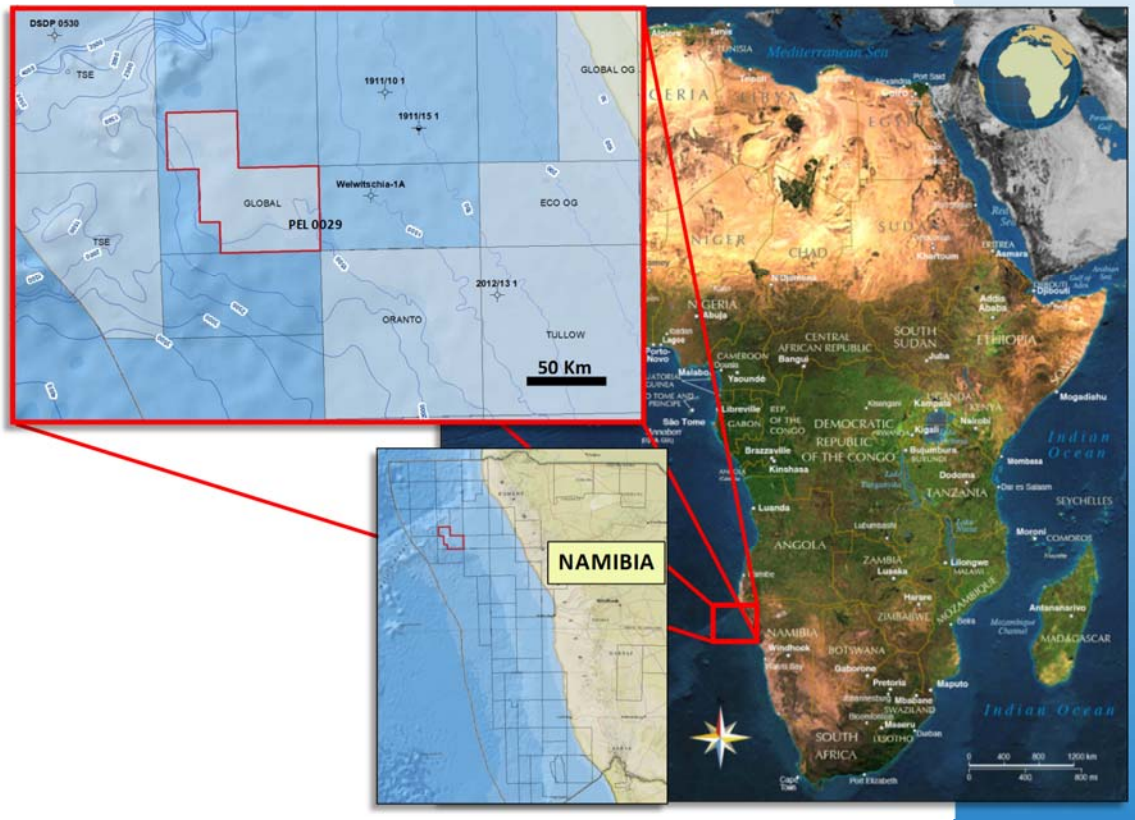
Competent Person's Report on exploration prospects in Licence 0029, offshore Namibia, for Global Petroleum Limited



Location map, Global Petroleum's Licence 0029 offshore Namibia

Peter Chandler, Jackie Mullinor,
Anand Rao, Bjørn Smidt-Olsen

12th January 2018

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This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, in particular the 2007 SPE PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR TRACS International Ltd., a wholly owned subsidiary of AGR Group (Holdings) Ltd. shall have no liability arising out of or related to the use of the report.

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Revision:

Prepared by:

Bjørn Smidt-Olsen

Project Manager

Approved by:

Mike Wynne

Reviewer

Mike Wynne

Authorised for release by

Certified by (reserves reports) [first name last name]

Cover Letter

The Directors
Global Petroleum Limited,
111 Buckingham Palace Road,
London SW1W 0SR

12th January 2018

Gentlemen,

Competent Person's Report on the exploration prospect portfolio in Global Petroleum's Licence 0029, offshore Namibia

AGR TRACS International Ltd ("AGR TRACS") has been requested by the Directors of Global Petroleum Limited ("Global") to review the exploration prospect portfolio in Global's Licence 0029 offshore Namibia. Three substantial prospects have been mapped (Gemsbok, Lion and Dik-Dik), along with two leads (Choje and Pangolin). The Gemsbok prospect has multiple reservoir targets; carbonate reservoirs are assumed in Gemsbok Main, while within the deeper targets both aeolian and marine reservoirs are considered possible. Two parts (North and South) of the Lion prospect have been assessed separately.

The main focus was to review all the available subsurface data including 2D seismic, well and geological data with supporting studies, and to derive independent estimates of prospective resources. Global holds a 85% net interest in Licence 0029.

Following this review AGR TRACS can report that the aggregate Best Estimate Gross Technical Unrisked Prospective Resources are estimated at 3.66bln bbls, and the Best Estimate Net Unrisked Technical Prospective Resources to Global are estimated at 3.11bln bbls, see Table 0.1 below.

Oil & Liquids: MMbbls Gas: Bscf	Gross Technical Prospective Resources			Net Attributable Technical Prospective Resources			Risk Factor	Operator
PROSPECT	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	**POS (%)**	
OIL - MMbbls								
Gemsbok Main	318	1091	2581	270	927	2194	12.3	Global
Gemsbok Aeolian	66	330	1296	56	281	1102	5.4	Global
Gemsbok Marine	63	323	945	53	275	803	8.8	Global
Lion North	104	291	743	88	247	631	7.5	Global
Lion South	290	823	2105	247	700	1789	7.5	Global
Dik-Dik	224	805	1969##	190	685	1674##	5.0	Global
TOTAL#	**1065**	**3663**	**9639**	**904**	**3115**	**8193**		

Table 0.1: AGR TRACS estimates of Gross and Net Attributable Unrisked Technical Prospective Resources in Global's Licence 0029 offshore Namibia

Source: AGR TRACS review

Note: "Risk Factor" for Prospective Resources means the chance, or probability, of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the

Prospective Resources maturing into a Contingent Resource. Where a prospect could contain either oil or gas the hydrocarbon type with the higher probability of being discovered has been listed in the table.

"Operator" is the name of the company that operates the asset.

"Gross" are 100% of the resources attributable to the licence whilst "Net Attributable" are those attributable to the AIM company.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"##" - Excludes area outside Global licence.

AGR TRACS has carried out independent risk assessments for each prospect yielding risk factors (POS) between 5.0% and 12.2% for the individual prospects. These risk factors represent solely the exploration risk (as per the June 2009 AIM Guidance Note) and do not include any assessment of commercial chance of success. The resulting aggregate Best Estimate of Net Risked Technical Prospective Resources attributable to Global are estimated at 258.0 MMbbls, see Table 0.2 below. It should be noted that about 44% of this risked volume is estimated to be contained in the Gemsbok Main prospect, thus suggesting this prospect should be the primary focus for a future exploration well.

Oil & Liquids: MMbbls Gas: Bscf	Unrisked Technical Prospective Resources Net Attributable to Global			Risk Factor	Risked Technical Prospective Resources Net Attributable to Global		
PROSPECT	**Low Estimate**	**Best Estimate**	**High Estimate**	**POS (%)**	**Low Estimate**	**Best Estimate**	**High Estimate**
OIL - MMbbls							
Gemsbok Main	270	927	2194	12.3	33.1	113.6	268.7
Gemsbok Aeolian	56	281	1102	5.4	3.0	15.1	59.5
Gemsbok Marine	53	275	803	8.8	4.7	24.0	70.3
Lion North	88	247	631	7.5	6.6	18.6	47.4
Lion South	247	700	1789	7.5	18.5	52.5	134.2
Dik-Dik	190	685	1674##	5.0	9.5	34.2	83.7##
TOTAL#	**904**	**3115**	**8193**		**75.4**	**258.0**	**663.8**

Table 0.2: AGR TRACS estimates of Net Attributable Unrisked and Risked Technical Prospective Resources in Global's Licence 0029 offshore Namibia

Source: AGR TRACS review

Note: "Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

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Qualifications

AGR TRACS International Ltd is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, AGR TRACS International Ltd does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The project was managed and signed off by Mike Wynne (D. Phil.), an AGR TRACS Manager. Dr. Wynne, a reservoir engineer and SPE Member, has 30+ years' experience from the Africa, FSU,

Middle East, and NW Europe. AGR TRACS International Ltd has conducted valuations for many energy companies and financial institutions.

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data.

It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

Yours faithfully,

Mike Wynne
AGR TRACS International Ltd
(a wholly owned subsidiary of AGR)

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Disclaimer

CPR on exploration prospects in Licence 0029, offshore Namibia

This report relates specifically and solely to the subject petroleum licence interests and is conditional upon the assumptions made therein. This report must therefore be read in its entirety.

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of prospective hydrocarbon resources should be regarded only as estimates that may change as additional information become available. Not only are these estimates based on the information currently available, but are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR TRACS International Ltd shall have no liability arising out of, or related to, the use of the report.

12th January 2018

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Executive Summary

AGR TRACS International Ltd. ("AGR TRACS") was engaged by Global Petroleum Limited ("Global") to review the exploration prospect portfolio in Global's Licence 0029 offshore Namibia (Global net interest 85%). Three substantial prospects have been mapped (Gemsbok, Lion and Dik-Dik), along with two leads (Choje and Pangolin). Multiple reservoir targets have been identified in the Gemsbok prospect; whereby carbonate reservoirs are assumed in Gemsbok Main, while within the deeper targets both aeolian and marine reservoirs are considered possible. Two parts (North and South) of the Lion prospect have been assessed separately.

The main focus was to review all the available subsurface data including 2D seismic, well and geological data with supporting studies, and to derive independent estimates of prospective resources and associated independent risk assessments for each prospect.

Following this review AGR TRACS can report that the aggregate Best Estimate Gross Technical Unrisked Prospective Resources are estimated at 3.66bln bbls, and the Best Estimate Net Unrisked Technical Prospective Resources to Global are estimated at 3.11bln bbls, see Table ES.1 below:

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Source: AGR TRACS review

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Prospective Resources attributable to Global are estimated at 258.0 MMbbls, see Table ES.2 below. It should be noted that about 44% of this risked volume is estimated to be contained in the Gemsbok Main prospect, thus suggesting this prospect should be the primary focus for a future exploration well.

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Table ES.2: AGR TRACS estimates of Net Attributable Unrisked and Risked Technical Prospective Resources in Global's Licence 0029 offshore Namibia

Source: AGR TRACS review

Note: "Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"##" - Excludes area outside Global licence.

AGR TRACS have reached the following conclusions following the subsurface geoscience review:

- The 2D seismic coverage is generally good, particularly over the Gemsbok and Lion prospects. It is sparser over Dik Dik.
- The seismic quality is good in the shallow section, but fair in the deeper section.
- The density of 2D seismic data is sufficient to ensure the maps provide a good representation of the structures.
- Uncertainties remain with regards to the complexity of the structures and the acquisition of additional seismic data may lead to alternative structural configurations.
- Further work is required on the leads to establish the extent of the Choje sand distribution and the Pangolin reef structure. Maps of these structures are required to fully evaluate their potential.

AGR TRACS would also make the following recommendations:

- To address the structural uncertainties, the acquisition of 3D seismic data over the primary prospect is recommended.
- If 3D data is acquired detailed attribute analysis is recommended to assist in the location of future exploration wells.

Contents

Figures

Tables

1 Introduction

The aim of this report is to provide an independent assessment of the prospect portfolio identified by Global in Licence 0029 offshore Namibia. The licence is located in water depths of 1,200 – 2,000m. No wells have to date been drilled on the licence, and the closest offset wells are located some 110km to the NE, with the Welwitschia-1 well around 80km east of the licence (see Figure 1.1 below).

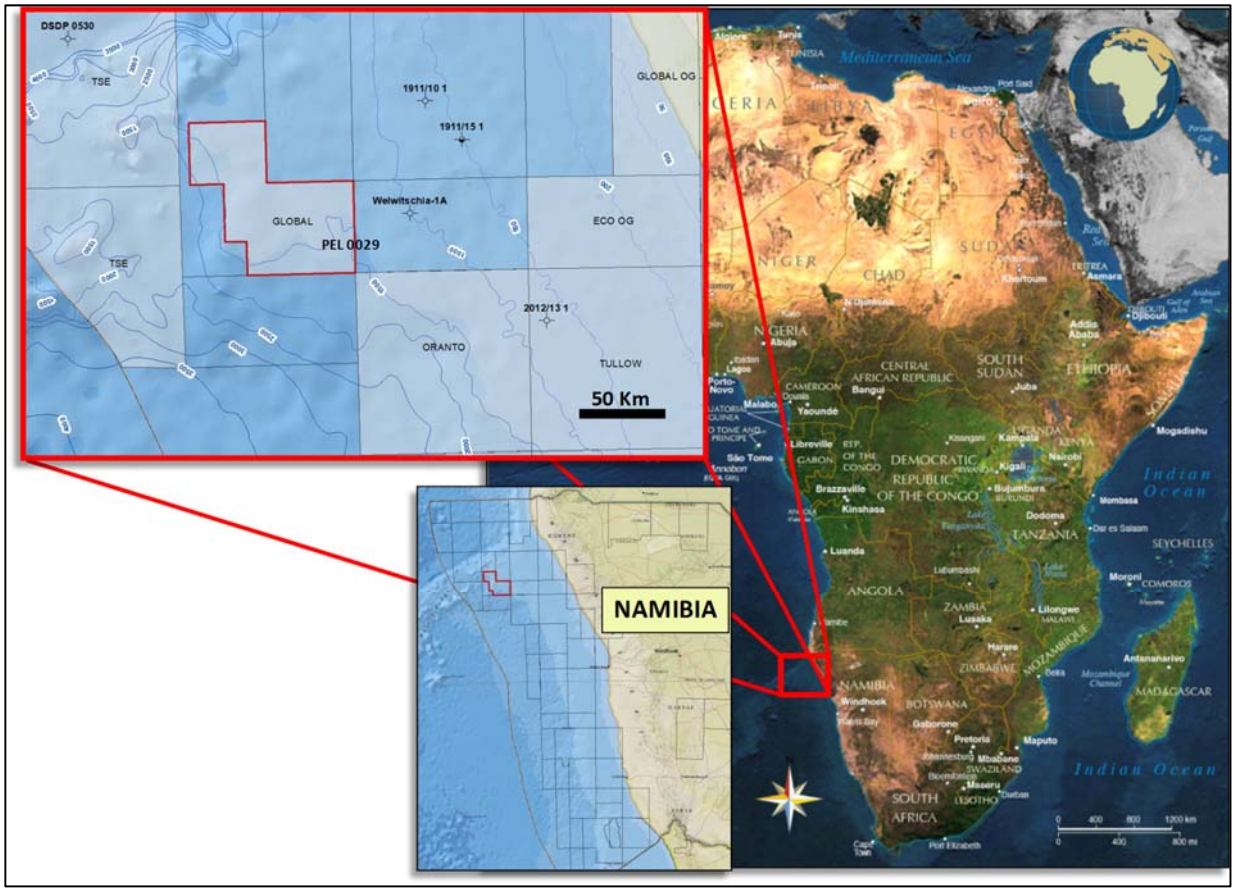

Figure 1.1: Location of Global's Licence 0029, offshore Namibia
(Source: Global)

Licence 0029 incorporating Blocks 1910B and 2010A was originally granted to Jupiter Petroleum (Namibia) ltd, a 100% subsidiary of Global Petroleum Limited, on 3rd December 2010. The other licence partners were Bronze Investments Pty Ltd and NAMCOR (see Table 1.1). The licence had an initial exploration period of 4 years from date of award, followed by two optional 2-year renewal periods. The initial 4-year period was extended for one year to December 2015, after which there was a 50% relinquishment in accordance with the Licence terms, resulting in the current licence area of 5,810 km². The Namibian authorities have recently agreed a one year extension to the First Renewal Period which now runs to December 2018, at which time there would also normally be a further 25% relinquishment. The minimum work programme and minimum exploration expenditures for each period are summarised below:

Initial Exploration Period (4 years, extended by one year to December 2015): Full evaluation of all available materials and geological, geochemical and geophysical studies, purchase of all available seismic data, and the acquisition, processing and interpretation of not less than 1,000km of 2D data. The minimum expenditure should be at least US$1.0mln; minimum US$150,000 for studies and US$850,000 for 2D seismic data. The minimum work programme for

the 1-year extension was extra mapping on the 2D seismic data, inversion of the gravity/magnetic data and maturity mapping with a minimum financial expenditure of US$0.25mln.

First Renewal Exploration Period (2 years, but extended by 1 year to 3rd December 2018): Minimum work programme revised to reprocessing of all 2D seismic lines in the retained area and the acquisition of 800km of long-offset 2D seismic data. This licence period was scheduled to end 3rd December 2017. Subsequently a 1-year extension of the First Renewal Period to 3rd December 2018 was agreed with the Ministry, with entry into the Second Renewal Period at that point in time. The minimum work programme for the 1-year extension is the acquisition of 600km² of 3D seismic data, contingent on Global Petroleum finding a farm-in partner to fund the 3D seismic survey. If the acquisition of the 3D seismic survey is not completed during the 1-year extension, then it can be carried over into the Second Renewal Exploration Period.

Second Renewal Exploration Period (2 years): Minimum work programme altered, in agreement with the Ministry, to drill one well (depth and location to be agreed) unless the Ministry and Global agree that circumstances dictate otherwise.

Asset	Company	Equity Interests		Status	Expiry date First Renewal Period	Licence Area	Work Obligations
		Expl. Phase	Cost-bearing				
Licence 0029 (Blocks 1910B & 2010A)	Jupiter Petroleum (Namibia) Limited (operator)	85.00%	100.0%	Expl.	One year extension agreed to 03/12/2018	5,810 km²	First and Second Exploration Renewal periods as detailed above.
	NAMCOR	10.00%	0.0%				
	Bronze Investments Namibia	5.00%	0.0%				

Table 1.1: Licence 0029 – equity interests during exploration stages

2 Geological Overview

Global holds an 85% interest and operatorship in Licence 0029 (Blocks 1910B and 2010A) is located in the northern part of the Walvis Basin approximately 230 km from the Namibian coastline. The area is under-explored with fewer than 20 wells drilled over a wide area. Some of these wells have encountered hydrocarbon shows, but to date no commercial volumes have been discovered. Figure 2.1 shows location of the Global's Licence 0029 (in red, after 50% relinquishment).

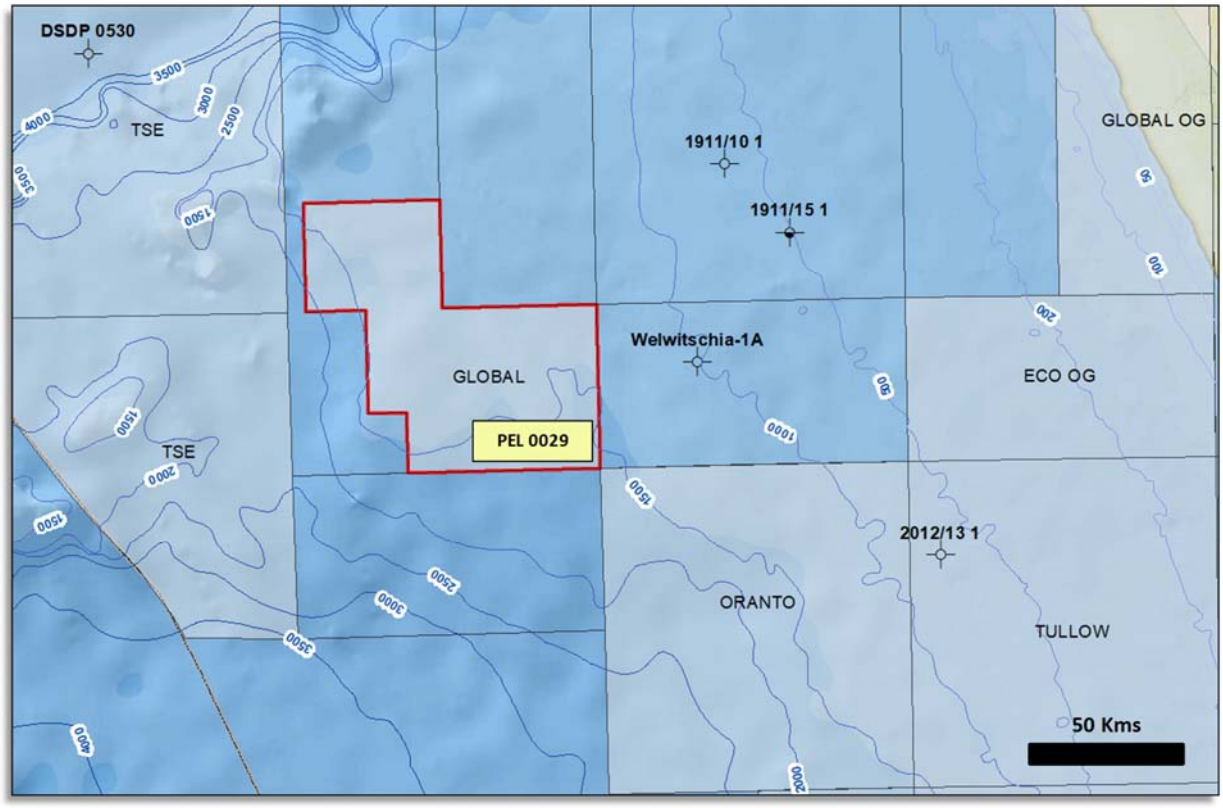

Figure 2.1: Global Licence 0029 location map
(Source Global)

No wells have been drilled to date on the licence area, and the nearest offset wells are 50 to 100km+ away (e.g. 1911/10-1 and 1911/15-1 to the NE and Welwitschia-1 due east, see Figure 2.1). In addition, there are a number of DSDP wells drilled in the vicinity of Licence 0029 providing additional regional stratigraphic data-points.

The four main basins offshore Namibia (Namibe Basin, Walvis Basin, Luderitz Basin and Orange Basin) developed in a passive margin setting during the opening of the South Atlantic, when a thick sequence of Cretaceous to Tertiary sediments were deposited over an early Cretaceous rift margin. A long-distance South-North well correlation through the Namibian offshore basins is presented in Figure 2.2, which illustrates the varying packages of Cretaceous sediments deposited in the different basins.

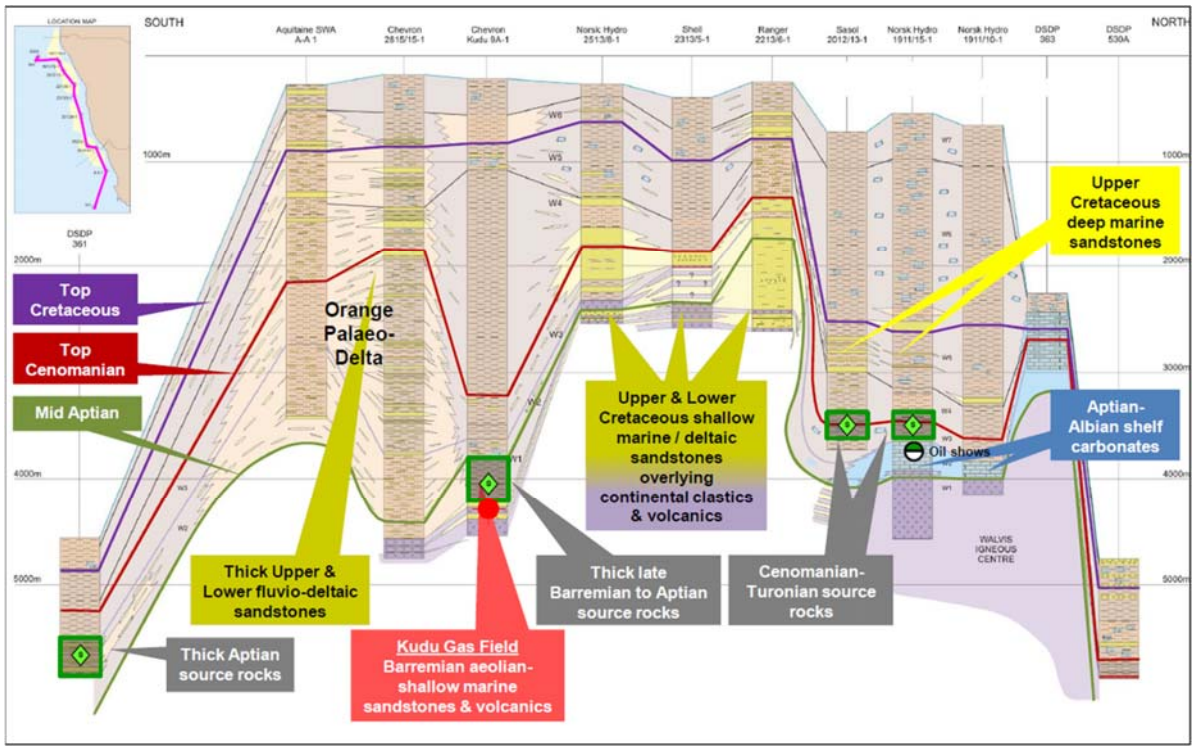

Figure 2.2: Namibia offshore - South-North well correlation
(Source: after NAMCOR pre-2012 in Pritchard 2014)

Figure 2.3 shows a composite stratigraphic column for the Namibian offshore area from the four main basins with the elements of various petroleum systems.

Rich source rocks have been drilled in the Cenomanian (oil prone in 1911/15-1, 2012/13-1, Kabeljou-1, Moosehead-1 and DSDP wells) and Aptian (oil prone in Wingat, Murombe and Kudu, but in the gas window at Kudu). Mature source rocks for oil and gas are inferred as migration of oil and gas is proven by the Wingat oil discovery (in marine sandy silts of Aptian age, so not the target carbonates envisaged for the majority of Global's prospects). The Kudu and Kunene gas discoveries and sampled thermogenic gas seeps in seabed cores at various points along the Namibian margin also confirm the presence of mature source rocks. Further supporting evidence comes from satellite radar slicks, including some just to the north of the Gemsbok licence.

Data gathered from the 1911/15-1 well just 100km to the east of licence 0029 indicates a maturity profile that enters the oil generating window at 3,000m below sea floor, with the main oil window at 3,500m. At Kudu the early oil window is reached at 1,450m of rock overburden, the main oil window at 2,100m of rock overburden and the gas window at 3,800m. Either of these could be used as a proxy for the top of the main oil window in the Global licence.

The main uncertainties remaining include the presence and maturity of source rocks, well-developed reservoirs and effective regional seals.

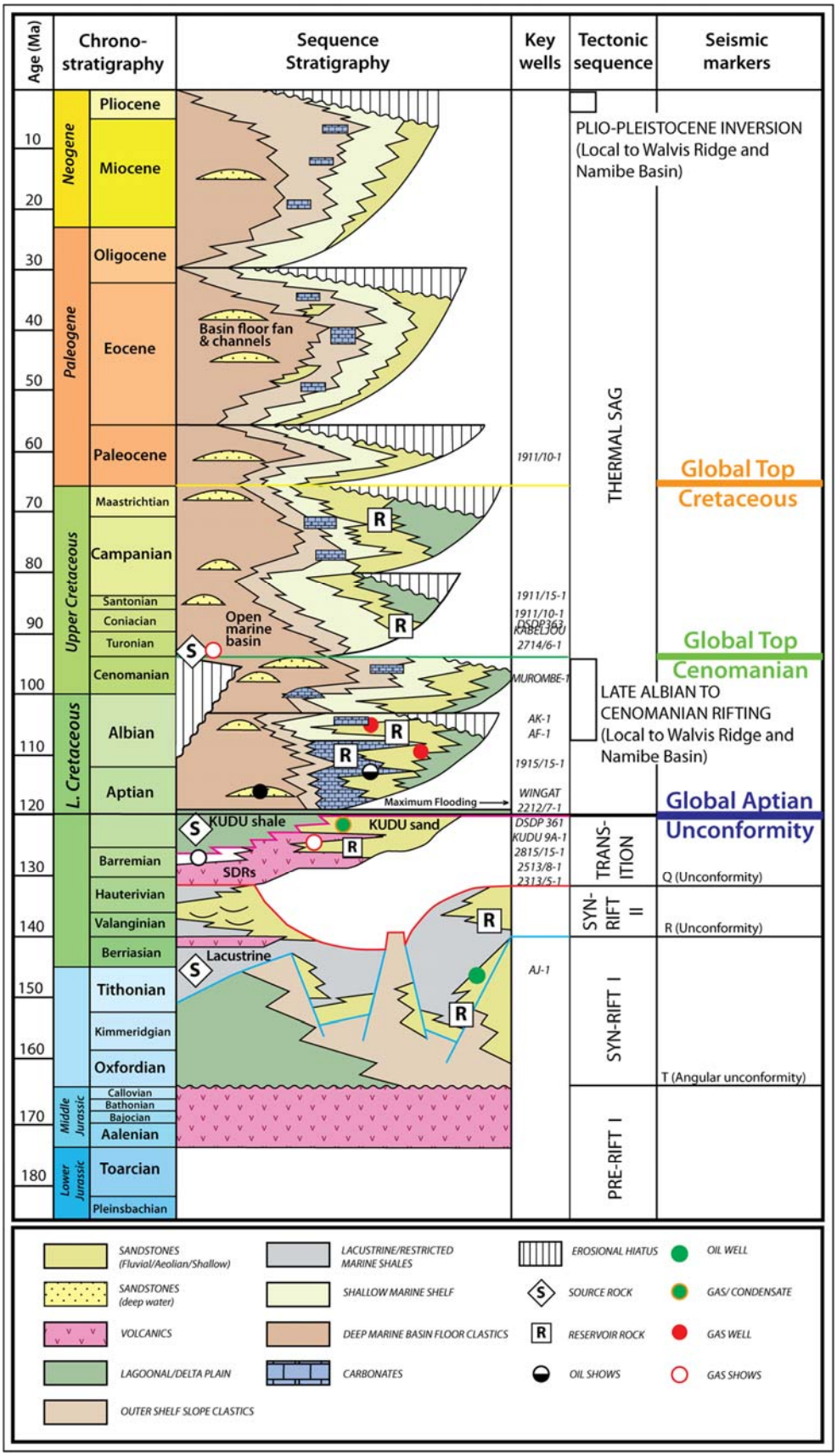

Figure 2.3: Composite stratigraphic column from Namibia offshore basins
(Source: Global)

3 Geophysics

3.1 Introduction

The objectives of the geophysical review were to:

- Confirm the seismic interpretation for the prospects identified.
- Estimate the range of Stock Tank Oil Initially In Place (STOIIP) for the prospects.
- Carry out a Risk Analysis for the prospects

In order to meet these objectives, the data provided was analysed and the following sections provide a summary of the geoscience data available and the volumetric potential of the prospects.

3.2 Database

A comprehensive dataset was provided by Global Petroleum which included a Kingdom project, presentations, reports and various supporting documentation. From the geophysical perspective, the primary source of data was the Kingdom project which contained 2D seismic lines, well data and interpreted horizons in time and depth.

The seismic dataset consists of 128 2D lines, totalling over 2,500 line km. This includes approximately 800km of new data acquired in 2017. The lines over the prospects form an irregular grid varying from approximately 2km by 7km apart over Gemsbok, 3km by 5km over the Lion prospect and 13km by 19km over Dik Dik.

The data quality of the lines reviewed at the intervals of interest is generally good and allows the structural configuration of the prospects to be mapped.

There are 23 wells provided in the Kingdom project all of which are outside the licence area. The wells include a number of Deep Sea Drilling Programme (DSDP) wells as well as some exploration wells. The nearest of the exploration wells is Welwitschia-1A which is approximately 60km to the east of the Gemsbok prospect. This well was drilled in 2015, but failed to reach the target horizon mapped at Gemsbok. It does, however, represent a good tie point for the shallower events.

Only five of the wells have significant log data.

Figure 3.1 and Figure 3.2 show the seismic and well database.

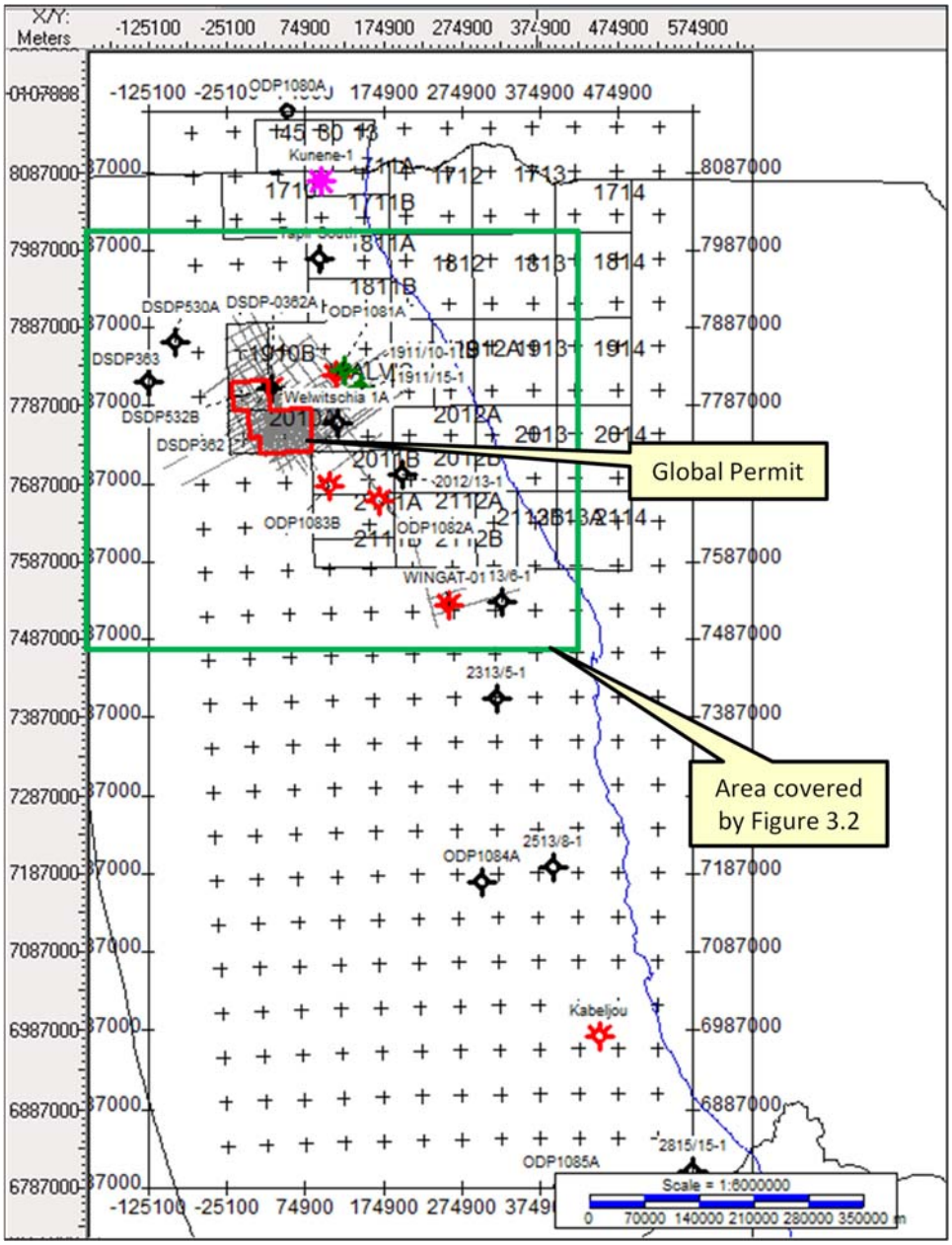

Figure 3.1: Seismic and Well Database

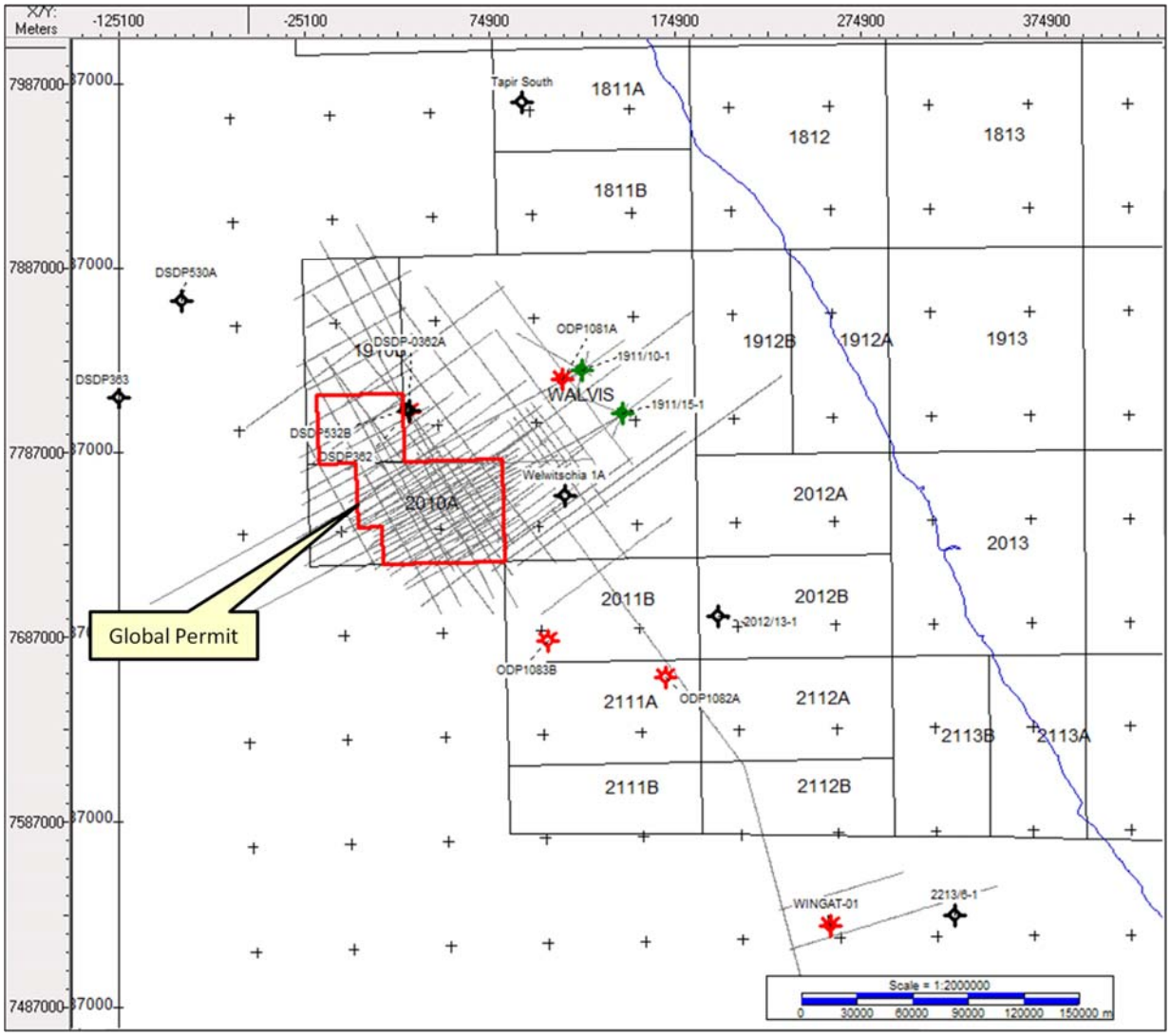

Figure 3.2: Zoomed in Base map

3.3 Seismic Interpretation Review

The 2D seismic data has been reviewed to assess the continuity of the interpreted horizons and faulting for each of the prospects. In addition, the depth conversion method has been analysed to determine the potential impact on the mapped structures.

Three prospects and two Leads have been identified by the latest mapping exercise (Figure 3.3). The following sections provide a summary of the review of these Prospects and Leads.

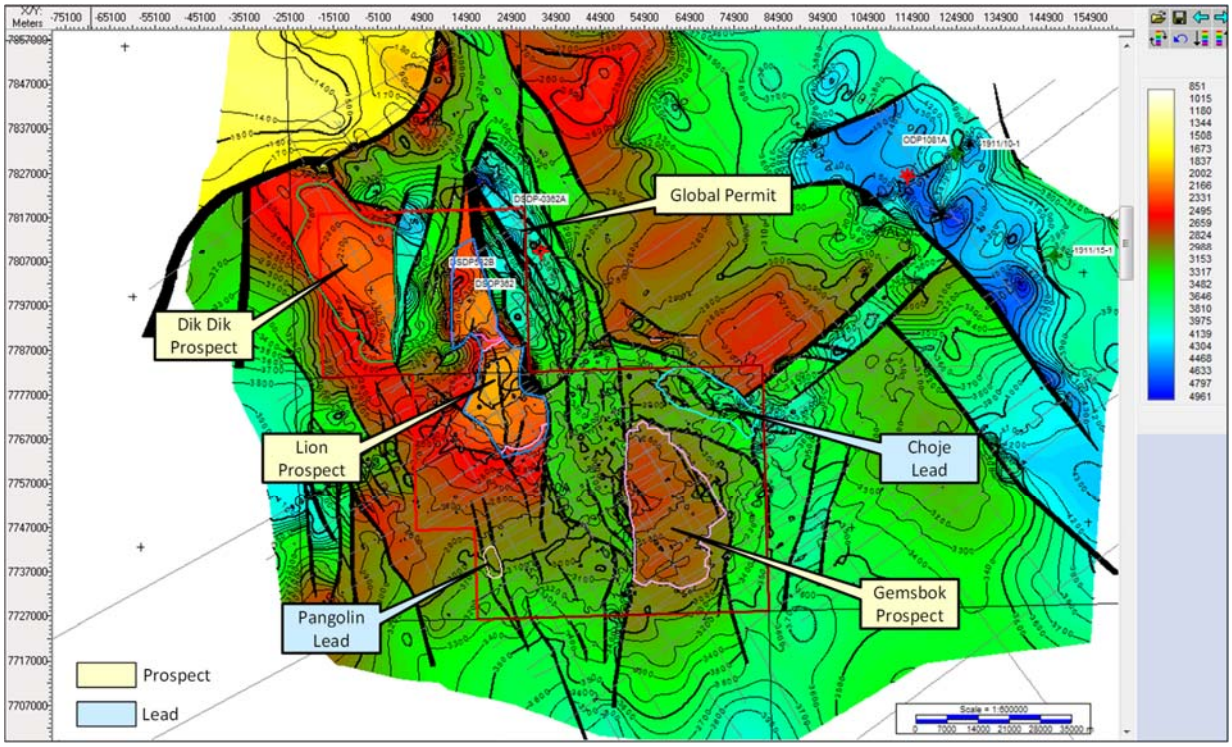

Figure 3.3: Map showing Prospects and Leads

3.3.1 Gemsbok Prospect

The Gemsbok Prospect is located in the south-eastern part of the Global licence approximately 230 km from the Namibian coastline. The structure is covered by 30 2D lines including seven of the recently acquired lines. The line spacing is approximately 2km by 7km which given the scale of the structure is considered a reasonable coverage. The data quality is generally good with good continuity of reflectors down to the Base AptoAlbian unconformity. Below this the quality is fair with the major reflectors being reasonably continuous although in some areas the continuity is variable. Figure 3.4 shows a typical line across the Gemsbok structure illustrating the data quality.

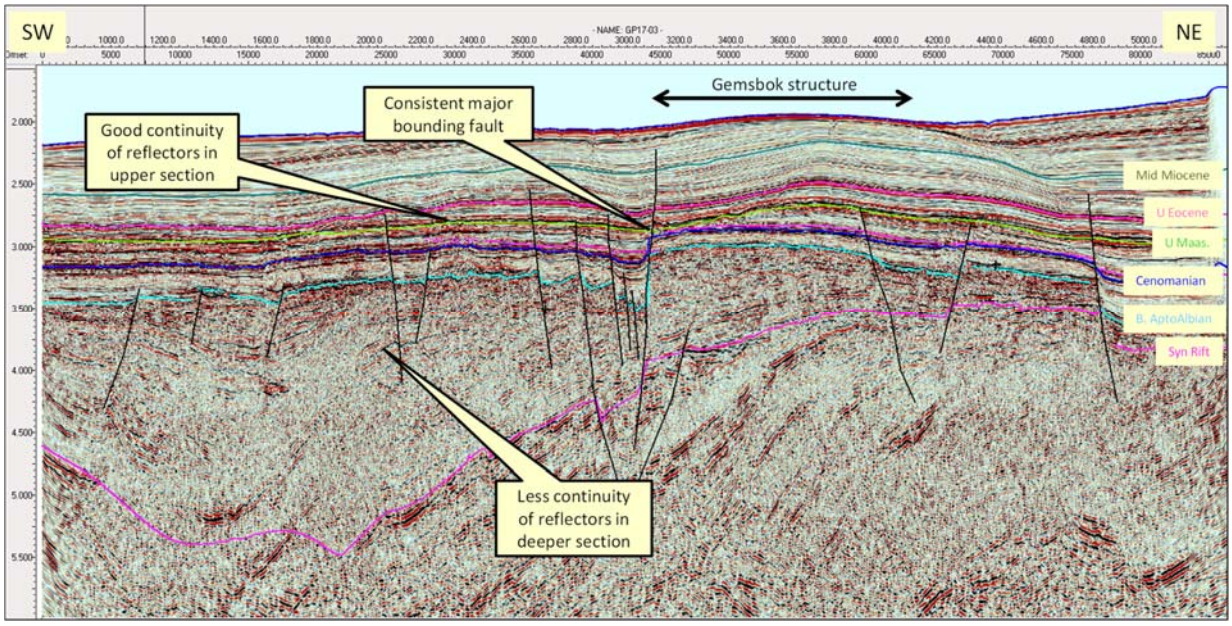

Figure 3.4: Line GP17-03 showing data quality (for line location see Figure 3.5)

The key horizon that defines the Gemsbok structure is the Base AptoAlbian unconformity. This has generally been picked as a trough on the seismic although in places the peak has been used. An alternative pick was interpreted using the peak consistently but this was found to make no significant difference to the structure as the reflector used is basically a good event which can be interpreted reliably across the area.

The resulting TWT interpretation has identified a large fault bounded, three-way dip closed structure. The major westerly bounding fault can be mapped consistently from line to line and has a significant throw. The dip to the east is also consistent on all the lines creating a large structural closure.

The Two-Way time (TWT) map is considered a good representation of the time structure based on the 2D interpretation.

Figure 3.5 shows the TWT map for the Base AptoAlbian unconformity.

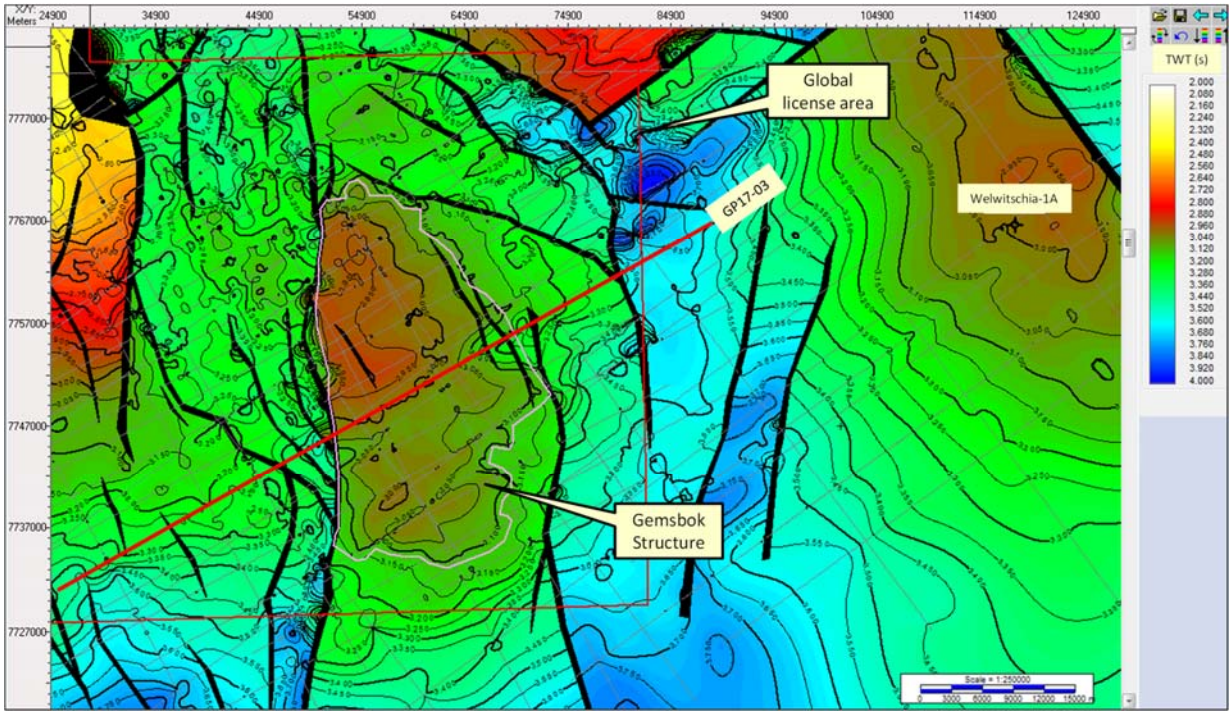

Figure 3.5: Gemsbok Main prospect AlboAptian TWT map

The depth conversion has used a simple two-layer approach. Table 3.1 shows the intervals and velocities used.

Interval	Interval Velocity (m/s)
Sea level – Sea bed	1,531
Sea bed – AlboAptian	3,092

Table 3.1: Gemsbok depth conversion

There is very little velocity data from wells to allow a more sophisticated depth conversion to be carried out so this is considered an acceptable approach for deriving depth surfaces.

The resulting AptoAlbian depth map, which is regarded as the primary surface for deriving volumetric estimations, is shown in Figure 3.6.

As the depth conversion is based on average velocities, the depth map shows the same basic structural closure as the TWT map. This is an area that is likely to change once more data becomes available and the depth conversion method becomes more refined. However, for the current evaluation, the depth map is considered acceptable.

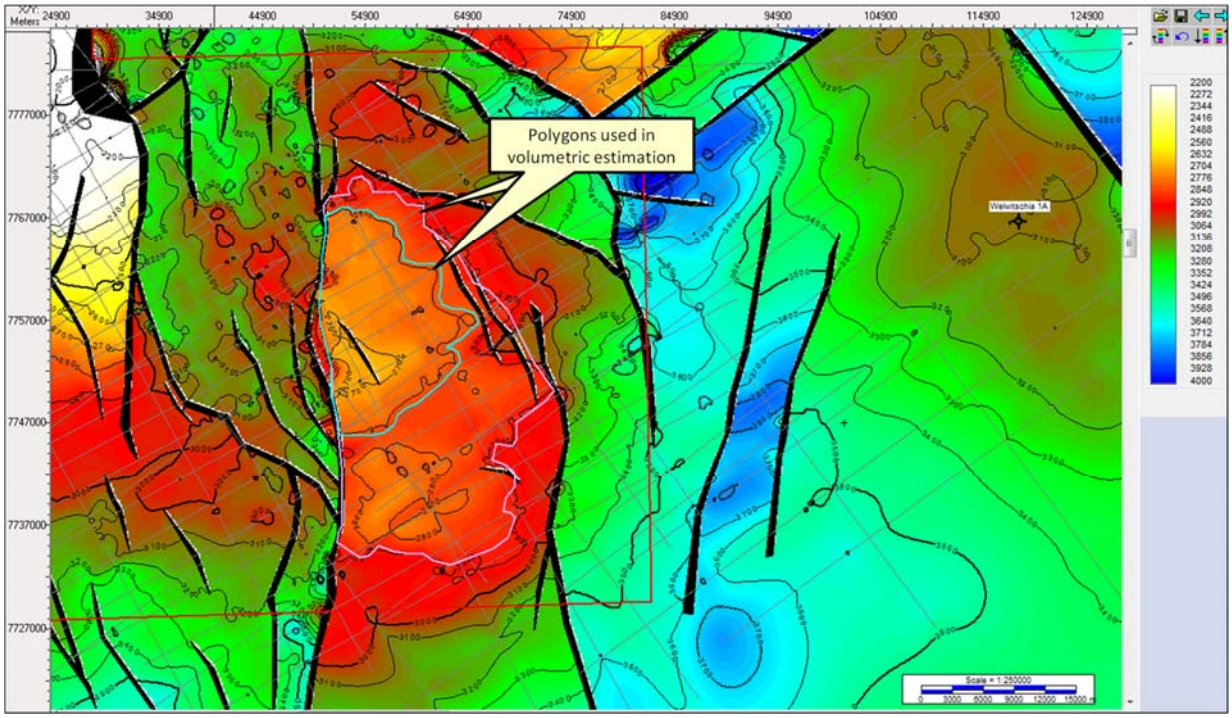

Figure 3.6: Gemsbok Main prospect AlboAptian Depth structure map

Since the Gemsbok structure is currently undrilled it is considered a prospect and as such carries a geological risk.

The Probability of Success (POS) for the Gemsbok prospect was estimated using a combination of the probability of hydrocarbon charge, seal, reservoir and trap.

There is some concern regarding the source as a number of wells in the area have failed to find hydrocarbons. However, there are some wells drilled in the area that have encountered variable quantities of hydrocarbons. The nearest well to the Global licence that has indicated the presence of hydrocarbons is the 1911/15-1 well drilled by Norsk Hydro in 1995. This well, which encountered oil shows in the AptoAlbian carbonate reservoir, is approximately 100km to the northeast of the Gemsbok prospect so is some distance away.

Approximately 330km to the north, the Kunene-1 well found a gas condensate also in the AptoAlbian carbonate reservoir although at this location the reservoir was tight.

In addition to the hydrocarbons seen in the wells, oil seeps have also been identified by Fugro and these suggest the possibility of an active petroleum system. Figure 3.7 shows a summary map taken from the Fugro report of the suspected seeps. The Rank 3 seepage cluster illustrated lies close to the major fault trend mapped from the seismic.

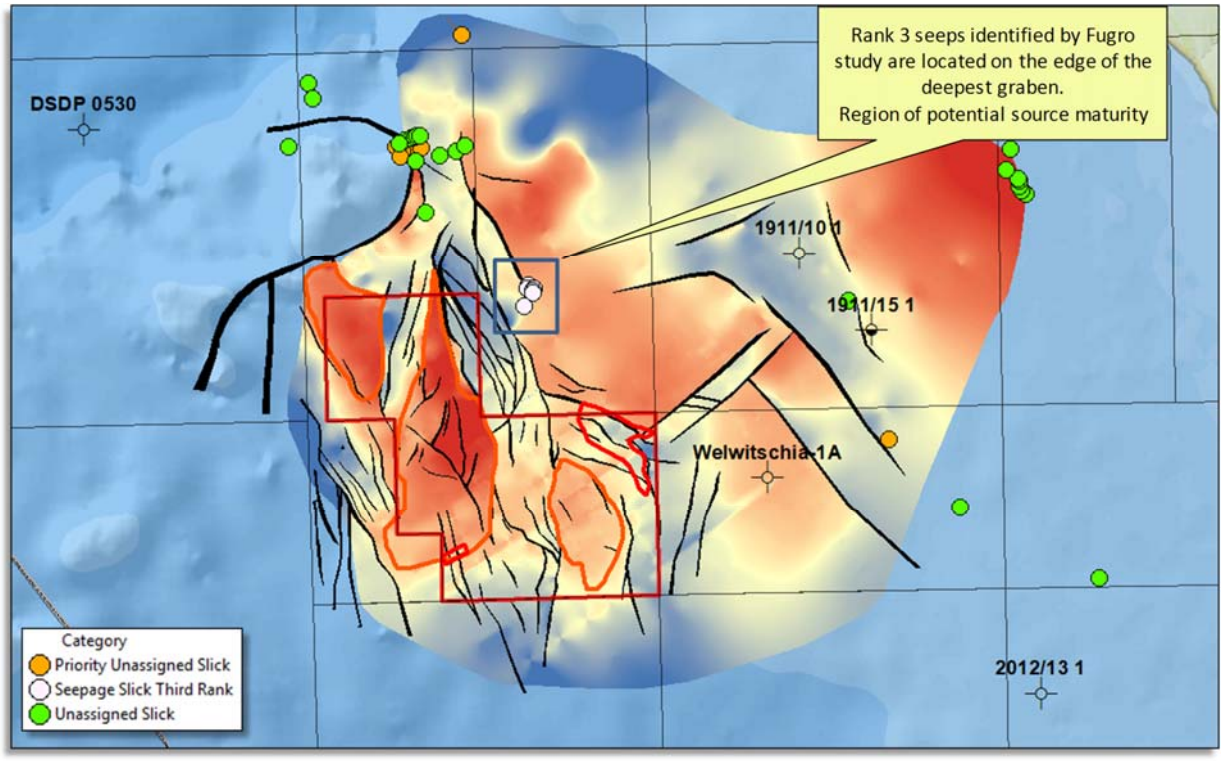

Figure 3.7: Distribution of all slicks mapped by Offshore Basin Screening (OBS)
(Source: Fugro)

The adjacent grabens are believed to be of sufficient depth to allow a local source generation. Source presence and effectiveness are however a key uncertainty.

The seal is considered a low risk as there are significant shales seen on the offset wells.

Reservoir presence is a concern as some of the offset wells have either failed to encounter the target reservoir or, when they have, it has been thinner than expected or tight (for example, the Wingat well). However, there are wells that have encountered a reasonable thickness of reservoir with reasonable quality (for example the Tapir South well). These results suggest that the reservoir presence and effectiveness can be variable.

The trap is considered a relatively low risk as the structure can be seen on several lines and a large closure can be mapped. The only concern is that because only 2D seismic data is currently available, the mapping may not have captured the full complexity of the structure so it may not consist of a single large structure. This is not considered a serious issue as the structure is certainly present.

The parameters and overall probability of success estimated for the Gemsbok carbonate prospect is summarised in Table 3.2:

Parameter	POS	Comments
Source	0.50	Nearest well with hydrocarbons 100km away.
Seal	0.70	Low risk. Offset wells have significant shale
Reservoir	0.50	Key uncertainty on presence.
Trap	0.70	Low risk. Mapped on several 2D lines. May be more complex than currently mapped.
Overall	0.123	12.3% Chance of Success (or approximately 1 in 8)

Table 3.2: Gemsbok Carbonate prospect Probability of Success

In addition to the Carbonate reservoir, a second, deeper reservoir, similar to that seen at Kudu, is also considered a possibility by Global. It is not clear whether the Kudu Aeolian reservoir or the younger marine reservoir will be present and this represents a risk for this target.

The hydrocarbon source of an Aeolian reservoir has the same uncertainty as for the carbonate with uncertainty over presence as well as effectiveness.

The seal requires the presence of volcanics to encase the aeolian sand as it does at Kudu. This is a concern as it relies on the volcanics to be erupted at the right time to protect the reservoir from later reworking.

The reservoir presence is considered a high risk for the aeolian sands as a number of factors have to be in place to ensure the preservation of the sand.

The trap has some risk as a stratigraphic element is required and so is a more complex mechanism.

The parameters and overall probability of success estimated for the Gemsbok Barremian Aeolian sand prospect is summarised in Table 3.3:

Parameter	POS	Comments
Source	0.50	Uncertainty on source presence and effectiveness.
Seal	0.60	If the same as Kudu it requires volcanics to seal the Aeolian sand so presence is a risk.
Reservoir	0.30	Reservoir presence a key concern.
Trap	0.60	More complex trapping mechanism required.
Overall	0.054	5.4% Chance of Success (or approximately 1 in 18.5)

Table 3.3: Gemsbok Barremian Aeolian sand prospect Probability of Success

In the case of the marine sand, the source presence and effectiveness is considered to have the same risk as for the carbonate reservoir.

The seal is considered a relatively low risk as it is likely that shales will be present to provide the seal.

The reservoir presence is thought to be relatively low risk. However, the effectiveness is a concern as it is thought to be a poor reservoir in analogue fields.

Trap presence is considered a risk as the current mapping is based on the AptoAlbian carbonate but the marine sand may not have the same structural style as the carbonate. Trap is therefore a concern.

The parameters and overall probability of success estimated for the Gemsbok Barremian marine sand prospect is summarised in Table 3.4:

Parameter	POS	Comments
Source	0.50	Uncertainty on source presence and effectiveness.
Seal	0.70	Low risk as shales should be expected.
Reservoir	0.50	Effectiveness is a concern as well as presence.
Trap	0.50	Uncertainty on presence.
Overall	0.088	8.8% Chance of Success (or approximately 1 in 11)

Table 3.4: Gemsbok Barremian marine sand prospect Probability of Success

3.3.2 Lion Prospect

The Lion Prospect is located approximately 40km to the north west of the Gemsbok structure (Figure 3.3 above). It is covered by 21 lines, three of which are the newly acquired lines. The line spacing is variable ranging from approximately 3km by 5km to 7km by 5km. With the number of lines covering the structure, this spacing is considered acceptable to define the closure.

The data quality is similar to the Gemsbok area and Figure 3.8 shows line GP17-10 crossing the Lion structure.

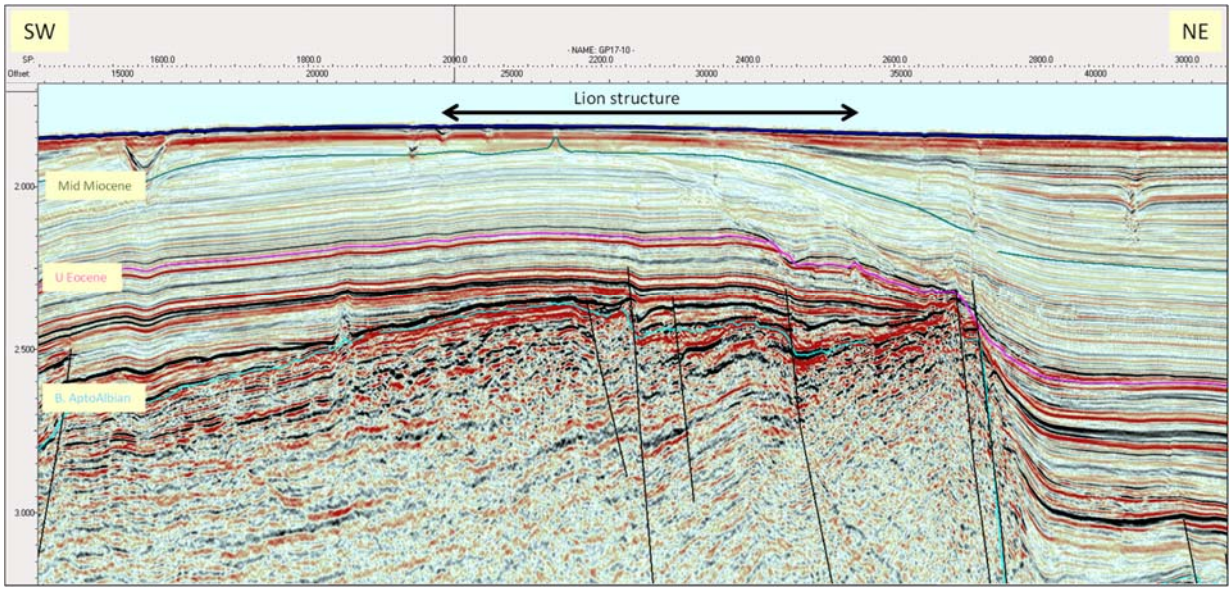

Figure 3.8: Line GP17-10 over the Lion prospect
(for line location see Figure 3.9)

The horizon that defines the Lion prospect is also the AptoAlbian event and it has been picked consistently across the structure. The TWT map is considered to be a good representation of the structure (Figure 3.9).

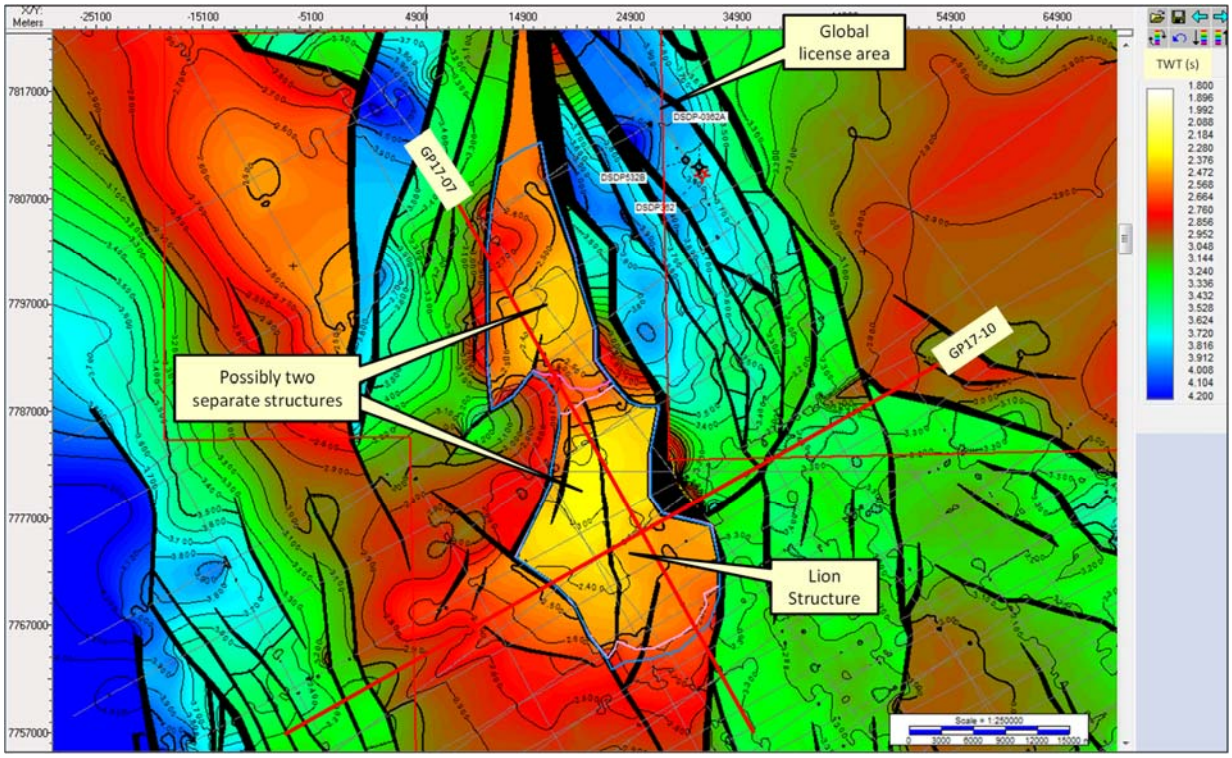

Figure 3.9: Lion prospect AlboAptian TWT map

Global have interpreted the Lion prospect as a single structure. However, there is the possibility that it is separated into two closures. Figure 3.9 shows three polygons that outline the north and south closures and the single closure. Figure 3.10 shows a northwest to southeast line across the saddle to show the extent of the low area.

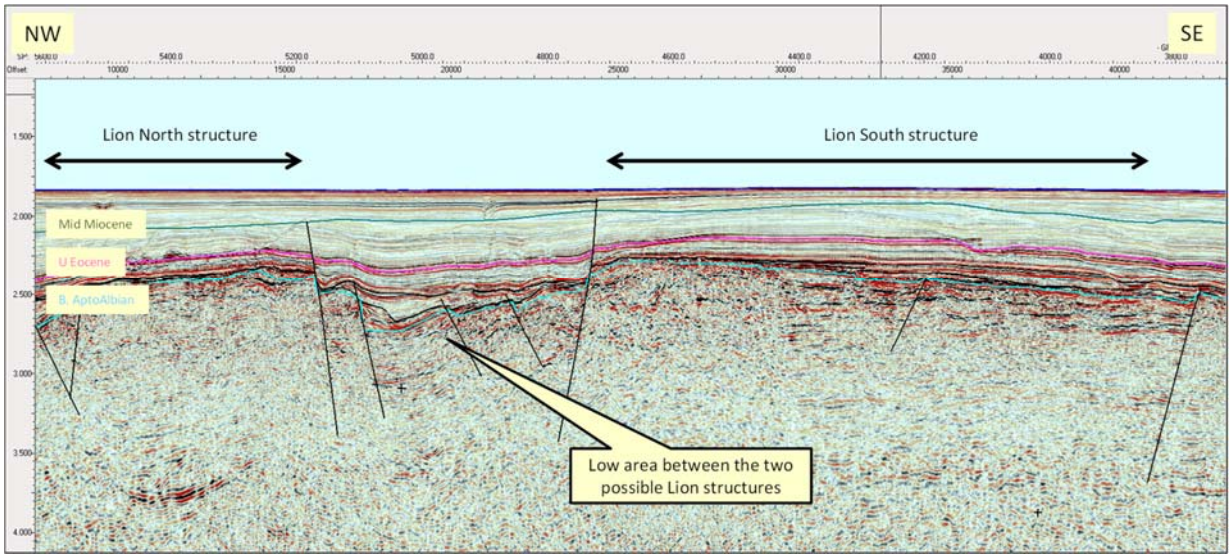

Figure 3.10: Line GP17-07 showing Lion structural configuration
(for line location see Figure 3.9)

The depth conversion has been carried out using the same two-layer method used for the Gemsbok prospect. The resulting depth map is shown in Figure 3.11.

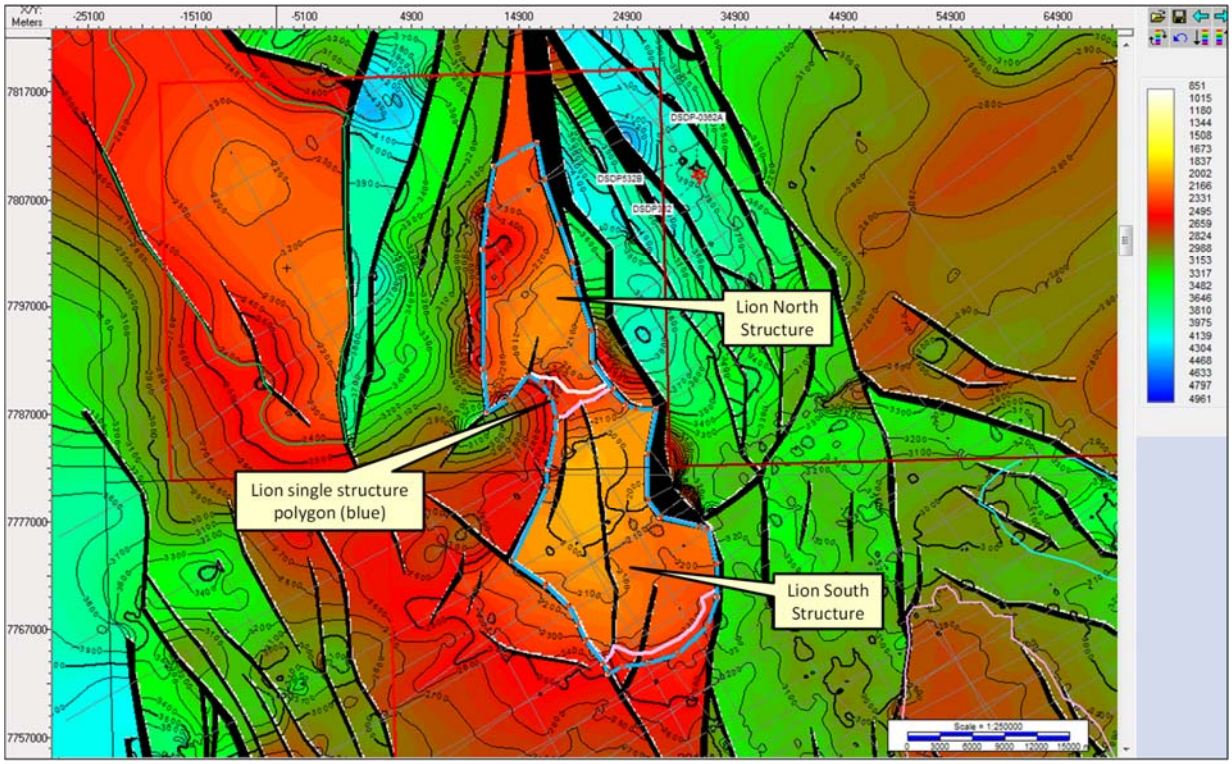

Figure 3.11: Lion prospect AlboAptian Depth structure map

At this location, only the carbonate reservoir is considered most likely to be present.

Since the Lion structure is currently undrilled it is considered a prospect and as such carries a geological risk.

The Probability of Success (POS) for the Lion prospect was estimated using a combination of the probability of hydrocarbon charge, seal, reservoir and trap.

Some of the wells drilled offshore Namibia have encountered variable quantities of hydrocarbons. The nearest well to the Global licence that has indicated the presence of hydrocarbons is the 1911/15-1 well drilled by Norsk Hydro in 1995 some 100km from the Global licence. This well encountered oil shows. The risk on source is considered to be the same for the Lion prospect as it is for the Gemsbok prospect.

Top seal is considered a low risk as there are shales seen on the offset wells however the structure relies on faults for the closure so there is some risk on the fault seals.

Reservoir presence is a concern as some of the offset wells have either failed to encounter the target reservoir or, when they have, it has been thinner than expected or tight. However, thicker reservoir has also been encountered with reasonable effectiveness. Reservoir presence and effectiveness are therefore variable.

The trap is considered likely to be present as the structure can be seen on several lines. The main issue with Lion is whether the structure is a single feature, as assumed by Global, or is divided into a north and south closure. This may be partly compounded by the fact that the structure is mapped on 2D seismic data and so the full complexity of the prospect has not been fully captured. This is not considered to be a major concern as the structure does appear to be present. The POS is considered to be the same in each scenario.

The parameters and overall probability of success estimated for the Lion carbonate prospect is summarised in Table 3.5:

Parameter	POS	Comments
Source	0.50	Uncertainty on source presence and effectiveness.
Seal	0.60	Some risk as the structures rely on multiple fault seals.
Reservoir	0.50	Concern with presence and effectiveness.
Trap	0.50	Mapped on several 2D lines. May be more complex than currently mapped.
Overall	0.075	7.5% Chance of Success (or approximately 1 in 13)

Table 3.5: Lion prospect Probability of Success

3.3.3 Dik Dik Prospect

The Dik Dik prospect is located approximately 40km northwest of the Lion prospect (see Figure 3.3 above). It is only covered by eight 2D seismic lines, none of which are the newly acquired lines. The 2D coverage is variable with the majority of the structure having a line spacing in excess of 11km by 13km. This limited 2D seismic coverage leads to more uncertainty in the structural configuration of this prospect and with more seismic data, the trap geometry could be different. However, the lines that do cover the structure have been interpreted consistently so the resulting TWT map provides the best representation of the structure based on the data available.

Note that part of this prospect falls outside the licence area.

Figure 3.12 shows a line across the structure and Figure 3.13 shows the TWT map.

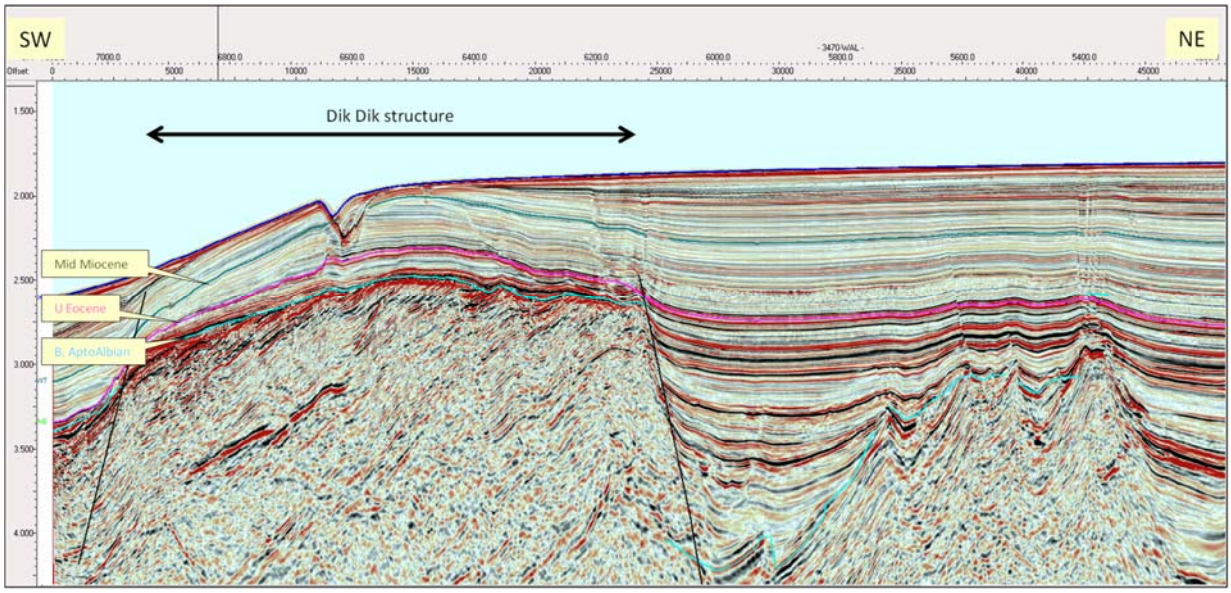

Figure 3.12: Line 3470-WAL over the Dik Dik prospect
(for line location see Figure 3.13)

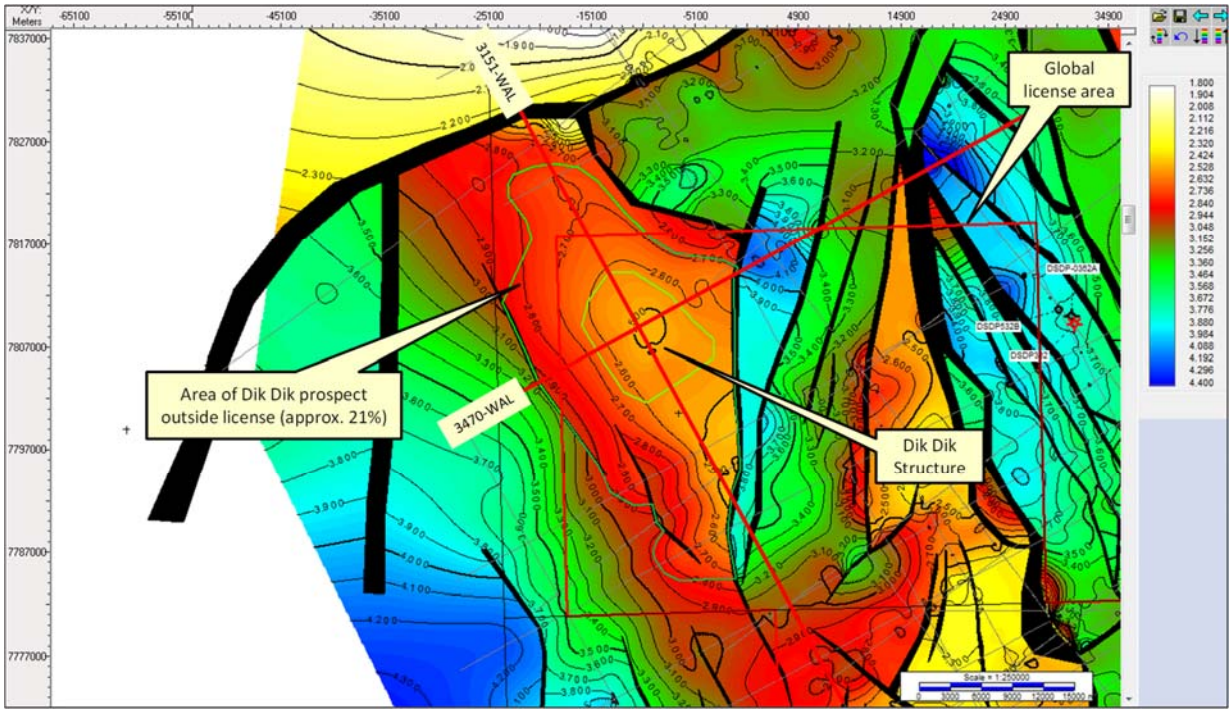

Figure 3.13: Dik Dik prospect AlboAptian TWT map

The depth conversion has used the same intervals and velocities as for the other prospects and the resulting depth map is shown in Figure 3.14.

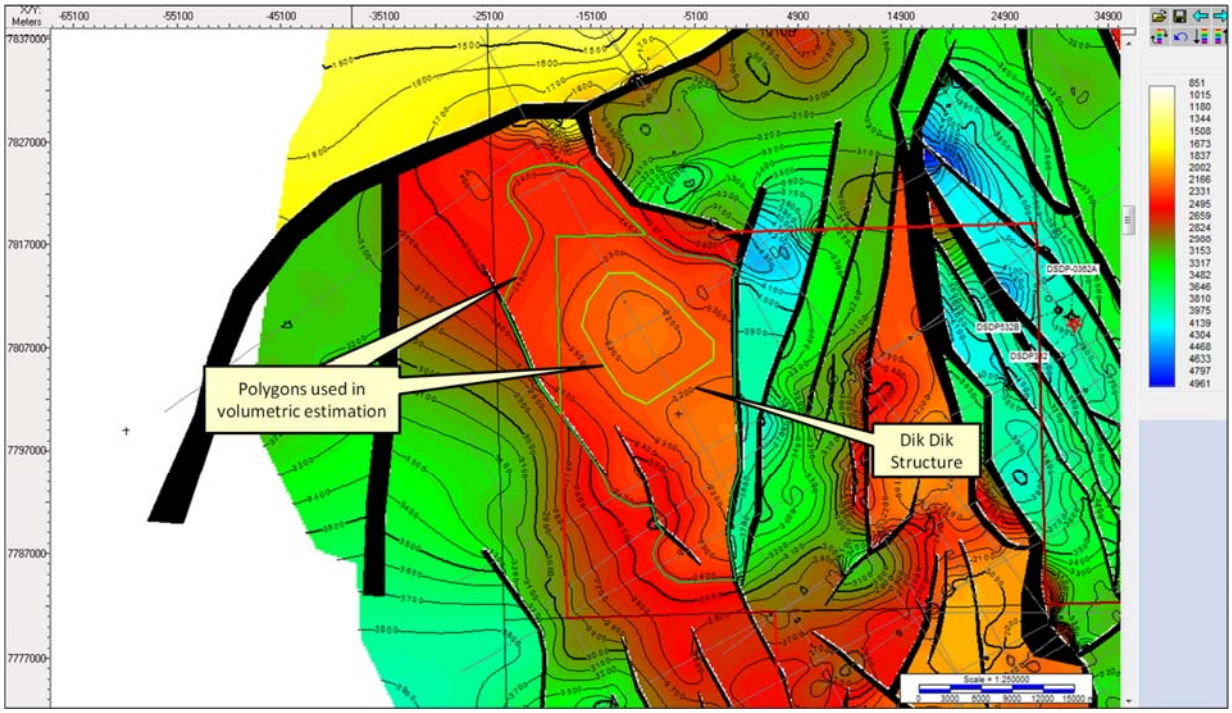

Figure 3.14: Lion prospect AlboAptian Depth structure map

Since the Dik Dik structure is currently undrilled it is considered a prospect and as such carries a geological risk.

The Probability of Success (POS) for the Dik Dik prospect was estimated using a combination of the probability of hydrocarbon charge, seal, reservoir and trap.

The Dik Dik prospect is subject to the same risk on source as the other carbonate prospects.

The seal is considered a low risk as there are shales seen on the offset wells although there is less overburden at this location and deep seabed channels and faulting may compromise the seal. Reservoir presence and effectiveness are considered to be a similar risk to the other carbonate reservoirs.

The trap risk is slightly higher for Dik Dik as there are fewer 2D seismic lines available to define the structure.

The parameters and overall probability of success estimated for the Dik Dik prospect are summarised in Table 3.6:

Parameter	POS	Comments
Source	0.50	Uncertainty on source presence and effectiveness.
Seal	0.50	Some risk as there is less overburden and seabed channels and faulting may compromise the seal.
Reservoir	0.50	Concern with presence and effectiveness.
Trap	0.40	Slightly higher risk due to less seismic coverage.
Overall	0.05	5% Chance of Success (or approximately 1 in 20)

Table 3.6: Dik Dik prospect Probability of Success

3.3.4 Choje Lead

As well as the prospects described above, Global are currently working up other opportunities in the licence area one of which is Choje. Choje is a Late Cretaceous deep water sandstone lead located between the Gemsbok prospect and the Welwitschia structure (see Figure 3.3 with locations above). It consists of a series of seismic reflectors onlapping and pinching out onto the edge of the Gemsbok high. The seismic character changes from linear reflectors to a more chaotic appearance which is potentially indicating a change in facies. This can be seen on a number of the lines that define the lead (for example Figure 3.15).

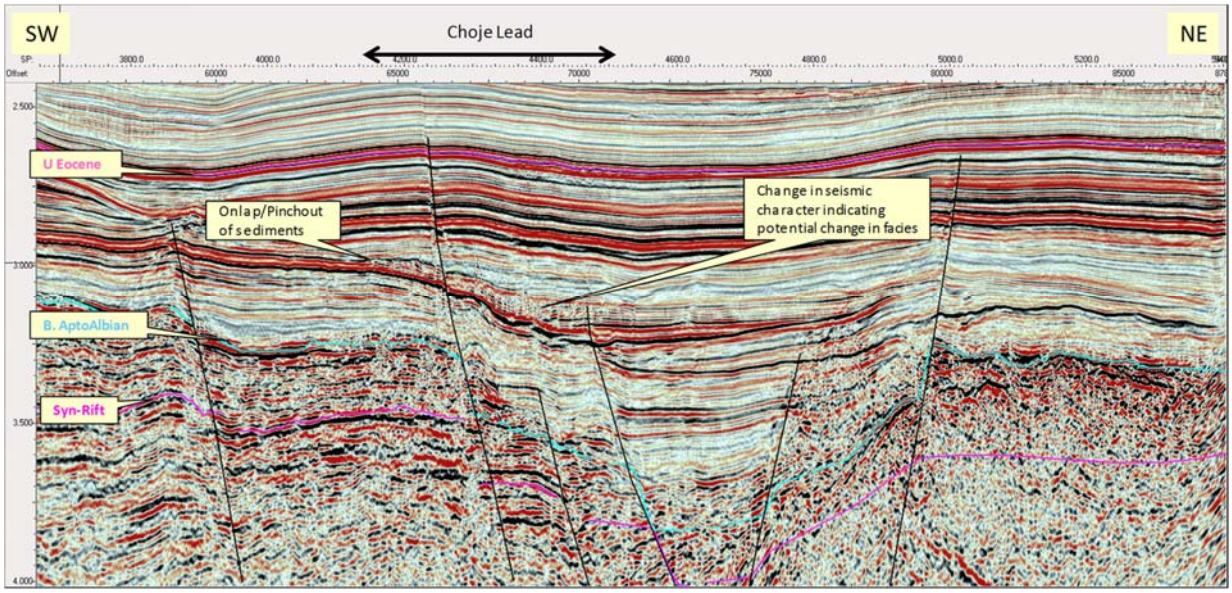

Figure 3.15: Line GP17-05 showing Choje lead
(for line location see Figure 3.16)

Global have not provided a digital interpretation for this lead but it was mapped by Xodus in 2014 and the resulting TWT and isochron maps were provided in hard copy. No depth map was provided. The Xodus interpretation was carried out prior to the acquisition of the new 2D data so some updating of their maps is required.

The TWT map is shown in Figure 3.16 and the hashed area is considered to be the potential area for volumetric estimation. The volumetric method and results are summarised in Section 5 below.

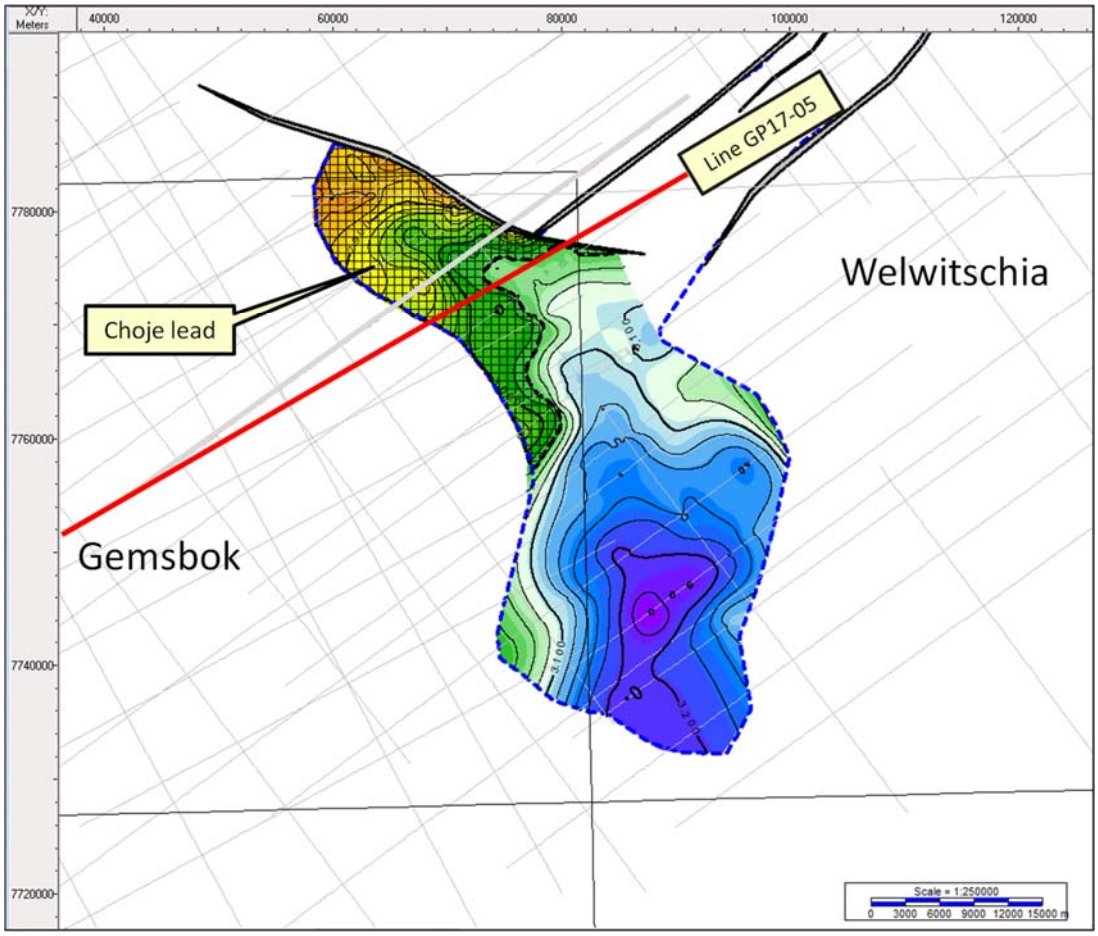

Figure 3.16: Choje lead TWT map
(Source: Global Petroleum from Xodus 2014 report)

Since the Choje lead is currently undrilled and there is further work required to firm it up as a prospect it is considered a lead and as such carries a geological risk.

The Probability of Success (POS) for the Choje lead was estimated using a combination of the probability of hydrocarbon charge, seal, reservoir and trap.

The source is assumed to have the same risk as for the prospects. The seal is considered a low risk as there are significant shales seen on the offset wells.

Reservoir presence and effectiveness are considered to have some risk as there have been no penetrations of this reservoir type in the area.

Trap is also considered to have some risk as Choje is a stratigraphic play which increases the uncertainty in mapping the extent of the structure and the integrity of the trap.

The parameters and overall probability of success estimated for the Choje lead are summarised in Table 3.7:

Parameter	POS	Comments
Source	0.50	Similar risk to prospects.
Seal	0.70	Shales are expected to be present to create the seal.
Reservoir	0.40	Uncertainty on reservoir presence and effectiveness.
Trap	0.50	Increased risk due to stratigraphic trapping.
Overall	0.07	7% Chance of Success (or approximately 1 in 14.3)

Table 3.7: Choje lead Probability of Success

3.3.5 Pangolin Lead

The Pangolin lead is another feature that has been identified on a number of lines but requires further work to establish it as a prospect. This lead is located approximately 30km to the south of the Lion prospect and is thought to be a Late Albian – Cenomanian reefal build up. Figure 3.17 shows a line through this feature which can be traced over a number of lines.

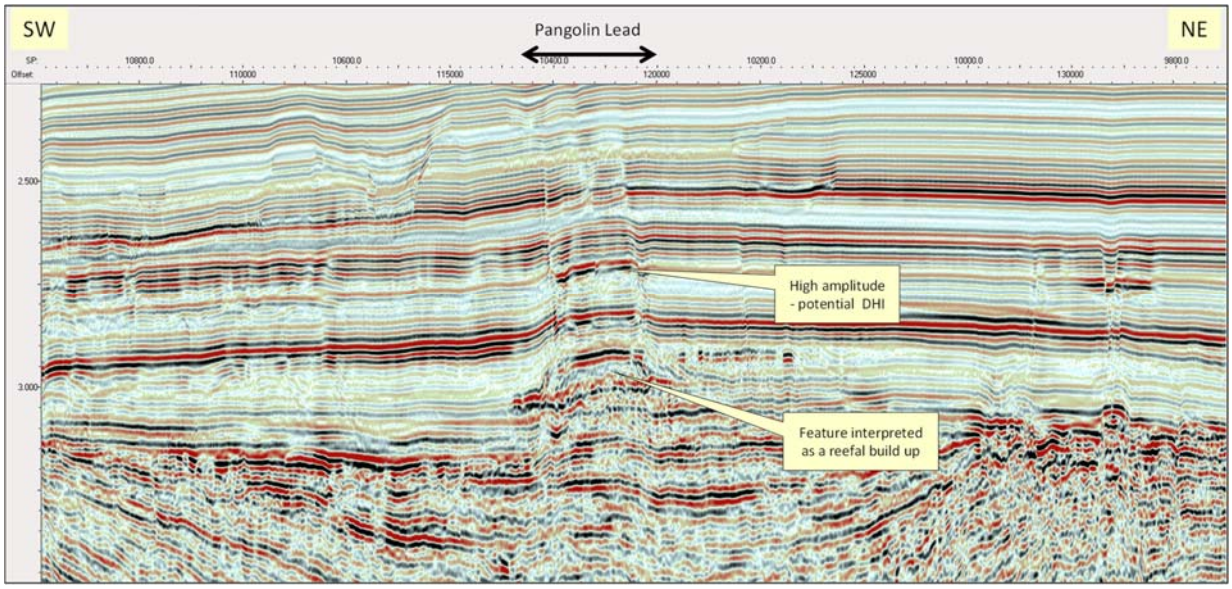

Figure 3.17: Line 3370-WAL showing Pangolin lead

No maps have been provided for this lead in either TWT or depth so it has not been possible to fully assess the extent of this structure. Further work is required to establish the geometry and structural configuration of this lead.

It should be noted that the Pangolin lead is one of a number of similar features that have been identified on the 2D seismic data and if this were to prove successful the other structures could also be of interest. These have not yet been mapped in any detail and require further interpretation to fully understand their extent.

Since the Pangolin lead is currently undrilled and there is further work required to firm it up as a prospect it is considered a lead and as such carries a geological risk.

The Probability of Success (POS) for the Pangolin lead was estimated using a combination of the probability of hydrocarbon charge, seal, reservoir and trap.

The source is assumed to have the same risk as for the prospects.

The seal is considered to have some risk as it is likely to require a stratigraphic element.

Reservoir presence and effectiveness are considered to have some risk as there have been no penetrations of this reservoir type in the area.

Trap is also considered to have some risk as only a few 2D seismic lines define the trap and with additional data the size and shape of the trap are likely to change.

The parameters and overall probability of success estimated for the Pangolin lead are summarised in Table 3.7:

Parameter	POS	Comments
Source	0.50	Similar risk to prospects.
Seal	0.50	Sealing mechanism is uncertain.
Reservoir	0.50	Uncertainty on reservoir presence and effectiveness.
Trap	0.40	Increased risk due to limited data.
Overall	0.05	5% Chance of Success (or approximately 1 in 20)

Table 3.8: Pangolin lead Probability of Success

4 Petrophysics

The petrophysical input to this CPR is to provide information from offset wells as a guide to possible properties in the Global Petroleum licence area. There are currently no wells on the licence itself.

4.1 Data

Data sets were provided for five wells in total, four of which penetrate the Albian Limestone which is the main target of the prospects in the Global Petroleum licence (Table 4.1).

Well	Well name	Comment	Spud Date	Deviation Survey	TD (m)	Formation at TD
1911/10-1	1911/10-1	Nearest offset wells	28/03/1995	Near Vertical	4185.0	W-1 Volcanics
1911/15-1	1911/15-1	Nearest offset wells	04/11/1993	Near Vertical	4586.0	Volcanics
1811/5-1	Tapir South-1	Further to North	05/04/2012	Yes - from Composite Log	4998.0	Volcanics
2011/2-1A	Welwitschia-1	Closest well - did not reach Albian	01/05/2014	Near Vertical	2450.9	Maastrichtian
2212A/07-1	Wingat-1	Furthest offset well (to South)	25/03/2013	Near Vertical	5000.0	Kudu Shale

Table 4.1: Well data supplied

The nearest wells (1911/10-1 and 1911/15-1) had the most complete data set which included well reports and petrophysical reports.

Formation tops were gathered from well reports and previous work was taken as a guide for the reservoir intervals. Some wells were confirmed as being vertical by the MD and TVDSS depths on the Composite Logs. The Tapir South well was the only well indicated to be non-vertical and a deviation survey was included on the Composite Log.

Core was cut in the two closest wells and digital core analysis was provided for 1911/15-1.

4.2 Log Analysis

Log analysis had already been carried out on the two closest wells and the interpretation input parameters were gathered from the accompanying petrophysical reports. The digital interpretation logs were not supplied but it was possible to reproduce the interpretation using the petrophysical report as a starting point. The input parameters were robust and the reservoir properties from the log analysis are close to those quoted in the reports.

4.2.1 Methodology

All of the available well data was loaded into LR's Interactive Petrophysics (IP).

Clay Volume (Vcl) was calculated using a combination of the Gamma Ray Log and the Neutron/Density and cross-plot. Vcl from both methods was very similar and the minimum Vcl was taken as input for porosity (Phi) and water saturation (Sw) calculations.

Porosity was calculated using the Neutron/Density cross-plot where both logs were available or the Density log where necessary.

Water Saturation was calculated using the Indonesia equation (the Archie equation in clean formations with clay corrections applied elsewhere).

$$Sw = \sqrt[n]{\frac{a \times Rw}{Phi^m \times Rt}}$$

Rt = Deep Resistivity

Ø = porosity (decimal)

a = 1

m = 2 (cementation exponent from Archie equation)

n = 2 (saturation exponent from Archie equation)

Rw = water resistivity (ohmm)

The wells are all water bearing with no indications of hydrocarbons recorded.

4.2.2 Results

Log analysis was run in all four wells which penetrated the Albian Limestone. The results are displayed for 1911/10-1 in Figure 4.1 illustrating that generally the better quality reservoir with good porosity is in the upper part of the interval. This is even more evident in 1911/15-1 where the upper 100m is of much better quality than the rest of the interval (Figure 4.2). These intervals have been treated separately and in combination for average property calculations.

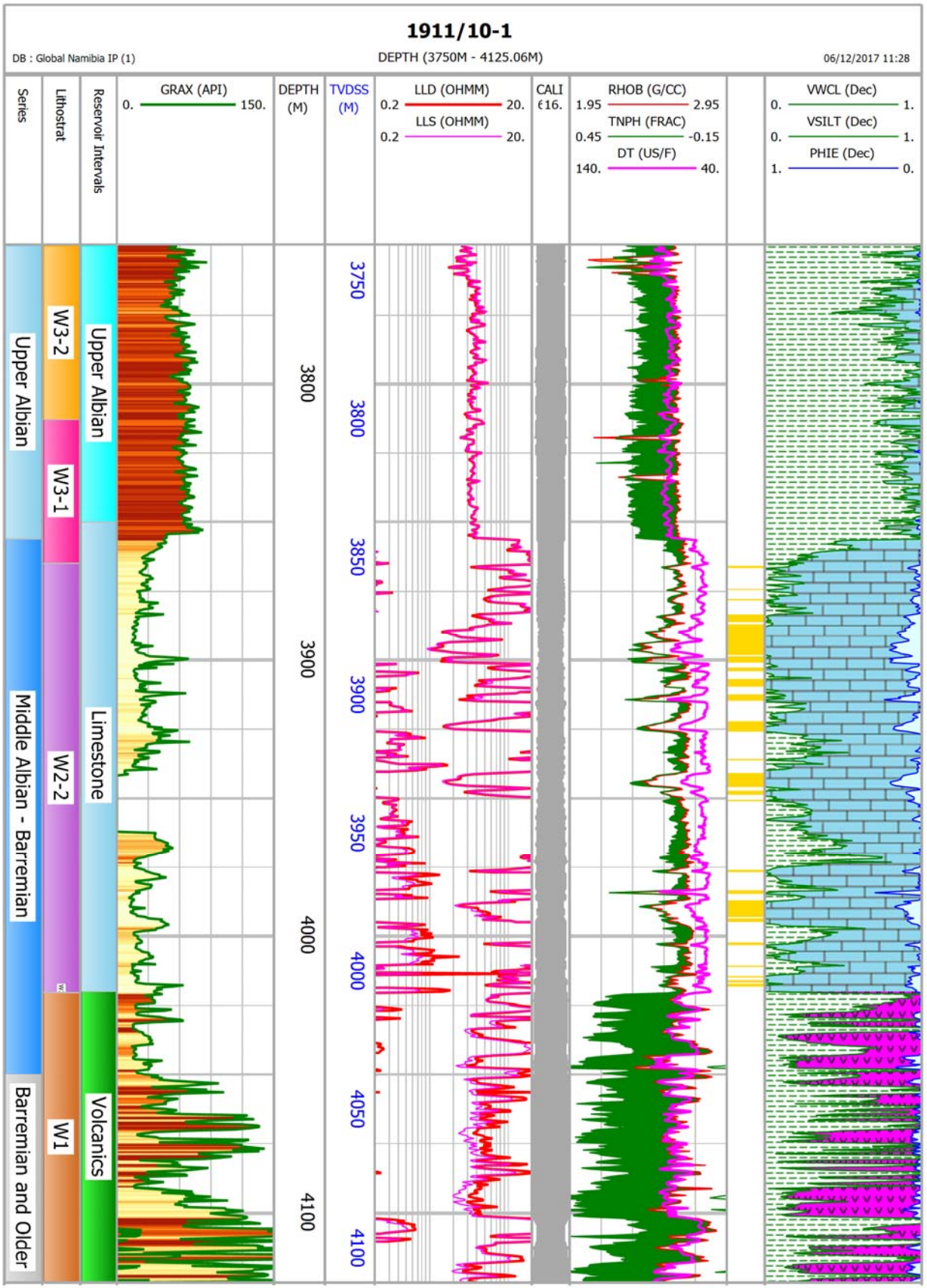

Figure 4.1: Logs and CPI for well 1911/10-1

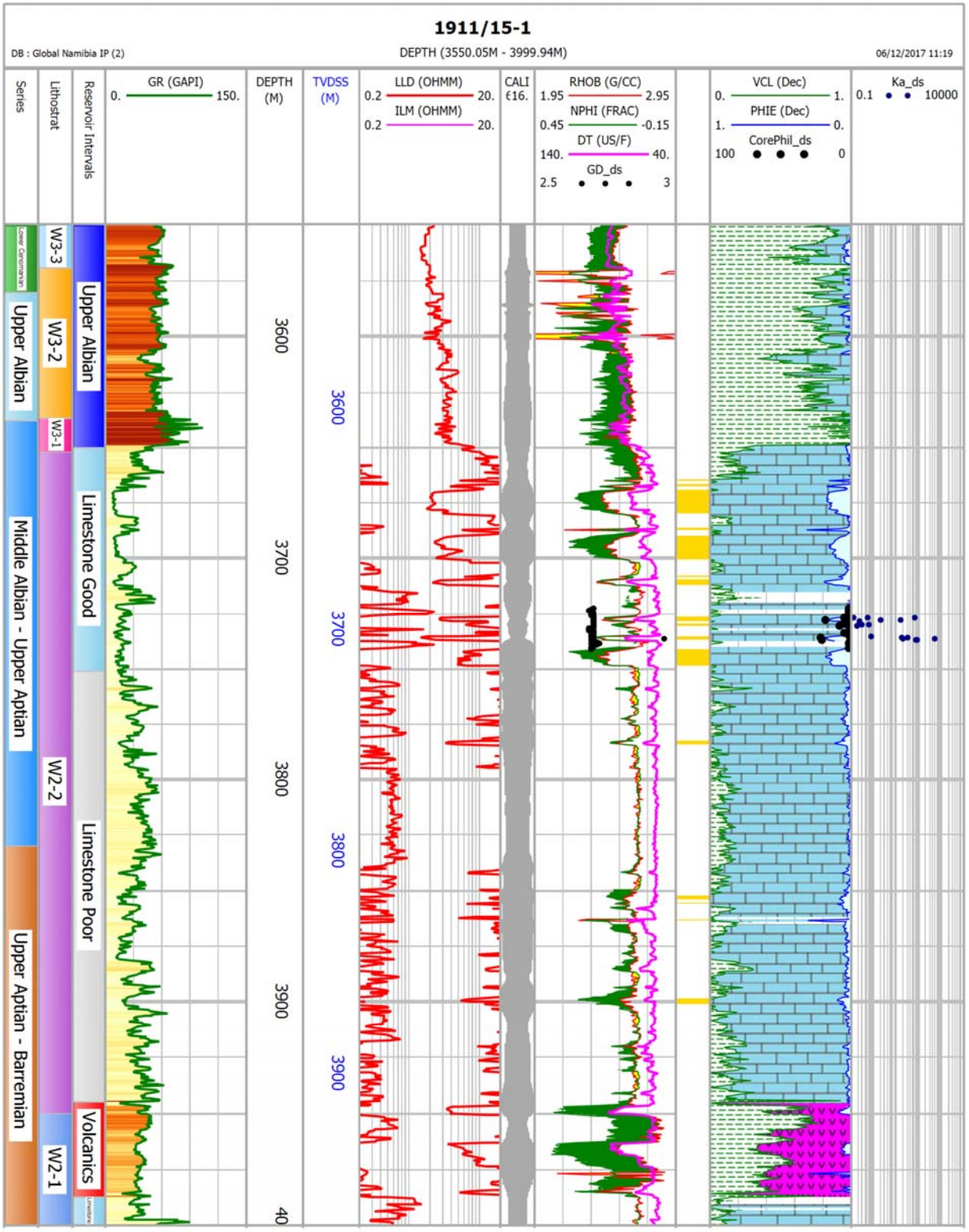

Figure 4.2: Logs and CPI for 1911/15-1

Well Tapir South-1 which is farther away to the north encounters a thinner section of the limestone reservoir but still contains a similar cumulative amount of net reservoir as the two 1911 wells (Figure 4.3).

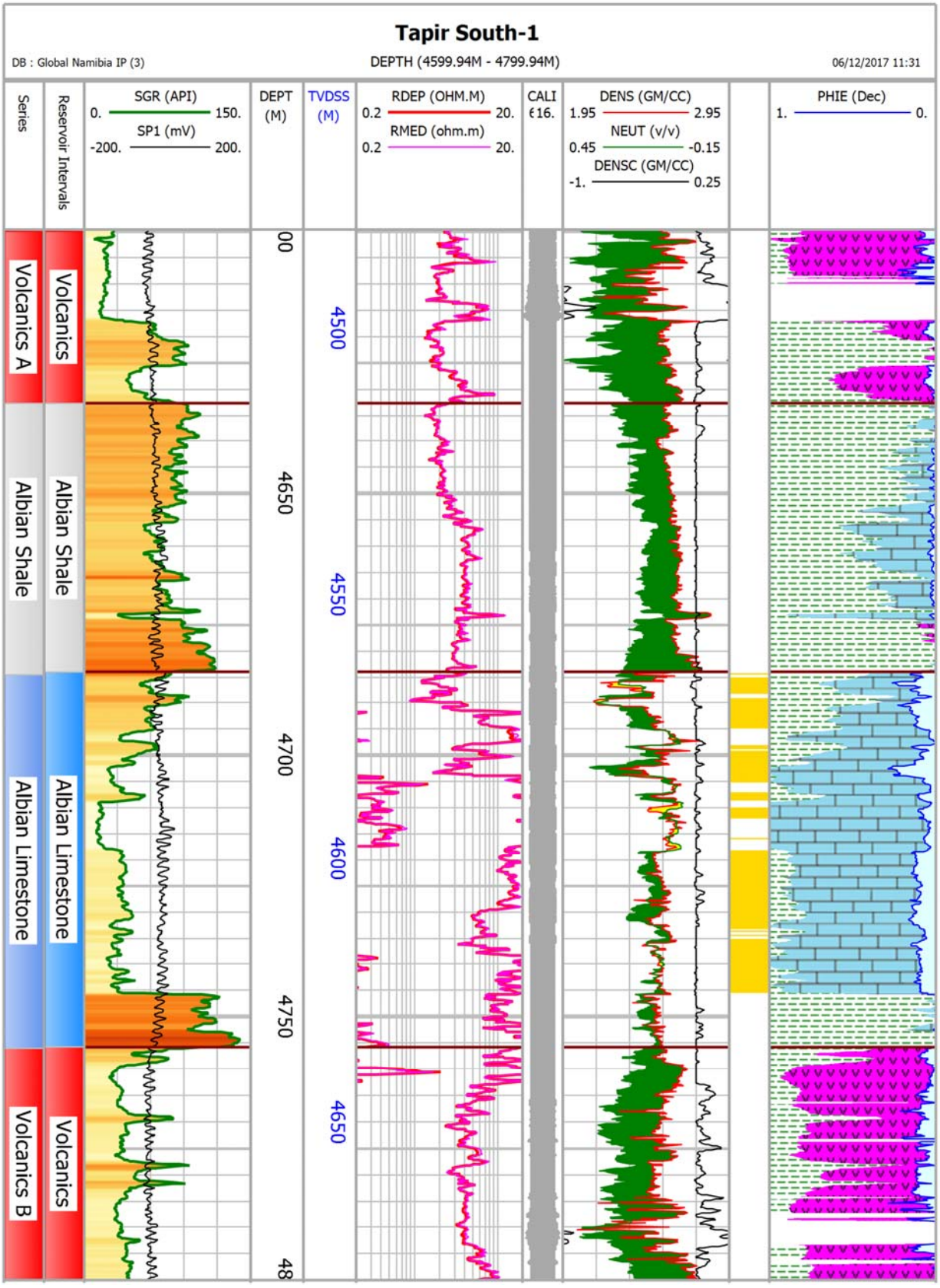

Figure 4.3 Logs and CPI for Tapir South-1

The average properties were calculated using the cut-offs as previously used for the two nearest wells:

Vsh <= 0.5

PHIE >= 0.07

Well	Zone Name	Units	Top MD	Bottom MD	Top TVDSS	Bottom TVDSS	Gross TVDSS	Net TVDSS	N/G TVDSS	Av Phi
Tapir South-1	Albian Limestone	m	4684.00	4746.00	4564.63	4626.00	61.38	45.96	0.75	0.12
1911/10-1	Limestone	m	3850.00	4020.00	3836.98	4007.06	170.00	48.16	0.28	0.12
1911/15-1	Limestone_Good	m	3650.00	3751.38	3618.03	3719.37	101.38	39.47	0.39	0.14
1911/15-1	Limestone_Poor	m	3751.38	3945.00	3719.37	3913.08	193.62	7.62	0.04	0.10
1911/15-1	Good & Poor	m	3650.00	3945.00	3618.03	3913.08	295.00	47.09	0.16	0.13
Wingat-1	Limestone	m	4036.73	4095.94	4009.63	4068.84	59.21	0.46	0.01	0.07

Table 4.2: Average properties for Albian Limestone reservoir in regional wells

Table 4.2 shows that the average porosity is quite consistent in all wells which are relatively close to the prospective area. The Wingat-1 well is the furthest away to the south and has very little net. The nearer wells have 45m to 50m of net in the reservoir interval with 12% to 14% porosity.

5 In-Place Volumetric Estimates

To estimate the In-Place hydrocarbon volumes for each of the prospects, Gross Rock Volumes (GRVs) were calculated from Kingdom and input to the Monte Carlo simulation using Crystal Ball. These were combined with ranges of reservoir properties resulting in a range of Stock Tank Oil Initially In Place (STOIIP) estimations. The following sections provide a summary of the inputs and results for the prospects and leads.

5.1 Prospects

5.1.1 Gemsbok Main

Gross Rock Volumes (GRVs) were extracted from Kingdom and a range was established based on different assumptions for the reservoir thickness and potential closures. For the Gemsbok Main prospect the thickness range used was 60 – 100 – 290m. This accounts for the thicknesses seen in Tapir South (approximately 60m), the upper good section of the 1911/15-1 well (approximately 100m) and the entire section of the 1911/15-1 well (approximately 290m). In order to more accurately assign the N/G, an inverse correlation was applied. This is because the thinner Tapir South well section exhibits higher N/G and the total 1911/15-1 thickness has much lower N/G.

Two contours were used to define the potential closure; 2800m which represents a separate closure against the western bounding fault and 2875m which represents a closure of approximately a third of the total potential closure. The shallow contour was combined with the minimum thickness to produce the low case. The mid and maximum thicknesses were combined with the deeper contact to derive the mid and high case GRVs.

Global have used the deeper closure for all their cases but there is the possibility that the independent closure may represent the structure so it was decided to use this for the low case. The maximum closing contour has not been used for the high case as it is considered unlikely that such a thick hydrocarbon column could be sustained. The current high case contour is considered a reasonable scenario for defining the range of prospective resources.

The polygons that represent the two contour scenarios are shown on the depth map in Figure 3.6 above in Section 3

The range of input parameters are based on regional analogues and well data where available.

The resulting range of inputs to the Monte Carlo analysis are shown in Table 5.1.

Reservoir	GRV (MMm3)#			NTG (Frac)#			Porosity (Frac)			Sw (Frac)			FVF		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Gemsbok Main	11700	23575	35600	0.15	0.40	0.75	0.10	0.12	0.18	0.20	0.30	0.40	1.10	1.32	1.72

Table 5.1: Gemsbok Main prospect property ranges

#Note: An inverse correlation between N/G and GRV has been applied

Using the input ranges shown in Table 5.1 the following Stock Tank Oil Initially In Place (STOIIP) ranges were estimated.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Gemsbok Main	2121	3636	5162	3644

Table 5.2: Gemsbok Main Unrisked STOIIP

5.1.2 Gemsbok Barremian

Global have proposed that in addition to a carbonate reservoir at Gemsbok, there could also be Kudu type reservoirs present. There are two potential reservoirs that could be present; an aeolian sand and/or a marine sand. In terms of reservoir quality, the aeolian sand is likely to be better than the marine sand. Two scenarios have therefore been analysed.

To estimate the GRVs for the aeolian sand option, a range of thicknesses were used; 30 – 55 – 80m. In addition, three different closing contours were used; 2720m, 2750m and 2800m. These correspond to areas of approximately 40km^2, 100km^2 and 200km^2. These are considered reasonable parameters to represent the aeolian scenario based on analogues.

For the marine sands, the range of thicknesses used was 30 - 65 - 100m. The corresponding contour value used was 2875m. It should be noted that the marine sand is likely to be a poor reservoir based on analogues and may not be commercially viable.

Input reservoir property ranges were based on analogues and well data where available, and the resulting ranges are shown in Table 5.3 below.

Reservoir	GRV (MMm3)			NTG (Frac)			Porosity (Frac)			Sw (Frac)			FVF		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Gemsbok Aeolian	740	2600	9100	0.60	0.75	0.90	0.10	0.14	0.18	0.14	0.24	0.34	1.10	1.32	1.72
Gemsbok Marine	13500	25680	33520	0.15	0.25	0.35	0.05	0.10	0.15	0.20	0.35	0.50	1.10	1.32	1.72

Table 5.3: Gemsbok 'Kudu' prospect property ranges

Using the input ranges shown in Table 5.3 the following Stock Tank Oil Initially In Place (STOIIP) ranges were estimated.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Gemsbok Aeolian	328	943	2592	1284
Gemsbok Marine	627	1617	3150	1783

Table 5.4: Gemsbok 'Kudu' Unrisked STOIIP

5.1.3 Lion

The Lion prospect is potentially split into two separate structures so volumes have been estimated for the North and South closures and also a total closure.

For the Lion North prospect, Gross Rock Volumes (GRVs) were extracted from Kingdom and a range was established based on different reservoir thicknesses and potential closures. The thickness range used was 60 – 100 – 290m. As with the Gemsbok prospect these thicknesses relate to the offset well data and a similar inverse relationship between the GRV and N/G was applied.

Two contours were used to define the potential closure; 2100m which represents a four-way dip closure and 2275m which represents a closure down to the saddle with the southern culmination.

The shallow contour was combined with the minimum thickness to produce the low case. The mid and maximum thicknesses were combined with the deeper contact to derive the mid and high case GRVs.

For the Lion South prospect, the same thickness range was used. The low case contour used was 2000m which represents the four-way dip closure for this structure. The mid and high cases used the 2275m contour which corresponds to the depth of the saddle between the North and South closures.

The polygons that represent these scenarios are shown on the depth map in Figure 3.11 above in Section 3

The range of input parameters are based on regional analogues and well data where available.

The resulting range of inputs to the Monte Carlo analysis are shown in Table 5.5.

Reservoir	GRV (MMm3)#			NTG (Frac)#			Porosity (Frac)			Sw (Frac)			FVF		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Lion North	3878	7312	10776	0.15	0.40	0.75	0.10	0.12	0.18	0.20	0.30	0.40	1.07	1.28	1.67
Lion South	10467	20861	31405	0.15	0.40	0.75	0.10	0.12	0.18	0.20	0.30	0.40	1.07	1.28	1.67

Table 5.5: Lion prospect property ranges

#Note: An inverse correlation between N/G and GRV has been applied

Using the input ranges shown in Table 5.5 the following Stock Tank Oil Initially In Place (STOIIP) ranges were estimated.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Lion North	693	1164	1651	1168
Lion South	1934	3294	4677	3311
Lion Total*	2627	4458	6328	4479

Table 5.6: Lion prospect Unrisked STOIIP

*Note: Totals are arithmetic summations

5.1.4 Dik Dik

For the Dik Dik prospect the range of GRVs were extracted from Kingdom using different contour values and thicknesses. The thickness range used was 60 – 100 – 290m. The thicknesses are based on the offset well data and as with the other carbonate prospects, an inverse correlation between the GRV and N/G was applied.

Three contours were used to define the potential closure; 2230m which represents a four-way dip closure and gives the low case, 2400m which represents the closure against the southeasterly bounding fault and gives the high case. The mid case uses 2300m which approximates to a half full structure.

The shallow contour was combined with the minimum thickness to produce the low case GRV. The mid thickness and mid contour were combined and the maximum thickness was combined with the deeper contact to derive the mid and high case GRVs.

The polygons that represent the different scenarios are shown on the depth map in Figure 3.14 above in Section 3

The range of input parameters are based on regional analogues and well data where available.

The resulting range of inputs to the Monte Carlo analysis are shown in Table 5.7.

Reservoir	GRV (MMm3)#			NTG (Frac)#			Porosity (Frac)			Sw (Frac)			FVF		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Dik Dik	6079	18451	56000	0.15	0.40	0.75	0.10	0.12	0.18	0.20	0.30	0.40	1.07	1.28	1.67

Table 5.7: Dik Dik prospect property ranges

#Note: An inverse correlation between N/G and GRV has been applied

Using the input ranges shown in Table 5.7 the following Stock Tank Oil Initially In Place (STOIIP) ranges were estimated. Note that approximately 21% of the prospect falls outside the licence area. The STOIIP range below is for the whole prospect so the on block volumes will therefore be smaller than the figures quoted.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Dik Dik	1492	3222	5538	3395

Table 5.8: Dik Dik Unrisked STOIIP

5.2 Leads

Global have identified two leads for which volumes have been estimated. The following sections summarise the inputs for the volumetrics.

5.2.1 Choje

Global did not provide any depth maps for the Choje lead so the GRVs were calculated using an area and a net sand thickness. The net thickness range used by Global was 15 – 25 – 35 m and the areas were 100 – 160 and 226 km^2. AGR TRACS have taken these numbers as provided as it is not possible to make an independent assessment based on the limited data provided. The resulting GRV and property ranges are provided in Table 5.9 below. The property ranges are those used by Global.

Reservoir	GRV (MMm3)			NTG (Frac)			Porosity (Frac)			Sw (Frac)			FVF		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Choje	750	4000	7910	0.90	0.95	1.00	0.14	0.19	0.24	0.19	0.28	0.40	1.08	1.29	1.69

Table 5.9: Choje lead property ranges

Using the input ranges shown in Table 5.9 the following Stock Tank Oil Initially In Place (STOIIP) ranges were estimated from Monte Carlo.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Choje	1210	2402	4002	2531

Table 5.10: Choje Unrisked STOIIP

5.2.2 Pangolin

Depth maps have not been provided for the Pangolin lead. Glogal have estimated the volumes by assuming an area of 20 km^2 and a thickness of 125m together with a shape factor of 0.65. The GRV range was derived by assuming different proportions of charge (25 – 50 – 75%). The resulting GRVs used by Global are shown in Table 5.11 below. The property ranges are those provided by Global.

Reservoir	GRV (MMm3)			NTG (Frac)			Porosity (Frac)			Sw (Frac)			FVF		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Pangolin	406	813	1219	0.20	0.40	0.60	0.14	0.18	0.22	0.22	0.30	0.40	1.10	1.32	1.72

Table 5.11: Pangolin lead property ranges

Using the input ranges shown in Table 5.11 the following Stock Tank Oil Initially In Place (STOIIP) ranges were estimated from Monte Carlo.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Pangolin	82	175	309	188

Table 5.12: Pangolin Unrisked STOIIP

5.3 STOIIP Summary

The following table (Table 5.13) provides a summary of the STOIIP estimates for the prospects.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Gemsbok Main	2121	3636	5162	3644
Gemsbok Aeolian	328	943	2592	1284
Gemsbok marine	627	1617	3150	1783
Lion North	693	1164	1651	1168
Lion South	1934	3294	4677	3311
Dik Dik	1492	3222	5538	3395
TOTAL*	**7195**	**13876**	**22770**	**14585**

Table 5.13: Prospect Unrisked STOIIP Summary

* Note: Totals are arithmetic summations.

The following table (Table 5.14) provides a summary of the STOIIP estimates for the leads.

Reservoir	STOIIP (MMbls)			
	P90	P50	P10	Mean
Choje	1210	2402	4002	2531
Pangolin	82	175	309	188
TOTAL*	**1292**	**2577**	**4311**	**2719**

Table 5.14: Lead Unrisked STOIIP Summary

* Note: Totals are arithmetic summations.

6 Reservoir Engineering

AGR TRACS has reviewed the Information Memorandum in respect of Formation Volume Factors and Recovery Factors.

6.1 Formation Volume Factors

6.1.1 Introduction

GOR is a significant factor in calculating formation volume factor using correlations. Global suggest a broad range of 200-700-1500 scf/bbl, and in the absence of further defining data, this seems a large, though reasonable range, to cover the uncertainty at the exploration stage.

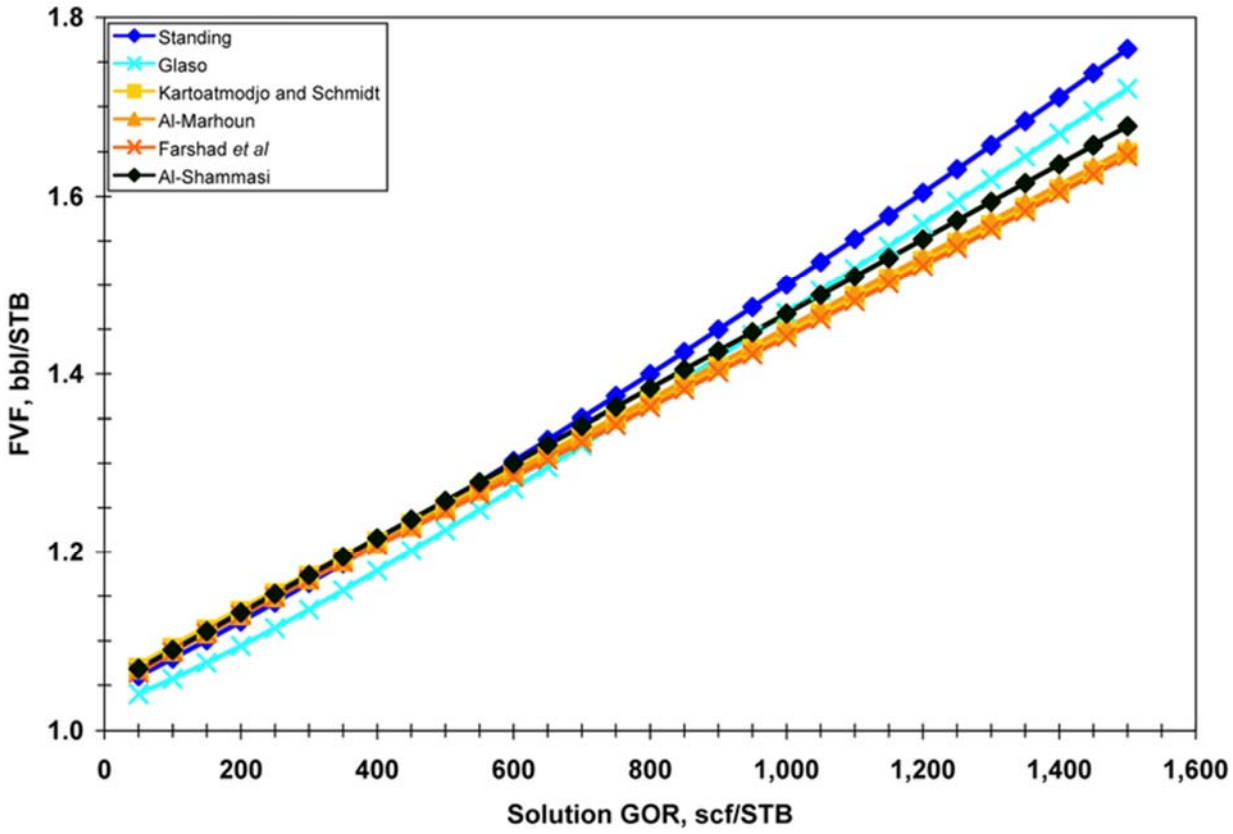

Figure 6.1: Oil Formation Volume Factor Correlations
(Source: http://petrowiki.org/Oil_formation_volume_factor)

Figure 6.1 shows the variation of FVF with GOR using various correlations. Three major correlations (Standing, Glaso, & Al-Marhoun; Ref. [1, 2, and 3]) have been used to check the formation volume factors supplied.

6.1.2 Prospects

Gemsbok Main

Global have suggested a medium gravity oil of 30 deg API. Assuming a temperature of 118 deg F (based on a temperature gradient of 35 deg C/km from a surface temperature of 4 deg C) and a mid-range gas gravity of 0.7, Table 1.1 shows that the range supplied by Global is consistent with the Standing, Glaso, & Al-Marhoun correlations.

GOR	200 scf/stb	700 scf/stb	1425 scf/stb	1500 scf/stb
GLOBAL	**1.10**	**1.32**		**1.67**
Standing	1.104	1.336	1.716	
Glaso	1.082	1.310		1.720
Al-Marhoun	1.105	1.310		1.630

Table 6.1: Gemsbok Main prospect - Formation Volume Factor Correlations
(Source: http://www.petroleumoffice.com/functions)

Gemsbok Kudu (Aeolian and Marine)

The fluid property range for Gemsbok Kudu (Aeolian and Marine) prospects have been assumed to be the same as Gemsbok Main.

Lion

Global have suggested a medium-heavy oil gravity of 25 deg API, using the assumption that the Lion prospect is slightly shallower than at Gemsbok, and therefore one would expect a slightly heavier oil. Assuming a temperature of 81 deg F (based on a temperature gradient of 35 deg C/km from a surface temperature of 4 deg C) and a mid-range gas gravity of 0.7, Table 6.2 shows that the range supplied by Global is consistent with the Standing, Glaso, & Al-Marhoun correlations.

GOR	200 scf/stb	700 scf/stb	1425 scf/stb	1500 scf/stb
GLOBAL	**1.07**	**1.28**		**1.67**
Standing	1.092	1.318	1.690	
Glaso	1.066	1.285		1.686
Al-Marhoun	1.069	1.264		1.567*

Table 6.2: Lion prospect - Formation Volume Factor Correlations
(Source: http://www.petroleumoffice.com/functions)

*Note: The gas gravity (Sg) has been adjusted slightly to be within the valid range for these correlations, however as explained above the dominant factor in FVF correlations is the GOR.

Dik Dik

The fluid properties at Dik Dik are the same as those assumed at Lion. Global have suggested a medium-heavy oil gravity of 25 deg API, using the assumption that the Dik Dik prospect is slightly shallower than at Gemsbok, and therefore one would expect a slightly heavier oil. Assuming a temperature of 81 deg F (based on a temperature gradient of 35 deg C/km from a surface temperature of 4 deg C) and a mid-range gas gravity of 0.7 Table 6.3 shows that the range supplied by Global is consistent with the Standing, Glaso, & Al-Marhoun correlations.

GOR	200 scf/stb	700 scf/stb	1425 scf/stb	1500 scf/stb
GLOBAL	**1.07**	**1.28**		**1.67**
Standing	1.092*	1.318*	1.690*	
Glaso	1.066	1.285		1.686
Al-Marhoun	1.069	1.264		1.567*

Table 6.3: Dik Dik prospect - Formation Volume Factor Correlations
(Source: http://www.petroleumoffice.com/functions)

*Note: The temperature and Sg have been adjusted slightly to be within the valid range for these correlations, however as explained above the dominant factor in FVF correlations is the GOR.

6.1.3 Leads

Choje

The formation volume factor range supplied by Global for the Choje Lead is 1.08 (200 scf/stb) – 1.29 (700 scf/stb) – 1.69 (1500 scf/stb) for the low-mid-high cases, and these are consistent with the calculations performed above. The slight increase from the Lion and Dik Dik values are due to a slightly higher temperature (34 deg C vs. 27 deg C).

Pangolin

The same values have been used as at Gemsbok Main (Aptian Carbonate) prospect. This is assuming the same types of oil, GORs, pressures (1.25sg overpressure) and temperatures.

6.2 Recovery Factors

6.2.1 Introduction

Global's Namibia prospects are located in a new, under-explored region and therefore do not have nearby fields that can be used as analogues. Aside from the size, depth, expected thickness and the more general issues surrounding carbonate fields, there is little data available to help narrow the likely expected recoveries and therefore a more generic (top-down) approach has been taken.

The average recovery factor for oil fields worldwide is 35% and the average recovery of carbonate fields is 30%. There are some other more general factors that have been taken into account to come up with the recovery factors used here in the AGR-TRACS evaluation.

Size

Although the structures here are not of the same order of magnitude as some of giant Middle Eastern fields, size still plays an important role, as multi-billion barrel fields, afford an economy of scale, especially in respect of facilities costs. There is also the possibility of achieving commercial rates at a much lower percentage of ultimate recovery produced per year, which allows a higher recovery factor to be achieved.

Thickness

The reservoir thicknesses found here are relatively thin and therefore this will impact on recovery. In the Gemsbok prospect, for example, the net reservoir of around 30m is distributed in some 170m. There are many competing factors when it comes to recovery. For example, the vertical baffles reducing overall vertical permeability (Kv) could be beneficial in a scenario where there are vertical fractures and force an edge drive mechanism and prevent early water breakthrough from below.

Fractures

One of the challenges with carbonate reservoirs and how to develop them is the type of fracturing present. One of the nearby wells shows very low signs of fracturing, though is 100km away. These so-called Type I reservoirs (little matrix porosity and permeability) have very low fracture density; however, this also results in low permeability and potentially productivity issues. Ideally, carbonate reservoirs have enough fracturing to enhance permeability, but not so much as to promote early water breakthrough through large connected fracture channels. Given that the seismic is sparse, it is not clear as to what the degree of intra-field faulting and fracturing at smaller scales might be.

Broadly speaking four categories of fractured carbonate reservoirs are recognised in the technical literature:

- Type I reservoirs have little matrix porosity and permeability, thus fractures provide both storage capacity and fluid-flow pathways.
- Type II reservoirs have low matrix porosity and permeability. Matrix porosity provides some storage capacity and fractures provide the fluid-flow pathways.
- Type III (microporous) reservoirs have high matrix porosity and low matrix permeability. Matrix provides the storage capacity and fractures provide the fluid-flow pathways.
- Type IV (macro-porous) reservoirs have high matrix porosity and permeability, thus matrix porosity provides both storage capacity and fluid-flow pathways, while fractures merely enhance permeability.

Drive Mechanism

One of the biggest challenges with developing carbonate reservoirs is selecting the appropriate reservoir development strategy. There are many examples of unsuccessful developments, especially in Type II (low matrix porosity and permeability) & Type III (high matrix porosity and low matrix permeability) reservoirs likely due to not having a good enough characterisation of fracture density and distribution, early enough in the life of field. Water injection can be used as an energy source for the reservoir, and success has been achieved elsewhere with gas injection as a further recovery mechanism

Offshore

The Namibia prospects are offshore, in relatively deep water and therefore the economically achievable well density is much less than could be achieved in the larger onshore carbonate fields.

Overpressure

In terms of reservoir energy, there is benefit to overpressure, however it is likely that some form of secondary energy source (water / gas injection) will be required to produce the hydrocarbons.

6.2.2 Prospects

Gemsbok Main

The AGR-TRACS evaluation assumes a recovery factor range of 15%-30%-50%. The low case reflecting the experience of more challenging carbonate fields seen around the world. The mid case is reflecting the world average, balancing the field size, with the thickness, and achievable well spacing. The high case reflects more creative and successful attempts to improve carbonate recovery, for example, an SPE Forum in 2015 “Can we double the recovery from Carbonate Fields”.

It is acknowledged that this is a wide range; however, it is considered appropriate given the lack of project maturity.

Gemsbok Kudu

Sandstone reservoirs on average have a higher recovery factor than carbonates, and therefore a recovery factor range of 20%-35%-50% for the Aeolian Gemsbok sandstone has been assumed.

The Gemsbok Marine reservoir is considered to be of much poorer quality and therefore a recovery factor range of 10%-20%-30% has been applied.

Lion

The Lion prospect is considered to have a slightly heavier oil than Gemsbok potentially due to biodegradation, thus a recovery factor range of 15%-25%-45% has been assumed.

Dik Dik

The Dik Dik prospect is assumed to have a slightly heavier oil than Gemsbok potentially due to biodegradation; hence a recovery factor range of 15%-25%-45% has been applied.

The assumed recovery factor ranges for the individual prospects have been summarised in Table 6.4 below.

Prospect	Low	Mid	High
Gemsbok Main	15%	30%	50%
Gemsbok Aeolian	20%	35%	50%
Gemsbok Marine	10%	20%	30%
Lion	15%	25%	45%
Dik Dik	15%	25%	45%

Table 6.4: AGR TRACS assumed ranges of recovery factors for Global's prospects

6.2.3 Leads

Choje

In the absence of further data, AGR-TRACS have accepted the relatively large range of 10%-30%-50% supplied by Global (see Table 6.5).

Pangolin

Pangolin is mapped as a much smaller structure. The range of recovery factors assumed for the Pangolin lead is also 10%-30%-50%.

Lead	Low	Mid	High
Choje	10%	30%	50%
Pangolin	10%	30%	50%

Table 6.5: AGR TRACS assumed ranges of recovery factors for Global's leads

6.3 Recoverable Volumes

The recovery factors derived above have been applied to the Prospect and Lead STOIIP estimates arithmetically to preserve the range. The resulting estimates of gross prospective resources (100% of each prospect and lead) are shown in Table 6.6 and Table 6.7 below.

Prospect	Gross Prospective Resources (MMbls)		
	P90	P50	P10
Gemsbok Main	318	1091	2581
Gemsbok Aeolian	66	330	1296
Gemsbok Marine	63	323	945
Lion North	104	291	743
Lion South	290	823	2105
Dik Dik	224	805	2492#
TOTAL*	**1065**	**3663**	**10162**

Table 6.6: Summary of Unrisked Gross Prospective Resources for Global's prospects

* Note: Totals are arithmetic summations.

Note: This is the total Dik Dik structure including the area outside the Global licence. Approximately 21% of the Dik-Dik High case lies outside Global's licence, thus the on-block Gross estimate is 1969 MMbbls, and the total would be 9639 MMbbls.

Lead	Gross Prospective Resources (MMbls)		
	P90	P50	P10
Choje	121	720	2001
Pangolin	8.2	52	154
TOTAL*	**129.2**	**772**	**2155**

Table 6.7: Summary of Unrisked Gross Prospective Resources for Global's leads

* Note: Totals are arithmetic summations.

7 Conclusions and Recommendations

Following the subsurface geoscience review AGR TRACS have reached the following conclusions:

- The 2D seismic coverage is generally good, particularly over the Gemsbok and Lion prospects. It is sparser over Dik Dik.
- The seismic quality is good in the shallow section, but fair in the deeper section.
- The density of 2D seismic data is sufficient to ensure the maps provide a good representation of the structures.
- Uncertainties remain with regards to the complexity of the structures and the acquisition of additional seismic data may lead to alternative structural configurations.
- Further work is required on the leads to establish the extent of the Choje sand distribution and the Pangolin reef structure. Maps of these structures are required to fully evaluate their potential.

AGR TRACS would also make the following recommendations:

- To address the structural uncertainties, the acquisition of 3D seismic data over the primary prospect is recommended.
- If 3D data is acquired detailed attribute analysis is recommended to assist in the location of future exploration wells.

8 References

1) Standing, M.B. 1947. A Pressure-Volume-Temperature Correlation for Mixtures of California Oils and Gases. API Drilling and Production Practice (1947): 275-287.

2) Glasø, Ø. 1980. Generalized Pressure-Volume-Temperature Correlations. J Pet Technol 32 (5): 785-795. SPE-8016-PA. http://dx.doi.org/10.2118/8016-PA

3) Al-Marhoun, M.A. 1992. New Correlations For Formation Volume Factors Of Oil And Gas Mixtures. J Can Pet Technol 31 (3): 22. PETSOC-92-03-02. http://dx.doi.org/10.2118/92-03-02

9 Glossary of Terms

$	US Dollars
%	percent
°C	Degrees Celcius
2D	Two Dimensional
3D	Three Dimensional
API	American Petroleum Institute
AVO	Amplitude Variation with Offset
Av Phi	Average Porosity (from log evaluation)
Av Sw	Average water Saturation (from log evaluation)
bbls	Barrels
Bscf	Billion standard cubic feet of natural gas
bfpd	Barrels of fluid per day
boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
bopd	barrels oil per day
bpd	barrels per day
bwpd	barrels of water per day
Cali	Caliper
Capex	capital expenditure
CGR	Condensate Gas Ratio
CHP	Combined Heat-Power plant for gas-to-power generation
cm^3	cubic centimetre
COCS	Chance of Commercial Success
CPI	Computer Processed Interpretation (of logs)
CT	Corporation Tax
Den	Density log
D res	Deep resistivity log (deep investigation)
DST	Drill Stem Test
DT	Sonic log
E & A	Exploration & Appraisal
ft	feet
FTHP	Flowing Tubing Head Pressure
FWL	Free Water Level
G & G	Geological and Geophysical
Gas sat	Gas saturation
GDT	Gas Down To
GIIP	Gas Initially In Place
GOR	Gas to Oil Ratio
GR	Gamma Ray log
GRV	Gross Rock Volume
GUT	Gas Up To
GWC	Gas Water Contact
HCDT	Hydro-Carbon Down To
HCWC	Hydro-Carbon Water Contact
IRR	Internal Rate of Return (from MOD cashflows)
JV	Joint Venture
K	Permeability
km	Kilometre
km^2	Square kilometres
m	metre
m^3	cubic metre
Mbbls	thousand barrels of oil (unless otherwise stated)
Mboe	thousand barrels of oil equivalent
Mbopd	thousand barrels of oil per day
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day of natural gas
MD	Measured Depth
mD	milli Darcies
mln	million (monetary costs and values)
MM	Million (for volumes)
MMbbls	million barrels of oil
MMstb	million stock-tank barrels of oil
MMbo	million barrels of oil
MMboe	million barrels of oil equivalent
MMcf	million cubic feet of natural gas
MMscfd	million cubic feet of natural gas per day
MOD	Money Of the Day
N/G	Net to Gross
Neu	Neutron log
NFA	No Further Activity
NPV	Net Present Value
NRU	Nitrogen Removal Unit
OBC	Ocean Bottom Cable
ODT	Oil Down To
OML	Oil Mining Licence
Opex	operating expenditure
OUT	Oil Up To
OWC	Oil Water Contact

P & A	Plugged and Abandoned
p.a.	per annum
P10	10% probability of being exceeded
P50	50% probability of being exceeded
P90	90% probability of being exceeded
POS	Possibility Of Success
ppm wt	Parts per million by weight
PRMS	Petroleum Resource Management System
PSC	Production Sharing Contract
psi	pounds per square inch
psia	pounds per square inch absolute
PV	Present Value
PVT	Pressure Volume Temperature
RF	Recovery Factor
RFT	Repeat Formation Tester
RROR	Real Rate of Return (from RT cashflows)
RT	Real Terms
SG	Specific Gravity
SMT Kingdom	a PC-based interpretation workstation
SPE	Society of Petroleum Engineers
sq km	square kilometres
S res	Short resistivity log (shallow investigation)
ss	subsea
STOIIP	Stock Tank Oil Initially In Place
Sw	water Saturation
Swavg	average water Saturation
Sxo	water Saturation in invaded zone
TD	Total Depth
tvd	true vertical depth
tvdss	true vertical depth subsea
tvt	true vertical thickness
TWT	Two-Way Time
UAP	Unallocated Provision
WI	Working Interest

Appendix A - Summary of 2007 SPE Petroleum Resources Classification

The following table has paragraphs that are quoted from the 2007 SPE PRMS Guidance Notes and summarise the key resources categories, while Figure B-1 shows the recommended resources classification framework.

Class / Sub-class	Definition
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.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
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.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Table A-1: Summary of 2007 SPE Petroleum Resources Classification

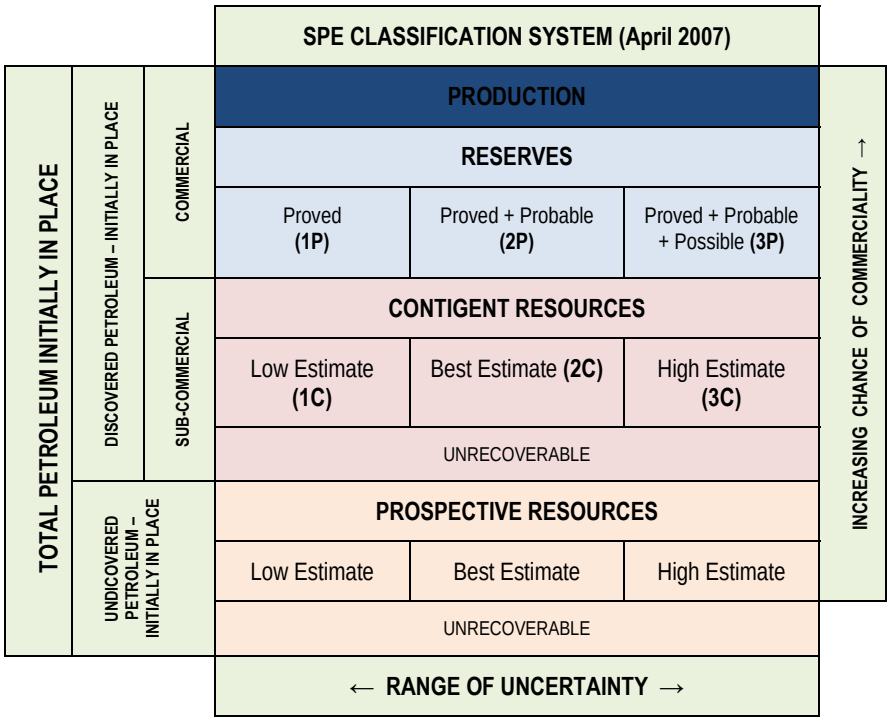

Figure A-1: SPE PRMS Petroleum Resources Classification Framework

Appendix B - Reserves and Resources Summary Tables

The tables below have been compiled in a manner consistent with that prescribed by the London Stock Exchange June 2009. The POS risk factors quoted in the following tables for the prospects represent solely the exploration risk (as per the June 2009 AIM Guidance Note) and do not include any assessment of commercial chance of success.

Oil & Gas – Reserves

There are no discoveries on Global's Licence 0029, and hence no reserves.

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable			Operator
DISCOVERY	1P Proved	2P Proved & Probable	3P Proved, Probable & Possible	1P Proved	2P Proved & Probable	3P Proved, Probable & Possible	

Source: AGR TRACS review

Note: "Operator" is the name of the company that operates the asset.

"Gross" are 100% of the reserves attributable to the licence whilst "Net Attributable" are those attributable to the AIM company. Reserves calculated under US$40/bbl or US$6.00/Mscf.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent.

Oil & Gas – Contingent Resources

There are no discoveries on Global's Licence 0029, and hence no contingent resources.

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable			Risk Factor	Operator
DISCOVERY	1C Low Estimate	2C Best Estimate	3C High Estimate	1C Low Estimate	2C Best Estimate	3C High Estimate	COCS (%)	

Source: AGR TRACS review

Note: "Risk Factor" for Contingent Resources means the chance, or probability, that the hydrocarbons will be commercially extracted.

"Operator" is the name of the company that operates the asset.

"Gross" are 100% of the resources attributable to the licence whilst "Net Attributable" are those attributable to the AIM company. Contingent Resources calculated under US$40/bbl.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent.

Oil & Gas – Technical Prospective Resources

Oil & Liquids: MMbbls Gas: Bscf	Gross Technical Prospective Resources			Net Attributable Technical Prospective Resources			Risk Factor	Operator
PROSPECT	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	**POS (%)**	
OIL - MMbbls								
Gemsbok Main	318	1091	2581	270	927	2194	12.3	Global
Gemsbok Aeolian	66	330	1296	56	281	1102	5.4	Global
Gemsbok Marine	63	323	945	53	275	803	8.8	Global
Lion North	104	291	743	88	247	631	7.5	Global
Lion South	290	823	2105	247	700	1789	7.5	Global
Dik-Dik	224	805	1969##	190	685	1674##	5.0	Global
TOTAL#	**1065**	**3663**	**9639**	**904**	**3115**	**8193**		

Source: AGR TRACS review

Note: "Risk Factor" for Prospective Resources means the chance, or probability, of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resources maturing into a Contingent Resource. Where a prospect could contain either oil or gas the hydrocarbon type with the higher probability of being discovered has been listed in the table.

"Operator" is the name of the company that operates the asset.

"Gross" are 100% of the resources attributable to the licence whilst "Net Attributable" are those attributable to the AIM company.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"##" - Excludes area outside Global licence.

Overview of Risked Prospective Resources Net to Global:

RISKED TECHNICAL PROSPECTIVE RESOURCES

Oil & Liquids: MMbbls Gas: Bscf	Unrisked Technical Prospective Resources Net Attributable to Global			Risk Factor	Risked Technical Prospective Resources Net Attributable to Global		
PROSPECT	**Low Estimate**	**Best Estimate**	**High Estimate**	**POS (%)**	**Low Estimate**	**Best Estimate**	**High Estimate**
OIL - MMbbls							
Gemsbok Main	270	927	2194	12.3	33.1	113.6	268.7
Gemsbok Aeolian	56	281	1102	5.4	3.0	15.1	59.5
Gemsbok Marine	53	275	803	8.8	4.7	24.0	70.3
Lion North	88	247	631	7.5	6.6	18.6	47.4
Lion South	247	700	1789	7.5	18.5	52.5	134.2
Dik-Dik	190	685	1674##	5.0	9.5	34.2	83.7##
TOTAL#	**904**	**3115**	**8193**		**75.4**	**258.0**	**663.8**

Source: AGR TRACS review

Note: "Risk Factor" for Prospective Resources means the chance, or probability, of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resources maturing into a Contingent Resource. Where a prospect could contain either oil or gas the hydrocarbon type with the higher probability of being discovered has been listed in the table.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"##" - Excludes area outside Global licence.