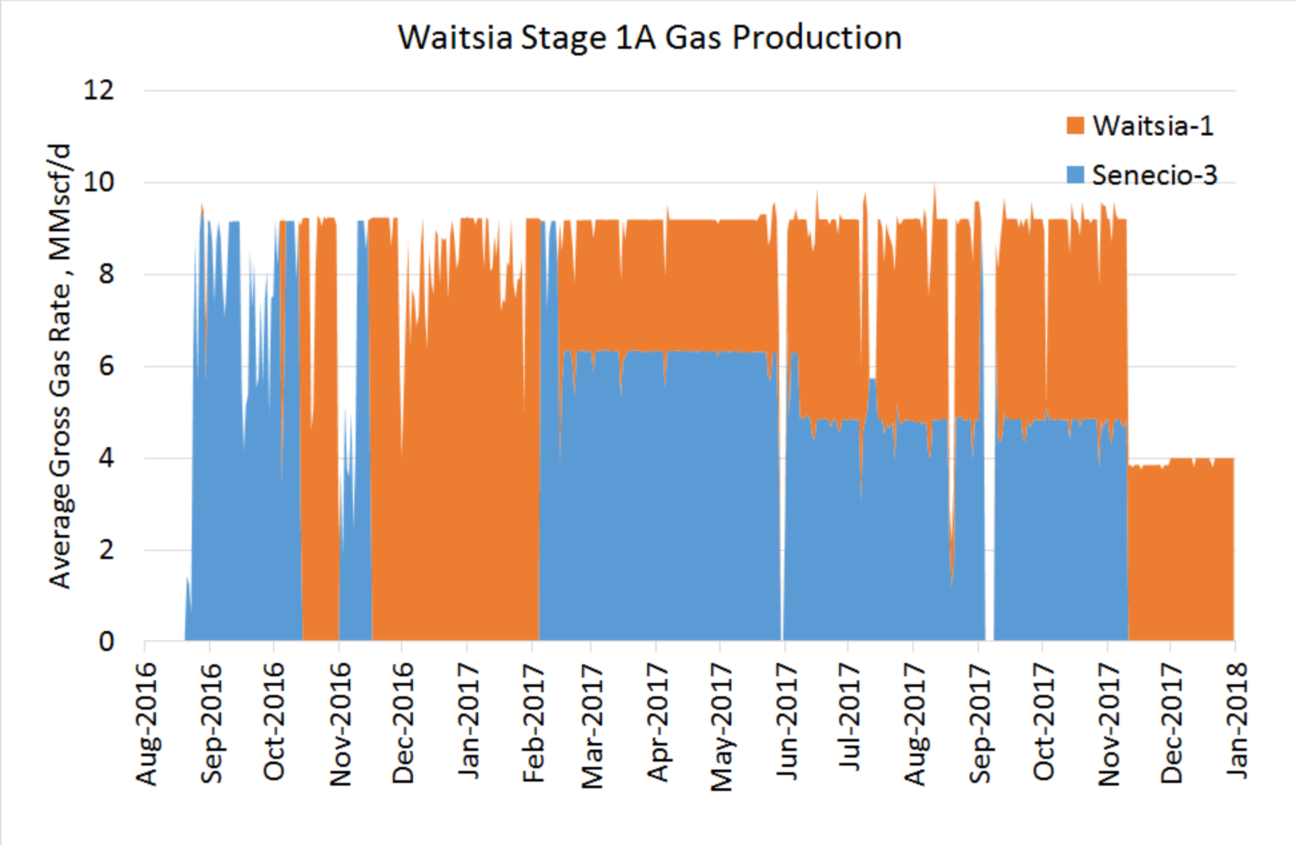


Figure 4-4: Waitsia Stage 1A Gross Gas Production History

Stage 2 of WGP focuses on the development of the remaining high deliverability Kingia and High Cliff Sandstones (HCSS), whereas, Stage-3 includes development of tight gas in the HCSS, Dongara and Irwin River Coal Measures (IRCM) Sandstones. Prospective resources within the IRCM (tight gas), Kockatea Shale and Carynginia Formation (both shale gas targets) represent further growth opportunities in the area.

4.1.1.2. Existing Facilities

Stage 1A production of up to 10 TJ/day from two wells is supported by the installation of new infrastructure and upgrades to existing assets to connect the Waitsia-1 and Senecio-3 gas wells to the Xyris Production Facility (XPF). Treated gas from the production facility is delivered into the nearby Parmelia gas pipeline for domestic consumption.

4.1.1.3. Future Development and Production

AWE's Stage 2 base case development plan is:

- 19 completions in the Kinga reservoir;
- 4 completions in the High Cliff reservoir;
- 6" infield gathering flowlines to three gas gathering Hubs;
- 10" pipelines connecting each Hub to the Waitsia Gas Plant;

- A new 100 TJ/d gas conditioning and processing facility. The concept included a CO_2 reduction facility and LTS separation unit to remove CO_2 down to of about 3 mol% (sales specifications <5mole%) and achieve dewpoint control;
- LP Hub compression.

AWE plan Stage-2 construction to commence in the second half of CY2018, with first gas in CY2020 (subject to FID by the joint venture).

RISC anticipates that the production facilities are likely to have a capacity upgrade to 200 TJ/d after 3-4 years of production to coincide with market availability (Stage-2 expansion), although this is not part of AWE's Stage-2 project. If the facilities are not expanded the 2P plateau would be 22 years resulting in a lower project NPV. The potential development of Contingent Resources after the 22 year 2P plateau would have little value due to their delayed development. This higher plateau rate is required to evaluate full asset value.

Stage 3 is currently unplanned but estimated to involve an additional 11 new tight gas completions from existing vertical wells targeting tight gas in the High Cliff sandstone as well as horizontal tight gas wells targeting the Dongara and IRCM reservoirs.

RISC's estimated Waitsia Stage 1A and Stage-2 2P and Stage-3 2C production forecasts including RISCs assumed Stage-2 expansion are shown in Figure 4-5.

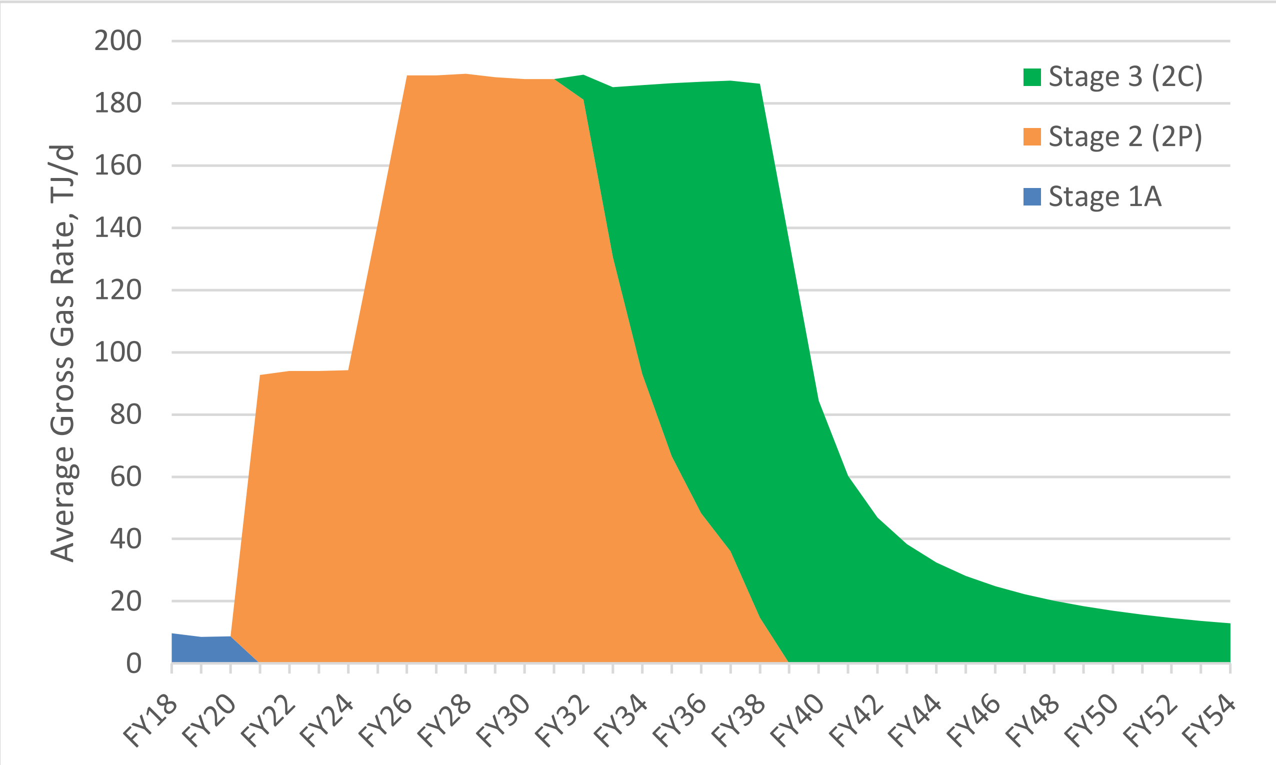


Figure 4-5: Waitsia Gross 2P + 2C Production Forecasts

4.1.1.4. *Waitsia reserves and contingent resources*

The probabilistically estimated raw gas GIIP in the Kingia and HCSS formations for the Waitsia field are given in Table 4-1.

Table 4-1: Waitsia field GIIP: Kingia and HCSS (Raw Gas, Bcf, 100%)

Formation	P90	P50	P10
Kingia	701	1039	1471
HCSS	176	300	488
Total	**877**	**1339**	**1959**

RISC has reviewed the seismic interpretation, petrophysics, fluid contact estimates, geological modelling, well test data and support the AWE GIIP and estimates in Table 4-1.

The gross and net to AWE reserves and contingent resources in the Kingia and HCSS formations as at 31 December 2017 are set out in Table 4-2. The reserves and resources have been estimated in accordance with the Petroleum Resources Management System (PRMS). The economic cut-off is estimated to be 6 MMscf/d of sales gas. The undeveloped reserves are classified as Justified for Development under PRMS guidelines. The contingent resources are classified as Development on Hold under PRMS guidelines. Cumulative production to 31 December 2017 is 4.1 Bcf (4.3 PJ). Minor condensate of 1179 bbl has been recorded (0.2 bbl/MMscf).

Table 4-2: Waitsia Gross Developed + Undeveloped Reserves and Contingent Resources as at 31 December 2017 (Kingia and HCSS)

Sales product	Unit	1P	2P	2C[6]
Gross sales gas	Bcf	466.9	785.9	86.5
Gross sales gas	PJ	485.6	817.5	89.9
Gross condensate	MMbbl	0.10	0.17	0.02
Net sales gas	Bcf	233.5	392.5	43.2
Net sales gas	PJ	242.8	408.7	45.0
Net condensate	MMbbl	0.05	0.08	0.01

1. AWE interest 50%.
2. Probabilistic methods have been used.
3. Reserves include 8.0 PJ gross, 4.0 PJ net developed reserves anticipated to be produced for the remainder of Stage 1A to mid-2020
4. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated as sales quantities net of fuel estimated at an average of 4.8% for reserves and 5% for contingent resources. Sales gas conversion factor is 1.04 PJ/Bcf of sales gas.
5. The resources are classified as conventional under PRMS definitions
6. Additional gross 2C resources of 263.1 PJ sales gas and 3.9 MMbbl condensate are estimated in the IRCM and Dongara formations

Gross developed reserves are estimated at 8.0 PJ. These are associated with the 10 TJ/d development through the Xyris Production Facility and limited to the facility life estimated to be 20 years.

We estimate that the chance of development for the contingent resources in lower permeability HCSS shown in Table 4-2 is approximately 50%.

In addition to the Contingent Resources shown in Table 4-2, there are overlying gas resources in the Irwin River Coal Measures Group and the Dongara Sandstone that have been penetrated by wells in the Waitsia area and are potentially recoverable. AWE recognized the potential for these resources, but does not carry it in their formal contingent resource estimates. RISC estimates that approximately 350 Bcf gross of discovered unrisked recoverable tight gas potential exists in the Waitsia area, in the Irwin River Coal Measures Group and the Dongara Sandstone. This comprises gross contingent resources of 363.1 PJ of sales gas and 3.9 MMstb condensate. Although these resources are not expected to be developed in the near term due to relatively low gas prices and the fracking moratorium currently in-place in Western Australia, a notional development plan has been prepared to enable an value estimate to be made by Grant Thornton. The chance of commerciality will be driven by the costs of development, gas prices and social factors. We estimate that under the present conditions, the chance of development for these resources is relatively low at 20%. These resources are combined with the HCSS contingent resources in Table 4-2 as the potential Phase-3 development. The weighted average chance of success is 25%.

Watsia contingent resources in the HCSS, IRCM and Dongara are

4.1.1.5. Capital and operating costs - 2P + 2C development

Development capital costs for the Phase 1A development have been spent and ongoing opex associated with the project is estimated to be A$6.3 million p.a. (gross). Abandonment cost for the existing Phase 1A facilities and wells as well as other legacy facilities in permit L1/L2 is estimated to be approximately A$10 million (gross).

A summary of the estimated capital costs associated with the development of the Waitsia reserves (Phase 2) and contingent resources (Phase 3) is shown in Table 4-3 below. These cost are associated with all capital expenditure over the life of the reservoir to 2054. The Phase-2 cost include the facility expansion from 100 to 200 TJ/d.

Table 4-3: Future Waitsia 2P+2C development scope and capital cost (2018 to 2054, gross)

Phase 2 Development scope	Cost (A$ million)
Wells D&C	130
Tie-In's	40
Facilities	420
Compression	171
Project Management and Engineering	79
Owners costs and Other costs	23
Total Phase 2 Development capital	**863**
Phase 3 Development scope (conceptual)	**Cost (A$ million)**
Wells D&C	555
Tie-In's	58
Total Phase 3 Development capital	**613**

The total Phase 2 development capital is broken down as follows:

Table 4-4: Future Waitsia 2P capital breakdown (2018 to 2054, gross)

Phase 2 Development scope	Cost (A$ million)
Costs up to first gas	270

Development wells and tie-in after first gas	163
Compression	89
Project management, owners and other costs	58
Facilities expansion from 100 to 200 TJ/d	201
Compression expansion	82
Total	**863**

An operating cost forecast has been generated based on known costs in the area for existing developments and estimates for future activities. The operating costs peak at A$32 million p.a. (gross) in the 2P case and A$46 million p.a. (gross) in the 2P+2C case. A forecast of the operating costs is shown in Figure 4-6 below.

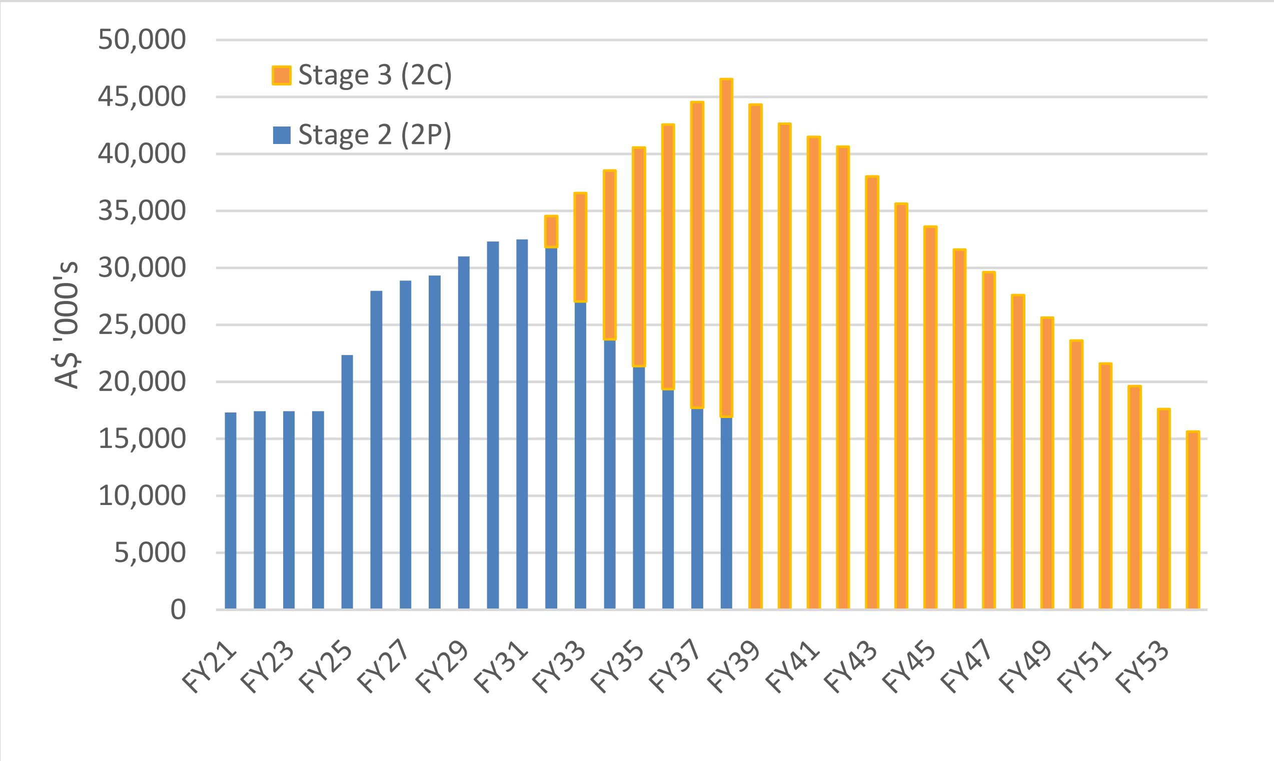


Figure 4-6: Waitsia Gross 2P + 2C Operating Cost Forecasts (100% gross)

Decommissioning and abandonment of the Waitsia development scope is estimated at A$138.3 million (gross) in the 2P case and A$58 million (gross) for the additional 2C scope.

4.1.2. Other AWE Perth Basin Fields

4.1.2.1. Introduction

AWE's other onshore Perth Basin assets include:

- Beharra Springs, Redback and Tarantula fields operated by Beach Energy (AWE 33%). These fields are producing with developed reserves;

- Dongara, Corybas, Senecio, Synaphea and Irwin fields operated by AWE. Dongara and Corybas are largely depleted and shut-in with further development potential. Senecio, Synaphea and Irwin have not been developed (sub-commercial). These fields have contingent resources.

Woodada operated by AWE: Shut-in since 2010 with facility under care and maintenance. No firms plans for further production. Possible re-development not included as not material, high uncertainty and limited probability. Decommission cost included. See Table 7-1 for full list of permits and interests. AWE exploration opportunities in Perth Basin are discussed in section 5.1. The Waitsia discovery has opened up the Kingia/HCSS play with the Beharra Springs deep prospect planned to target this play in 2019.

4.1.2.2. Beharra Springs – Redback - Tarantula

The Beharra Springs, Redback and Tarantula gas fields are located in Permit L11 in the North Perth Basin (Figure 4-2). The Beharra Springs and Redback structural terraces are a part of a series of north-south orientated terraces located on the western margin of the North Perth Basin. The Beharra Springs Terrace is bounded by the Mountain Bridge Fault to the west, and by the Redback Fault to the east. The Redback Terrace is bounded by the Redback Fault to the west and the Jewell Fault to the east. Both Beharra Springs and Redback Terraces can be subdivided into separate structural blocks bounded by east-west orientated subordinate normal faulting. Fault throws observed within the terraces themselves are variable but approach in excess of 100 m of throw along the fault.

The primary reservoir is the Late Permian Wagina Formation. This gas reservoir which is informally sub-divided into 3 subunits: “Upper Wagina”, Wagina “A” and Wagina “B”. Eight separate compartments or hydrocarbon pools are recognised.

To date eleven wells have been drilled in the area. Commercial hydrocarbons were discovered in 1990 at Beharra Springs 1, which intersected gas in Late Permian Wagina Formation. This was quickly followed by Beharra Springs 2; both wells were drilled and completed as gas producers and started production in 1991.

Beharra Springs North 1 which tested a northern fault block was drilled and completed in August 2001 and put on production in July 2002. Beharra Springs South 1 drilled in September 2001 but was plugged and abandoned as the reservoir was interpreted to be wet based on lack of shows and low resistivity log response.

Redback 1 was drilled in February 2004; the well was plugged and suspended as the primary Wagina “A” was interpreted to be faulted out. Tarantula 1 was drilled in mid-2005. The well had well control failure and blew-out on intersecting the primary reservoir interval. It was subsequently side-tracked. Tarantula 1 intersected an additional gas bearing reservoir above the Wagina which is interpreted to be the stratigraphic equivalent of the Bookera/Dongara Sandstone. It has not been intersected in any of the other BS and Redback wells drilled to date and is considered to be of limited extent in the BS-Redback area. Tarantula 1ST1 was completed as a gas producer in June 2005 and was brought on line in September 2005.

Beharra Springs 4 was drilled in a fault compartment immediately south of the BSN compartment. Reservoir pressure was measured to be approximately 3000 psi lower than initial pressures measured in Beharra Springs 1 prior to the onset of Field production. The well was completed in March 2007 and production commenced in December 2007.

Redback South 1 was drilled as a side track from the Redback 1 motherbore and completed in August 2009 and was put on production in April 2010. The Redback 2 deviated well was drilled in April 2010 to intersect the Wagina “A” that was faulted out at Redback 1 and encountered a thicker Wagina “A” section than all previous Beharra Springs and Redback wells. Redback 2 flowed at approximately 5 MMscf/d during a 2 hour clean-up flow. Both Redback 1 and Redback South 1 wellstream compositions include moderate levels of CO_2 and as such their sales/raw gas conversions post $C0_2$ extraction are approximately 0.92 PJ/Bscf.

Currently there are 5 wells available for production, with Tarantula-1 shut in for production rotation. As at 31 December 2017 the current 5 wells have produced 62.2 Bscf and 64.9 Mbbls of condensate with their historical gross sales gas production shown in Figure 4-7.

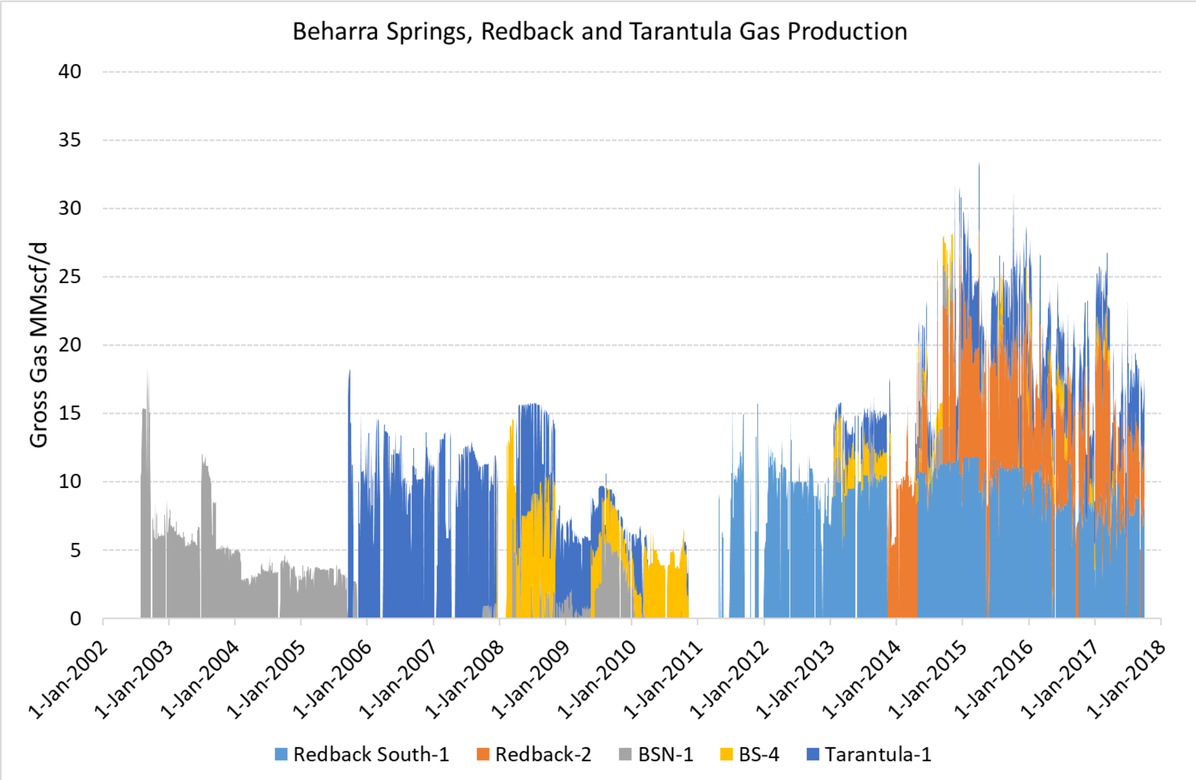


Figure 4-7: Beharra Springs, Redback and Tarantula Historical Sales Gas Production

4.1.2.3. Existing Facilities

All produced gas is processed in the Beharra Springs Gas plant which has a nameplate capacity of 25 TJ/d.

4.1.2.4. Future Development

No further development is planned for Beharra Springs, Redback and Tarantula fields and as such only developed reserves are attributed. AWE's production forecasts are based on existing wells modelled with a history matched GAP Integrated Production Model. RISC has reviewed the model including the analytical derived GIIP estimates and supports the in place volumes and production forecast. Figure 4-8 shows the 2P historic and forecast gas sales production. There are no Contingent Resources in the Beharra Springs, Redback or Tarantula Fields.

The forecasts assume:

- An average sales gas demand rate of 12 TJ/d and includes plant maintenance shutdowns;
- The sales gas conversion of 0.95 TJ/MMscf(raw) reflects historical data;
- Condensate has been forecasted with a historical field producing CGR of 0.71 bbls/MMscf;

- Well production is truncated at 1 MMscf/d raw gas reflecting liquid loading of wells, with wells shutin if flow become unstable;
- Field production is truncated at the plant turn downrate of 5 MMscf/d raw gas.

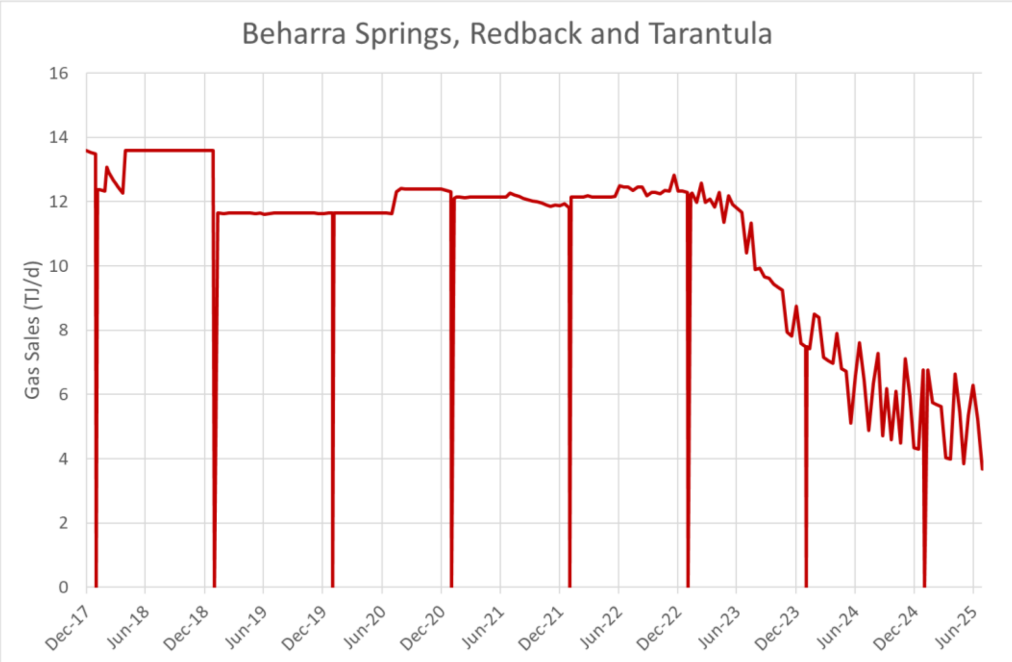


Figure 4-8: Beharra Springs, RedBack and Tarantula Gross 2P Production Forecast

4.1.2.5. Dongara and Corybas Fields

The Dongara field produced gas from seven wells to the Dongara Gas Plant until it was shut-in late 2016 due to compressor and maintenance requirements at the gas plant. The cost of maintenance was uneconomic so the plant has remained closed. No reserves or contingent resources are assigned to Dongara.

Corybas is a low permeability field with gas in three Irwin River Coal Measure sands (B, D and F). Vertical well Corybas-1 was hydraulically fractured and produced through the Dongara Gas Plant from 2010. Initial production was up to 4 MMscf/d but declined to below 1 MMscf/d. The well produced 0.8 Bcf of gas between 2010 and mid-2015 with a final rate of 0.3 MMscf/d. Flowing material balance and typecurve analysis indicates the well was connected to a GIIP of between 1 and 4 Bcf.

Gas is mapped in north, middle and south segments with Corybas-1 is in the middle segment. There are no firm plans for reinstating production or further development and hence no reserves are assigned to Corybas. However, 2C gross contingent resources are estimated based on a re-development using six horizontal, multi-staged hydraulically fracture stimulated wells with potential start-up in 2021. Figure 4-9 shows the estimated production forecast. The gross 2C contingent resources are 26.8 PJ of gas and 0.09 MMstb of condensate.

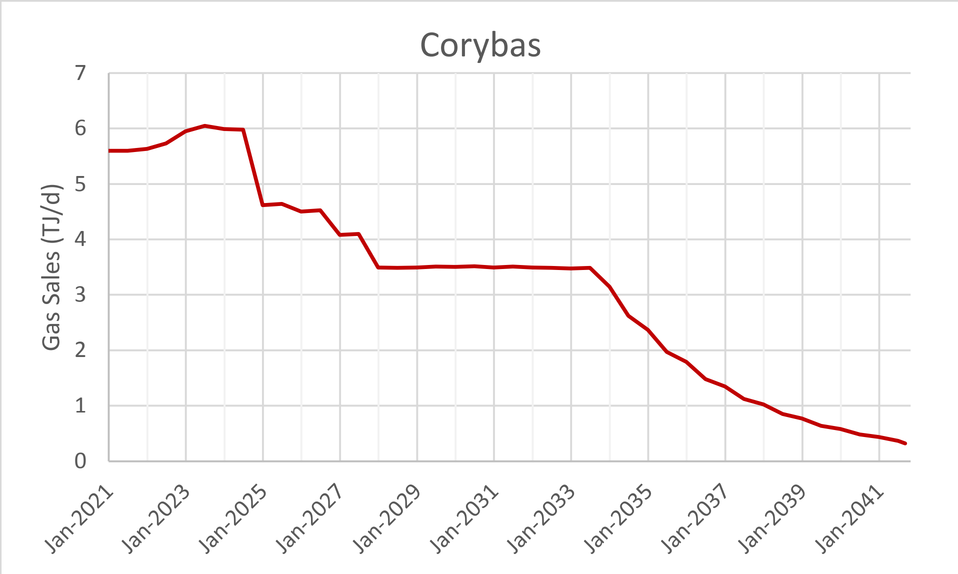


Figure 4-9: Corybas Gross 2C Production Forecast

4.1.2.6. Other AWE Perth Basin Field Reserves and Contingent Resources

The gross and AWE-net reserves and contingent resources as at 31 December 2017 are set out in Table 4-5 for other Perth Basin fields. Reserves are developed reserves from Beharra Springs, Redback and Tarantula and contingent resources are from Corybas. The contingent resources are classified as project maturity status Development Unclarified/On Hold under PRMS guidelines.

The reserves and resources have been estimated in accordance with the Petroleum Resources Management System (PRMS).

We estimate that under the present conditions, the chance of development (COD) for the Contingent Resources in Corybas IRCM is the same as Waitsia IRCM, relatively low at 20%.

Table 4-5: Other AWE Perth Basin Reserves and Contingent Resources as at 31 December 2017

Sales product	Unit	1P	2P	3P	2C
Gross sales gas	Bcf	22.4	30.5	39.7	26.8
Gross sales gas	PJ	21.3	28.9	37.6	28.6
Gross condensate	MMbbl	0.014	0.019	0.025	0.09
Net sales gas	Bcf	7.4	10.1	13.1	13.4
Net sales gas	PJ	7.0	9.5	12.4	14.3
Net condensate	MMbbl	0.005	0.006	0.008	0.04

1. AWE interest is 33% in Beharra Springs, Redback and Tarantula and 50% in Corybas. 2. Deterministic and Probabilistic methods have been used 3. Contingent resources are stated on an unrisked basis 4. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated as sales quantities net of fuel estimated at an average of 4.8% for reserves and 5% for contingent resources. 5. Beharra Springs, Redback and Tarantula weighted sales gas conversion factor is 0.95 PJ/Bcf of sales gas. Corybas conversion factor is 1.07 PJ/Bcf of sales gas 6. The resources are classified as conventional under PRMS definitions

4.1.2.7. Capital and Operating Costs – 2P Development

Outside of Waitsia the Beharra Springs, Redback and Tarantula gas fields are the only remaining producing fields for AWE in the North Perth Basin. The Beharra Springs Field commenced production in January 1991 when BS1 was brought online. Gas production of approximately 18.5 TJ/d is currently managed from Beharra Spring North 1, Beharra Springs 4, Redback 2, Redback South 1, and Tarantula 1. All produced gas is processed in the Beharra Springs Gas plant which has a nameplate capacity of 25 TJ/d.

Table 4-6 below has a summary of capital, operating and abandonment forecasts from 31 December 2017.

Table 4-6: Beharra Springs 2P Operating and Capital Cost Forecasts (A$ million, RT, 100% gross)

Cost Item	FY18*	FY19	FY20	FY21	FY22
Operating Cost	5.1	10.5	10.5	10.5	-
Capital Cost	1.1	0.8	0.8	0.8	-
Abandonment Cost	-	-	-	-	6.3

** Remainder in calender year 2018*

2018 cost assumptions are based on the FY18 Work Plan and Budget (WP&B) issued by the Operator, adjusted to calendar years

Operating and minor capital cost forecasts have been provided by AWE in the corporate model for the 2P scenario. RISC has reviewed these forecasts as well as the FY18 work plan and budget for the asset and historic costs. We conclude the AWE cost assumptions are reasonable.

We have reviewed the AWE "stay in business" (SIB) capex and shutdown cost assumptions against industry benchmarks and see the assumptions as reasonable.

4.1.2.8. Abandonment Costs

Abandonment costs for the existing Beharra Springs wells and surface facilities are estimated to be $2 million (gross) for facilities and $4.3 million (gross) for well P&A (15 wells in total).

AWE currently operates five oil and gas production facilities in the Onshore Northern Perth Basin (ONPB), of which only the Dongara Production Facility (DPF) and the Xyris Production Facility (XPF) are operational. XPF is covered in the Waitsia section of this report. DPF is temporarily shut-in and planning is underway to potentially transition into a Care and Maintenance mode. The three remaining facilities are currently under Care and Maintenance. The sale of Mt Horner Oil Field Production Facility is due to complete in 2018. The Jingemia Oil Field Production Facility was sold in 2017.

AWE also operates 61 oil and gas wells in the ONPB outside of the Senecio-3 and Waitsia-1 and 2 wells which are the only wells on production. A Well Decommissioning programme commenced in 2013 and 4 of these wells have been decommissioned in 2017. A further 18 wells are part of the Mt Horner and Jingemia divestments leaving a total of 39 wells remaining to be decommissioned.

A decommissioning cost estimate has been provided by DecomRem in 2016 and has been reviewed by RISC. The Decommissioning report covers the following AWE operated facilities that are not on production and will be decommissioned prior to 2023:

- Dongara Gas Field Production Facilities (DGF) and Dongara Production Facility;
  - Gas production through DPF has reached the economic limit and was terminated in December 2016.
  - Plans are underway to potentially transition into a phased Care and Maintenance mode.
  - DPF will remain the hub of AWE's Perth Basin activities for several years. It is currently scheduled for decommissioning in 2023.
- Woodada Gas Field (WGF);
  - Currently not operational and, since January 2010, under a Care and Maintenance regime.
- Hovea Production Facility (HPF);
  - Currently not operational and since April 2012 under a Care and Maintenance regime.

RISC estimates that the total cost to decommission the Dongara, Woodada and Hovea facilities as well as associated wells and flowlines is A$80 million (gross). This money is assumed to be spent over the next 10 years in discrete decommissioning campaigns.

4.2. Bass Gas Project

4.2.1. Introduction

The Yolla gas field, operated by Beach Energy, has produced gas to the Bass Gas project at Lang Lang since 2006. Additional undeveloped discoveries have been made at Bass (1967), White Ibis (1998), Trefoil (2004), and Rockhopper (2009) and held under retention leases since 2015.

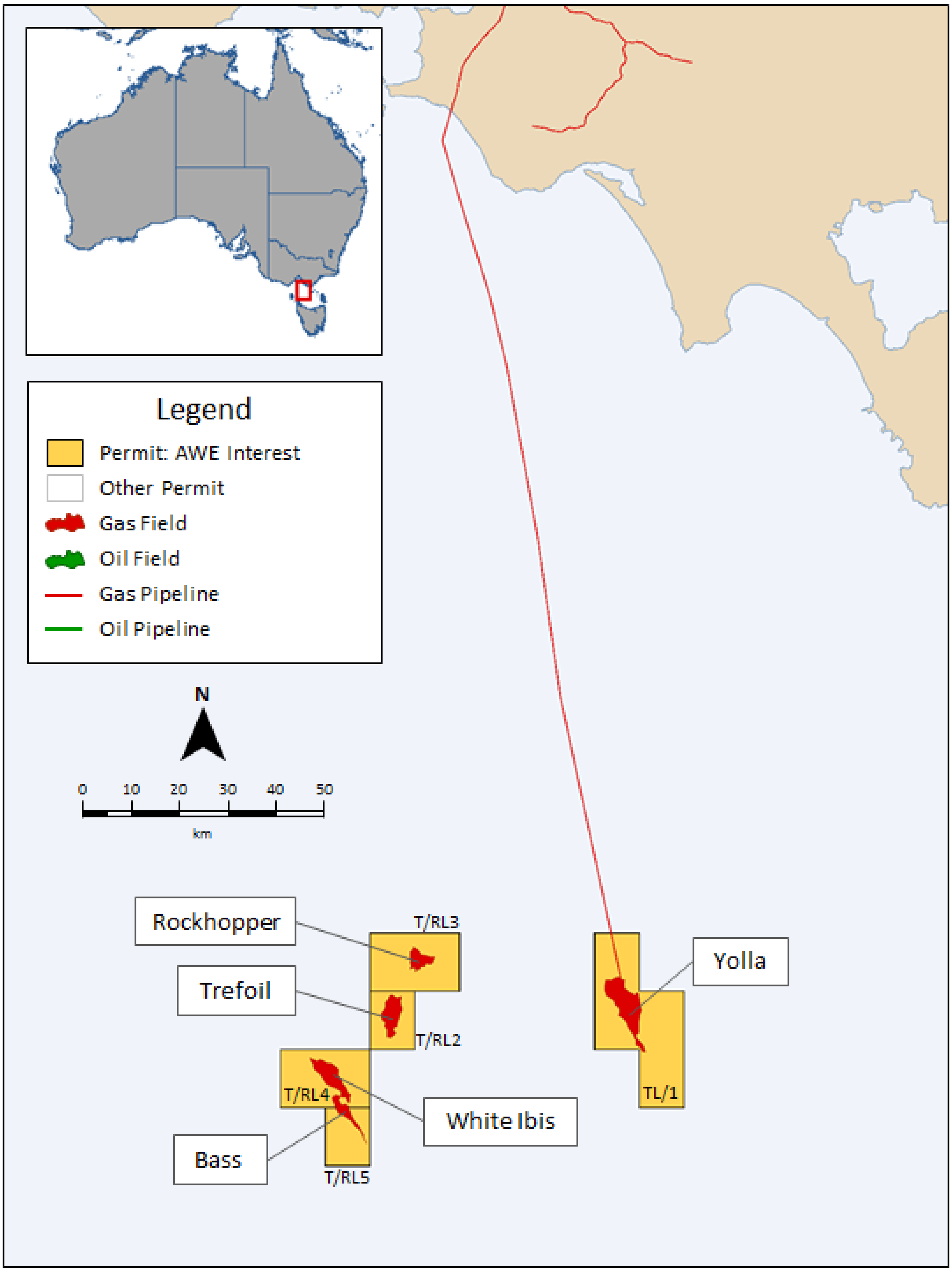


Figure 4-10: Location Map - AWE Bass Basin Oil and Gas Properties

AWE's equity within these Bass Basin production licences and retention leases (all operated by Beach Energy) are shown in Table 7-1 and Table 7-2.

4.2.1.1. Yolla

The Yolla gas-condensate field in Production Licence T/L1 lies within the Bass Basin, offshore south-eastern Australia (Figure 4-10). The field lies 200 km south southeast of Melbourne in a water depth of approximately 80 m. The entire project is commonly referred to as the Bass Gas Project.

Yolla-1 was drilled in June 1985 and encountered gas in both the Intra-Eastern View Coal Measures (EVCM) between 2700 m and 3000 m, and also in the Upper-EVCM at around 1830 m. Gas pay was encountered in five separate zones within the Intra EVCM, and these provide the main reserves for the BassGas development. DST-1 in Yolla-1 tested gas and liquids from the 2809 sand of the Intra-EVCM at rates of up to 15.1 MMscf/d and 580 bcpd.

The Yolla-2 appraisal well was drilled in April and May 1998. The well was drilled 2.35 km south-southeast of Yolla-1, and approximately 45 m downdip. The well demonstrated good correlation to the sands intersected in Yolla-1, although many were intersected below the gas-water contact due to the low structural location of the well. Pressure data obtained allowed confident inference of the GWC levels in the different Intra EVCM sands.

The field is a large northwest-southeast trending tilted fault block intersected by one major fault and a number of north-south trending dykes. The field is covered by the Yolla 3D seismic survey processed as broadband in 2014.

Of the five reservoirs identified the '2755' sand is currently assessed to contain the majority (55%) of the field's original gas volumes, with the 2809 sand containing 35% and the 2973 containing 10%. The Upper EVCM contains gas with an oil rim, and the 2458 sands contain waxy oil. The primary reservoirs are thin (< 20 m TVT) and tend to be laterally continuous but with variable quality.

The reservoirs comprise a lacustrine setting with fluvio-deltaic successions deposited in response to base-level variations. Lateral variations were controlled by syn-depositional faulting, local gradient variations and changes in rates of accommodation.

The Yolla top structure map is shown in Figure 4-11 below.

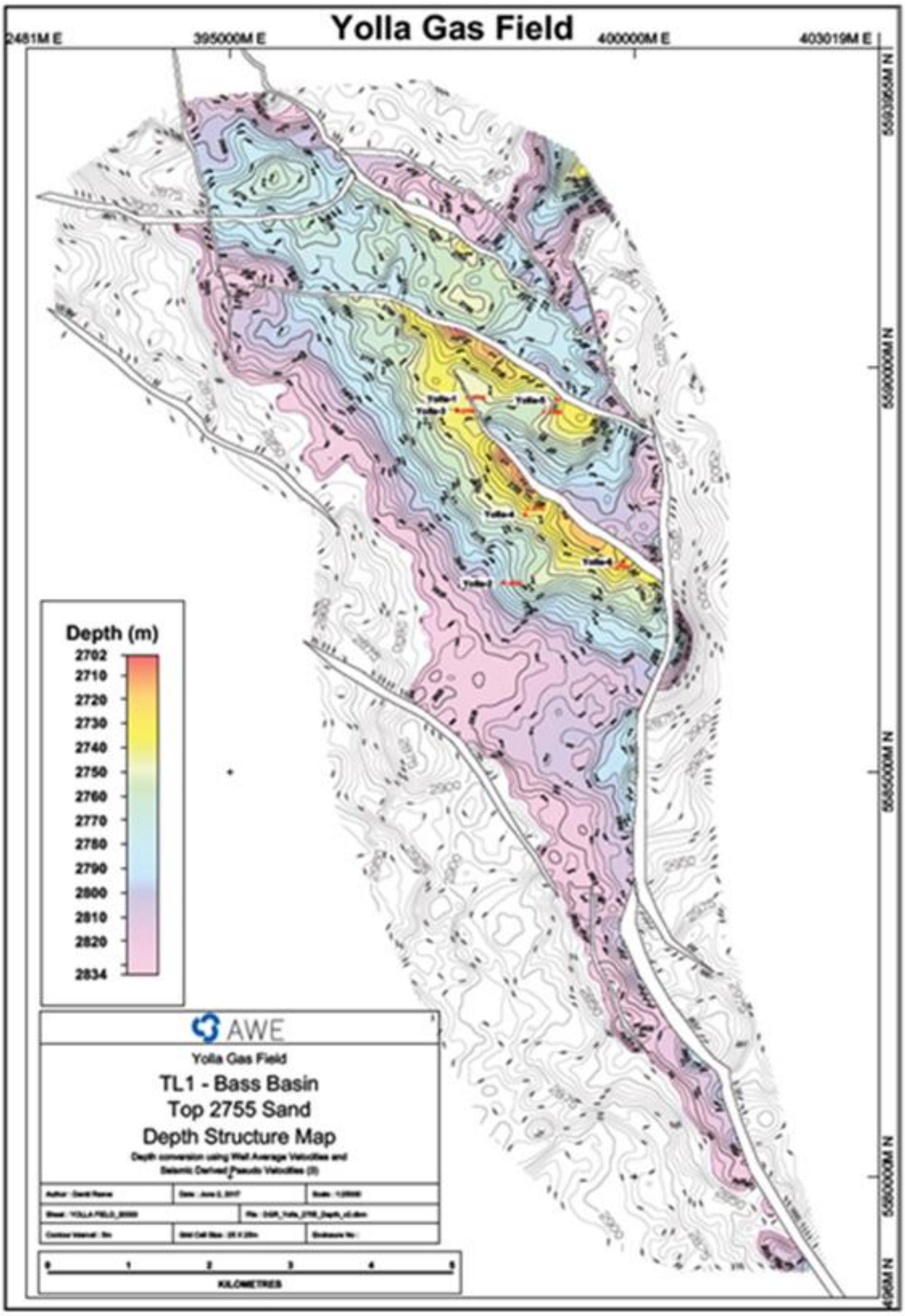


Figure 4-11: Yolla Gas Field Top Structure Map

The Yolla resources for the 2809, 2755 and 2973 reservoirs are estimated by AWE and the Operator using material balance analysis and numerical simulation modelling completed mid-2017. These indicate an aggregated range of GIIP from 427 to 451 Bcf.

As of the 31 December 2017 the Yolla field's cumulative production was 219 Bscf of raw gas, 6.6 MMstb of condensate and 174 TJ of sales gas. Gas production in October-2017 was 71 MMscf/d raw gas with a condensate gas ratio of 26 bbl/MMscf and water gas ratio of 11 bbl/MMscf. Historical production history is shown in below in Figure 4-12.

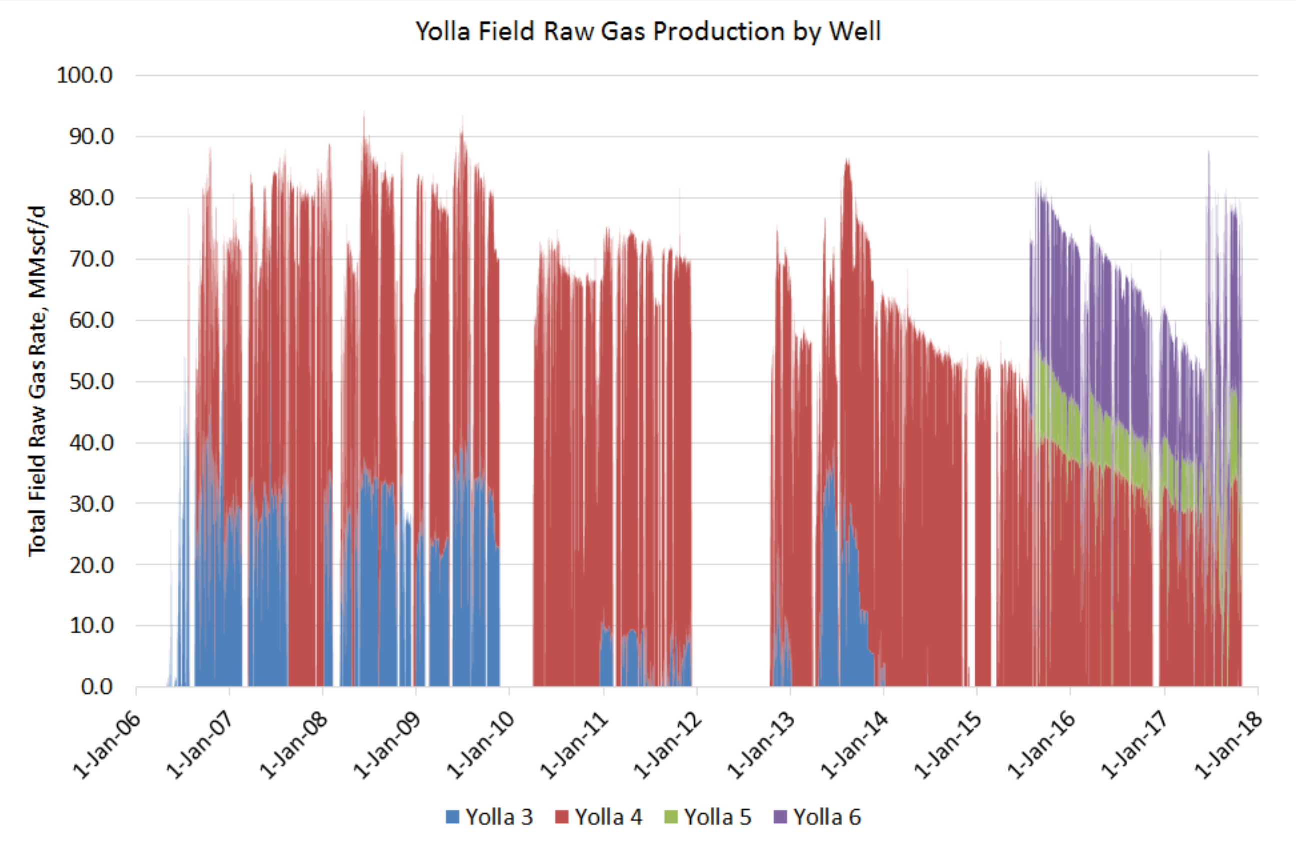


Figure 4-12: Yolla Field Historical Gross Gas Production

4.2.2. Existing Facilities

Yolla was developed in 2004 with installation of the Yolla A platform and drilling of development wells Yolla-3 and Yolla-4. Production commenced in 2006 via a 189 km wet gas export pipeline, initially to Kilcunda (on the south coast of Victoria) and then on to the onshore gas processing plant located at Lang Lang. Sales gas is then exported via a 32 km pipeline to enter the AEMO network at Packenham. Condensate is extracted at the gas plant, sold to Viva and trucked to the Corio refinery (in Geelong). AWEs share of LPG is sold ex-plant to Elgas and CO_2 is sold ex-plant to Air-Liquide.

Initially the offshore platform was unmanned and the raw gas production was dehydrated prior to export to shore via a multiphase pipeline.

Plant operability issues limited initial production until June-2007 when the design capacity was reliably achieved. The project has continued to suffer downtime due to planned and unplanned maintenance. Total gas sales at end Oct 2017 were 169 PJ equivalent to an average rate of 44 TJ per calendar day since facility start-up which is approximately 66% of the facility design capacity.

The field was shut-down for 3 months in Nov 2009 to conduct workovers to replace failed subsurface safety values and install permanent downhole pressure gauges.

The 2012 Yolla MLE (Mid-Life-Enhancement) Project installed (but not commissioned) compression and an accommodation module. The scheduled three-month installation was prolonged due to weather, industrial action and a number of failed lifting attempts. In October 2012 production resumed from the Y4 well however significant water production was encountered beyond the platforms water handling capacity and the well was subsequently choked back. In late 2017 the water handling system was modified by removing the liner from the hydrocyclone and changing choke trims in Yolla-A which has increased nominal water handling capacity from 140 m3/d to 260 m3/d.

Two additional gas production wells, Yolla-5 and 6, were drilled as deviated wells during 2015. These found better reservoir quality but were deeper than prognosed and unexpectedly found depleted reservoir pressures. The depletion seen in Y5 and Y6 led to a downgrading of GIIP estimates. Coupled with the recent evidence of water influx has led to write down in Estimated Ultimate Recovery (EUR) with Origin duly noting that formation water encroachment and production is a key risk to future production from the 2809 reservoir.

The compression platform was commissioned then brought online June 2017. Production is currently constrained by well deliverability.

4.2.3. Future Development

Planned future development is limited to the re-completion of Yolla wells:

- In Yolla-3, isolate 2809 (water), additional perfs in 2755 reservoir (Feb 2018);
- In Yolla-4, isolate 2809 reservoir (water production). 2755 completion retained (Feb 2018);
- In Yolla-5, open up 2809 reservoir. 2755 completion retained (2020);
- In Yolla-6, open up 2973 reservoir and possible isolation of 2809 if it produces water (2020).

Re-wheeling of compression is also planned around 2021 when production declines.

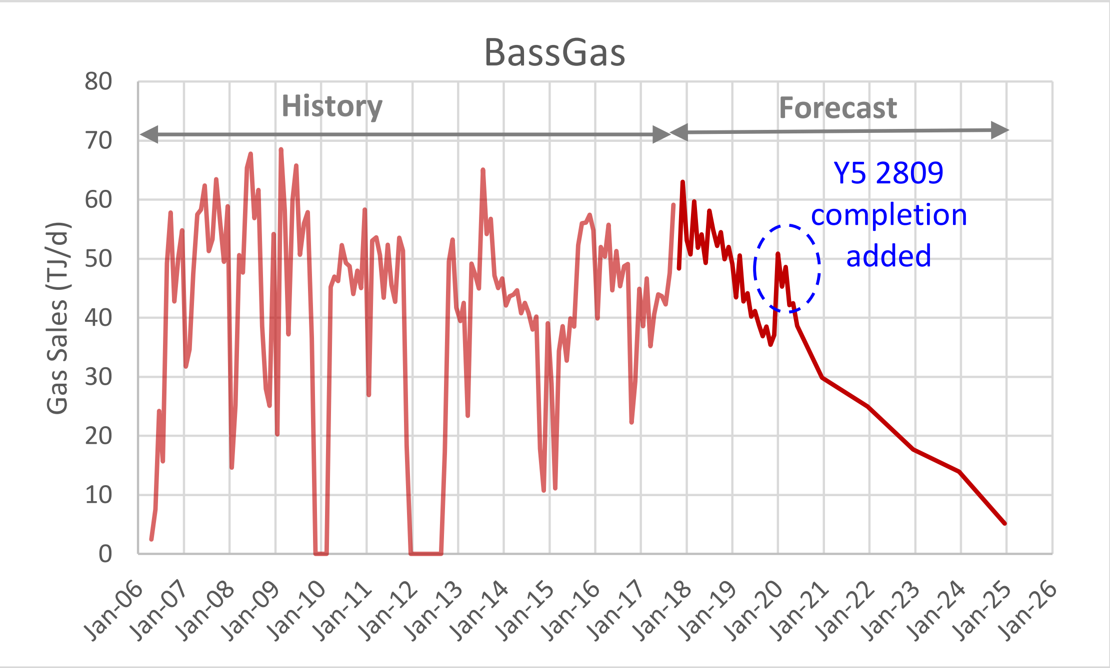


Figure 4-13: Bass Gas Fields Gross 2P + 2C Production History and Forecasts

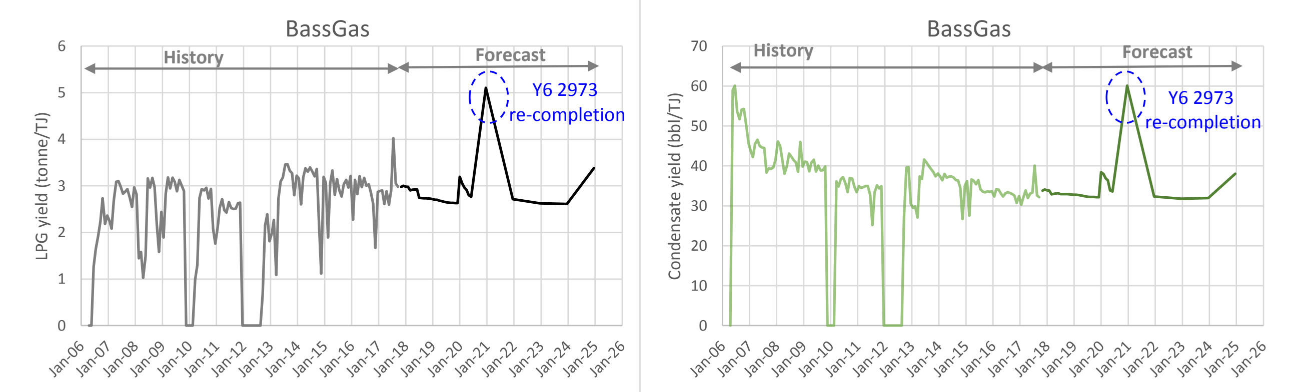


Figure 4-14: Bass Gas LPG and Condensate Yield History and Forecast

RISC has reviewed and supports the production forecast provided by AWE. Figure 4-13 and Figure 4-14 shows the historic and forecast gas sales and liquid yields from Bass Gas project.

- The planned 2018 re-completions have a small effect on production;
- Recompletion on Yolla-5 to the 2809 reservoir adds 12 TJ/d early 2020;
- Recompletion of Yolla-6 to the undepleted 2973 reservoir improves liquid yields in FY 2021.

AWE estimate 2C contingent resources of 7.9 PJ gas and 0.8 MMbbl oil+condensate for the EVCM reservoir and 0.8 MMbbl oil in the 2548 sand. The Upper EVCM in Yolla-3 produced minor gas volumes (0.45 Bcf raw gas) in 2012-2013 at about 6 MMscf/d. There, are no plans to re-complete wells on these intervals.

4.2.3.1. Trefoil, White Ibis, Bass and Rockhopper Discoveries

Four undeveloped gas fields have been discovered 40 - 50 km west of Yolla in approximately 70 m water depth. These are named Trefoil, White Ibis, Bass and Rockhopper in decreasing order of resource volume.

Trefoil, Rockhopper and White Ibis are covered by the 2005 Shearwater 3D seismic survey (PSTM processing). Data quality is very good in the overburden and fair across the reservoir section (but the thin sands are not individually resolvable). This data is currently being reprocessed for increased bandwidth (resolution) and an improved seismic velocity model.

Trefoil

Trefoil contingent resources are being studied for a tieback development to Yolla in 2022 when ullage is available in the system.

The Trefoil field is geologically complex, comprising a minimum of 17 stacked gas bearing reservoirs over an interval of 228 m, and well data density is low. Trefoil-1 (drilled 2004) has the better reservoir quality than Trefoil-2. Gross reservoir thicknesses range from 5-30 m, most at 5-10 m. Correlation of units between wells is uncertain and less reliable than at Yolla.

Reservoir units are vertically compartmentalised, as evidenced by differing pressure gradients, but no lateral compartmentalisation from faulting is expected. However, some stratigraphic compartmentalisation due to stratigraphic changes cannot be ruled out. Six reservoir units have both gas and water pressure data from the two Trefoil wells, there is contact uncertainty for the remainder. Increasing aquifer pressure gradients with depth is observed. Zero to weak aquifer support to gas production is expected, consistent with Yolla performance to date.

The Operator's gross GIIP estimates range from 187 to 778 Bcf with a 'reference case' estimate of 320 Bcf.

White Ibis

The White Ibis oil and gas field, discovered in 1998, is less complex from a geological perspective than the adjacent Trefoil field. The field comprises 3 stacked oil/gas bearing reservoirs ("2002", "2044", and "2128") over an interval of approximately 150 m and are generally poor quality with low permeabilities encountered over a significant proportion of the section.

The Operator estimates a most likely gross GIIP of 98 Bcf and 8 MMbbl of oil in -place.

Operator studies indicate that the White Ibis resources are unable to support an economic standalone development and would need to be tied in to a Trefoil field development.

Rockhopper

The Rockhopper oil and gas field, discovered in 2009 approximately 10 km northeast of the Trefoil field, is complex from a geological and fluid perspective. The discovery well, Rockhopper-1, was drilled updip of Aroo-1 exploration well (drilled in 1974) to test the crestal area of the structure. Subsequently, Rockhopper-1 ST1 was drilled as an appraisal side-track to evaluate a downdip extension of the hydrocarbon columns. Three cores were acquired in Rockhopper-1 ST1 over the RL40, RL50, RL90, RL100 and RL110 zones. The fluid content of 10 zones was confirmed by MDT sampling or optical analyser.

The field comprises 15 stacked oil/gas bearing reservoirs within the Eastern View Coal Measures (L. balmei and F. longus) over an interval of approximately 400 m. The reservoirs are generally poor quality with low permeability encountered over a significant portion of the section. The structure is fault-bounded and higher relief than Trefoil.

The most likely GIIP of 178 Bcf GIIP has been accessed by totalling 20 stacked reservoir with individual sand GIIP ranging from 0.7 to 20.1 Bcf. Four separate sands are assessed as oil bearing with a total STOIIP of 9.6 MMstb.

Operator studies indicate that the Rockhopper field resources are currently unable to support an economic standalone development and would need to be developed via a tie-in to the Trefoil field development.

4.2.3.2. Bass

In view of the minor volumes, RISC has not reviewed the Bass field gas discovery and has reported the estimates provided by AWE.

4.2.4. Bass Gas Reserves and Contingent Resources

The Bass Gas gross and AWE-net reserves and contingent resources as at 31 December 2017 are set out in Table 4-7. The reserves and resources have been estimated in accordance with the Petroleum Resources Management System (PRMS). The economic cut-off is estimated to be 10 TJ/d of sales gas. The undeveloped reserves are classified as Justified for Development under PRMS guidelines. The contingent resources are classified as Development on Hold under PRMS guidelines, except for the small sub-economic resource in Bass which is classified as Development not Viable. Cumulative production to 31 December 2017 is estimated to be 218 Bcf raw gas, 173 PJ sales gas, 471 ktonne LPG and 6.6 MMbbl condensate.

Table 4-7: Bass Gas Gross Developed + Undeveloped Reserves and Contingent Resources as at 31 December 2017

Sales product	Unit	2P	2C
Gross sales gas	PJ	78.1	281.4
Gross LPG	ktonne	217	987.5
Gross condensate	MMbbl	2.6	15.6
Net sales gas	PJ	27.3	112.5
Net LPG	ktonne	76.0	394.4
Net condensate	MMbbl	0.9	6.53
1. AWE interest 35% in Yolla and 40% in T18P discoveries. 2. Probabilistic methods have been used. 3. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated as sales quantities net of fuel estimated at an average of 13% for reserves and contingent resources. Average sales gas conversion factors are 0.75 PJ/Bcf of raw gas. Average LPG and condensate yields are 2.1 tonne and 25 bbl/MMscf raw gas respectively. 4. The resources are classified as conventional under PRMS definitions			

The YEJ16 resources were based on an analytical GAP Material Balance Model by the Operator. In 2017 Yolla field static and dynamic models were rebuild and YEJ17 reserves were estimated by reservoir simulation. RISC has reviewed the dynamic models and consider them representative. We note that an EUR increase of 16 Bscf in the YEJ17 2P case compared to YEJ16 EUR, which is due to additional tail end volumes in the 2973 sand based on an increased 2973 sand GIIP.

RISC has reviewed the Yolla dynamic modelling history matching and considers the history matching adjustments made to the static model in terms of well deliverability and connectivity to be reasonable. Well by well flowing pressures and reservoir shut in pressure history matches are reasonable.

AWE carry minor contingent resources for the undeveloped EVCM reservoirs in Yolla. Larger contingent resources are associated with the undeveloped Trefoil, White Ibis, Rockhopper and Bass discoveries (Table 4-8).

Table 4-8: Unrisked Contingent Resources Bass Basin at 31 December 2017

Resource	Field	2C (100%)
Gas (PJ)	**Total**	**281.4**
	Yolla EVCM	1.9
	Trefoil	182
	White Ibis	50.1
	Rockhopper	35.2
	Bass	12.2
LPG (ktonnes)	**Total**	**987.5**
	EVCM	11.5
	Trefoil	435
	White Ibis	196.4
	Rockhopper	296.9
	Bass	47.7
Condensate (MMstb)	**Total**	**15.6**
	Yolla EVCM	0.03
	Trefoil	7.1
	White Ibis	2.9
	Rockhopper	5.6
	Bass	0.7
Oil (MMstb)	**Total**	1.8
	Yolla EVCM	0.9
	Bass	0.9

4.2.5. Capital and Operating Costs – 2P Development

The Yolla wet gas field lies within the Bass Basin, offshore south-eastern Australia.

Table 4-9 below has a summary of future capital, operating and abandonment cost forecasts from 31 December 2017 based on the FY18 Work Plan and Budget (WP&B). The FY18 estimates are from 31 December 2017.

Table 4-9: Yolla 2P Operating and Capital Cost Forecast (A$ million, RT, 100% gross)

Cost Item	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Operating Cost	38.2	65.5	52.4	55.6	44.6	41.3	38.3	22.4
Capital Cost	1.0	7.9	3.9	19.2	1.1	0.9	0.3	
Abandonment Cost						3.0	25.9	108.2

Operating and minor capital cost forecasts have been provided by AWE in the corporate economic model for the 2P scenario. RISC has reviewed this forecast as well as the FY18 work plan and budget for the asset. We conclude the AWE cost forecasts are reasonable.

There is currently no further development planned for the Yolla asset following the completion of the Mid Life Extension (MLE) project.

4.2.5.1. Trefoil

Currently Trefoil is being studied for a tieback development to Yolla to backfill capacity when Yolla is in decline.

The current base case development plan is for 3 to 6 development wells drilled from a minimum facilities wellhead platform (WHP) located in 70 m of water depth. A 38 km, 12" pipeline is used to export produced fluids to the Yolla platform. Subject to economics, FID is envisaged in 2019 with first gas being produced in early 2022.

The project is currently in the Assess phase and development costs have been provided for a number of different scenarios. The development is currently viewed as economically marginal and the project will need to undergo further study to ascertain if it can be commercialised.

4.3. Casino Gas Project

4.3.1. Introduction

The Casino development is located in the Otway Basin, offshore Victoria in water depths between 60 m and 70 m. It is covered by Licences VIC/L24 and VIC/L30, which contain the producing Casino, Netherby and Henry (CHN) gas fields (Figure 4-15). The Joint Venture participants are Cooper 50% (Operator), Mitsui 25% and AWE 25%. The same Joint Venture also holds the surrounding acreage; VIC/P44, VIC/RL 11 and VIC RL/12.

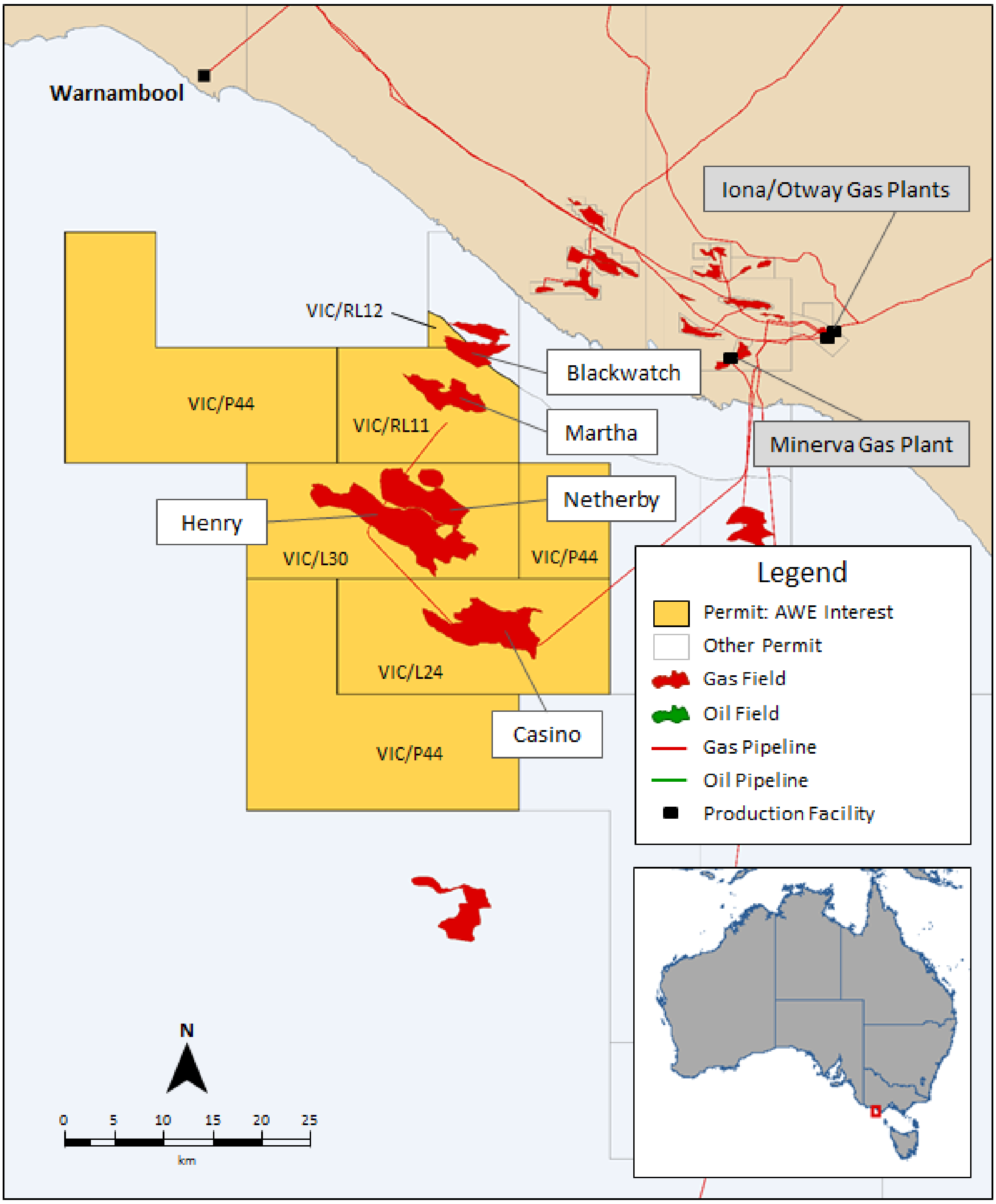


Figure 4-15: Location of the Otway Basin Casino, Netherby and Henry fields

The CHN fields are all formed as three-way dip closures on the upthrown side of tilted fault blocks. The reservoir is the Late Cretaceous Waarre Formation, deposited in shallow marine and braided fluvial environments, which is divided into three units called A, B and C. The main reservoir for the fields is the Waarre A unit, but the Waarre C unit also contains gas in the Casino field. The Waarre B unit provides an intra-formational seal.

The Casino field was discovered in 2002 with the drilling of the exploration wells Casino-1 and Casino-2, followed by the appraisal well Casino-3 in 2003. The Henry field was discovered in 2005 with Henry-1ST1 and the Netherby field in 2008 with Netherby-1.

The gas is dry with 2016 average field producing condensate to gas ratios (CGR) ranging from 0.64 to 1.71 stb/MMscf. The gas has low inerts (N_2 and CO_2) ranging up to a maximum of 3.5% in Casino-4, with no H_2S present. The Netherby and Henry fields are normally pressured, while reservoirs in the Casino field are over-pressured and not in pressure communication with each other. On the Casino field, the Waarre A water leg is significantly over-pressured (190 psi), whereas the Waarre C water leg is only slightly over-pressured (14 psi).

The Casino and Netherby fields produce under volumetric depletion drive and as such recovery will be a function of reservoir abandonment pressure. The Henry field drive mechanism is less well understood and the reservoir is interpreted to be segmented into a number of fault blocks. The field appears to exhibit multi-compartment behaviour, although the presence of an aquifer cannot be discounted.

The PSDM seismic data is high quality and provides a good structural image and amplitude map of the fields.

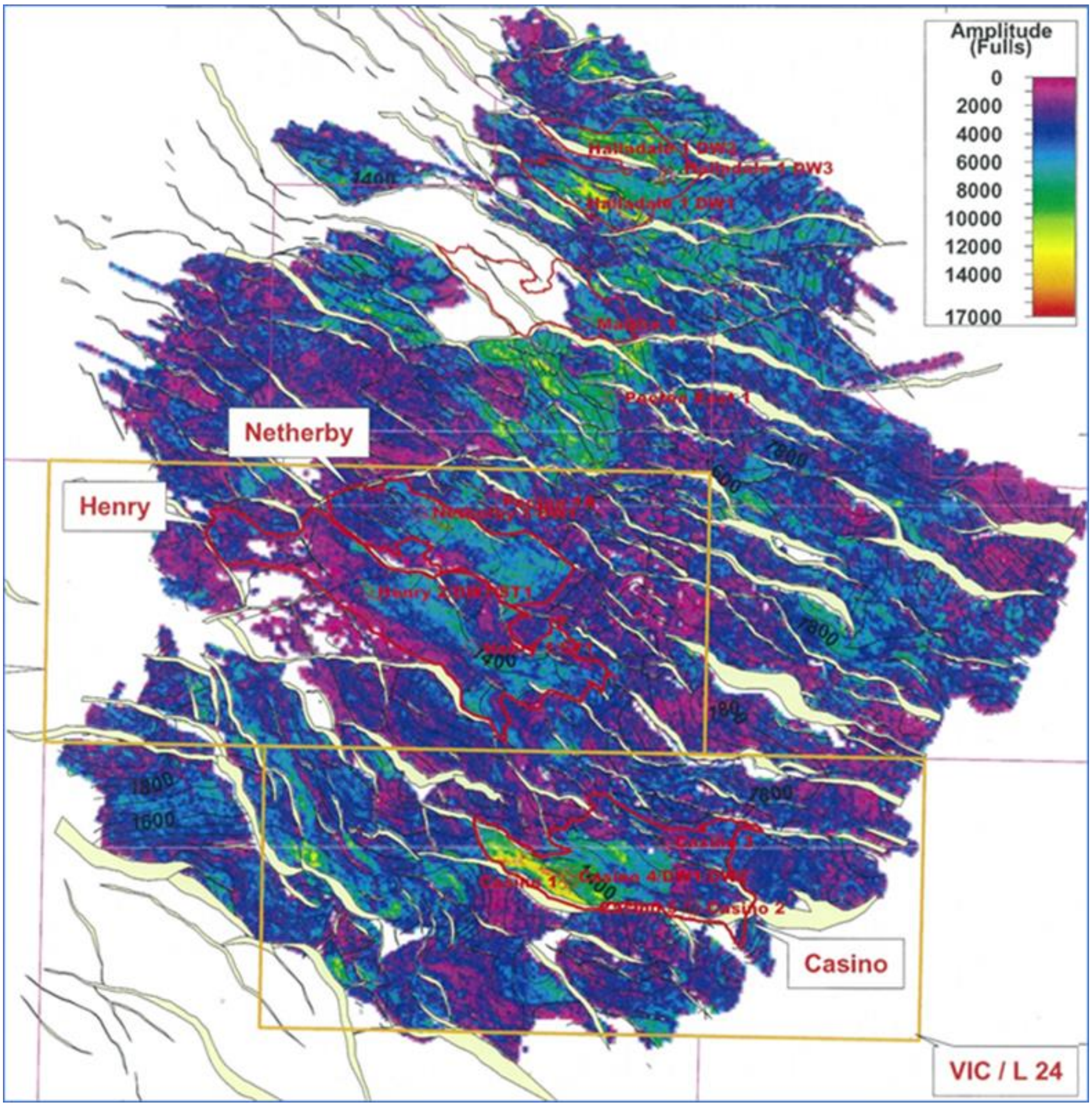


Figure 4-16: Amplitude map over the Casino Henry and Netherby fields

The amplitude of the seismic events appear to increase in the presence of gas sands. Amplitudes have been used to constrain the seismic interpretation and provide subjective/interpretative constraints to the building of 3D geological models.

The reservoir was deposited in a marginal marine to fluvial-deltaic environment, which can have variable facies distribution. However, the reservoir packages are regionally correlatable, and similar facies can be expected to extend over the limits of the fields.

There are significant differences in fluid contacts between the two reservoirs In the Casino field. The Waarre A and Waarre C reservoirs are not in pressure communication. The Waarre A water leg is slightly over-pressured (190 psi) compared to the regional Waarre A trend, whereas the Waarre C water leg is only 14 psi above the regional Waarre C trend. The pressure data enable Free Water Levels (FWLs) to be determined with reasonable confidence.

There is more uncertainty in the FWL for the Netherby and Henry fields as the aquifer gradient is not known. The Lowest Known Gas (LKG) is used as the P90 FWL and the intersection of the gas and Pecten East-1 aquifer gradient for the P10 FWL.

AWE has estimated connected GIIP for each Casino Netherby wells. RISC has reviewed and conducted its own material balance analysis and supports AWE's estimates for Casino 5, Netherby and carries a slightly lower range for Casino 4. At Henry 2, RISC material balance estimated volumes are at the low end of the geologically estimated GIIP carried by AWE. The production well Henry-2DW1ST1 has under-performed and an additional well (Henry-3) is planned to access poorly connected/unconnected GIIP in adjacent blocks.

The estimated GIIP is shown in Table 4-10.

Table 4-10: RISC material balance GIIP versus AWE Geological GIIP; Casino Gas Project

Well	Reservoir	Gas Production to date (Bcf)	RISC Material Balance GIIP Bcf			AWE GIIP (Bcf)
			1P	2P	3P	P90-P10
Casino-4	Waarre A	52.8	72	80	85	82-96
Casino-5	Waarre C	193.4	251	266	283	256 - 286
Netherby-1	Waarre A	69.9	102	108	112	103 - 107
Henry-2	Waarre A	29.1	44	61	70	91 - 192

As of the 30 November 2017, the Casino gas project cumulative production was 345.2 Bscf of raw gas (356.9 PJ of sales gas) and 0.26 MMstb of condensate. Gas production rate in November-2017 was 31.5 MMscf/d raw gas. Historical production history is shown in below in Figure 4-17. Production is currently below the project potential as Casino-5 has been shut-in since May-2017 due to a casing leak. This is anticipated by the joint venture to be addressed in February/March 2018, subject to regulatory approvals.

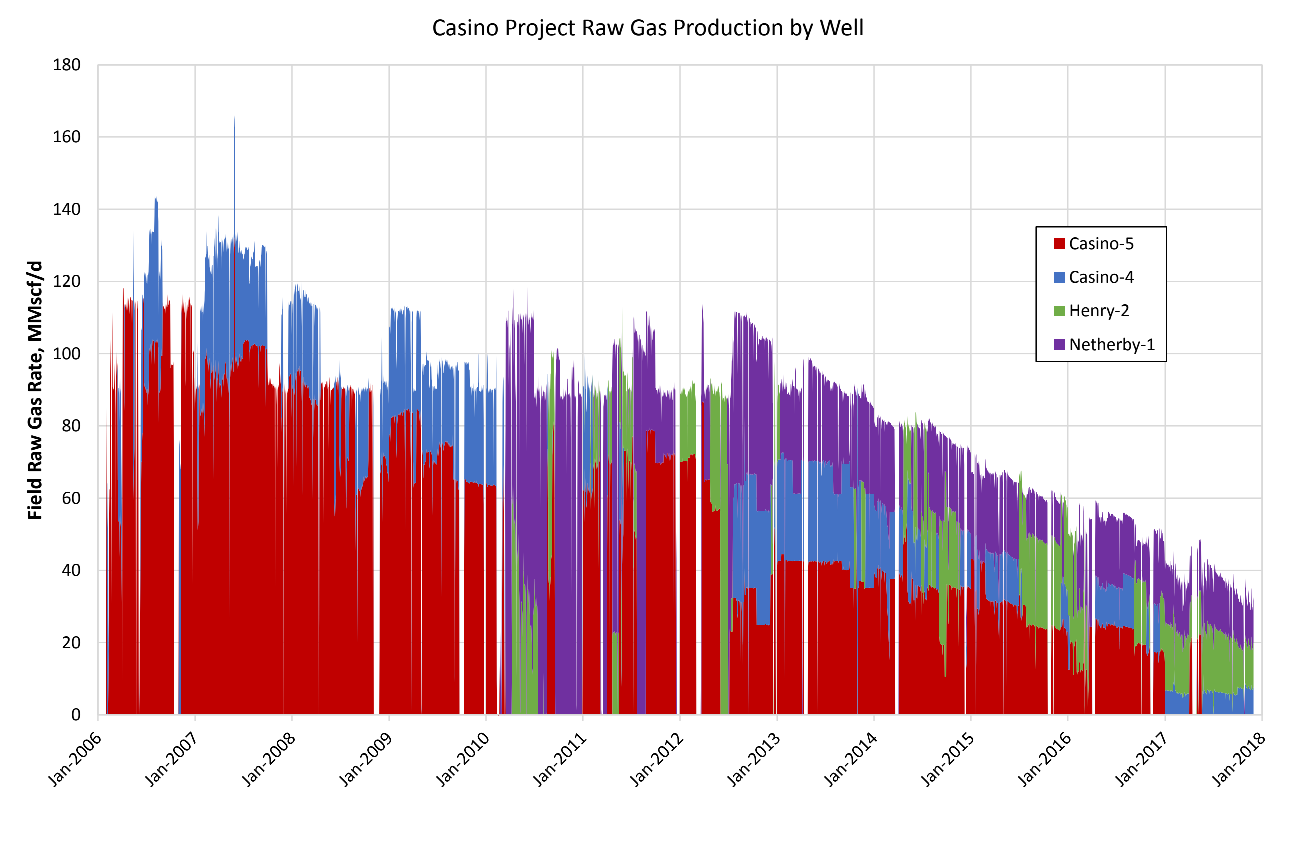


Figure 4-17: Production History Casino, Netherby and Henry fields

4.3.2. Existing Facilities

Phase 1 development included development wells Casino-4DW2 and Casino-5, which are connected to the Iona gas plant (IGP) through a subsea pipeline (Figure 4-18). Production commenced in 2006 and the Henry and Netherby fields were brought on line in 2010 as part of the Phase 2 development, with Henry-2DW1ST1 and Netherby-1ST1 horizontal development wells tied into the Casino pipeline.

The offshore subsea production system consists of a 55 km subsea pipeline and control umbilical run with four single well tie-ins along the length of the pipeline. The onshore pipeline runs ~13 km from the shore crossing to the IGP. A mainline valve station is located near the onshore end of the shore crossing with Electro-Hydraulic Umbilical (EHU) facilities for controlling the offshore wells.

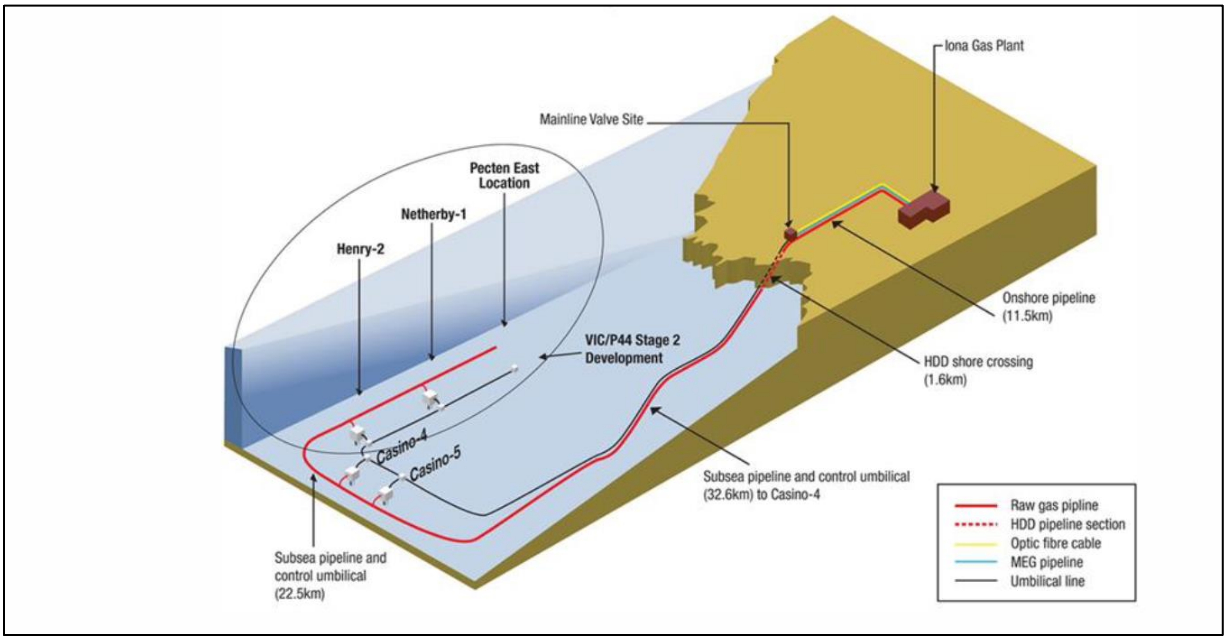


Figure 4-18: Development plan for the Casino, Netherby and Henry fields

The IGP owned by Lockhart Energy, currently processes produced gas from the CHN at an inlet pressure of 2,500 kPa. AWE has confirmed that under the original gas sales arrangements, the Joint Venture has processing rights via the IGP until the end of February 2018. The Joint Venture has recently concluded a further processing arrangement with the owner of the IGP for the period March to December 2018 at an amended inlet pressure of 2200 kPa. In addition, the Joint Venture has entered into a new gas sales arrangement for the corresponding period.

In parallel, the Joint Venture is progressing alternative longer term gas processing arrangements. RISC understands the JV is intending to produce to the alternative processing facility (APF) upon expiration of the Iona processing rights.

The gas is dry with minor condensate volumes at Henry. Fuel gas is approximately 4% of dry gas production and planned pre-inlet compression at the APF is estimated to require an additional 1.5% of raw gas production.

4.3.3. Future Development

The previous Operator (Santos) proposed for an additional well (Henry-3) to access undrained volumes in the Henry field and carried these volumes as undeveloped reserves. The proposed development of Henry-3 in 2021 is within the 5 year time frame considered reasonable under the SPE PRMS, and the project is economic in the 2P case. However, the final investment decision has not be made yet.

Reduction in plant inlet pressure, via compression, is being investigated as GAP modelling suggests the fields will likely cease production in 2019 based on the current IGP inlet pressure. Options are currently being explored for a new processing agreement at the IGP.

The JV is currently in the process of commercial negotiations to secure post 2018 processing and compression options at an Alternative Processing Facility (APF) and is undertaking FEED studies. Discussions with the owners are progressing and are considered likely to result in an agreement to allow processing of the CHN gas. RISC has reviewed plans for the APF but cannot disclose the name due to ongoing commercial discussions. Some modifications and tie-in works for the CHN production tie-back will be required. AWE estimate use of Iona gas plant to Mar 2019 and re-start of production through the APF from May 2019.

This APF modification project is estimated by RISC to have an earliest completion date of end May-2019. Major uncertainties exist with the first gas date. This uncertainty can be mitigated by extending the production agreement with the IGP, although the CHN production rates will be impacted through 2018/19 in this scenario. Compression at the APF would reduce current plant inlet pressure of 2800 kPa (410 psi) to 1900 kPa (275) psi and finally to 1250 kPa (180 psi).

RISC has reviewed the production forecast provided by AWE and reduced the projected recovery from Henry-3. AWE consider Henry-3 will develop the remaining GIIP in Henry that has not been developed by Henry-2. However, Henry-2 has not developed the full Henry GIIP due to partial compartmentalisation and in RISC's view there is a material risk that Henry-3 also connects a limited GIIP. In the 1P case, RISC has limited the recovery from Henry-3 to no more than analogue well Henry-2. RISC's sales gas production forecast is shown in Figure 4-19.

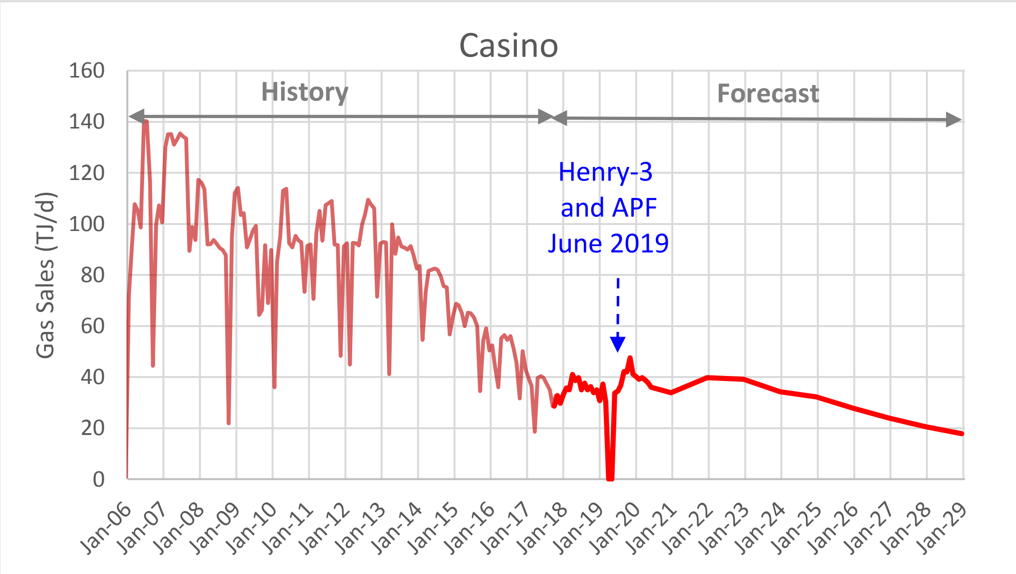


Figure 4-19: Casino Gas Project Gross 2P Production Forecasts

The condensate forecast is estimated using a constant condensate yield of 0.6 bbl per TJ of sales gas.

4.3.4. Casino Gas Project Reserves and Contingent Resources

The Casino project gross and AWE-net reserves and contingent resources as at 31 December 2017 are set out in Table 4-11. The reserves and resources have been estimated in accordance with the Petroleum Resources Management System (PRMS). The economic cut-off is estimated at the minimum plant turndown which is reduced to 20 TJ/d of sales gas at the APF compared to 30 TJ/d at IGP. The undeveloped reserves are classified as Justified for Development under PRMS guidelines. The contingent resources are classified as Development on Hold under PRMS guidelines. Cumulative production to 31 December 2017 is 346 Bcf raw gas, 358 PJ sales gas and 0.3 MMbbl condensate.

Table 4-11: Casino Project Gross Developed + Undeveloped Reserves as at 31 December 2017

Sales product	Unit	2P	2C
Gross sales gas	Bcf	126.8	28.6
Gross sales gas	PJ	131.2	29.6
Gross condensate	MMbbl	0.08	0.28
Net sales gas	Bcf	31.7	7.15
Net sales gas	PJ	32.8	7.41
Net condensate	MMbbl	0.02	0.07
1. AWE interest 25%. 2. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated as sales quantities net of fuel estimated at an average of 4.0% for reserves and contingent resources. Sales gas conversion factor is 1.04 PJ/Bcf of sales gas. 3. The resources are classified as conventional under PRMS definitions			

AWE carry minor contingent resources for the undeveloped Black Watch and Martha gas fields. The Black Watch resources are related to an extension of the Black Watch discovery in VIC/L1 into adjacent AWE block VIC/RL12 (25% AWE), however there has been no unitisation. Martha i.e. a small gas discovery in VIC/RL11.

Table 4-12: Unrisked Contingent Resources Otway Basin at 31 December 2017

Resource	Field	2C (Gross)
Gas (PJ)	**Total**	**29.6**
	Martha	9.6
	Blackwatch	20.0
Condensate (MMstb)	**Total**	**0.3**
	Martha	0.0
	Blackwatch	0.3

RISC has not included the Otway Basin 2C resources in production and cost forecasts as development is currently considered to be uneconomic.

AWE exploration opportunities in the Otway Basin are discussed in section 5.3.

4.3.5. Capital and Operating Costs – 2P Development

Table 4-13 below has a summary of future capital, operating and abandonment cost forecasts from 31 December 2017.

Table 4-13: Casino 2P Operating and Capital Cost Forecast (A$ million, RT, 100% gross)

Cost Item	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Operating Cost	3.1	4.9	18.7	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	10.0	
Capital Cost	36.1	78.0	5.9	9.6	0.6	0.6	0.6	9.6	0.6	0.6	0.6		
Abandonment Cost													130.0

Major development works planned in 2018/19 include a workover of the Casino-5 well to restore production, and subsea interventions to repair hydraulic and electrical systems. A total of A$75 million (gross) is estimated to be spent on these projects over the 2018/19 period.

Additional future projects include the transition to a new processing plant and the Henry-3 development well. These projects are explained in more detail below.

Operating costs for the period leading up to the switch to the new processing plant are estimated to be approximately A$400,000 (gross) per month. This is in line with previously experienced operating costs.

Abandonment costs for the four existing wells, the subsea production system and the new Gas Plant are estimated to be A$130 million (gross).

4.3.5.1. Alternative Processing Facility Project

Initial engineering assessments of the alternative processing facility (APF) to ascertain compatibility with the Casino production fluids and required modifications have been completed. The Operator’s assessments (including site visits) have not identified any major issues that would prevent the processing of Casino gas at APF. A scope of modifications and tie-in works has been produced with associated costs by the engineering contractor, Jacobs. This scope is considered to be suitable for concept select purposes.

Major works required include;

- Tie-in of the existing onshore CNH pipeline to the onshore pipeline downstream of the mainline valve station including new pig launching and receiving facilities;
- New fibre optic control cable and chemical injection lines run from the APF to the mainline valve station;
- Modified subsea control panels;
- Chemical injection skid installation at the APF;
- Modification to the condensate stabilisation system to increase capacity at the APF;
- Piping modifications to the APF inlet piping, gas-gas exchanger system and the sales gas export compressors;
- Installation of new MEG treatment system at the APF.

The cost of these refurbishment works have been estimated by Jacobs and included in the valuation. The estimates appear reasonable for the scope and maturity of the proposed project.

Operating costs for the CHN fields and the APF once the modifications have been completed are estimated by RISC to average A$20 million p.a. (gross) with additional Stay In Business (SIB) capex of A$0.35 million p.a. (gross).

4.3.5.2. *Henry-3 Development Well*

A single future development well is planned for the CHN fields. Henry-3 is planned to be drilled as either a new well or a sidetrack from Henry-2 in 2018, with the well tied-in to the existing subsea infrastructure. AWE have provided a cost estimate of A$41 million (gross) for the sidetrack option which RISC considers to be reasonable based on the limited scope definition currently available. Shared mobilisation costs and sidetracking has reduced the well cost.

4.4. Ande Ande Lumut Oil Project

4.4.1. Introduction

The Ande Ande Lumut oil field is located in the Natuna Sea, Indonesia, in 73 m water depth (Figure 4-20). The field was discovered by the exploration well, AAL-1, drilled by Premier in April 2000 in the central part of the structure. Heavy oil was discovered in a thick Upper Gabus K-sand and a number of thinner G-sands below. Oil was recovered by wireline formation tests (MDT), however, all attempts to get the K-sand to flow during testing were not successful and the DST was inconclusive. The discovery was considered as uneconomic at that time, and the permit was later relinquished by Premier.

The Northwest Natuna PSC was awarded to Genting Oil Natuna Pte. Ltd. (Genting) on 12 December 2004. The PSC is located ~1,300 km from Jakarta and 535 km from Singapore and has an area of 461 km2 (Figure 4-20).

Exploration by Genting commenced in 2005 with the acquisition of 300 km2 full-fold of 3D seismic survey over the AAL structure. This was followed by the drilling of two successful appraisal wells (AAL-2X-R and AAL-3X) on the AAL structure in 2006.

AWE currently holds a 50% participating interest and Santos Natuna BV (also 50%) is the operator of the PSC. AAL-4X was drilled by Santos in 2016 and provided further information on FWL, top structure depth, flow rates and fluid samples. Well tests using an ESP flowed oil at 830 bpd from the G sand and 2000 bpd from the K sand.

All firm exploration obligations have been met and all relinquishments have been satisfied. The PSC expires in December 2034.

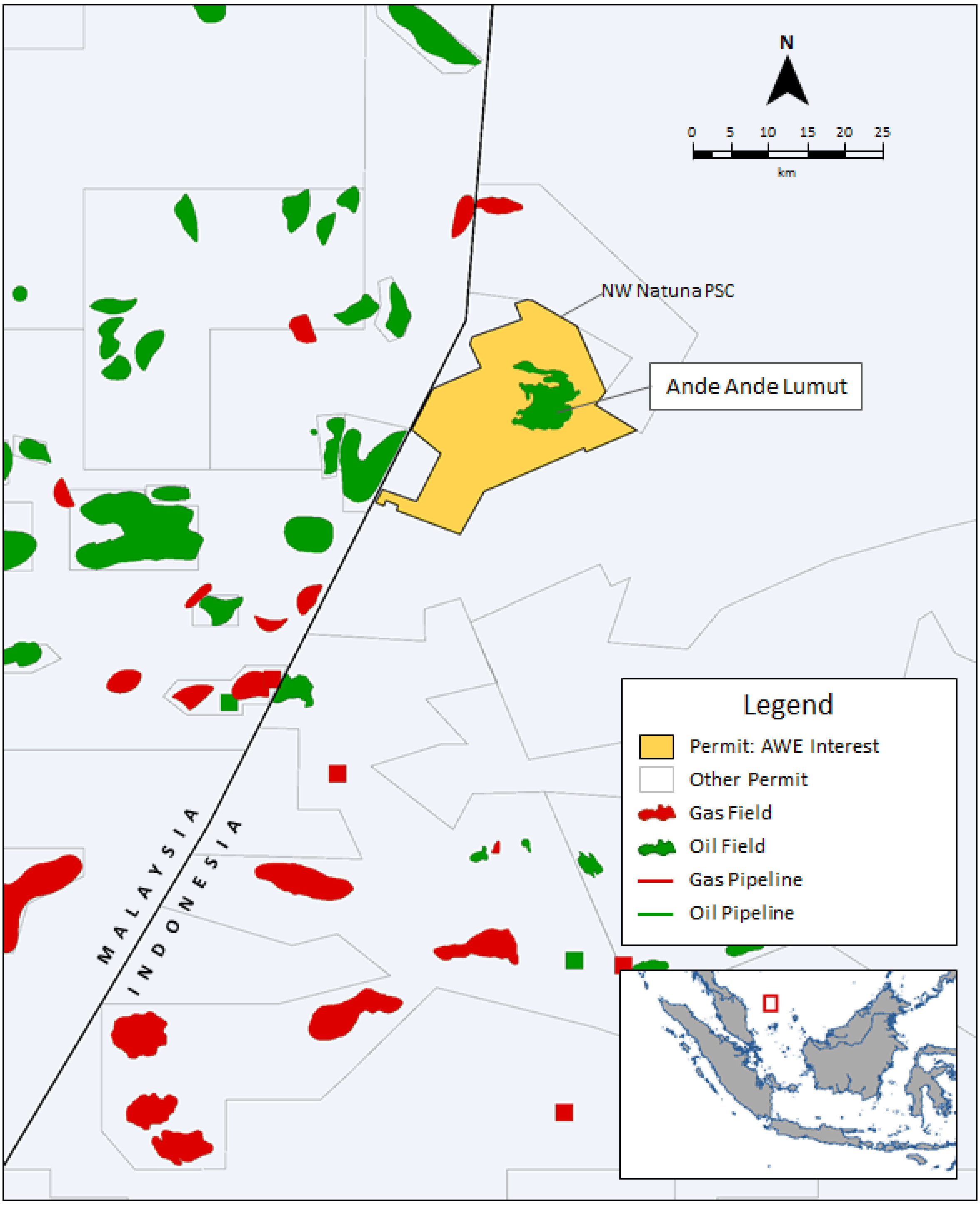


Figure 4-20: Location Map of NW Natuna PSC

The Ande Ande Lumut Field is a well defined, simple unfaulted, four-way dip closure draped over a basement high. It has a total oil-bearing area of approximately 23 km^2. The Late Oligocene Upper Gabus K-sand reservoir is a massive 35 to 40 m thick, widely distributed braided sand body, consisting of poorly consolidated medium to coarse grained sandstones, with high porosities ranging from 25 to 32% and permeabilities in multiple Darcies. The Lower Gabus G-sand secondary reservoir consists of a fluvial channel setting. The oil column is underlain by a widespread regional aquifer which is expected to provide strong water drive (Figure 4-21 and Figure 4-22).

Although the oil is relatively heavy (14.8 degrees API), it is not highly viscous (18 - 33 cP at reservoir condition) and it is not waxy (pour point of -18 to - 6^{o} C).

Well data for the reservoir description and static model build was available from AAL-1X, AAL-2X, AAL-3X and AAL-4X. Three wells in AAL have core these are AAL-2X, AAL-3X and AAL-4X. Pressure data available from AAL-4X was from MDT. This gives an indication of FWL for the K Sand at -1145m TVDss on the main area of the field, with -1150 m TVDss in the southern area (Figure 4-21 and Figure 4-22). There will always be some uncertainty on the exact FWL position from pressure data due to the similarity of fluid densities between oil and water when the oil is relatively heavy. There is MDT pressure data available in the G sand, but this is all in the oil leg so cannot be used to help define the FWL directly. For FWL the range was taken from estimated values from petrophysics and fluid sampling assumptions as outlined below:

- Base case -1190m TVDss based on AAL-3X probable water from MDT 19447cc pumped;
- Low case -1185m TVDss ODT based density neutron and resistivity logs in AAL-4X;
- High case -1195m TVDss WUT based on density neutron and resistivity logs in AAL-3X.

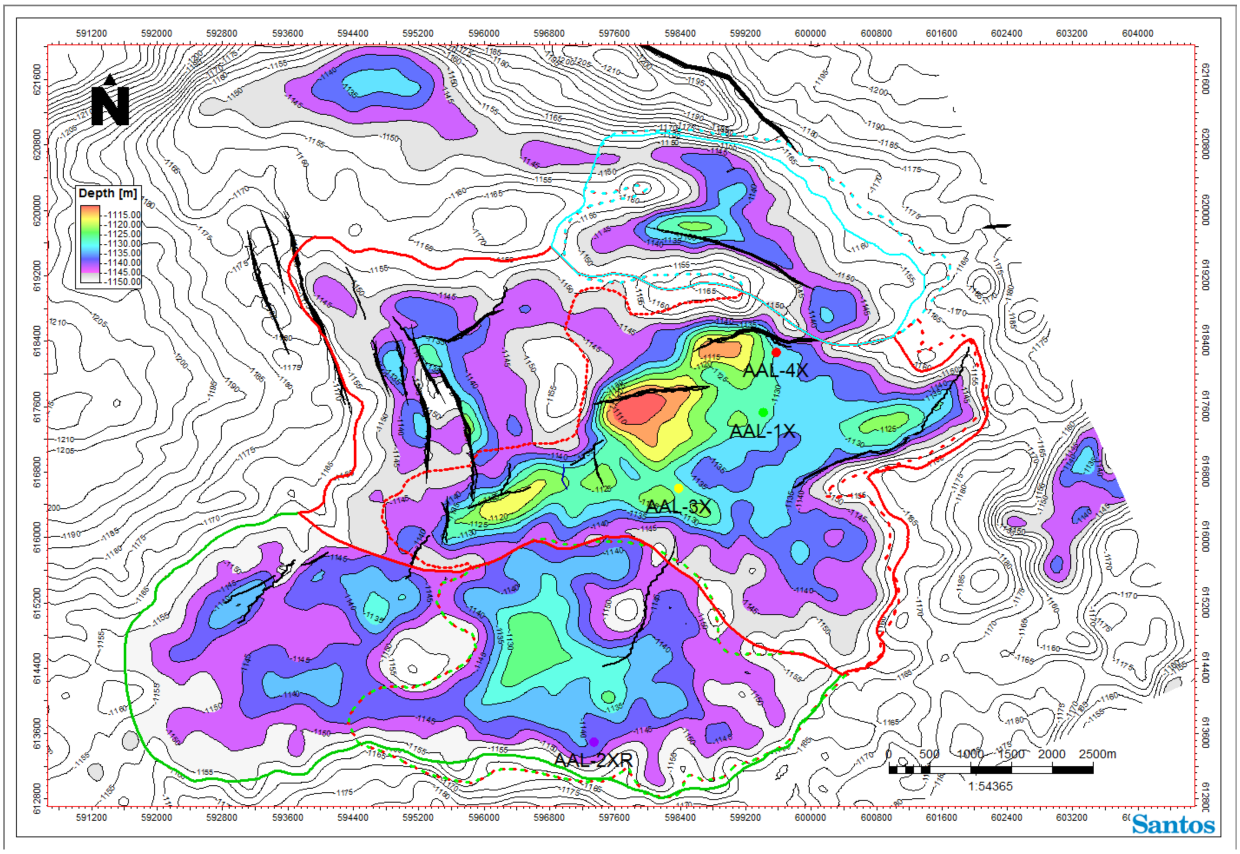


Figure 4-21: AAL K Sand Top Structure Base Case Map

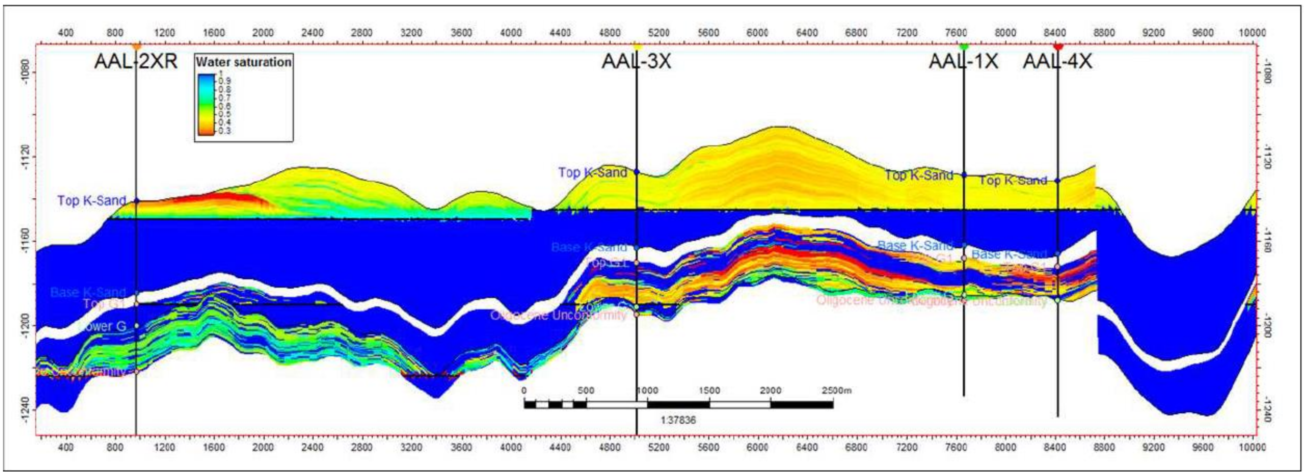


Figure 4-22: AAL Cross Section

3D seismic was acquired by Genting in 2005. In 2012 AWE used 3D reprocessed seismic volumes to build interpretation for models and volumes to support the FDP. Seismic data quality is good, and event continuity is high, hence RISC has a high confidence in the TWT interpretation. The overburden is relatively benign, with the exception of some channels which impact the depth conversion.

The reservoir contains low GOR relatively heavy (low API) and moderately viscous oil. Sampling indicated the K sand has 14.8 API oil with a GOR of 57 scf/stb and in-situ viscosity of 17.6 cp. The G sand has 11.7 API oil with a GOR of 46 scf/stb and in-situ viscosity of 33.1 cp.

AAL-3X tested an oil rate of 1430 stb/d from the K sand and 531 stb/d from the G sand. AAL-4XTst1 was tested in the G and then K sand. The G sand produced oil at 600 to 830 stb/d with the aid of an ESP. Permeability is estimated to be 1000 to 2000 mD. The K sand was tested at an oil rate of 500 to 2000 stb/d with the aid of an ESP. The water cut increased during flow periods and is interpreted as coning or flow behind pipe due to poor cement.

The reservoir is expected to have strong water drive. Early water production is expected due to the viscous oil, with significant oil production at high water cut.

4.4.2. Existing Facilities

There is currently no existing infrastructure at AAL.

4.4.3. Future Development

The PoD (Plan of Development) was approved in Oct-2011 for the K sand development. The JV plan to expand the development to include the G sand following results from well AAL-4X, as detailed in an FDP addendum dated 24 Sept 2017. The proposed development consists of:

- 24 slot wellhead platform bridge linked to a leased FPSO;
- 22 horizontal production wells in the K sand (2 wells per slot); 200m well spacing with average horizontal length of 1327 m;
- 10 sinusoidal horizontals in the G sands;
- 4 pilot wells are required to help position the horizontal development wells;
- Water injection is not planned but carried as a contingency if water drive is weaker than expected.

The proposed facilities are able to produce at up to 40,000 bpd oil and have the capacity to handle 350,000 bpd produced water and 365,000 bpd liquids.

The AWE production forecast supported by RISC includes 7 months ramp-up to plateau production (40,000 bpd) and 5% facility downtime. During decline, production is constrained by the 350,000 bpd water handing capacity with water cut increasing to over 99%.

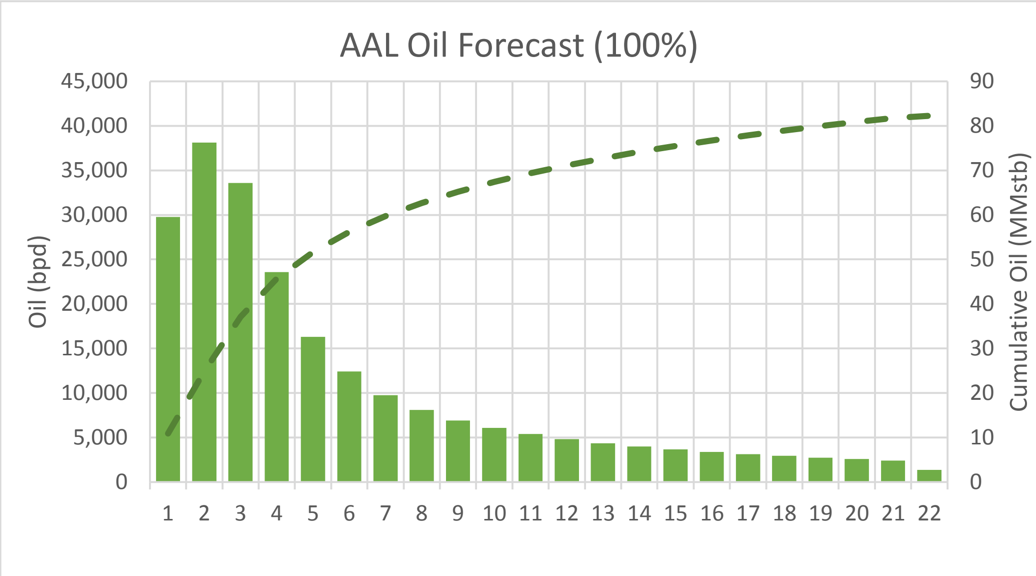


Figure 4-23: AAL Project Gross 2C Production Forecasts

With first oil estimated in 2023, production forecasts extend beyond the PSC expiry in December 2034; 71 MMstb are produced before PSC expiry. Santos and AWE are proposing a 9.5 MMstb increase in 2C for YE2017 by including development of the lower G. This would increase production before PSC expiry to about 79 MMstb.

4.4.4. AAL Project Contingent Resources

K Sand:

Six K-sand static models built in Petrel^{TM} by the Operator. Three of these were deterministic cases based on the different time to depth conversions. Three were stochastic models which flexed the structural base case within a given depth uncertainty range. The deterministic base case and the stochastic low and high cases were carried forward for simulation. The operators 'base case' in place volumes can be seen in Figure 4-24 Figure 4-25.

RISC supports these static models as being a reasonable representation of in-place volumes for this field. It is noted that volumes have decreased from previous reports due to deeper structure in the north as demonstrated by AAL-4X.

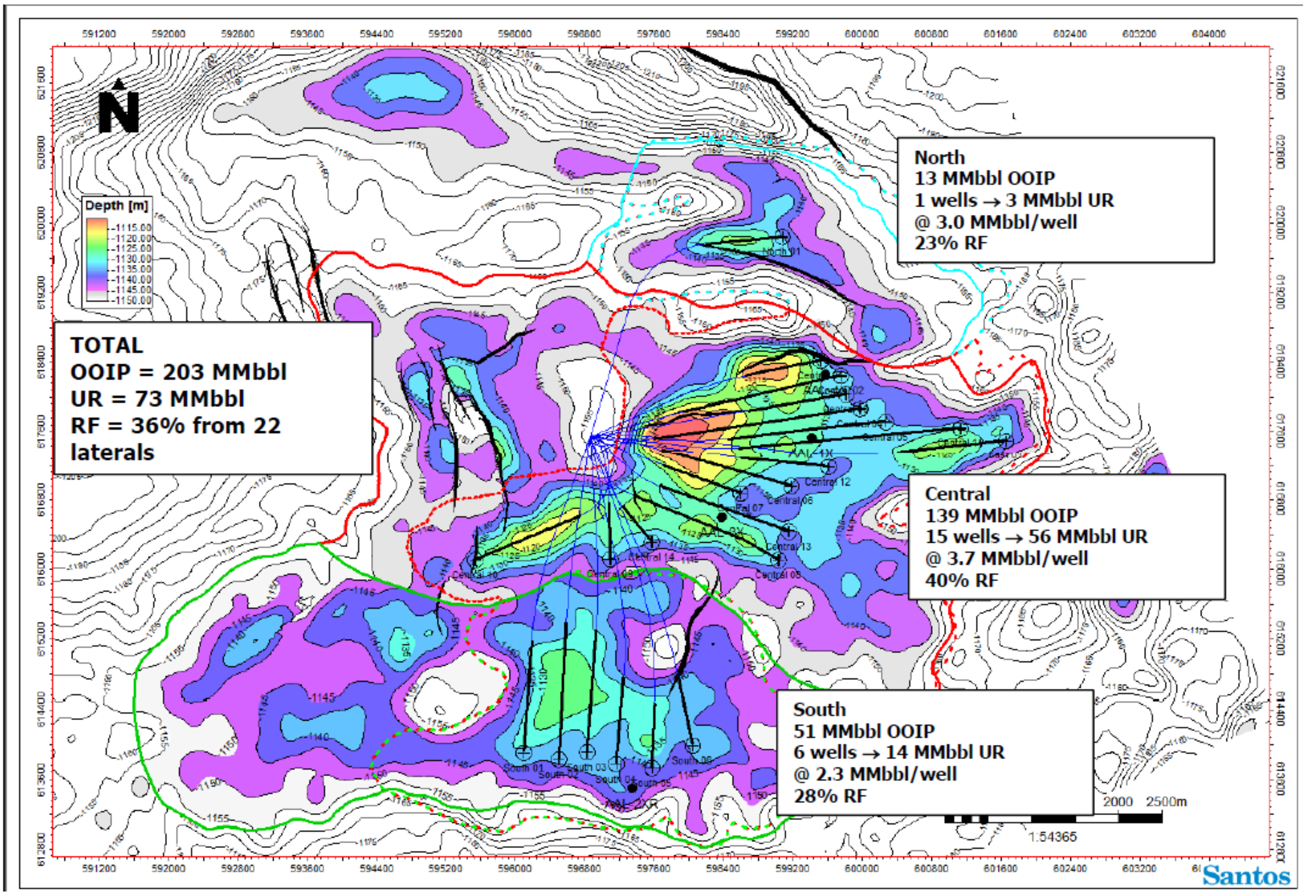


Figure 4-24: K-sand Base Case Depth Map Showing Distribution of Volume (Development Areas)

The operator estimates the K sand oil recovery to be between 55 and 113 MMbbl over a 20 year period with a base case estimate of 73 MMstb. These volumes have not been subject to economic cutoff.

A large number of development wells (22) are required to provide close well spacing (200 m) and optimal recovery in this strong bottom water drive, viscous oil reservoir.

RISC supports the implied 35-40% recovery factor over 20 years given the continuity of the K sand, good horizontal well coverage and production up to and above 99% water cut using ESPs.

G Sand:

There are three upper G-sand models and one lower G-sand model built by the Operator. The three upper G-sand models were stochastic models which flexed the structural base case and used alternative facies Petrel seeds (stochastic random sampling). Development of the lower G-sand would require an extension to the development drilling area. RISC supports these static models as being a reasonable. There are no high and low case lower G-sand models. The Operator’s estimated base case in place volumes can be seen in Figure 4-25.

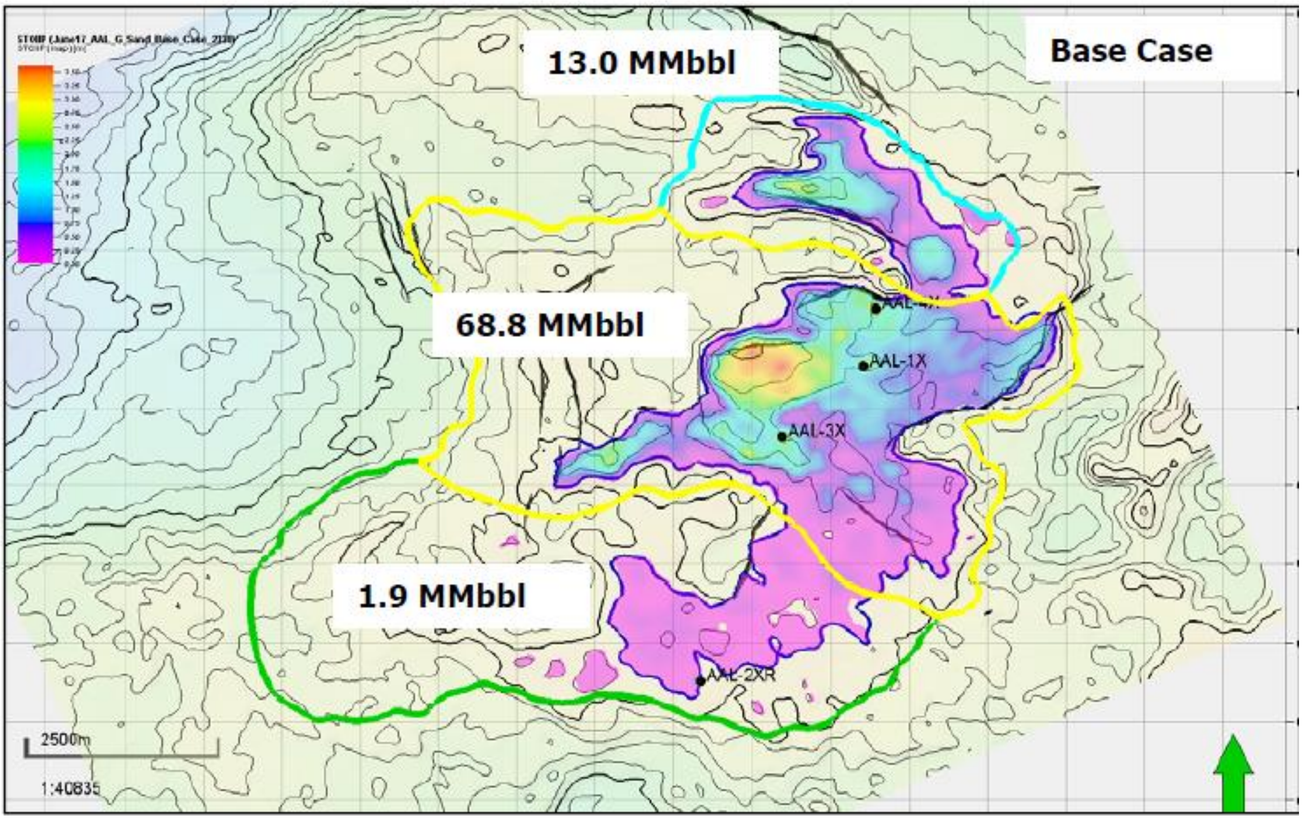


Figure 4-25: Upper G-sand Base Case Depth Map Showing Distribution of Volume (Full-field)

The operator estimates the G sand oil recovery to be between 8 and 17 MMbbl over a 20 year period with a base case estimate of 12 MMstb. These volumes have not been subject to economic cutoff.

RISC supports the implied 12-15% recovery factor over 20 years given the limited continuity of the G sand, more viscous, edge water drive reservoir. ESPs are required to produce at the high water cut expected.

The contingent resources for AAL carried in AWE's 30 June 2017 Reserve and Resource Report are not consistent with the latest study, amended FDP or gross production forecast in the financial model. In Table 4-14, RISC has updated resource estimates in line with the FDP and latest studies.

Table 4-14: Unrisked Contingent Resources Ande Ande Lumut as at 31/12/2017

Resource	Field	2C (100%)
Oil (MMstb)	**Total**	**93.0[#1]**
	AAL (K-Sand)	71.2
	AAL (Upper G-Sand)	12.3
	AAL (Lower G-Sand)	9.5

The Operator (Santos) has identified an additional 9.5 MMbbl gross 2C resources in the Lower G sand, developed with an estimated 8 additional wells. AWE support this and plan to increase their 2C contingent resource estimate accordingly to 93 MMstb.

RISC has updated the 82 MMstb gross 2C contingent resources forecasts in the financial model to a 2C contingent resource of 93 MMstb including lower-G sand, prior to any economic cut-off. AWE has a 50% contractor interest in the PSC and their net entitlement is subject to the terms of the PSC, which are not modelled here.

AWE exploration opportunities in the West Natuna Basin are discussed in section 5.5.

4.4.5. Schedule, Capital and Operating Costs – 2P + 2C Development

4.4.5.1. Schedule

The schedule in the 2011 POD required production to commence within 5 years of the end of the exploration period, which was 28 October 2016. This has subsequently been renegotiated to require the contractor to conduct activities in accordance with the amended field development plan.

Santos anticipate FID in Q4 2018 with first oil 33 months later in Q3 2021, however this has subsequently been revised to FID in late Q4 2019 and startup in Q3 2022. There is still significant uncertainty if and when FID and first oil will occur. RISC have assumed first oil in 2023 in our forecasts.

4.4.5.2. Capital Costs

Capital costs are now estimated by AWE to be US$ 815m (gross) from 1/12/17 in real terms for a K and G sand development. RISC support these as reasonable. Costs are summarised in Table 4-15 below.

Table 4-15: CAPEX Summary (2017 RT, 100% gross)

Item	Cost US$
Development Wells	604
Facilities - WHP, FPSO Mooring etc.	150
Owners Costs	33
Overhead	28
Total	**815**

As mentioned above, the timing of any development is uncertain, however, assuming first production in 2023 the majority of expenditure is incurred in 2020 to 2024, as development drilling continues after production commences.

4.4.5.3. Operating Costs

The main component of operating costs is the cost of leasing the FPSO. The FPSO lease period has a significant influence on annual lease costs. Assuming an initial 6 year lease, AWE estimate the gross bareboat dayrate is $304k/day ($111 million p.a.). This then reduces if the contracting period is extended.

In the event of an extended lease period, forecast operating costs reduce from $176 million p.a. (gross) in the first 6 years to $98 million pa for the next 6 years then $76 million p.a. (gross) thereafter as the FPSO lease rate decreases.

This is summarised in Table 4-16 below.

Table 4-16: Operating Costs (2017 RT, 100% gross)

USD million p.a.	Years 1-6	Years 7-13	Year 14+
FPSO lease rate	110.8	33.2	10.95
O&M	40.0	40.0	40.0
Santos Ohead	16.0	16.0	16.0
ESP	8.8	8.8	8.8
Total	175.6	98.0	75.7

4.4.5.4. *Abandonment Costs*

According to the financial model abandonment costs are $113 million (2017 RT, gross). RISC accept as reasonable.

4.4.6. **Valuation of Ande Ande Lumut**

RISC has collated comparable transactions to provide a method of estimating of value for the AAL field in Indonesia.

The transactions reviewed have been limited to a contingent resource oil dominated resource base in PSC regimes post 2014 after the oil price crash. In our opinion earlier transactions will provided an overly optimistic view of value compared to the current market.

Since 2014, there have been a relatively limited number of oil dominated contingent resource transactions in PSC regimes. We have used SE Asian and African transactions to provide a reasonable range. The transactions used are shown in Figure 4-26 with the details presented in Appendix 1. We have presented unit values based on 2P reserves and 2P + 2C reserves plus contingent resources.

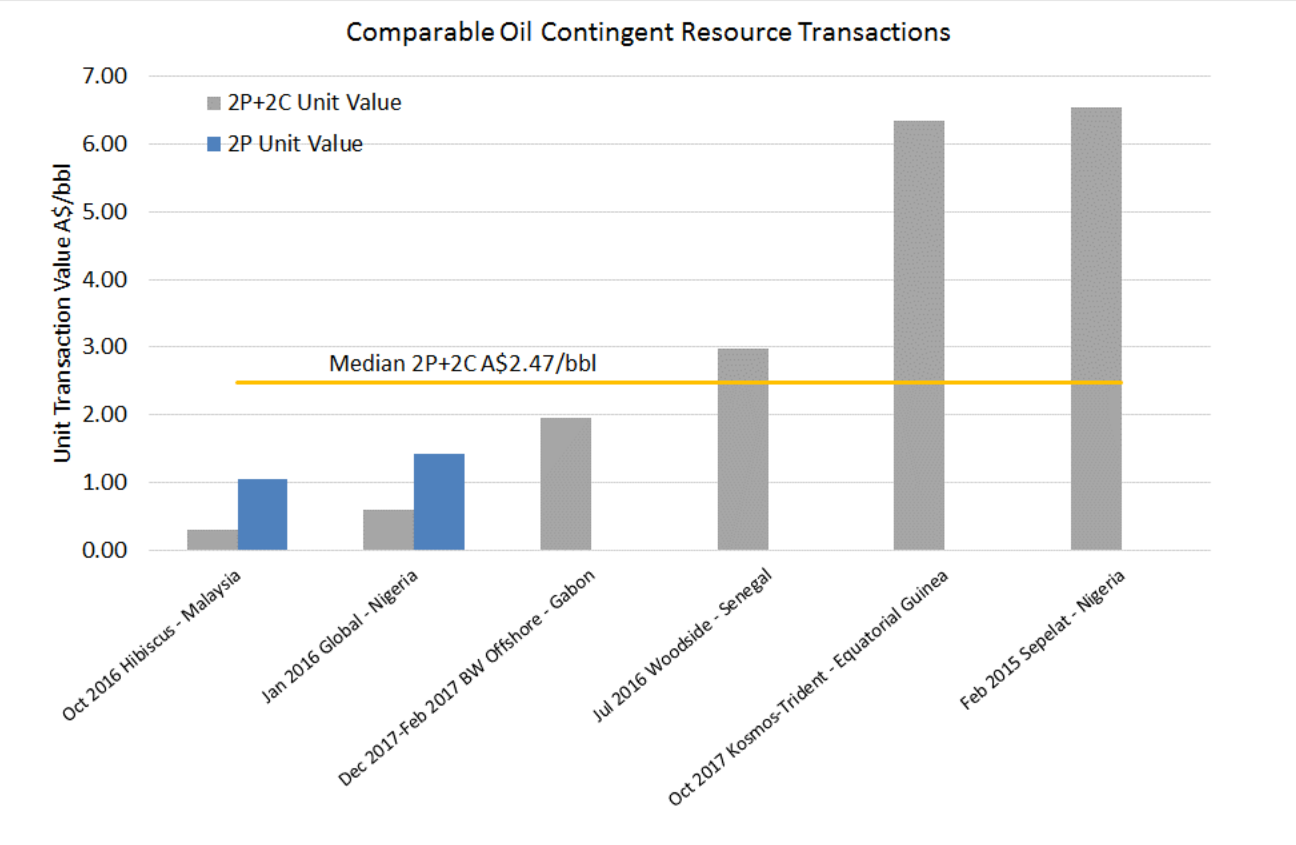


Figure 4-26: AAL Comparable Transactions

Santos paid AWE US$188m[17] for 2P+2C resources of 72 MMbbl (Santos share) in August 2013 when oil prices were trading at around US$110/bbl and a USD was A$0.90. This represents a 2P + 2C unit value of A$2.89/bbl and incorporated a free carry of US$88m upon FID. Excluding this free carry, the unit value was A$1.54/bbl. Since 2013, the oil price has reduced substantially and the development has been deferred. We therefore expect the AAL would trade in the lower end of the unit value range of A$1-2/bbl in the current market.

Based on a 2023 start up, the production to the end of the PSC term in 2034 is approximately 79 MMbbl gross (AWE working interest 39.5 MMbbl). AWE's interest in AAL is valued at A$40 to 79 million with a mid-range value of A$59 million (Table 4-17). These values are exclusive of any free carry.

Table 4-17: AAL Valuation – Net to AWE A$ million

	Low	Mid	High
Unit Value A$/bbl	1.0	1.5	2.0
Value A$million	40	59	79

The Local Government has an option to take a 10% participation in the development, reducing AWE's interest from 50 to 45%. They would either pay their own way as a JV partner or more likely have their share of development costs carried by the other JV parties who would then retain the cost recovery. Such Government participation is common in PSCs in the area, and incorporated in the transaction values discussed. Therefore, in this analysis AWE's 50% PSC interest has not been reduced to 45% due to potential Government participation.

AWE has a US$88 million carry on development costs from the Santos acquisition. However, this carry has the risk of delaying development as development may be sub-economic for Santos while it is economic for AWE. This carry has some value to AWE that is not incorporated into the value in Table 4-17.

[17] Santos ASX Release, 22 August 2013

5. Exploration Properties

AWE holds acreage with exploration potential in the Perth, Carnarvon, Otway Basins in Australia and onshore Taranaki Basin, New Zealand. RISC have not independently assessed these prospects from basic data, rather we have conducted a high level review of prospectivity from presentations provided by AWE.

5.1. Perth Basin

5.1.1. Introduction

AWE has an interest in 8 permits and licenses onshore and offshore Perth Basin (Figure 4-1). There are multiple near-field exploration and appraisal opportunities in the acreage held. A possible unconventional shale gas play in Kockatea and Carynginia Shales may provide long-term value.

AWE has indentified 27 leads and prospects in the onshore Perth Basin permits with an estimated total unrisked mean prospective resource of 208 MMboe and a total risked mean prospective resource of 35 MMboe.

5.1.2. Volumetric estimates and risking

EP-320

The EP-320 prospects consist of three tilted fault blocks with closure at Dongara and Kingia/High Cliff levels. Large throw across faults puts most of the Irwin River Coal Measures, Kingia Fm. and High Cliff Sst (if present) against the Kockatea Shale. Key risks are reservoir quality and poor quality 2D seismic definition of traps.

EP-455

AWE (Operator) are yet to define prospects in EP-455.

EP-413

Conventional and unconventional prospects are still to be defined by the Operator Norwest energy NL.

WA-512-P

AWE holds 100% equity in exploration permit WA-512-P in the offshore Northern Perth Basin. WA-512-P consists of 12,400 km^2 in water depths of 100 – 1500 m, and expires 3 February, 2021. Eight dry wells have been drilled in or around WA-512-P, with 4 wells reported to have palaeo-oil columns within the Dongara Sandstone. Seismic coverage is a combination of 2D and 3D surveys. The forward exploration programme is focused on the Primary Dongara/Wagina Play. Aside from trap definition, seal and charge are generally key risks in the offshore Perth Basin. Individual prospects contain mean prospective recoverable oil resources of 30 - 60 mmbbls with an upside of over 100 mmbbls. Although significant sized leads have been recognised in the area the geological risk is considered very high. The current 2D seismic dataset is unlikely to provide sufficient information/ for drilling and further 3D seismic is required.

5.1.3. Work program and commitments

RISC has collated the planned work programme and commitments cost to estimate exploration value.

Table 5-1: EP-320 Work Programme

Year of Term	Title Year Starts	Title Year Ends	Minimum work requirements	Estimated Expenditure Constant Dollars (indicative only) $AMM
1	20/10/2016	19/10/2017	Geological and Geophysical Studies	1.0
2	20/10/2017	19/10/2018	100 km^2 3D Seismic Survey	3.5
3	20/10/2018	19/10/2019	Geological and Geophysical Studies	1.0
4	20/10/2019	19/10/2020	One (1) Exploration Well	12.0
5	20/10/2020	19/10/2021	Geological and Geophysical Studies	1.0

Table 5-2: EP-455 Work Programme

Year of Term	Title Year Starts	Title Year Ends	Minimum work requirements	Indicative Minimum Expenditure $AMM
1	18/01/2016	17/01/2017	Geological Studies **110 km 2D Seismic Reprocessing** Geotechnical Studies	0.15
2	18/01/2017	17/01/2018	Geological and Geophysical Studies	0.10
3	18/01/2018	17/01/2019	Geological and Geophysical Studies	0.10
4	18/01/2019	17/01/2020	Geological and Geophysical Studies	0.10
5	18/01/2020	17/01/2021	One (1) Exploration Well	5.00

Norwest Energy NL is the operator for EP413, in which AWE has a 44.252% interest. The DMP granted renewal of EP413 for a 5 year term commencing 23 August 2013. The work requirements for Years One to Year Three are minimum guaranteed, whilst those for Year Four and Year Five become guaranteed on a year by year basis. Years 1 – 3 work programmes have been fulfilled. A variation to the renewal work programme was authorised on 7 December 2016, as follows:

Table 5-3: EP-413 Work Programme

Year of Term	Title Year Starts	Title Year Ends	Minimum work requirements	Indicative Minimum Expenditure $AMM
1	23 August 2013	22 August 2015	110sq km new 3D Seismic Survey	3,50
2	23 August 2014	22 February 2016	3D Seismic Interpretation	0.20
3	23 February 2016	22 February 2018	Commercial Studies	0.20
4	23 February 2018	22 February 2019	One (1) Exploration Well	15.00
5	23 February 2018	22 February 2020	One (1) Appraisal Well	15.00

WA-512-P

All major commitments until end of Year 3 (2018) have been completed.

Table 5-4: WA-512-P Work Programme

Proposed Programme		Actual Programme
Permit Year	**Minimum work requirement (as per title instrument)**	**Work Completed**
Primary Work Programme		
Year 1-3 February 2015-18	▪ 560 km new 2D Seismic Acquisition ▪ 1000 km 2D seismic reprocessing ▪ Reprocess 525 km^2 of Macallan 3D Seismic data including PSDM ▪ Rock Physics Studies and 3D Seismic Inversion ▪ Geological and Geophysical Studies	▪ 1434 km new 2D seismic acquisition fulfilled by licencing of Rocket 2D Multi-client Survey (Total 3000 km) ▪ 2239 km 2D Seismic Reprocessing in permit (Total 4110 km) ▪ 525 km^2 3d Seismic Reprocessing (including PSDM) Completed ▪ Rock Physics Studies and 3D Seismic Inversion ▪ Geological and Geophysical Studies
Secondary Work Programme		
Year 4 February 2018-19	Geological and Geophysical Studies	*Potential 3D Seismic Programme*
Year 5 February 2019-20	One (1) Exploration Well	
Year 6 February 2020-21	Geological and Geophysical Studies	

5.1.4. Valuation

WA-512-P (Offshore Perth Basin) has been valued using comparable transaction analysis. A value range of A$0 million to A$2.5 million has been given based on a notional farm-out of successfully farming 50% working interest out for a farminee to pay 75% of a $10 million 3D seismic program. A success (high case) would equate to A$2.5 million value to AWE. In the current environment a successful farm-out of this acreage is considered unlikely so a low case and mid case valuation is given as A$ 0 million.

There are currently no firm commitments to drill any of the identified prospects in the Onshore Perth Basin. Given the size and risk of the currently identified prospects, combined with the delayed timing of any exploration in the area outside of the existing discoveries, an EMV valuation is not considered appropriate. Despite the current poor market conditions for farm-outs in the region, the AWE onshore Perth Basin acreage is considered attractive for exploration given the proximity to Waitsia and the new stimulus the Waitsia discovery has given to exploration in the adjacent area. A notional 2 for 1 promoted farm-out of the exploration work program is assumed for the valuation giving a net value range to AWE in the order of A$6.25 million (mid case) and a high case valuation, assuming improved farm-out terms, of A$9.4 million.

5.2. Carnarvon Basin

5.2.1. Introduction

AWE holds 100% equity in exploration permits WA-497-P and WA-511-P in the Exmouth Sub-basin (Figure 5-1:). WA-497-P covers an area of 560 km^2 in water depths of 180 – 400 m, and expires 2April, 2020. WA-511-P covers an area of 880 km^2 in water depths of 1140 – 1700 m, and expires 3 February 2021.

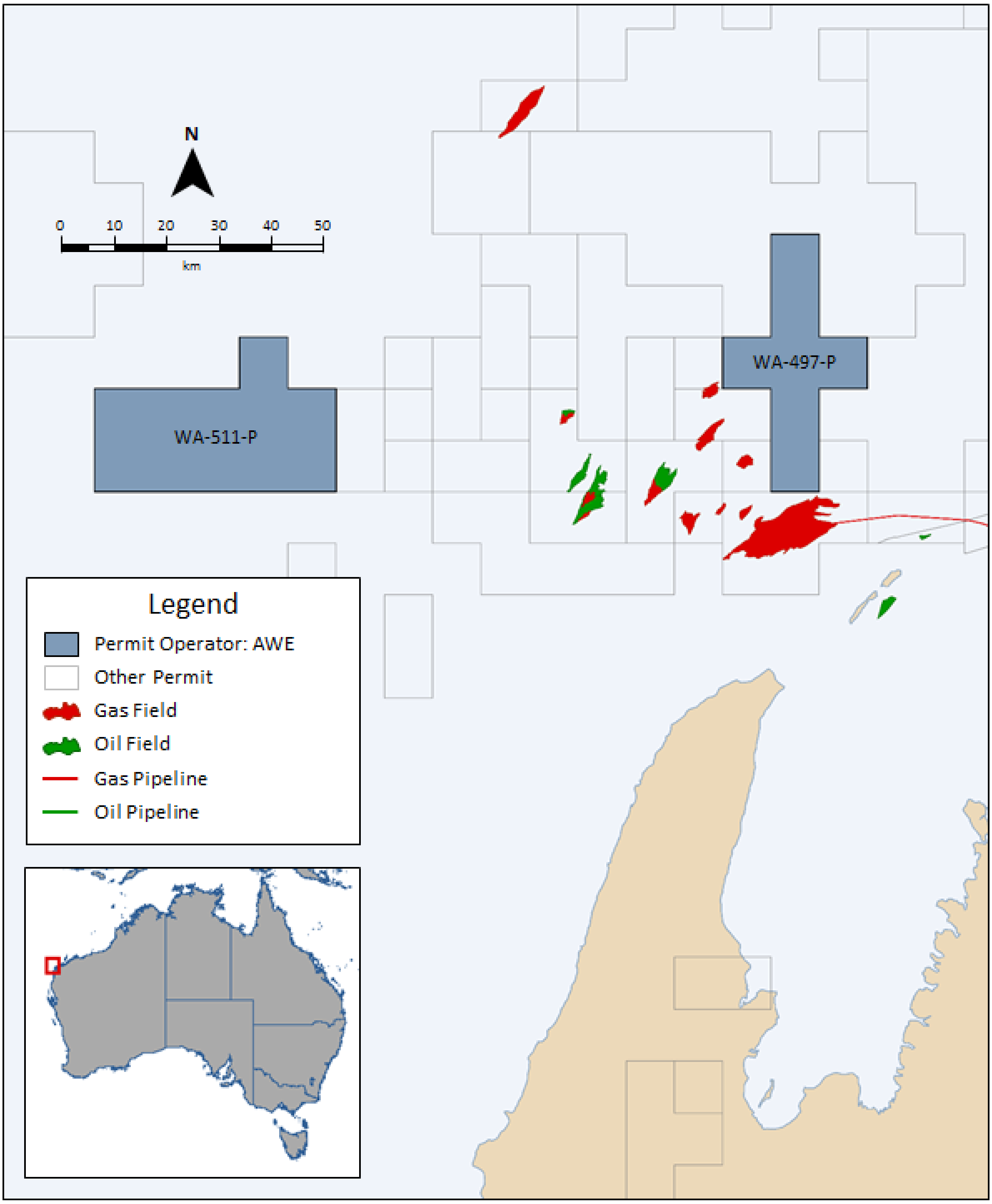


Figure 5-1: AWE's Northern Carnarvon Basin Exploration Permits

5.2.2. Volumetric estimates and risking

South of WA-497-P, a number of oil and gas fields exist (Macedon, Vincent / Van Gogh, Laverda, Coniston, Stybarrow, and Pyrenees Fields). Three wells have been drilled within the permit:

- Vlaming Head-1 (1982 - Dry);
- Langdale-1 (2005 - Gas Discovery);
- Beg-1 (2007 - Oil Column).

AWE have identified multiple seismic QI supported oil prospects within a Cretaceous K5 slope fan trend. A large Jurassic J40 sub-marine fan prospect with an upside of over a billion barrels of oil provides a large alternative play. Updip lateral seal would be the main (high) risk to these stratigraphic plays. Source for the oil would be the Jurassic Dingo Claystone.

WA-511-P is adjacent to Woodside's recent gas discoveries: Ragnar-1/1A (2011 – 190 m gross gas column within the Mungaroo) and Toro-1 (2014 -150 m gross, 55 m net gas column, average porosity 16 – 19% within a similar section). Within WA-511-P, the Triassic section is dominantly transgressive Mungaroo fluvial sequence with "possible" overlying Brigadier deltaic / lagoonal sequence. The general maturity trend for wells along the Resolution Arch suggests that the top Triassic Mungaroo Fm is low maturity. Source rock modelling suggests that gas expulsion likely ceases after Valanginian Breakup; traps must therefore be established before the Valanginian to enable the trapping of Mungaroo gas. Lateral migration from the Exmouth Sub-basin from the East would be required for this sequence to charge the Toro-1 and Ragnar-1 discoveries. Seals consist of intra-formational Mungaroo Shales and Dingo Claystone.

A large structural prospect (Triassic rotated fault block play), Michaux, has been identified by AWE. The Dingo Jurassic sequence is very thin to absent over this structure. Sealing Intra-Triassic shales are required to traps large gas columns within this prospect. A number of amplitude supported combined structural / stratigraphic traps have been identified in close proximity to Toro-1. Charge and seal are the key risks, but not quantified by AWE.

5.2.3. Work program and commitments

WA-497-P

All major commitments until end of Year 5 (2019) have been completed.

Table 5-5: WA-497-P Work Programme

PROPOSED PROGRAMME			ACTUAL PROGRAMME	
Permit Year	**Work Requirements**	**Estimated Cost $A**	**Work Completed**	**Actual Expenditure $A**
Primary Work Programme				
Year 1 April 2014-15	• 250km 2D seismic reprocessing • 231 km² 3D Seismic Reprocessing (HCA04A survey) • 56 km² 3D seismic reprocessing (HCA2000A survey) • 339 km² 3D seismic reprocessing (West Gorgon survey) • Geological and geophysical studies	$800,00	• 282km 2D seismic reprocessing • 231 km² 3D seismic Reprocessing (HCA04A survey) • 56 km² 3D seismic reprocessing (HCA2000A survey) • 339 km² 3D seismic reprocessing (West Gorgon survey) • Geological and geophysical studies	$891,588 *Comprising:* $610,155 (seismic reprocessing) $281,433 (G&G studies)
Year 2 April 2015-16	• 400 km² 3D seismic Inversion Studies • Geological and geophysical studies	$ 500,000	• 1050 km² seismic inversion and reprocessing • Interpretation of new reprocessed seismic • Geological and geophysical studies	$ 989,866 *Comprising:* $ 293,000 (3D inversion) $ 696,866 (G&G studies)
Year 3 April 2016-17	Geological and geophysical studies, including prospect assessment	$ 200,000	• Geological and geophysical studies	$ 257,615
Secondary Work Programme				
Year 4 April 2017-18	Geological and geophysical studies	$200,000	All major commitments until end of year 5 (2019) completed	
Year 5 April 2018-19	Geological and geophysical studies Well Planning	$ 250,000		
Year 6 April 2019-20	1 Exploration Well	$20,000,000		

WA-511-P

AWE will surrender the permit and default on the Year 3 seismic programme with a penalty amount to be determined.

Table 5-6: WA-511-P Work Programme

PROPOSED PROGRAMME		ACTUAL PROGRAMME
Permit Year	Minimum work requirement (as per title instrument)	**Work Completed**
Primary Work Programme		
Year 1 to 3 February 2015-18	Licensing of 718 km2 of Multi-client 3D seismic data (Eendracht) Geological and geophysical studies 3D seismic inversion studies 300 km new 2D seismic acquisition	788 km2 of Eendracht MC3D licensed (of which 718 km2 lies within WA-511-P) Geological and Geophysical Studies 3D seismic inversion studies
Secondary Work Programme		
Year 4 February 2018-19	Geological and geophysical studies	
Year 5 February 2019-20	Geological and geophysical studies	
Year 6 February 2020-21	One (1) Exploration well	

5.2.4. Valuation

AWE are in the process of attempting to farm-out the WA-497-P permit. For this reason, a valuation based on comparable market transactions is considered most appropriate. AWE will surrender or default on the WA-511-P permit. For this reason a valuation based on work program commitments is considered reasonable. Farm-out activity has been very limited in recent years. Our analysis shows that typical farm-out promotes in the Asia-Pacific region for opportunities such as WA-497-P are in the order of a 1.2 for 1 promote. For a work program commitment of A$20 million, and assuming a notional farm-out of 80% working interest, this translates to a value spread of A$0 million (low case, unsuccessful farm-out and permit relinquishment) to A$4 million (high case, successful 1.2 to 1 promote). Given our opinion of the unlikelihood of this permit being farmed-out in the current market, our best estimate value for the permit is A$0 million

AWE will surrender the WA-511-P permit and could be potentially exposed to an unfulfilled work program obligation of $1.5 million. A range of $-1.5 million (low case) to $0 million (best and high case) is given.

5.3. Otway Basin

5.3.1. Introduction

AWE holds a 25% interest in the 603 km^2 offshore exploration permit VIC/P44 located in the Otway Basin in Victorian waters, which is operated by Cooper Energy (CH) Pty Ltd. Gas from the nearby Casino, Henry and Netherby gas fields is produced via subsea wells, connected by pipeline to the Iona gas processing facility in Victoria (Figure 4-15).

Exploration permit VIC/P44 was granted to Strike Oil in August 1999. Santos farmed in for a 50% stake and operatorship in September 2002. Strike Oil then sold its 50% share of VIC/P44 to AWE in 2003. Later that year, AWE farmed out 25% to Mittwell Energy Resources Pty Ltd (a subsidiary of Mitsui Ltd). Cooper Energy acquired Santos' 50% equity in VIC/P44 as part of the acquisition of Santos' Victorian gas assets effective 1 January 2017.

Current participating interests in the licences are:

- Cooper Energy (CH) Pty Ltd (Cooper Energy, 50%) [18];
- Mitsui E&P Australia Pty Ltd (Mitsui, 25%);
- Peedamullah Petroleum Pty Ltd (AWE, 25%).

5.3.2. Volumetric estimates and risking

The Operator has 44 Exploration Prospects and Leads in their inventory. Targets include:

- 40 Shipwreck (Waarre) Plays;
- 2 Sherbrook (Paaratte/Thylacine) Plays;
- 1 EumerallaPlay;
- 1 Wangerrip Play.

The Eumeralla Fm. coals and carbonaceous shales provide proven source in the Shipwreck Trough. Elsewhere there is a risk of absence of carbonaceous material and timing. Seal is proven for the play. The Joint Venture acreage is mostly imaged with high quality reprocessed 3D seismic.

A total of 42 leads and prospects have been identified by AWE with an estimated total unrisked mean prospective GIIP of 3.2 Tcf and a total risked mean prospective gas resource of 858 Bcf.

Champion South is the prospect with largest estimated unrisked mean gas prospective resource at 270 Bcf. It consists of a broad faulted anticline west of the Pecten High containing a series of faulted culminations within a confined graben of preserved Late Cretaceous sediment. The closest well control is the dry hole Champion-1. Fault seal is a key risk.

[18] as beneficial owner of the participating interest under the JOA pending legal transfer of the title from Santos Ltd

5.3.3. Work program and commitments

The work program for VIC/P44 has been varied as of 5 September 2017. An original exploration well in Year 5 has been removed and replaced with a Seismic Quantitative Interpretation Study, Table 5-7.

Table 5-7: VIC/P44 Work Programme

Year of Permit Term	Permit Year Starts	Permit Year Ends	Minimum Work Requirements	Estimated Expenditure Constant dollars (indicative only) $A
1	08/11/2012	07/05/2014	400 km² 3D Seismic Reprocessing (PSDM) Geological and Geophysical Studies	750,000
2	08/05/2014	07/05/2015	Seismic Inversion Studies (interpretation)	750,000
3	08/05/2015	07/05/2016	Geological, Geophysical and Engineering Studies (prospect evaluation)	500,000
4	08/05/2016	07/05/2017	Geological, Geophysical and Engineering Studies (well planning)	1,000,000
5	08/05/2017	07/05/2018	537 km² Quantitative Interpretation Study	500,000

5.3.4. Valuation

Although the VIC/P44 permit has a number of low risk prospects identified they have to date been deemed too small to be commercially attractive by the Joint Venture group. Likewise, larger potential prospects in the area have been deemed too high risk to drill in the current environment. The Joint Venture has recently applied for a work program variation to their Year 5 commitment well showing a reluctance to drill any of the currently identified prospects in the current environment. However, it is most likely that the Joint Venture Group will retain the acreage in a secondary term with a one well commitment. The VIC/P44 valuation has been based on future work program commitment with a low case of A$0 million value, and a best and high case of A$12.5 million value net to AWE.

5.4. Onshore Taranaki Basin

5.4.1. Introduction

PEP 55768, covering an area of 133.72 km^2 in the northern onshore Taranaki Basin, was awarded effective from 1 April 2014, to a joint venture comprising AWE (51%) and Mitsui (49%). An extension of the area of the permit to cover the whole of the Kohatukai prospect was granted on 13 March 2015 (Figure 5-2).

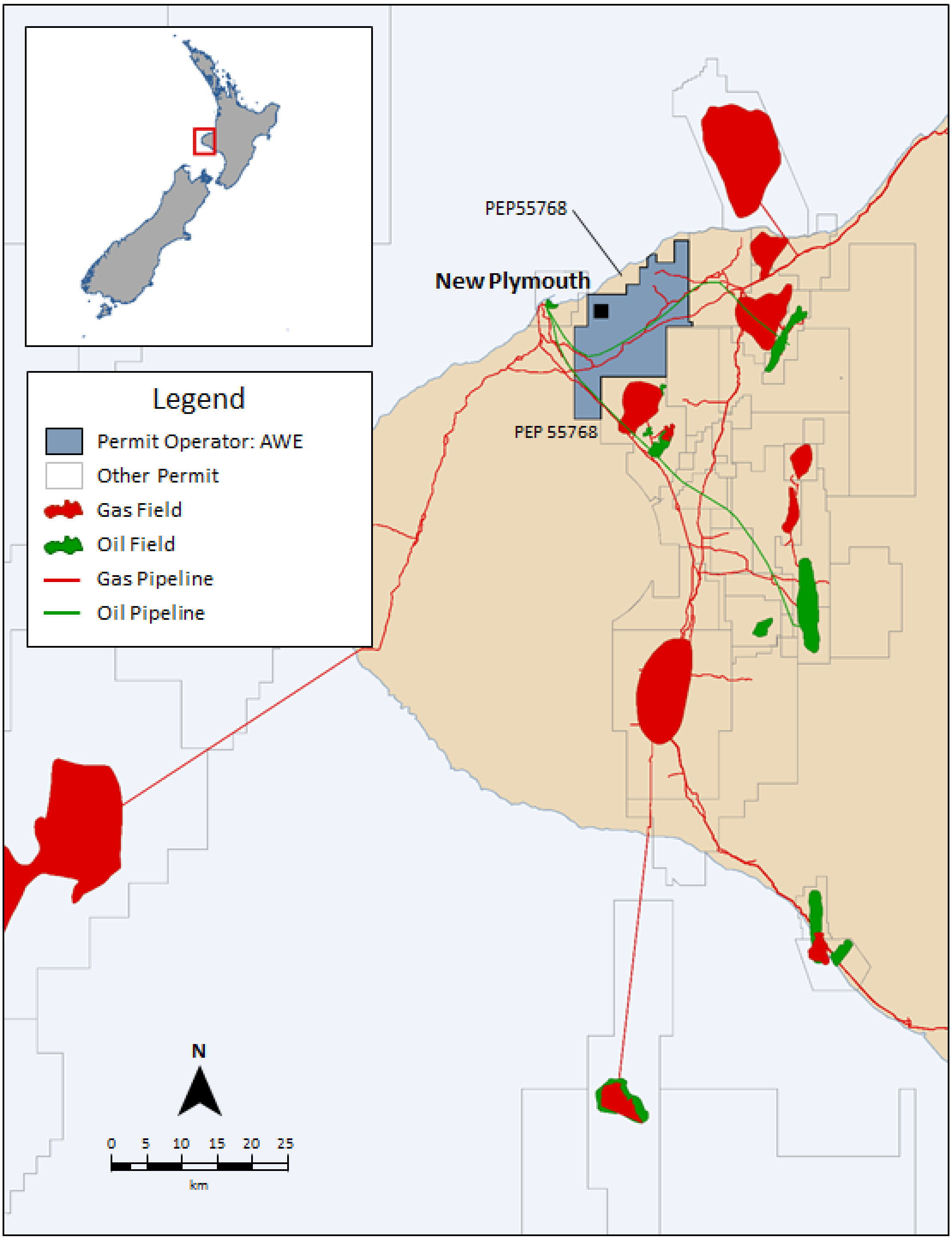


Figure 5-2: PEP 55768 Location Map

5.4.2. Volumetric estimates and risking

The Kohatukai prospect is situated on a regional anticline to the north of the Kaimiro oil and gas field. The target reservoirs are within a ~1,000 m gross column of coastal plain and marginal marine strata comprising the Kapuni Group, in particular the Mangahewa Formation, within which analogous fields to the east produce gas and condensate from multiple sandstone units. Three way dip closure of shoreface sands crossing the northern flank of the Kaimiro Anticline is thought to be sealed updip by lagoonal facies in the KA-18/21 interval. This trapping geometry would constitute the main risk.

A thin sand at the very top of the Kapuni Group ("Matapo Sand") has been proven as effective reservoir in some relatively recent wells in the play, and a seismic anomaly has been recognised associated with a map-able Matapo sand lens within the Kohatukai prospect area. Modelling results suggest a gas sand of about 9 m thickness.

AWE's Best Estimate of unrisked prospective hydrocarbon resources for the Kohatukai Prospect are 70 Bcf gas and 2.1 MMbbl of condensate in the Mangahewa, and 100 Bcf gas in the Matapo.

5.4.3. Work program and commitments

The next phase of work is the drilling of a well to the Kapuni before March 2018. The Basis of Design and the wellsite engineering plan are complete, and relevant consents have been negotiated or in place.

Table 5-8: PEP 55768 Work Programme

		2016	2017	2018	2019	2020
		Committed Activities		Contingent Activites		
PEP55768 Kohatukai	Granted 1/4/2014 Expiry 31/3/2024	Seismic reprocessing Interpretation Inversion studies by 1 March 2017	Drill one well to Kapuni objectives by 1 March 2018	3D Seismic (or second well) by 1 Oct 2018	Relinquish 50% of Permit Area by 1 Oct 2019	Drill second well by 1 Oct 2020

5.4.4. Valuation

AWE are in the process of attempting to farm-out PEP 55768. For this reason a valuation based on comparable market transactions is considered most appropriate. Although farm-out activity has been very limited in recent years, our analysis shows that typical farm-out promotes in the Asia-Pacific region for this type of opportunity are in the order of a promote of 1.5 for 1. For an anticipated A$5 million (net to AWE) promoted well and assuming a 75% farm-out of the AWE net working interest, this translates to a value spread of A$0 million (low case, unsuccessful farm-out and permit surrender) to A$2.5 million (high case, successful 1.5 to 1 promote). Given the low chance of success for farm-outs in the current market, RISC have given the PEP 55768 permit a best case valuation of A$0 million in current market conditions.

5.5. West Natuna Basin

5.5.1. Introduction

AWE have a portfolio of near-field, low-risk oil exploration prospects and leads within the Northwest Natuna PSC. The largest prospects lie on a spill-chain from East Belumut to the west through AAL field to Betet in the East. The planned FPSO is designed to have sufficient flexibility to allow for tie-in of nearby discoveries. Exploration drilling is cost recoverable against production from AAL.

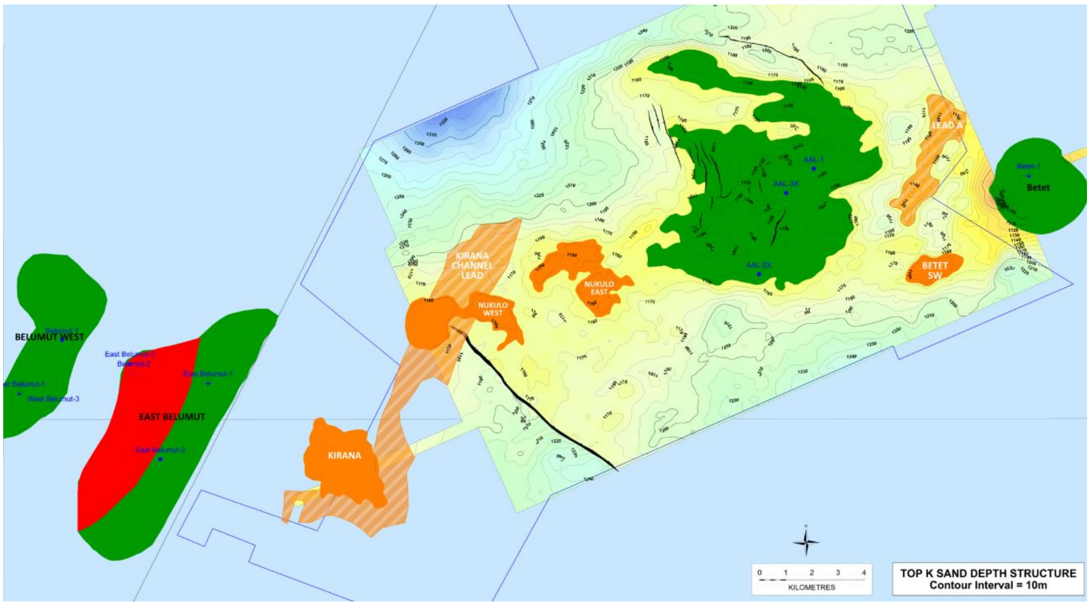


Figure 5-3: Northwest Natuna PSC K-sand Prospects

5.5.2. Volumetric estimates and risking

It is expected that the geological chance of success would be relatively high for these near-field prospects, although Kirana is outside of the 3D seismic area. Additional leads at the G-sand level also have been identified.

Four prospects have been identified to date with a total mean unrisked prospective STOIIP of 139 MMstb.

5.5.3. Work program and commitments

All firm exploration obligations have been met and all relinquishments have been satisfied. The Northwest Natuna PSC expires in December 2034.

5.5.4. Valuation

There are no commitments for exploration drilling in the West Natuna permit and the Joint Venture group has yet to demonstrate any willing intent to drill any of the identified prospects. The identified prospects are considered relatively low risk and could potentially attract a potential farm-out market, however, the size of the identified prospects would most likely be not large enough for any standalone development, and as such, would be contingent on development of the AAL field. With the AAL development being put on hold, the best case valuation for the exploration prospects is currently considered at A$0 million. A high case valuation is based on the assumption of a national farm-out of one exploration well. A successful farm-out of 75% of the net AWE equity for one A$50 million well on a 1.5 to 1 promoted basis gives a high case value of A$12.5 million net to AWE.

5.6. Value of Exploration Properties

RISC has assessed the value of the AWE exploration properties using various valuation methods as described in Section 2.2.3 and summarized in Table 5-9.

Table 5-9: Valuation of AWE's exploration portfolio, A$ million net to AWE

Project area	Valuation method	Low (A$million)	Best (A$million)	High (A$million)
Perth Basin	Comparable Transactions	3.1	6.3	11.9
Otway Basin	Proposed Work Program Commitment	0	12.5	12.5
Carnarvon Basin	Comparable Transactions and Work Program Commitment	-1.5	0	4.0
Onshore Taranaki Basin	Comparable Transactions	0	0	2.5
West Natuna	Comparable Transactions	0	0	12.5
Total		**1.6**	**18.8**	**43.4**

The values of individual assets are typically determined at low, best and high values. As the low and high values of the exploration assets portfolio are derived by the arithmetic addition of the individual assets low and high values, respectively, they represent the possible extremes of the exploration value envelop.

While acquirers of the individual permits could value the assets at either end of the value range, it is unlikely that potential buyers of the exploration asset portfolio would value all of the assets at either all of the low or all of the high estimated extremes.

Their own assessments of individual permits will span the low, best or high outcomes based on factors including: their strategic objectives and region or geological basin focus; assessment of an asset's prospectivity and associated geological risks; the fiscal and regulatory framework applicable to the asset; accessibility of commercialisation routes, including markets and infrastructure, for each asset; equity interests, operator capability and joint venture partners in each asset.

RISC accounts for the portfolio effects by determining the low and high values of the portfolio of exploration assets at an estimated one standard deviation from the total best value of the portfolio. There may be further adjustments required to the range based on judgement taking into account the specifics of the portfolio and market.

Adjusting for portfolio effects, RISC estimates a value range on the AWE exploration assets of between A$11.5 million and A$26.0 million.

Table 5-10: Valuation of AWE's exploration portfolio, A$ million net to AWE, adjusting for portfolio effects

Project area	Low (A$million)	Best (A$million)	High (A$million)
Total	**11.5**	**18.8**	**26.0**

6. Declarations

6.1. Qualifications

RISC is an independent oil and gas advisory firm. The RISC staff engaged in this assignment include qualified petroleum reserves and resources evaluators as specified in ASX listing rules, engineers, geoscientists and commercial analysts, each with many years of relevant experience and most have in excess of 20 years.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth and Brisbane, Jakarta and London. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/Portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been supervised **by Mr Peter Stephenson**, RISC Partner. Mr Stephenson has over 34 years' experience in the upstream hydrocarbon industry with BP, Shell and RISC. He has extensive experience with mature and greenfield oil, gas, gas-condensate and CSG developments in the North Sea, Africa, Middle East and Australasia. Mr Stephenson holds global experience in project gate reviews, data room and investment evaluation. Mr Stephenson specialises in reservoir evaluation, field development planning, integrated project reviews, multidisciplinary team coordination and leadership preparation of Independent Technical Specialist reports. Mr Stephenson is Member of the Society of Petroleum Engineers and the Institution of Chemical Engineers, and holds a M.Eng Petroleum Engineering, Heriot Watt University, 1984 as well as a B.Sc Chemical Engineering (IIi Hons), University of Nottingham, 1982. Mr Stephenson and is a qualified petroleum reserves and resources evaluator (QPPRE) as defined by ASX listing rules.

The summary of experience of other staff contributing to this report follows:

Mr Geoffrey Barker, RISC Partner has thirty-five years of global experience in the upstream hydrocarbon industry, with extensive expertise in the areas of asset valuation, business strategies, evaluation of conventional and non-conventional petroleum (coal seam gas and tight gas), due diligence assessment for mergers, acquisitions and project finance requirements and reserves assessment/certification and preparation of Independent Technical Specialist reports. Mr. Barker is a Past Chairman of the SPE WA Section, a past member of the SPE International's Oil and Gas Reserves Committee 2007-2009, and is a co-author of the Guidelines for Application of the Petroleum Resources Management System published by the SPE in November 2011 (Chapter 8.5 Coal Bed Methane). Mr Barker is a Member of the Society of Petroleum Engineers (SPE), and holds a BSc (Chemistry), Melbourne University, 1980 and a M.Eng.Sc. (Pet. Eng.), Sydney University, 1989, a member of the Australian Institute of Company Directors and is a qualified petroleum reserves and resources evaluator (QPPRE) as defined by ASX listing rules.

Ian Cockerill, Head of Geoscience is a Petroleum Geologist with 19 years of experience and a successful record of value creation through oil and gas discoveries, new venture development, and asset / corporate promotion. Mr Cockerill has a background in geological and geophysical interpretation with experience in conventional and unconventional exploration and development projects in a wide range of geological settings. He has worked in technical positions for Hunt Oil and Apache and in executive positions for Transerv Energy, Verona Energy and TSV Montney. Mr Cockerill is a member of the following institutions; Petroleum Exploration Society of Australia (PESA), American Association of Petroleum Geologists (AAPG), South East Asia Petroleum Exploration Society (SEAPEX) and Canadian Society of Petroleum Geologists (CSPG). Mr Cockerill holds MSc. Basin Evolution and Dynamics - Royal Holloway, University of London, UK, 1999 and a BSc. Geological Sciences – 1st Class (Honours) - University of Leeds, UK, 1996.

Adrian Young, Principal Advisor over 39 years of world-wide experience including positions with several operating companies within Australia, Southeast Asia and the Middle East region. In addition to an extensive exploration background, he has gained around 20 years of development experience in both offshore and onshore environments. Mr Young has a proven track record in delivering high quality technical subsurface results in a fit-for-purpose manner, underpinned by practical, hands-on operational experience and a broad business perspective. These skills have been applied through involvement in various field development activities and near-field exploration discoveries. Geophysical skills and experience include seismic processing, 2D and 3D seismic interpretation and depth conversion are established. He is experienced in quantifying HCIIP uncertainty through the use of geostatistics and probabilistic tools, in addition to applying a systematic risking approach for exploration prospects. Mr Young is a member Petroleum Exploration Society of Australia (PESA), SPE and Australian Society of Exploration Geophysicists. Mr Young holds a Bachelor of Applied Science (Geophysics), W.A. Institute of Technology, 1977, a Graduate Diploma in Advanced Geophysics, Curtin University, 1987 and a Certificate in Project Management, Curtin University, 2007.

Joe Collins, Principal Consultant, has 14 years' experience in Process and Facilities engineering. During his time at RISC he has participated in over 100 assignments including due diligence work, asset evaluations, reserves certifications and project reviews with clients located all over the world. He has in-depth skills in the areas of; upstream facility capital and operational cost estimating, conceptual facilities design, well design & cost estimation and project performance evaluation & forecasting. Joe has particular experience in reviewing and evaluating LNG projects and unconventional developments in Australia. Prior to joining RISC Mr Collins worked for Wesfarmers for six years at their Petrochemical facilities in Kwinana, Western Australia where he filled a number of engineering and management roles. Joe started his career in the exploration industry gaining experience in electric wireline logging throughout Australasia with Halliburton. Mr Collins is a chartered professional engineer with Engineers Australia and a member of SPE. Mr Collins holds a Bachelor of Oil & Gas Engineering (Petroleum and Process Engineering), UWA, 2004 and a Diploma of Project Management.

Simon Whitaker, RISC Partner has over 30 years of experience in the petroleum industry in UK, Egypt, South East Asia and Australia. He has a background in petroleum engineering including reservoir and production engineering, well evaluation and varied operational experience. His subsequent career development has involved an MBA, asset management, field development planning and implementation and commercial roles. Mr Whitaker currently leads the Development Engineering function in RISC. This involves taking responsibility for Drilling & Completions, Facilities, Project performance, Operations and HSE aspects of RISC assignments. Mr Whitaker is a member of the SPE and holds and MBA – International Business & Export Management, City University Business School, 1991, and MSc Petroleum Engineering, Imperial College of Science and Technology, 1981 and a BSc (Hons) Engineering Geology, University of Newcastle Upon Tyne, 1980.

6.2. VALMIN Code and ASIC Regulatory Guides

This Report has been prepared by RISC. This Report has been prepared in accordance with the Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2015 Edition ("The VALMIN Code") as well as the Australian Securities and Investment Commission (ASIC) Regulatory Guides 111 and 112.

6.3. Petroleum Resources Management System

In the preparation of this Report, RISC has applied the guidelines and definitions of the Petroleum Resources Management System approved by the Board of the Society of Petroleum Engineers in 2007 (PRMS).

6.4. Report to be presented in its entirety

RISC has been advised by AWE that this report will be presented in its entirety without summarisation.

6.5. Independence

This report does not give and must not be interpreted as giving, an opinion, recommendation or advice on a financial product within the meaning of section 766B of the Corporations Act 2001 or section 12BAB of the Australian Securities and Investments Commission Act 2001.

RISC is not operating under an Australian financial services licence in providing this report.

In accordance with regulation 7.6.01(1)(u) of the Corporations Regulation 2001. RISC makes the following disclosures:

- RISC is independent with respect to AWE and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and AWE for the provision of this report RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report;
- Neither RISC nor any of its personnel involved in the preparation of this report have any material interest in AWE or in any of the properties described herein;
- RISC has provided the following professional services to AWE in the past two years.

Table 6-1: Projects completed

Project Name	Assignment Manager	Project completion date
Waitsia Resource Review[1]	Geoff Barker	24/11/2017
Waitsia Phase 2 Feasibility Study	Joe Collins	12/01/2017
Waitsia Reserve Certification	Geoff Barker	31/08/2016

- RISC has not provided advice to AWE specifically in relation to the Proposed Transaction.

6.6. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from AWE as well as information in the public domain.

The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and senior AWE staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, we believe our review and conclusions are sound, but neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

This report was substantially completed by 19 January 2018. We are not aware of any changes since that date that would have a material impact on the values and opinions contained within this report.

6.7. Consent

RISC has consented to this report, in the form and context in which it appears, being included in the Prospectus. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any other document, circular, resolution, letter or statement without the prior consent of RISC.

This Report is authorised for release by Mr. Peter Stephenson, RISC Partner dated 19 February 2018.

Peter Stephenson

RISC Partner

7. Tabulation of petroleum tenement terms

On 13 December 2016, AWE entered into an agreement to sell its 57.5% working interest in the Tui Area Oil Fields to Tamarind Management Sdn Bhd, for US$1.5 million. The transaction was completed on 1 March 2017 with an effective date of 30 November 2016.

On 5 May 2016, AWE entered into an agreement to sell its 42.5% interest in the Bulu PSC, including the Undeveloped Lengo gas project, to a subsidiary of HyOil Pte Ltd for up to A$27.5 million cash, with an effective date of 30 November 2016. The transaction was approved by the Indonesian Government in August 2017.

On 9 September 2016, AWE entered into an agreement to sell its 41.141% interest in the L14 Permit in the Perth Basin, which incorporates the Jingemia Oil Field, to Cyclone Energy and RCMA Australia. The transaction was completed on 17 July 2017.

On 30 June 2017, AWE entered into an agreement to sell its 100% interest in the L7 Permit in the Perth Basin, which incorporates the Mount Horner Oil Field, to Key Petroleum Ltd.

The North Madura and Titan PSCs have been relinquished following official communication from MIGAS.

The East Muriah and Terumbu PSCs are awaiting official communication from MIGAS to relinquish the blocks.

Table 7-1: Production and Development Tenements

Basin	Block	Project/Field	AWE Interest	Operator	Status	Licence Expiry Date	Licence Area km2
Onshore Perth	L 1/L 2	Dongara, Yardarino	100.00%	AWE	Production Licence	17/05/2014 Renewing	36
	L 1 FO	Hovea, Eremia, Xyris, Waitsia	50.00%	AWE	Production Licence	17/05/2014 Renewing	320.5
	L 2 FO	Senecio, Corybas	50.00%	AWE	Production Licence	17/05/2014 Renewing	275.5
	L 4/L 5	Woodada	100.00%	AWE	Production Licence	04/04/2027	670.5
	L 7[1]	Mt Horner	100.00%	AWE	Production Licence	25/04/2027	150
	L 11	Beharra Springs, Redback	33.00%	Beach Energy	Production Licence	14/05/2013	75
Bass	T/L1	Yolla	35.00%	Beach Energy	Production Licence	Life of Field	263.5
Otway	VIC/L24	Casino	25.00%	Cooper Energy	Production Licence	Life of Field	201
	VIC/L30	Henry, Netherby	25.00%	Cooper Energy	Production Licence	Life of Field	201
West Natuna	Northwest Natuna PSC[2]	Ande Ande Lumut	45.00%	Santos	PSC	12/12/2035	465
East Java	Bulu PSC[1]	Lengo	42.50%	Kris Energy	PSC	14/10/2033	696

1. Asset sold, subject to completion, not included in evaluation
2. In October 2017, the Indonesian Government advised that it would exercise its right to assign 10% of the Contractors' interest in AAL to a local entity in 2018. The assignment will be made up of 5% from each of Santos and AWE. Under the PSC, the existing partners will carry the local entity through the development phase but will be repaid from production, once it commences.

Table 7-2: Exploration and Appraisal Tenements

Basin	Block	Project/Field	AWE Interest	Operator	Status	Licence Expiry Date	Licence Area km2
Onshore Perth	EP320	Synaphea, Irwin	33.00%	Beach Energy	Exploration Permit	19/10/2021	897
	EP413	Arrowsmith	44.25%	Norwest Energy	Exploration Permit	22/02/2020	507
	EP455	Drover	100.00%	AWE	Exploration Permit	17/01/2021	297
Offshore Perth	WA-512-P		100.00%	AWE	Exploration Permit	03/02/2021	12,430
North Carnarvon	WA-497-P		100.00%	AWE	Exploration Permit	02/04/2020	561
	WA-511-P		100.00%	AWE	Exploration Permit	03/02/2021	881
Bass	T/RL2	Trefoil	40.00%	Beach Energy	Retention Lease	05/08/2020	66
	T/RL3	Rockhopper	40.00%	Beach Energy	Retention Lease	05/08/2020	132
	T/RL4	White Ibis	40.00%	Beach Energy	Retention Lease	05/08/2020	132
	T/RL5	Bass-3	40.00%	Beach Energy	Retention Lease	05/08/2020	66
Otway	VIC/RL11	Martha	25.00%	Cooper Energy	Retention Lease	01/05/2017 Renewing	128
	VIC/RL12	Blackwatch	25.00%	Cooper Energy	Retention Lease	01/05/2017 Renewing	5.7
	VIC/P44		25.00%	Cooper Energy	Exploration Permit	07/05/2018	603
Onshore Taranaki	PEP55768		51.00%	AWE	Exploration Permit	31/03/2024	134
East Java	East Muriah PSC[1]		50.00%	Kris Energy	PSC	12/11/2016	995
	Terumbu PSC[1]		100.00%	AWE	PSC	05/05/2039	716

8. List of terms

8.1. Abbreviations

The following table lists abbreviations commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
3P	The sum of Proved, Probable and Possible reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for expenditure
bbl	US barrel
bbl/d	US barrels per day
Bcf	Billion (10^9) cubic feet
Bcm	Billion (10^9) cubic meters
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British thermal units
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate gas ratio
CO_2	Carbon dioxide
cP	Centipoise
CPI	Consumer price index
DEG	Degrees
DHI	Direct hydrocarbon indicator
DST	Drill stem test
E&P	Exploration and production
EMV	Expected monetary value
EOR	Enhanced oil recovery
ESMA	European Securities and Markets Authority
ESP	Electric submersible pump

Term	Definition
EUR	Estimated ultimate recovery
F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating production, storage and offtake unit
FWL	Free water level
FVF	Formation volume factor
GIIP	Gas initially in place
GJ	Gigajoules (10^9 J)
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas to liquid(s)
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal rate of return
JV(P)	Joint venture (parties)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilopascals (thousand Pascal)
Mstb/d	Thousand stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied natural gas
LTBR	Long-term bond rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies
MJ	Megajoules (10^6 J)
MMbbl	Million US barrels
MMscf(/d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels
MOD	Money of the day (nominal dollars)
MOU	Memorandum of understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels

Term	Definition
MPa	Megapascal (10^6 Pa)
mss	Metres subsea
MSV	Mean success volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net present value
NTG	Net to gross
ODT	Oil down to
OGIP	Original gas in place
OOIP	Original oil in place
Opex	Operating expenditure
OWC	Oil-water contact
P & A	Plug and Abandon (abandonment of wells)
PBU	Pressure build-up
PJ	Petajoules (10^{15} J)
POS	Probability of success
PRMS	Petroleum Resources Management System
PSC	Production sharing contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit
PVT	Pressure, volume and temperature
QA/QC	Quality assurance/ control
rb/stb	Reservoir barrels per stock tank barrel (at standard conditions)
RFT	Repeat formation tester
RT	Rotary table or real terms, depending on context
SC	Service contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
s.u.	Fluid saturation unit
stb	Stock tank barrels
STOIIP	Stock tank oil initially In place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Terajoules (10^{12} J)
TLP	Tension leg platform
TRSSV	Tubing retrievable subsurface safety valve

Term	Definition
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well head flowing pressure
WPC	World Petroleum Council
WTI	West Texas Intermediate

8.2. Definitions

The following table lists some definitions for terms commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
EG	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature)
Expectation	The mean of a probability distribution.
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively if probabilistic techniques are used.
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used,

Term	Definition
	there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
Working interest	A company’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

Appendix 1 – AAL Comparable Transactions

Transaction Label	Date	Buyer	Seller	Value	FX	Value	2P Reserves	2C	2P + 2C	2P Unit Value	2C Unit Value	2P+2C Unit Value	Description
				US$ mill	US$/A$	A$ mill	MMbbl	MMbbl	MMbbl	A$/MMbbl	A$/MMbbl	A$/MMbbl	
Oct 2016 Hibiscus - Malaysia	Oct 16	Hibsicus	Shell	$25	0.762	$32.8	31	79	110	1.06		0.30	Hibiscus acquired Shell's 50% interest in the North Sabah PSC, Malaysia
Jan 2016 Global - Nigeria	Jan 16	Global Energy Co	MX Oil PLC	$18	0.745	$24.2	17	23	40	1.42		0.61	Global Energy acquired OML113 including the Aje offshore oil development project
Dec 2017-Feb 2017 BW Offshore - Gabon	Feb 17	BW Offshore	Panoro-Harvest	$44	0.736	$59.8		31	31		1.95	1.95	BW Offshore acquired the 66.67% WI of Harvest then farmed in for a further 25% of Dissafu Maric PSC, Offshore Gabon
Jul 2016 Woodside - Senegal	Jul 16	Woodside	ConocoPhillips	$440	0.753	$584.3		196	196		2.98	2.98	Woodside acquired ConocoPhillips 35% interest in three Block offshore Senegal including the SEN discovery
Oct 2017 Kosmos-Trident - Equatorial Guinea	Oct 17	Kosmos-Trident	Hess	$650	0.779	$834.4		132	132		6.33	6.33	Kosmos and Trident acquisition of Offshore Equatorial Guinea Ceiba and Okume fields
Feb 2015 Sepelat - Nigeria	Feb 15	Sepelat Petroleum Devt Co	Belemaoil Producing Ltd	$132	0.779	$169.7		26	26		6.53	6.53	Sepelat acquired 22.5% intertest in OML55 shallow water block