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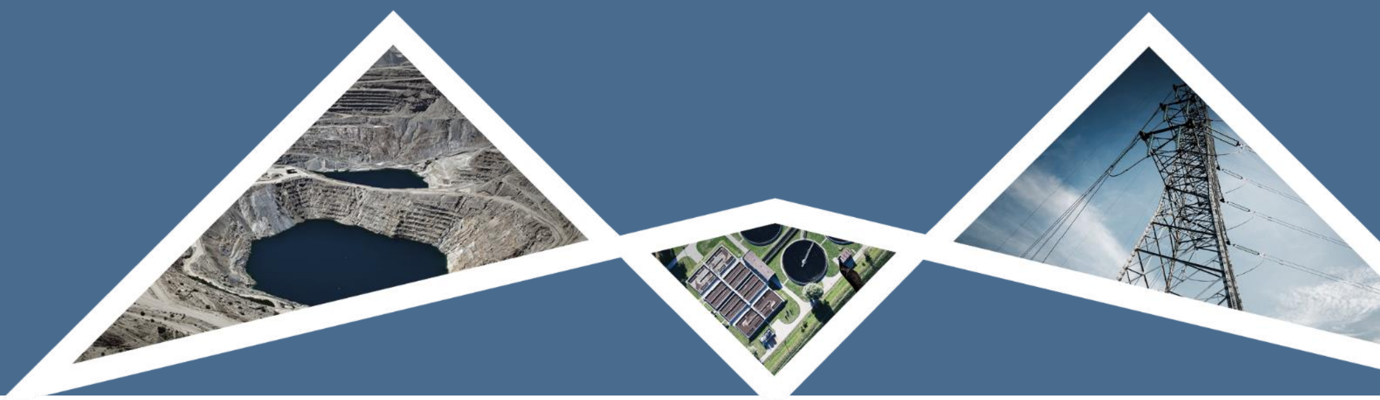
FINAL REHABILITATION, DECOMMISSIONING AND CLOSURE PLAN:

PROPOSED AFRICA OIL SOUTH AFRICA CORP BLOCK 3B/4B EXPLORATION RIGHT

PASA/DMRE REFERENCE: 12/3/339



DOCUMENT DETAILS

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COMPILED:	GP Kriel		2023/12/21
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AUTHORIZED:	Liam Whitlow	pp	2023/12/21

REVISION AND AMENDMENTS

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1 INTRODUCTION

Africa Oil SA Corp, Ricocure (Pty) Ltd and Azinam Limited (a wholly owned subsidiary of Eco Atlantic) (the Joint Venture (JV) Partners – hereafter jointly referred to as the Applicant) have applied for Environmental Authorization for a exploration drilling within Block 3B/4B off the West Coast of South Africa. The Applicants are the current holders of the Block 3B/4B Exploration Right (ER) in terms of the Mineral and Petroleum Resources Development Act (No. 28 of 2002 – MPRDA), as amended.

Environmental Impact Management Services (Pty) Ltd (EIMS) has been appointed to prepare and submit an application for Environmental Authorisation (EA) as per the requirements of the Environmental Impact Assessment (EIA) Regulations, 2014, as amended, promulgated under the National Environmental Management Act (Act No. 107 of 1998- NEMA) and the requirements of the Minerals and Petroleum Resources Development Act (Act No. 28 of 2002 – MPRDA).

In accordance with Section 24P of the NEMA the Applicant must, before the Minister responsible for mineral resources issues the EA, comply with the prescribed financial provision for the rehabilitation, closure and ongoing post decommissioning management of negative environmental impacts. This Final Rehabilitation, Decommissioning and Closure Plan (FRDCP) aims to meet this requirement and has been prepared in accordance with the requirements of the NEMA Financial Provisioning Regulations (2015) (NEMA GNR 1147).

According to the regulations, financial provision must be made for rehabilitation and remediation; decommissioning and closure activities at the end of prospecting, exploration, mining or production operations; and remediation and management of latent or residual environmental impacts which may become known in the future. In order to address these requirements, this document includes an annual rehabilitation plan, a final rehabilitation, decommissioning and mine closure plan, and an environmental risk assessment report.

Table 1 below lists the specific requirements that must be contained in each of the three plans as per the NEMA GNR 1147 Appendices 3, 4 and 5, as well as the associated section in this report where each requirement is addressed.

Table 1: NEMA GNR 1147 Appendix 3, 4 and 5 Requirements

No	Requirement	Relevant Section
Annual Rehabilitation Plan – Appendix 3		
3 (a)	details of the person or persons that prepared the plan, and timeframes of implementation of the current, and review of the previous rehabilitation activities;	Section 2
3 (b)	the pertinent environmental and project context relating directly to the planned annual rehabilitation and remediation activity;	Section 3.2
3 (c)	results of monitoring of risks identified in the final rehabilitation, decommissioning and mine closure plan with a view to informing rehabilitation and remediation activities;	To be confirmed after the first implementation of the Annual Rehabilitation Plan.
3 (d)	an identification of shortcomings experienced in the preceding 12 months;	Section 4.6
3 (e)	details of the planned annual rehabilitation and remediation activities or measures for the forthcoming 12 months;	Section 5
3 (f)	a review of the previous year's annual rehabilitation and remediation activities;	Section 4.6
3 (g)	costing;	Section 4.5

No	Requirement	Relevant Section
Final Rehabilitation, Decommissioning and Mine Closure Plan – Appendix 4		
3 (a)	details of the person or persons that prepared the plan;	Section 2
3 (b)	the context of the project, including material information and issues that have guided the development of the plan, an overview of the environmental context, the social context regarding closure activities and post-mining land use, stakeholder issues and comments, and the mine plan and schedule for operations;	Section 3.2
3 (c)	findings of an environmental risk assessment leading to the most appropriate closure strategy;	Section 3.3
3 (d)	design principles, including the legal and governance framework, the closure vision, objectives and targets, alternative closure and post closure options, a motivation for the preferred closure action, details of the closure and post closure period, details associated with any on-going research on closure options, and details of assumptions made to develop closure actions;	Section 3.5
3 (e)	a proposed final post-mining land use;	Section 3.5
3 (f)	closure actions required;	Section 4.1
3 (g)	a schedule of actions for final rehabilitation, decommissioning and closure;	Section 4.1
3 (h)	an indication of the organisational capacity that will be put in place to implement the plan, including the organisational structure;	Section 4.2
3 (i)	an indication of gaps in the plan;	Section 4.3
3 (j)	relinquishment criteria for each activity or infrastructure in relation to environmental aspects with auditable indicators;	Section 4.4
3 (k)	the closure cost estimation procedure;	Section 4.5
3 (l)	monitoring, auditing and reporting requirements which relate to the risk assessment, legal requirements and knowledge gaps;	Section 4.6
3 (m)	motivations for any amendments made to the final rehabilitation, decommissioning and mine closure plan, given the monitoring results in the previous auditing period and the identification of gaps as per 2(i).	Section 5
Environmental Risk Assessment – Appendix 5		
3 (a)	details of the person or persons that prepared the plan;	Section 2
3 (b)	details of the assessment process used to identify and quantify the latent risks;	Section 6.1
3 (c)	management activities;	Section 6.2
3 (d)	costing;	Section 6.2
3 (e)	monitoring, auditing and reporting requirements.	Section 6.2

2 DETAILS OF THE SPECIALIST

The details of the professionals who contributed to the preparation of the annual rehabilitation plan (ARP), FRDCP and environmental risk assessment (ERA) are provided in Table 2.

Table 2: Specialist Details

Name of Practitioner	GP Kriel (Compiler) / Liam Whitlow (Reviewer)
Tel No:	+27 11 789 7170
E-mail:	block3b4b@eims.co.za

2.1 EXPERTISE OF THE SPECIALIST

EIMS is a private and independent environmental management-consulting firm that was founded in 1993. EIMS has in excess of 30 years' experience in conducting EIA's. Please refer to the EIMS website (www.eims.co.za) for further details of expertise and experience.

Liam holds a B. Sc. Hons degree in Environmental Management and has completed an additional B. Sc. honours course in applied limnology. In addition, he has completed a higher certificate in Project Management with Damelin Business School and a course on ISO14001 Auditing Principles and Environmental Management Systems Auditor Training. Liam is a registered professional natural scientist with the South African Council for Natural Scientific Professions. Liam's professional experience, gained over more than 20 years, lies mainly with environmental impact assessments including project managing significantly large EIA's in the mining and infrastructure sectors. Liam's other experience includes ISO14001, Site Assessments, Water-use licensing, Environmental monitoring, and Environmental Management Plans. Liam's experience lies mainly within South Africa, but he has been involved in projects in both Lesotho and Botswana.

GP holds an M.Env.Sci (Water Sciences) Cum Laude from the North-West University (Potchefstroom Campus) and has been employed as an Environmental Consultant since 2007. GP is a Registered Professional Natural Scientist (South African Council for Natural and Scientific Professions) and a Registered Environmental Assessment Practitioner (Environmental Assessment Practitioner). He has delivered presentations locally and internationally concerning the use of bio-indicators for the determination of water quality, and has experience in a wide variety of environmental management projects including: Environmental Impact Assessments, Basic Assessments, Geographic Information Systems (GIS), Environmental Compliance Monitoring, Environmental Awareness Training, Aquatic Ecological Assessments, Drinking and Waste Water Treatment Process Audits, Wetland Delineation and Assessments, ISO 14001 Aspect Registers, Water Use Licence Applications, Waste Management Licence Applications and Integrated Waste and Water Management Plans (IWWMP).

3 FINAL REHABILITATION, DECOMMISSIONING AND CLOSURE PLAN

According to the NEMA GNR 1147 the objective of the final rehabilitation, decommissioning and closure plan, is to identify a post-exploration land use that is feasible through-

a) Providing the vision, objectives, targets and criteria for final rehabilitation, decommissioning and closure of the project;

b) Outlining the design principles for closure;

c) Explaining the risk assessment approach and outcomes and link closure activities to risk rehabilitation;

d) Detailing the closure actions that clearly indicate the measures that will be taken to mitigate and/or manage identified risks and describes the nature of residual risks that will need to be monitored and managed post closure;

e) Committing to a schedule, budget, roles and responsibilities for final rehabilitation, decommissioning and closure of each relevant activity or item of infrastructure;

f) Identifying knowledge gaps and how these will be addressed and filled;

g) Detailing the full closure costs for the life of project at increasing levels of accuracy as the project develops and approaches closure in line with the final land use proposed; and

h) Outlining monitoring, auditing and reporting requirements.

This section of the report aims to achieve these objectives.

3.1 THE PROJECT APPLICANT/PROPONENT

The applicant is the principal party (Proponent) of the project. For the purposes of this project it is understood that the Applicant role is fulfilled by the JV Partners specified in Section 1 above. The legal accountability for correct implementation of the relevant requirements of the EA and EMPr falls primarily upon the Applicant and must therefore be built into all contractor's contractual agreements. The Applicant's role typically includes:

- Provide for all necessary supervision during the execution of the project including appointment of key personnel to act on his/her behalf during the project (e.g.: Project Manager). The key personnel will be tasked with ensuring that the various contractors/developers comply with the necessary provisions of the EA and EMPr;
- Ensure that the various contractors and applicable sub-contractors appoint a suitably qualified, competent Environmental Officer (EO) that will be responsible for among others, ensuring daily compliance with the EMPr and EA throughout the execution of the relevant project components;
- Appoint a suitably qualified, competent independent Environmental Control Officer (ECO) who will undertake periodic audits on the various contractors works;
- Appoint an independent and suitably qualified MMO to monitor marine fauna for the duration of the exploration activities;
- Appoint an independent and suitably qualified PAM operator to monitor marine fauna for the duration of the exploration activities;
- Notify the relevant competent authority of changes in the development resulting in significant environmental impacts;
- Assess the various contractor's environmental performance during exploration, in consultation with the ECO;
- Ensure compliance with regulations;
- To implement the projects as per the approved project plan;
- To ensure that implementation is conducted in an environmentally acceptable manner;
- To inform and educate all employees about the environmental risks associated with the different activities that should be avoided during the survey process and lessen significant impacts to the environment; and
- Ensure MMOs and PAM operators are briefed on the area-specific sensitivities and on the exploration planning (including roles and responsibilities, and lines of communication).

Therefore, ultimately, the Applicant is responsible for the development and implementation of the EMPr and, where relevant, ensuring that the conditions in the EA are satisfied. Where exploration activities are contracted out (e.g. to Contractors and Subcontractors), the liability associated with non-compliance still rests with the Applicant (unless otherwise agreed upon between the authorities, the Applicant and the contracting parties). The Applicant (and not the Contractor) is therefore responsible for liaising directly with the relevant authorities with respect to the preparation and implementation of the EMPr and meeting authorisation conditions.

3.2 PROJECT AND ENVIRONMENTAL CONTEXT

This section aims to provide context and focus attention on the material information and issues that have guided the development of this FRDCP. Further details on the project and environmental context can be obtained from the EIA Report. Please refer to the detailed description of the project as provided for in Section 2 and 3 of the EIA Report.

The below activities are expected to be undertaken as part of the proposed exploration for oil and gas. It should be noted that the project described in this report, relates to exploration activities only. No production activities have been assessed as part of this Scoping and EIA Process – any production related activities would be subject to a separate production right application, including a new Scoping and EIA Process.

3.2.1 LOCATION

Table 3 indicates the details of the project area for the proposed project including details on the project location as well as the distance from the proposed project area to the nearest towns.

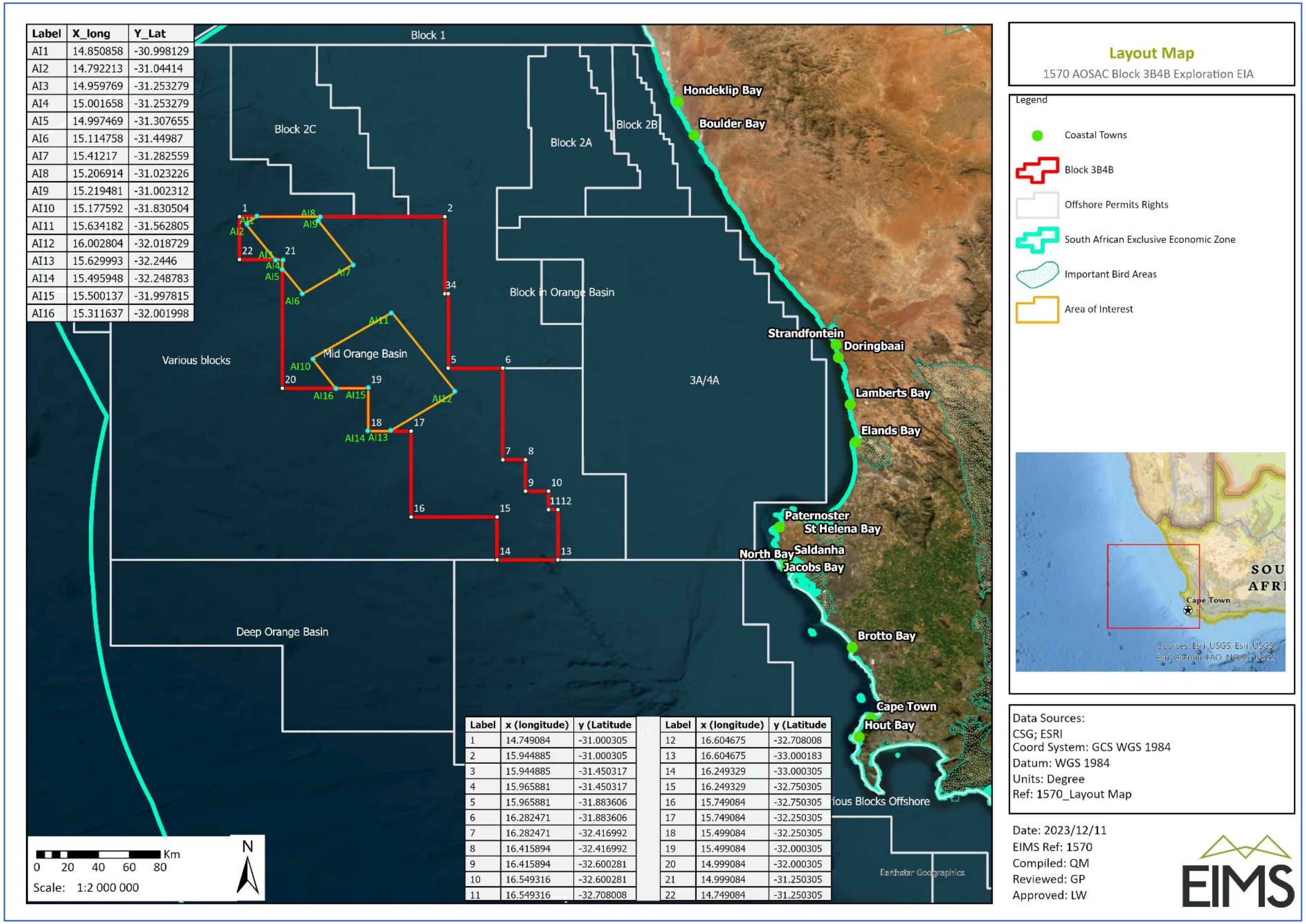
Table 3: Locality details

Project Area	Block 3B/4B off the West Coast of South Africa has an area of approximately 17 581 km^2. Two areas of interest (AOI) have been identified: • Northern AOI; and • Central AOI. The primary AOI for drilling is located in the northern portion of the licence area and covers ranging in water depths between 1 000 m and 2 600 m (Figure 1).
Application Area	Block 3B/4B Approximately 1 758 100 ha covers an area of approximately 17 581 km^2.
Magisterial District	Adjacent to the Namaqualand and West Coast District Municipalities.
District Municipality	Adjacent to the Namaqualand and West Coast District Municipalities.
Local Municipalities	Adjacent to the Kamiesberg; Richtersveld; Nama Khoi; Matzikama; Cederberg; Bergrivier; Saldanha Bay; Swartland; and City of Cape Town Local Municipalities.
Application area coordinates	The application area corner coordinate points are as follows:

Point	Latitude	Longitude	Point	Latitude	Longitude
1	-31.00030518	14.74908447	**12**	-32.70800781	16.60467529
2	-31.00030518	15.94488525	**13**	-33.00018311	16.60467529
3	-31.45031738	15.94488525	**14**	-33.00030518	16.24932861
4	-31.45031738	15.96588135	**15**	-32.75030518	16.24932861
5	-31.88360596	15.96588135	**16**	-32.75030518	15.74908447
6	-31.88360596	16.2824707	**17**	-32.25030518	15.74908447
7	-32.41699219	16.2824707	**18**	-32.25030518	15.49908447

	8	-32.41699219	16.41589356	**19**	-32.00030518	15.49908447
	9	-32.60028076	16.41589356	**20**	-32.00030518	14.99908447
	10	-32.60028076	16.54931641	**21**	-31.25030518	14.99908447
	11	-32.70800781	16.54931641	**22**	-31.25030518	14.74908447

The locality of the proposed exploration area is shown in Figure 1.



Label	X_long	Y_Lat
AI1	14.850858	-30.998129
AI2	14.792213	-31.04414
AI3	14.959769	-31.253279
AI4	15.001658	-31.253279
AI5	14.997469	-31.307655
AI6	15.114758	-31.44987
AI7	15.41217	-31.282559
AI8	15.206914	-31.023226
AI9	15.219481	-31.002312
AI10	15.177592	-31.830504
AI11	15.634182	-31.562805
AI12	16.002804	-32.018729
AI13	15.629993	-32.2446
AI14	15.495948	-32.248783
AI15	15.500137	-31.997815
AI16	15.311637	-32.001998

Label	x (longitude)	y (Latitude
1	14.749084	-31.000305
2	15.944885	-31.000305
3	15.944885	-31.450317
4	15.965881	-31.450317
5	15.965881	-31.883606
6	16.282471	-31.883606
7	16.282471	-32.416992
8	16.415894	-32.416992
9	16.415894	-32.600281
10	16.549316	-32.600281
11	16.549316	-32.708008

Label	x (longitude)	y (Latitude
12	16.604675	-32.708008
13	16.604675	-33.000183
14	16.249329	-33.000305
15	16.249329	-32.750305
16	15.749084	-32.750305
17	15.749084	-32.250305
18	15.499084	-32.250305
19	15.499084	-32.000305
20	14.999084	-32.000305
21	14.999084	-31.250305
22	14.749084	-31.250305

Figure 1: Locality map.

3.2.2 PRE-DRILLING SURVEYS

Pre-drilling surveys may be undertaken prior to drilling in order to confirm baseline conditions at the drill site and to identify and delineate any seabed and sub-seabed geo-hazards that may impact the proposed exploration drilling operations. Pre-drilling surveys may involve a combination of sonar surveys, sediment sampling, water sampling and ROV activities.

3.2.2.1 SONAR SURVEYS

Pre-drilling sonar surveys may involve multi- and single beam echo sounding and sub-bottom profiling. These surveys would not be limited to a specific time of the year but would be of short duration (around 10 days per survey) and focused on selected areas of interest within the block. The interpretation of the survey would take up to four weeks to complete.

3.2.2.2 ECHO SOUNDERS

The majority of hydrographic depth/echo sounders are dual frequency, transmitting a low frequency pulse at the same time as a high frequency pulse. Dual frequency depth/echo sounding has the ability to identify a vegetation layer or a layer of soft mud on top of a layer of rock. It is proposed to utilise a single beam echo-sounder with a frequency range of 38 to 200 kHz. In addition, it is proposed to also utilise multibeam echo sounders (70 - 100 kHz range and 200 dB re 1µPa at 1m source level) that are capable of receiving many return "pings". This system produces a digital terrain model of the seafloor.

3.2.2.3 SUB-BOTTOM PROFILERS

Sub-bottom profilers are powerful low frequency echo-sounders that provide a profile of the upper layers of the ocean floor. Bottom profilers emit an acoustic pulse at frequencies ranging between 2 and 16 kHz, typically producing sound levels in the order of 200-230 db re 1µPa at 1m.

3.2.2.4 SEABED SEDIMENT CORING

Seabed sediment sampling may involve the collection of sediment samples in order to characterise the seafloor and for laboratory geochemical analyses in order to determine if there is any naturally occurring hydrocarbon seepage at the seabed or any other type of contamination prior to the commencement of drilling.

No specific target area has as yet been identified for the sediment sampling. It is currently anticipated that up to 20 samples could be taken across the entire area of interest (AOI) potentially removing a cumulative volume of ~ 35 m^3. The sediment sampling process would take between three to five weeks to complete, depending on weather conditions.

Piston and box coring (or grab samples) techniques may be used to collect the seabed sediment samples. These techniques are further described below.

3.2.2.5 PISTON CORING

Piston coring (or drop coring) is one of the more common methods used to collect seabed geochemical samples. The piston coring rig is comprised of a trigger assembly, the coring weight assembly, core barrels, tip assembly and piston. The core barrels are 6 - 9 m in lengths with a diameter of 10 cm.

The recovered cores are visually examined at the surface for indications of hydrocarbons (gas hydrate, gas parting or oil staining) and sub-samples retained for further geochemical analysis in an onshore laboratory.

3.2.2.6 BOX CORING

Box corers are lowered vertically to the seabed from a survey vessel by. At the seabed the instrument is triggered to collect a sample of seabed sediment. The recovered sample is completely enclosed thereby reducing the loss of finer materials during recovery. On recovery, the sample can be processed directly through the large access doors or via complete removal of the box and its associated cutting blade. The Applicant is proposing to take box core samples (50 cm x 50 cm) at a depth of less than 60 cm.

3.2.3 WELL LOCATION AND DRILLING PROGRAMME

The Applicant is proposing to drill up to five exploration wells within an AOI within Block 3B/4B. The expected target drilling depth is not confirmed yet and a notional well depth of 3 500 m below sea floor (Water depth range 500 -1700m) is assumed at this stage. It is expected that it would take approximately three to four months to complete the physical drilling and testing of each well (excluding mobilisation and demobilisation). The applicant's strategy for future drilling is that drilling could be undertaken throughout the year (i.e. not limited to a specific seasonal window period).

The schedule for drilling the wells is not confirmed yet; however, the earliest anticipated date for commencement of drilling is third quarter of 2024 (Q3 2024) and is expected to take approximately 90 days per well.

3.2.4 MAIN PROJECT COMPONENTS

3.2.4.1 DRILLING UNIT OPTIONS

Various types of drilling technology can be used to drill an exploration well (e.g. barges, jack-up rigs, semi-submersible drilling units (rigs) and drill-ships) depending on, inter alia, the water depth and marine operating conditions experienced at the well site. Based on the anticipated sea conditions, the Applicant is proposing to utilise a semi-submersible drilling unit or a drill-ship, both of which utilise dynamic positioning systems suitable for the harsh deep-water marine environment in the AOI. The final rig selection will be made depending upon availability and final design specifications.

A semi-submersible drilling unit (Figure 2, right) is essentially a drilling rig located on a floating structure of pontoons. When at the well location, the pontoons are partially flooded (or ballasted), with seawater, to submerge the pontoons to a pre-determined depth below the sea level where wave motion is minimised. This gives stability to the drilling vessel thereby facilitating drilling operations.

A drill-ship (Figure 2, left) is a fit for purpose built drilling vessel designed to operate in deep water conditions. The drilling “rig” is normally located towards the centre of the ship with support operations from both sides of the ship using fixed cranes. The advantages of a drill-ship over the majority of semi-submersible units are that a drill-ship has much greater storage capacity and is independently mobile, not requiring any towing and reduced requirement of supply vessels.

Figure 2: Examples of drilling equipment.

3.2.4.2 SUPPORT VESSELS

The drilling unit would be supported / serviced by up to three support vessels, which would facilitate equipment, material and waste transfer between the drilling unit and onshore logistics base. A supply vessel will always be on standby near the drilling unit to provide support for firefighting, oil containment / recovery, rescue in the unlikely event of an emergency and supply any additional equipment that may be required. Support vessels can also be used for medical evacuations or transfer of crew if needed.

3.2.4.3 HELICOPTERS

Transportation of personnel to and from the drilling unit would be provided by helicopter from Springbok Airport (fixed wing trip from Cape Town) using local providers. It is estimated that there may be up to four return flights per week between the drilling unit and the helicopter support base at Springbok (i.e. 17 weeks (~120 days) x 4 = 68 trips per well). The helicopters can also be used for medical evacuations from the drilling unit to shore (at day- or night-time), if required, in which case the flights are likely to be directly to Cape Town.

3.2.4.4 ONSHORE LOGISTICS BASE

The primary onshore logistics base will most likely be located at the Port of Cape Town (preferred option), but alternatively at the Port of Saldanha. The shore base would provide for the storage of materials and equipment that would be shipped to the drilling unit and back to storage for onward international freight forwarding. The shore base would also be used for offices, waste management services, bunkering vessels, and stevedoring / customs clearance services.

3.2.5 MOBILISATION PHASE

The mobilisation phase will entail the required notifications, establishment of the onshore base, appointment of local service providers, procurement and transportation of equipment and materials from various ports and airports, accommodation arrangements and transit of the drilling unit and support vessels to the drilling area. The drilling unit and supply vessels could sail directly to the well site from outside South African waters or from a South African port, depending on which drilling unit is selected, and where it was last used.

Core specialist and skilled personnel would arrive in South Africa onboard the drilling unit and the rest of the personnel will be flown to Cape Town. Drilling materials, such as casings, mud components and other equipment and materials will be brought into the country on the drilling unit itself or imported via a container vessel directly to the onshore logistics base from where the supply vessels will transfer it to the drilling unit. Cement and chemicals will be sourced locally.

3.2.6 OPERATION PHASE

3.2.6.1 FINAL SITE SELECTION AND SEABED SURVEY

The selection of the specific well locations will be based on a number of factors, including further detailed analysis of the seismic and pre-drilling survey data and the geological target. A Remote Operating Vehicle (ROV) will be used to finalise the well position based on inter alia the presence of any seafloor obstacles or the presence of any sensitive features that may become evident.

3.2.6.2 WELL DRILLING OPERATION

The well will be created by drilling a hole into the seafloor with a drill bit attached to a rotating drill string, which crushes the rock into small particles, called “cuttings”. After the hole is drilled, casings (sections of steel pipe), each slightly smaller in diameter, are placed in the hole and permanently cemented in place (cementing operations are described below). The hole diameter decreases with increasing depth.

The casings provide structural integrity to the newly drilled wellbore, in addition to isolating potentially dangerous high-pressure zones from each other and from the surface. With these zones safely isolated, and the formation protected by the casing, the well will be drilled deeper with a smaller drill bit, and also cased with a smaller sized casing. For the current project, it is anticipated that there will be five sets of consecutively smaller hole sizes drilled inside one another, each cemented with casing, except the last phase that will remain an open hole.

Drilling is undertaken in two stages, namely the riserless and risered drilling stages (Figure 3). A typical well design is summarised in Table 4. The final well design depends upon factors such as planned depths, expected pore pressures and anticipated hydrocarbon-bearing formations. Several types of drilling fluids with different compositions and densities would be used for drilling operations. The composition of the muds is provided in Table 4. This may vary slightly depending on the contractor’s selection and may be modified to suit operational needs.

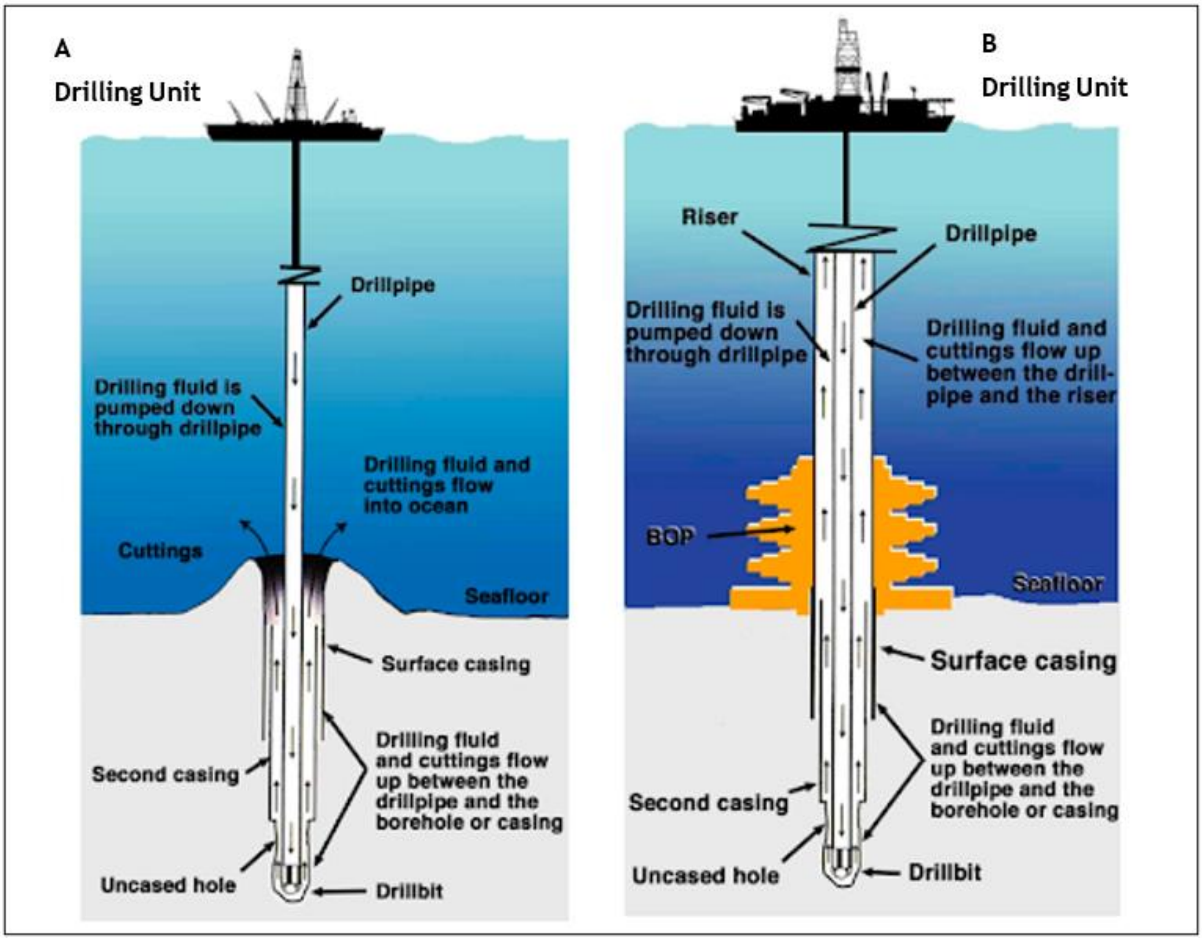


Figure 3: Drilling stages: (a) Riserless Drilling Stage; and (b) Risered Drilling Stage

Table 4: Cuttings and mud volumes per phase for notional base case well design and estimated drilling discharges.

Drill Section	Hole diameter (inches)	Depth of section (m)	Type of drilling fluid used	Mass of drilling fluid discharged (tonnes)	Volume of cuttings released (m^3)	Drilling fluid and cuttings discharge location
Riserless drilling stage						
1	36”	70	Seawater, viscous sweeps & WBM	209	40	At sea bottom
2	26”	320		135	76	
-	Suspension / Displacement before drilling Section 3	-	High Viscous Gel sweeps / KCl Polymer PAD mud	30	-	1 m above seabed
Total Riserless		390		374	131	
Risered drilling stage						
3	17.5”	700		133	74	

Drill Section	Hole diameter (inches)	Depth of section (m)	Type of drilling fluid used	Mass of drilling fluid discharged (tonnes)	Volume of cuttings released (m^3)	Drilling fluid and cuttings discharge location
4	12.25”	1 250	KCl/Glycol WBM	109	61	10 m below mean sea level
5	8.5”	1 160		61	27	
Total Risered		3 110	3110	303	162	
Total		3 500	3 500	677	278	-
Note: * Total quantity of mud discharged including Oil On Cuttings (OOC) @ 6% by weight of cuttings (metricT) + Other constituents.						

3.2.6.2.1 INITIAL (RISERLESS) DRILLING STAGE

The process of preparing the first section of a well is referred to as “spudding.” Sediments just below the seafloor are often very soft and loose, thus, to keep the well from caving in and to carry the weight of the wellhead, a 30- or 36-inch diameter structural conductor pipe is drilled and cemented into place or in some cases jetted.

For the proposed wells, the drill and cement option is preferred. It is usually implemented where the nature of the seafloor sediments (hard sediments) necessitate drilling. A hole of diameter 36 inches will be drilled, and the conductor pipe will be run into the hole and cemented into place. The cement returns exit the bottom of the conductor and travel up the annular space between the conductor and the hole with some cement being deposited on the seabed around the conductor pipe.

When the conductor pipe and low-pressure wellhead are at the correct depth, approximately 70 m deep (depending upon substrate strength), a new drilling assembly will be run inside the structural conductor pipe and the next hole section will be drilled by rotating the drill string and drill bit.

Below the conductor pipe, a hole of approximately 26 inches in diameter will be drilled to a depth of approximately 320 m below the seabed. The rotating drill string causes the drill bit to crush rock into small particles, called “cuttings”. While the wellbore is being drilled, drilling fluid is pumped from the surface down through the inside of the drill pipe, the drilling fluid passes through holes in the drill bit and travels back to the seafloor through the space between the drill string and the walls of the hole, thereby removing the cuttings from the hole. At a planned depth the drilling is stopped and the bit and drill string is pulled out of the hole. A surface casing of 20 inch diameter is then placed into the hole and secured into place by pumping cement through the casing at the bottom of the hole and back up the annulus (the space between the casing and the borehole). The 20-inch casing will have a high-pressure wellhead on top; which provides the entry point to the subsurface and it is the connection point to the Blow-out Preventor (BOP).

These initial hole sections will be drilled using seawater (with viscous sweeps) and water-based mud (WBM). All cuttings and WBM from this initial drilling stage will be discharged directly onto the seafloor adjacent to the wellbore.

3.2.6.2.2 RISERED DRILLING STAGE

The risered drilling stage commences with the lowering of a BOP and installing it on the wellhead. The BOP is designed to seal the well and prevent any uncontrolled release of fluids from the well (a ‘blow-out’). A lower marine riser package is installed on top of the BOP and the entire unit is lowered on riser joints. The riser isolates the drilling fluid and cuttings from the external environment, thereby creating a “closed loop system”.

Drilling is continued by lowering the drill string through the riser, BOP and casing, and rotating the drill string. During the risered drilling stage, should the WBMs not be able to provide the necessary characteristics, a low toxicity Non-aqueous Drilling Fluid (NADF) will be used. The drilling fluid emerges through nozzles in the drill bit and then rises (carrying the rock cuttings with it) up the annular space between the sides of the hole to the drilling unit.

The cuttings are removed from the returned drill mud, sampled for analysis and discharged overboard. In instances where NADFs are used, cuttings will be treated to reduce oil content and discharged overboard. Operational discharges are discussed further in Section 3.2.8.

The hole diameter decreases in steps with depth as progressively smaller diameter casings are inserted into the hole at various stages and cemented into place. The expected target drilling depth is not yet confirmed but the notional well depth is approximately 3 500 m below the seafloor with a final hole diameter between of 8.5 and 12.25 inches and a casing diameter of between 7 and 9.6 inches.

3.2.6.2.3 CEMENTING OPERATION

Cementing is the process of pumping cement slurry through the drill pipe and / or cement stinger at the bottom of the hole and back up into the space between the casing and the borehole wall (annulus). Cement fills the annulus between the casing and the drilled hole to form an extremely strong, nearly impermeable seal, thereby permanently securing the casings in place. To separate the cement from the drilling fluid in order to minimise cement contamination a cementing plug and/or spacer fluids are used. The plug is pushed by the drilling fluid to ensure the cement is placed outside the casing filling the annular space between the casing and the hole wall.

Cementing has four general purposes:

(i) it isolates and segregates the casing seat for subsequent drilling;

(ii) it protects the casing from corrosion;

(iii) it provides structural support for the casing; and

(iv) it stabilises the formation.

To ensure effective cementing, an excess of cement is often used. Until the marine riser is set, excess cement from the first two casings emerges out of the top of the well onto the seafloor. This cement does not set and is slowly dissolved into the seawater.

Offshore drilling operations typically use Portland cements, defined as pulverised clinkers consisting of hydrated calcium silicates and usually containing one or more forms of calcium sulphate. The raw materials used are lime, silica, alumina and ferric oxide. The cement slurry used is specially designed for the exact well conditions encountered.

Additives can be used to adjust various properties in order to achieve the desired results. There are over 150 cementing additives available. The volumes of these additives generally make up only a small portion (<10%) of the overall amount of cement used for a typical well. Usually, there are three main additives used: retarders, fluid loss control agents and friction reducers. These additives are polymers generally made of organic material and are considered non-toxic.

Once the cement has set, a short section of new hole is drilled, then a pressure test is performed to ensure that the cement and formation are able to withstand the higher pressures of fluids from deeper formations.

3.2.6.3 WELL LOGGING AND TESTING

Once the target depth is reached, the well would be logged and could be tested dependent on the drilling results. Well logging involves the evaluation of the physical and chemical properties of the sub-surface rocks, and their component minerals, including water, oil and gas to confirm the presence of hydrocarbons and the petrophysical characteristics of rocks. It is undertaken during the drilling operation using Wireline Logging or Logging While Drilling (LWD) to log core data from the well. Information from engineering and production logs, as well as mud logging, may also be used.

Vertical Seismic Profiling (VSP) is an evaluation tool used to generate a high-resolution seismic image of the geology in the well’s immediate vicinity. The VSP images are used for correlation with surface seismic images and for forward planning of the drill bit during drilling. VSP uses a small airgun array with a gun pressure of 450 per square inch (psi), which is operated from the drilling unit at a depth of between 7 m and 10 m. During VSP operations, four to five receivers are positioned in a section of the borehole and the airgun array is discharged approximately five times at 20 second intervals at each station. The generated sound pulses are reflected through the seabed and are recorded by the receivers to generate a profile along a 60 to 75 m section of the well. This process is repeated for different stations in the well and may take up to six hours to complete approximately 125 shots, depending on the well's depth and number of stations being profiled.

Well or flow testing is undertaken to determine the economic potential of the discovery before the well is either abandoned or suspended. One test would be undertaken per exploration well should a resource be discovered and up to two tests per appraisal well. Each test would take up to 7 days to complete (5 days of build-up and 2 days of flowing and flaring). For well flow-testing, hydrocarbons would be burned at the well site. A high-efficiency flare is used to maximise combustion of the hydrocarbons. Burner heads which have a high burning efficiency under a wide range of conditions will be used.

The volume of hydrocarbons (to be burned) and possible associated produced water from the reservoir which could be generated during well testing cannot be reliably predicted due to variations in gas composition, flow rates and water content. Burners are manufactured to ensure emissions are kept to a minimum. The estimated volume of hydrocarbons to be burned cannot be predicted with much accuracy because the actual test requirements can only be established after the penetration of a hydrocarbon-bearing reservoir. However, an estimated 10 000 bbl oil could be flared per test, i.e. up to 20 000 bbl over the two tests associated with an appraisal well. If produced water is generated during well testing, it will be separated from the hydrocarbons.

3.2.6.4 WELL SEALING AND PLUGGING

The purpose of well sealing and plugging is to isolate permeable and hydrocarbon bearing formations once drilling activities have been completed. Well sealing and plugging aims to restore the integrity of the formation that was penetrated by the wellbore. The principal technique applied to prevent cross flow between permeable formations is plugging of the well with cement, thus creating an impermeable barrier between two zones.

Once drilling and logging have been completed, the exploration wells will be sealed with cement plugs, tested for integrity and abandoned according to international best practices. Cement plugs will be set to isolate hydrocarbon bearing and / or permeable zones and cementing of perforated intervals (e.g. from well logging activities) will be evaluated where there is the possibility of undesirable cross flow. These cement plugs are set in stages from the bottom up. Three cement plugs would be installed: i.e. one each for isolation of the deep reservoir and the main reservoir; and a third as a second barrier for the main reservoir.

The integrity of cement plugs can be tested by a number of methods. The cement plugs will be tag tested (to validate plug position) and weight tested, and if achievable then a positive pressure test (to validate seal) and/or a negative pressure test will be performed. Additionally, a flow check may be performed to ensure sealing by the plug. Once the well is plugged, seawater will be displaced before disconnecting the riser and the BOP.

3.2.7 DEMOBILISATION PHASE

After the exploration wells have been sealed, tested for integrity and abandoned, the intention is to remove the wellheads from the sea floor on non-productive wells. On productive wells, it may be decided to abandon the wellheads on the seafloor after installation of over trawlable protective equipment. The risk assessment criteria will consider factors such as the water depth and use of the area by other sectors (e.g., fishing).

It is proposed temperature and pressure monitoring gauges be installed on wells where the Applicant may return in the future for appraisal / production purposes. The gauges will be placed and remain on the wellhead. Monitoring gauges are not proposed to be installed on exploration wells which are earmarked for abandonment.

With the exception of the over-trawlable protective equipment over abandoned wellheads and drilling discharges deposited on the seabed, no further physical remnants of the drilling operation will be left on the seafloor. A final clearance survey check will be undertaken using an ROV. The drilling unit and supply vessels will demobilise from the offshore licence area and either mobilise to the following drilling location or relocate into port or a regional base for maintenance, repair or resupply.

3.2.8 DISCHARGES, WASTES AND EMISSIONS

The proposed drilling operations (including mobilisation and demobilisation) will result in various discharges to water, the generation of waste and emissions. All vessels will have equipment, systems and protocols in place for prevention of pollution by oil, sewage and garbage in accordance with International Convention for the Prevention of Pollution from Ships, 1973/1978 (MARPOL) requirements. Any oil spill related discharges would be managed by an Oil Spill Contingency Plan (OSCP). Onshore licenced waste disposal sites and waste management facilities will be identified, verified and approved prior to commencement of drilling operations.

3.2.8.1 DRILLING CUTTINGS AND MUD

Drill cuttings, which range in size from clay to coarse gravel and reflect the types of sedimentary rocks penetrated by the drill bit, are the primary discharge during well drilling. Drilling discharges would be disposed at sea in line with accepted drilling practices as defined by the UK and Norway. This is in line with most countries (including South Africa) for early exploration development phases. The rationale for this is based on the low density of drilling operations in the vast offshore area and the high energy marine environment. As such, it is proposed to use the “offshore treatment and disposal” option for the drilling campaign. The same method was applied and approved for drilling other deep water exploration wells in Block 11B/12B (namely Brulpadda and Luiperd wells) off the South Coast of South Africa.

During the riserless drilling stage, all cuttings and WBM will be discharged directly onto the seafloor adjacent to the wellbore. An estimated volume of 131 m^3 of cuttings and 374 t of drilling fluid will be discharged per well during the riserless drilling stage (based on notional depth of 3 500 m).

Where NADFs are used (possibly during the risered drilling stage, if WBMs are not able to provide the necessary characteristics), these are sometimes treated onshore and disposed, treated to recover oil and disposed offshore and sometimes re-injected into wells. For the current project, in instances where NADFs are used, cuttings will be treated offshore to reduce oil content to <6.9% Oil on Cutting (OOC) and discharged overboard. During the risered drilling stage, an estimated volume of 257 m^3 of cuttings and 444 t of drilling fluid will be discharged per well (based on notional depth of 3 500 m). During this drilling stage the circulated drilling fluid will be cleaned and the cuttings discharged into the sea at least 10 m below sea level. The drill cuttings will be treated to reduce their mud content using shakers and a centrifuge.

Cuttings released from the drilling unit during the risered drilling stage will be dispersed by the current and settle to the seafloor. The rate of cuttings discharge decreases with increasing well depth as the hole diameter becomes smaller and penetration rates decrease. Discharge is intermittent as actual drilling operations are not continuous while the drilling unit is on location. Discharge is 10 m below sea level and cuttings then settle on the seabed below.

Further drilling fluid totalling 200 bbl will be released 1 m above the seafloor during well suspension and displacement (between drilling section 2 and 3). The mud used during these processes is a High Viscous Gel sweeps / KCl Polymer PAD mud.

The expected fall and spatial extent of the deposition of discharged cuttings have been investigated in the Drilling Discharges Modelling Study (Livas 2023a), the results of which will inform the Marine Ecology and Fisheries Assessments.

3.2.8.2 CEMENT AND CEMENT ADDITIVES

Typically, cement and cement additives are not discharged during drilling. However, during the initial cementing operation (i.e. surface casing), excess cement emerges out of the top of the well and onto the seafloor in order to ensure that the conductor pipe is cemented all the way to the seafloor. During this operation a maximum of 150% of the required cement volume may be pumped into the space between the casing and the borehole wall (annulus). In the worst-case scenario, approximately 50 m^3 of cement could be discharged onto the seafloor.

3.2.8.3 BOP HYDRAULIC FLUID

As part of routine opening and closing operations the subsea BOP stack elements will vent some hydraulic fluid into the sea at the seafloor. It is anticipated that between approximately 500 and 1 000 litres of oil-based hydraulic emulsion fluid could be vented per month during the drilling of a well. BOP fluids are completely biodegraded in seawater within 28 days.

3.2.8.4 PRODUCED WATER

If water from the reservoir arises during well flow testing, these would be separated from the oily components and treated onboard to reduce the remaining hydrocarbons from these produced waters. The hydrocarbon component will be burned off via the flare booms, while the water is temporarily collected in a slop tank. The water is then either directed to:

- a settling tank prior to transfer to supply vessel for onshore treatment and disposal; or
- a dedicated treatment unit on the rig where, after treatment, it is either:
    - o discharged overboard if hydrocarbon content is < 30 mg/l; or
    - o subject to a second treatment or directed to tank prior to transfer to supply vessel for onshore treatment and disposal if hydrocarbon content is > 30 mg/l.

3.2.8.5 VESSEL MACHINERY SPACES (BILGE WATER)

Vessels will occasionally discharge treated bilge water. Bilge water is drainage water that collects in a ship's bilge space (the bilge is the lowest compartment on a ship, below the waterline, where the two sides meet at the keel). In accordance with MARPOL Annex I, bilge water will be retained on board until it can be discharged to an approved reception facility, unless it is treated by an approved oily water separator to <15 ppm oil content and monitored before discharge. The residue from the onboard oil/water separator will be treated / disposed of onshore at a licenced hazardous landfill site.

3.2.8.6 DECK DRAINAGE

Deck drainage consists of liquid waste resulting from rainfall, deck and equipment washing (using water and a water-based detergent). Deck drainage will be variable depending on the vessel characteristics, deck activities and rainfall amounts.

In areas of the drilling unit where oil contamination of rainwater is more likely (i.e. the rig floor), drainage is routed to an oil / water separator for treatment before discharge in accordance with MARPOL Annex I (i.e. 15 ppm oil and grease maximum). There will be no discharge of free oil that could cause either a film, sheen or discolouration of the surface water or a sludge or emulsion to be deposited below the water's surface. Only non-oily water (i.e. <15 ppm oil and grease, maximum instantaneous oil discharge monitor reading) will be discharged overboard. If separation facilities are not available (due to overload or maintenance) the drainage water will be retained on board until it can be discharged to an approved reception facility. The oily residue from the onboard oil / water separator will be treated / disposed of onshore at an approved hazardous landfill site.

3.2.8.7 BRINE GENERATED FROM ONBOARD DESALINATION PLANT

The waste stream from the desalination plant is brine (concentrated salt), which is produced in the reverse osmosis process. The brine stream contains high concentration of salts and other concentrated impurities that may be found in seawater. Water chemical agents will not be used in the treatment of seawater and therefore the brine reject portion would be in a natural concentrated state. Based on previous well drilling operations, freshwater production amounts to approximately 40 m^3/day, which will result in approximately 35 g salt for each litre water produced (i.e. approx. 1 400 kg salt/brine per day).

3.2.8.8 SEWAGE AND GREY WATER

Discharges of sewage (or black water) and grey water (i.e. wastewater from the kitchen, washing and laundry activities and non-oily water used for cleaning) will occur from vessels intermittently throughout the project and will vary according to the number of persons on board, estimated at an average of 200 litres per person. All sewage discharges will comply with MARPOL Annex IV.

Sewage and grey water will be treated using a marine sanitation device to produce an effluent with:

- A Biological Oxygen Demand (BOD) of <25 mg/l (if the treatment plant was installed after 1/1/2010) or <50 mg/l (if installed before this date);
- Minimal residual chlorine concentration of 0.5 mg/l; and

- No visible floating solids or oil and grease.

3.2.8.9 FOOD (GALLEY) WASTES

The disposal into the sea of food waste is permitted, in terms of MARPOL Annex V, when it has been comminuted or ground to particle sizes smaller than 25 mm and the vessel is *en route* more than 3 nautical miles (approximately 5.5 km) from land. Disposal overboard without macerating is permitted for moving vessels greater than 12 nautical miles (approximately 22 km) from the coast. On the drilling unit, all food waste will be macerated to particles sizes <25 mm and the daily discharge is typically about seven tonnes per month.

3.2.8.10 BALLAST WATER

Ballast water is used during routine operations to maintain safe operating conditions onboard a ship by reducing stress on the hull, providing stability, improving propulsion and manoeuvrability, and compensating for weight lost due to fuel and water consumption.

Ballast water is discharged subject to the requirements of the 2004 International Convention for the Control and Management of Ships' Ballast Water and Sediments. The Convention stipulates that all ships are required to implement a Ballast Water Management Plan and that all ships using ballast water exchange will do so at least 200 nautical miles (nm) (± 370 km) from nearest land in waters of at least 200 m deep when arriving from a different marine region. Where this is not feasible, the exchange should be as far from the nearest land as possible, and in all cases a minimum of 50 nm (±93 km) from the nearest land and preferably in water at least 200 m in depth. Project vessels will be required to comply with this requirement.

3.2.8.11 DETERGENTS

Detergents used for washing exposed marine deck spaces will be discharged overboard. Water-based detergents are low in toxicity and are preferred for use. Preferentially biodegradable detergents should be used. Detergents used on work deck space will be collected with the deck drainage and treated as described under deck drainage above.

3.2.8.12 NOISE EMISSIONS

The key sources generating underwater noise are vessel propellers (and positioning thrusters), with a contribution from the pontoons (e.g. noise originating from within the pontoons and on-deck machinery), supply vessels and from drilling activities. This is expected to result in highly variable sound levels, being dependent on the operational mode of each vessel. The pre-drilling sonar surveys and VSP survey would generate a short-term noise, sonar acquisition takes 1.5 to 3 days to acquire with short bursts of the sound source and the VSP onboard between 4 to 6 hours dependent on the programme to complete, respectively.

The main sources of noise from these activities are categorised below.

- Pre-drilling sonar surveys may involve multi- and single beam echo sounding and sub-bottom profiling. These surveys would be undertaken between the 700 m and 1900 m depth ranges covering a survey area of approximately 150 km^2. Each wellsite survey would take up to 10 days to complete. A single beam echo-sounder operates within a frequency range of 38 to 200 kHz, whereas multibeam echo sounders operate in the 70 - 100 kHz range and have a 200dB re 1µPa at 1m source level. Sub-bottom profilers emit an acoustic pulse at frequencies ranging between 2 and 16 kHz, typically producing sound levels in the order of 200-230 db re 1µPa at 1m.

- Drilling noise: Drilling units generally produce underwater noise in the range of 10 Hz to 100 kHz (OSPAR commission, 2009) with major frequency components below 100 Hz and average source levels of up to 190 dB re 1 µPa at 1 m (rms) (the higher end of this range from use of bow thrusters). These noise levels will be assumed as indicative for the current project.

- Propeller and positioning thrusters: Noise from propellers and thrusters is predominately caused by cavitation around the blades whilst transiting at speed or operating thrusters under load in order to maintain a vessel's position. The noise produced by a drilling unit's dynamic positioning systems can be audible for many kilometres. Noise produced is typically broadband noise, with some low tonal peaks. The supply vessels will also contribute to an overall propeller noise generation.

- Machinery noise: Machinery noise is often of low frequency and can become dominant for vessels when stationary or moving at low speeds. The source of this type of noise is from large machinery, such as large power generation units (diesel engines or gas turbines), compressors and fluid pumps. Sound is transmitted through different paths, i.e. structural (machine to hull/pontoons to water) and airborne (machine to air to hull to water) or a mixture of both. The nature of sound is dependent on a number of variables, such as the type and size of machinery operating; and the coupling between machinery and the vessel body. Machinery noise is typically tonal in nature. A ROV will be used to conduct a sweep of the drilling site to identify any debris; however, this is not expected to form a significant noise source.
- Well logging noise: If relevant, VSP will be undertaken in order to generate a high-resolution image of the geology in the well's immediate vicinity. It is expected to use a small dual airgun array, comprising a system of three 150 cubic inch airguns and three 150 cubic inch airguns with a total volume of 450 cubic inches of compressed nitrogen at about 2 000 psi. VSP source will generate a pulse noise level in the 5 to 1 000 Hz range. The volumes and the energy released into the marine environment are significantly smaller than what is required or generated during conventional seismic surveys. The airguns will be discharged approximately five times at 20 second intervals. This process is repeated, as required, for different sections of the well for a total of approximately 150 shots. A VSP is expected to take up to six hours per well to complete, depending on the well's depth and number of stations being profiled.
- Well testing noise: Flaring would produce some air-borne noise above the sea level where flaring is implemented for up to two days of flowing and flaring.
- Equipment in water: Noise is produced from equipment such as the drill string. The noise produced will be low relative to the drilling noise and the dynamic positioning system.
- Helicopter noise: Helicopters will also form a source of noise, which can affect marine fauna both in terms of underwater noise beneath the helicopter and airborne noise.

The extent of project-related noise above the background noise level may vary considerably depending on the specific vessels used and the number of supply vessels operating. It will also depend on the variation in the background noise level with weather and with the proximity of other vessel traffic (not associated with the project).

An Underwater Noise Modelling Study has been undertaken to determine the underwater noise transmission loss with distance from well site and compare results with threshold values for marine fauna to determine zones of impact. These modelling results will be used in the assessment of impacts on marine fauna.

3.2.8.13 LIGHT EMISSIONS

Operational lighting will be required on the drilling unit and supply vessels for safe operations and navigation purposes during the hours of darkness. Where feasible, operational lights will be shielded in such a way as to minimise their spill out to sea.

3.2.8.14 HEAT EMISSIONS

Flaring during well testing generates heat emissions from the combustion of hydrocarbons at the burner head.

3.2.9 LISTED AND SPECIFIED ACTIVITIES

Please refer to Section 4 of the EIA Report for a detailed description of the applicable legislation.

In accordance with the provisions of Sections 24(5) and Section 44 of the NEMA the Minister has published Regulations (GN R. 982) pertaining to the required process for conducting EIA's in order to apply for, and be considered for, the issuing of an EA. These EIA Regulations provide a detailed description of the EIA process to be followed when applying for EA for any listed activity.

A Scoping and EIA process is reserved for activities which have the potential to result in significant impacts which are complex to assess. Scoping and EIA studies accordingly provide a mechanism for the comprehensive assessment of activities that are likely to have more significant environmental impacts. The Table 5 below identifies the listed activities the proposed project triggers and consequently requires authorisation prior to commencement.

Table 5: NEMA listed activities to be authorised

Activity	Activity Description	Applicability
Listing Notice 2 Activity 18	Any activity including the operation of that activity which requires an exploration right in terms of section 79 of the Mineral and Petroleum Resources Development Act, **as well as any other applicable activity as contained in this Listing Notice, in Listing Notice 1 of 2014 or in Listing Notice 3 of 2014, required to exercise the exploration right**[1], excluding (a) any desktop study; (b) any arial survey; (c) any onshore seismic survey which is included in activity 21C in Listing Notice 1 of 2014, in which case that activity applies; (d) a hydraulic fracturing activity which is included in activity 20A, in which case activity 20A of this Notice applies; and (e) the processing of a petroleum resource, including the beneficiation or refining of gas, oil or petroleum products, in which case activity 5 of this Notice applies.	The undertaking of exploration activities within the Block 3B/4B offshore area, requires an Exploration Right in terms of the MPRDA.

3.2.10 ENVIRONMENTAL AND SOCIAL CONTEXT

A detailed description of the receiving environment is provided in Section 8 of the EIA Report.

3.2.11 STAKEHOLDER ISSUES AND COMMENTS

Please refer to Section 7 and Appendix 2 of the EIA Report. The following main concerns were raised during the public participation with regards to closure:

- Well plugging and abandoning of the wellhead; and
- Well failure leading to releases from abandoned wells.

3.3 ENVIRONMENTAL RISK ASSESSMENT

Please refer to Section 9 of the EIA Report. The decommissioning, closure or post closure phase impacts were identified and described in detail in the EIA Report and are presented in Table 6 below. A final significance score of < -9 denotes a Low negative impact (i.e. where this impact would not have a direct influence on the decision to develop in the area), while a score of ≥ -9 < -17 denotes a Medium negative impact (i.e. where the impact could influence the decision to develop in the area).

[1] It is understood that bolded section was included in the Listed Activity 18 in order to ensure that it would not be required to apply for the "*other applicable activity as contained in this Listing Notice, in Listing Notice 1 of 2014 or in Listing Notice 3 of 2014, required to exercise the exploration right*". This understanding has been clarified with the Department of Forestry, Fisheries and the Environment (DFFE). As such, it is not required to apply for additional listed activities.

Table 6: Identified environmental impact associated with the decommissioning, closure or post closure phases

Discipline	Impact	Phase	Pre-Mitigation ER	Post-mitigation ER	Final score
Marine Ecology	Routine Operational Discharges to Sea	Decommissioning	-4	-3	-3.00
Marine Ecology	Lighting from Drill Unit and Vessels	Decommissioning	-4	-3	-3.00
Marine Ecology	Drilling and Placement of Infrastructure on the Seafloor	Rehab and Closure	-4	-3	-3.00
Marine Ecology	Disturbance, behavioural changes and avoidance of feeding and/or breeding areas in seabirds, seals, turtles and cetaceans due to drilling and vessel noise (continuous noise)	Decommissioning	-4.00	-3.00	-3.00
Marine Ecology	Impacts of infrastructure and residual cement on marine biodiversity - Wellhead removal	Decommissioning	-1.25	-1.25	-1.25
Marine Ecology	Impacts of infrastructure and residual cement on marine biodiversity - Wellhead Abandonment	Decommissioning	-2.75	-2.25	-2.25
Marine Ecology	Unplanned Collision of Vessels with Marine Fauna	Decommissioning	-4.00	-3.00	-3.00
Marine Ecology	Unplanned Loss of Equipment	Decommissioning	-1.25	-1.25	-1.25
Marine Ecology	Unplanned Oil release to the sea due to vessel collisions, bunkering accident and line / pipe rupture	Decommissioning	-9.75	-3.00	-3.00
Fisheries	Vessel and Drilling Noise	Decommissioning	-5.25	-5.25	-5.25

3.4 ENVIRONMENTAL INDICATORS AND MONITORING

Please refer to the EMPr (Appendix 5 of the EIA Report) for the mitigation measures associated with the decommissioning, closure or post closure phases, as well as the relevant performance indicators and monitoring requirements.

3.5 DESIGN PRINCIPLES

3.5.1 LEGISLATIVE AND GOVERNANCE FRAMEWORK

The requirement for final rehabilitation and decommissioning stems primarily from the legislative requirements of the MPRDA and the NEMA. The relevant extracts from each of these are presented in this section. Please also refer to Section 4 of the EIA Report for an overview of other enviro-legal requirements which may influence closure planning. The requirement for final rehabilitation and decommissioning stems primarily from the legislative requirements of the MPRDA and the NEMA. The relevant extracts from each of these are presented in this section.

3.5.1.1 MINERAL AND PETROLEUM RESOURCES DEVELOPMENT REGULATIONS

The following extracts from the MPRDA Regulations are specifically applicable to the preparation of this FRDCP:

- Regulation 30(1) An exploration work programme must contain –
    - (h) an estimate of the expenditure to be incurred for each stage of the exploration operation where the expenditure must be broken down into -

      (i) exploration costs; and

      (ii) costs pertaining to the rehabilitation and management of environmental impacts.
- (3) Quarterly progress reports must be submitted within 21 days of the end of the particular quarter of the year
    - (v) a statement reflecting rehabilitation work completed and the rehabilitation work uncompleted.
- and must include-Regulation 31(4) Annual progress reports must be submitted within 60 days of calendar year end and must include -
    - (v) a statement reflecting rehabilitation work completed and rehabilitation work uncompleted.

3.5.1.2 NATIONAL ENVIRONMENTAL MANAGEMENT ACT (ACT 107 OF 1998)

Prior to 8 December 2014, the environmental aspects of exploration activities were regulated in terms of the MPRDA. Recent legislative amendments and the drive towards a 'one environmental system' have resulted in the inclusion of the requirement for rehabilitation and decommissioning and associated financial provisions into the NEMA. Specific sections of the act are extracted below:

- Section 24P: Financial provision for remediation of environmental damage:

  (1) An Applicant for an environmental authorisation relating to prospecting, exploration, mining or production must, before the Minister responsible for mineral resources issues the environmental authorisation, comply with the prescribed financial provision for the rehabilitation, closure and ongoing post decommissioning management of negative environmental impacts.

  (2) If any holder or any holder of an old order right fails to rehabilitate or to manage any impact on the environment, or is unable to undertake such rehabilitation or to manage such impact, the Minister responsible for mineral resources may, upon written notice to such holder, use all or part of the financial provision contemplated in subsection (1) to rehabilitate or manage the environmental impact in question.

  (3) Every holder must annually-

  a. assess his or her environmental liability in a prescribed manner and must increase his or her financial provision to the satisfaction of the Minister responsible for mineral resources; and

b. submit an audit report to the Minister responsible for mineral resources on the adequacy of the financial provision from an independent auditor.

(4) (a) If the Minister responsible for mineral resources is not satisfied with the assessment and financial provision contemplated in this section, the Minister responsible for mineral resources may appoint an independent assessor to conduct the assessment and determine the financial provision. (b) Any cost in respect of such assessment must be borne by the holder in question.

(5) The requirement to maintain and retain the financial provision contemplated in this section remains in force notwithstanding the issuing of a closure certificate by the Minister responsible for mineral resources in terms of the Mineral and Petroleum Resources Development Act, 2002 to the holder or owner concerned and the Minister responsible for mineral resources may retain such portion of the financial provision as may be required to rehabilitate the closed mining or prospecting operation in respect of latent, residual or any other environmental impacts, including the pumping of polluted or extraneous water, for a prescribed period.

(6) The Insolvency Act, 1936 (Act No. 24 of 1936), does not apply to any form of financial provision contemplated in subsection (1) and all amounts arising from that provision.

(7) The Minister, or an MEC in concurrence with the Minister, may in writing make subsections (1) to (6) with the changes required by the context applicable to any other application in terms of this Act.

3.5.1.3 FINANCIAL PROVISIONING REGULATIONS

On 20th November 2015 the Minister promulgated the Financial Provisioning Regulations under the NEMA. The regulations aim to regulate the determine and making of financial provision as contemplated in the NEMA for the costs associated with the undertaking of management, rehabilitation and remediation of environmental impacts from prospecting, exploration, mining or production operations through the lifespan of such operations and latent or residual environmental impacts that may become known in the future. These regulations provide for, inter alia:

- Determination of financial provision: An Applicant or holder of a right or permit must determine and make financial provision to guarantee the availability of sufficient funds to undertake rehabilitation and remediation of the adverse environmental impacts of prospecting, exploration, mining or production operations, as contemplated in the Act and to the satisfaction of the Minister responsible for mineral resources.
- Scope of the financial provision: Rehabilitation and remediation; decommissioning and closure activities at the end of operations; and remediation and management of latent or residual impacts.
- Regulation 6: Method for determining financial provision – An Applicant must determine the financial provision through a detailed itemisation of all activities and costs, calculated based on the actual costs of implementation of the measures required for:
    - Annual rehabilitation – annual rehabilitation plan
    - Final rehabilitation, decommission and closure at end of life of operations – rehabilitation, decommissioning and closure plan; and
    - Remediation of latent and residual impacts – environmental risk assessment report.
- Regulation 10: An Applicant must-
    - ensure that a determination is made of the financial provision and the plans contemplated in regulation 6 are submitted as part of the information submitted for consideration by the Minister responsible for mineral resources of an application for environmental authorisation, the associated environmental management programme and the associated right or permit in terms of the Mineral and Petroleum Resources Development Act, 2002; and
    - Provide proof of payment or arrangements to provide the financial provision prior to commencing with any prospecting, exploration, mining or production operations.
- Regulation 11: Requires annual review, assessment and adjustment of the financial provision. The review of the adequacy of the financial provision including the proof of payment must be independently audited (annually) and included in the audit of the EMPR as required by the EIA regulations.

3.5.2 CLOSURE VISION, OBJECTIVE AND TARGETS

The vision, and consequent objective and targets for rehabilitation, decommissioning and closure, aim to reflect the local environmental and socio-economic context of the project, and to represent both the corporate requirements and the stakeholder expectations.

The receiving environment within which the activities will be undertaken include the following key uses:

- Critical biodiversity Areas (CBA);
- Oil and gas exploration;
- Fishing grounds;
- Maritime shipping; and
- Telecommunication infrastructure.

With reference to Section 3.2.11, the stakeholders have been consulted during the public participation process for the EIA and their comments relating to closure, decommissioning and rehabilitation have been considered in terms of this document.

With reference to both the environmental context of the project and the feedback from the consultation process the vision for closure is to: <u>Ensure that the post closure use aligns with the surrounding use and does not affect the sustained utilisation of the environment.</u>

In practice the post closure use will depend on the pre-exploration use applicable to the specific location of the exploration activities. This FRDCP aim to address the key closure objectives which are likely to remain consistent for the majority of the exploration activities.

Driven by the closure vision and with due consideration of the project context the following closure objectives are presented:

- Set the course for eventual ecosystem restoration, including the restoration of the natural vegetation community, and wildlife habitats;
- Prevent future environmental issues related to exploration areas;
- Protection of natural ecosystem resources; and
- Ensure that activity area is usable, in alignment with surrounding uses (specifically continued use of the area for prevailing fishing activities, and marine traffic).

Please refer to Section 3.4 above for the stipulated targets related to these closure objectives.

3.5.3 ALTERNATIVE CLOSURE AND POST CLOSURE OPTIONS AND MOTIVATION

There are various alternative closure and post closure options available. The identification and consideration of the most suitable alternatives are driven by, inter alia the following considerations:

- The ability of the selected alternative to adequately meet the specified closure vision and objectives;
- The efficiency, viability, and practicality of the selected alternative.
- The alignment with the local environmental and socio-economic context and associated opportunities and constrains.

As mentioned previously the final closure and decommissioning of an exploration site must be pre-empted by a site-specific assessment (i.e. in this case via pre-drilling surveys and ROV inspection) and where applicable the implementation of the most appropriate rehabilitation and closure strategy. Furthermore, the annual review of this FRDCP must where applicable include an assessment and adjustment of the closure strategy to reflect the most recent technical development and industry best practice, as well as any lessons learnt from the implementation of closure on this project. The available closure options considered for this project are described below:

3.5.3.1 WELL SEALING AND PLUGGING

The purpose of well sealing and plugging is to isolate permeable and hydrocarbon bearing formations as well as independently distinct flow (fluid or gas) zones. Well sealing and plugging aims to restore the integrity of the formation that was penetrated by the wellbore. The identification of differential flow zones and requirements for barrier placement will be determined during the initial well bore drilling and the site specific closure and plugging plan adjusted for the specific well. The principal technique applied to prevent cross flow between permeable formations is plugging of the well with cement, thus creating an impermeable barrier between two zones.

Once drilling and logging have been completed, the exploration wells will be sealed with cement plugs, tested for integrity and abandoned according to international best practices. Cement plugs will be set to isolate hydrocarbon bearing and / or permeable zones and cementing of perforated intervals (e.g. from well logging activities) will be evaluated where there is the possibility of undesirable cross flow. These cement plugs are set in stages from the bottom up. Three cement plugs would be installed: i.e. one each for isolation of the deep reservoir and the main reservoir; and a third as a second barrier for the main reservoir. Additional plugs may be required depending on the geological profile of the well bore, as determined during initial drilling and logging.

The integrity of cement plugs can be tested by a number of methods. The cement plugs will be tag tested (to validate plug position) and weight tested, and if achievable then a positive pressure test (to validate seal) and/or a negative pressure test will be performed. Additionally, a flow check may be performed to ensure sealing by the plug. Once the well is plugged, seawater will be displaced before disconnecting the riser and the BOP.

3.5.3.2 DEMOBILISATION PHASE

On productive wells, it may be decided to abandon the wellheads on the seafloor after installation of over trawlable protective equipment. The risk assessment criteria will consider factors such as the water depth and use of the area by other sectors (e.g. fishing).

Since wellhead abandonment would result in a more permanent (although very low) impact, it is recommended that wellhead removal be implemented, unless the wells have been identified as potential future production wells.

With the exception of the over trawlable protective equipment over abandoned wellheads and drilling discharges deposited on the seabed, no further physical remnants of the drilling operation will be left on the seafloor. A final clearance survey check will be undertaken using an ROV. The drilling unit and supply vessels will demobilise from area of interest.

3.5.4 CLOSURE PERIOD AND POST CLOSURE REQUIREMENTS

The closure period is defined as the period between the cessation of exploration activities. It is important to note that the nature of exploration drilling is such that closure may be implemented for individual wells as and when the testing and analysis ends.

Since wellhead abandonment would result in a more permanent (although very low) impact, it is recommended that wellhead removal be implemented, unless the wells have been identified as potential future production wells.

3.5.5 ASSUMPTIONS AND LIMITATIONS

The following assumptions and limitations apply to this FRDCP:

- The following assumptions have been made and used as the basis for the financial provision calculations:
    - Post closure land form to resemble the pre-drilling land form as close as possible;
    - Depth per borehole: ~3 500m below the seafloor;
    - The closure actions will commence as soon as a borehole is abandoned; and
    - It is assumed that the well will be plugged/ cemented as described above.

- It is assumed that the management and mitigation measures suggested in the EIA Report relating to environmental management will be complied with. This includes post drilling clean-up and rehabilitation; and
- It is assumed that the drilling, will be carried out in accordance with industry best practice.

4 FINAL POST EXPLORATION USES

Considering the extremely limited extent of each well, and considering the closure actions proposed, it is anticipated that the normal uses occurring in the area will be able to continue unabated post closure of the individual wells. For the purposes of this FRDCP it is assumed that the post closure use will continue to be:

- Critical biodiversity Areas (CBA);
- Oil and gas exploration;
- Fishing grounds;
- Maritime shipping; and
- Telecommunication infrastructure.

Residual impacts post completion of the exploration activities are limited (if any) and therefore there will be no requirements for further closure, decommissioning and rehabilitation actions. The overall closure objective will be to ensure that the post closure environment aligns with the pre-project environment.

4.1 CLOSURE ACTIONS

It should be noted that it is anticipated that the activities will have a limited impact on the receiving environment. The rehabilitation and closure actions required in terms of this project will be limited to (as described Section 3.5.3):

- Well sealing and plugging; and
- Demobilisation.

Residual impacts post completion of the exploration activities are limited (if any) and therefore there will be no requirements further (additional) post closure activites. The overall closure objective will be to ensure that the post closure environment aligns with the pre-project environment.

4.1.1 WELL SEALING AND PLUGGING

The purpose of well sealing and plugging is to isolate permeable and hydrocarbon bearing formations as well as independently distinct flow (fluid or gas) zones. Well sealing and plugging aims to restore the integrity of the formation that was penetrated by the wellbore. The identification of differential flow zones and requirements for barrier placement will be determined during the initial well bore drilling and the site specific closure and plugging plan adjusted for the specific well. The principal technique applied to prevent cross flow between permeable formations is plugging of the well with cement, thus creating an impermeable barrier between two zones.

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On productive wells, it may be decided to abandon the wellheads on the seafloor after installation of over trawlable protective equipment. The risk assessment criteria will consider factors such as the water depth and use of the area by other sectors (e.g. fishing).

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With the exception of the over trawlable protective equipment over abandoned wellheads and drilling discharges deposited on the seabed, no further physical remnants of the drilling operation will be left on the seafloor. A final clearance survey check will be undertaken using an ROV. The drilling unit and supply vessels will demobilise from area of interest.

4.1.3 ADDITIONAL WORK FOR ABANDONMENT PROGRAMME

Well Abandonment program detailing design will be developed and refined as the project progresses. Site specific oil spill contingency plan (OSCP) will be compiled and submitted for South African Maritime Safety Authority (SAMSA) approval before any commencement of operations. Further refinement of the estimated abandonment costs to a greater level of detail and accuracy considering the final well information and the applicable program for that particular well. The actual closure strategies will differ from well to well, depending on the geological profile. Following well development, a well specific decommissioning and closure plan should be developed for each well.

4.1.4 ADDITIONAL DECOMMISSIONING ACTIVITIES

The well abandonment cost estimates and the entire required framework will be maintained as a live document and updated with more information which comes available as the project matures. This new information will become available through changing market conditions, new studies and better understanding of the actual borehole configuration.

Once the well locations have been defined, a specific OSCP will be prepared which will be subject to SAMSA approval. It is standard practice to have this internal document prepared and aligned with local and national regulations under the South African National Oil Spill Contingency Plan (NOSCP) which includes applicable international conventions.

The applicant will conduct a final well clearance survey utilising a ROV under a separate contract to ensure and certify that the abandoned well has its wellhead has been removed and there are no physical remnants of the drilling operation. The drillship and support vessels will be demobilised from the well location. The onshore base will be closed post the termination of all drilling and associated operations.

4.2 ORGANISATIONAL CAPACITY

Capacity of the following key roles and responsibilities must be provided for the following:

4.2.1 APPLICANT

The Applicant/ Operator will remain primarily responsible for meeting the environmental and social commitments for the drilling project. The Applicant will engage competent personnel that will manage and execute the abandonment and demobilisation aspects of the drilling program. The abandonment program will be supported by clearly defined roles included in the Engineering Drilling Plan which will be validated by the operator before the commencement of any closure program post the well drilling completion.

4.2.2 INDEPENDENT ENVIRONMENTAL ASSESSMENT PRACTITIONER

This individual will be appointed to ensure compliance with the requirements of the FRDCP and specifically to undertake the following tasks:

- Undertake pre-closure environmental site assessment and risk assessment;

- Prepare a site-specific final closure and decommissioning plan; and
- Undertake the required periodic compliance monitoring and reporting during the closure period.

4.2.3 EXPLORATION SPECIALIST

This individual must be a suitably qualified professional who must have relevant experience in exploration. Key attributes must include experience and qualifications related to the technologies applicable to exploration site closure, as well as a thorough understanding of internationally accepted closure standards and guidelines. This specialist will be responsible for ensuring that the closure plan is implemented to ensure that the risks to the environment and surrounding communities are prevented or limited.

4.2.4 TRAINING AND CAPACITY BUILDING

Further education, training and capacity building is critical to ensure that the exploration activities align with evolving internally accepted best practice and research. In this regard the Applicant must ensure that regular review of international best practice is undertaken and where applicable implemented throughout the exploration programme.

As part of the drilling work program there will be opportunity for local technical staff selected by PASA to attend certain operations executed by the Applicant in the block to gain on site experience. The Applicant will encourage the use of local service companies to gain experience in the offshore drilling activities which will be controlled under stringent Oil and Gas HSE requirements for the offshore drilling operations.

4.3 IDENTIFICATION OF CLOSURE PLAN GAPS

The key gaps applicable to this closure plan are as follows:

- The geological stratigraphy and nature of the borehole profiles will only be confirmed during drilling and will be a determining factor in the planning for closure and decommissioning.
- The specific plug material and the location of the plug barriers ill only be confirmed during drilling.

The following actions have been proposed to address these gaps:

- A detailed drilling log will be prepared and maintained for each of the wells to ensure that the specific geological stratigraphy and sub-surface conditions are considering and inform the final site specific closure and decommissioning plan, and would specify the location of suitable plug barriers.

4.4 RELINQUISHMENT CRITERIA

Relinquishment can be defined as the formal approval by the relevant regulating authority indicating that the completion criteria for the exploration activity have been met to the satisfaction of the authority. In this regard the relinquishment criteria are driven by the objectives of closure and consequently the indicators applicable to each impact associated with the closure and decommissioning of the prospecting boreholes. In this regard reference is made to the EMPr, which presents each identified environmental impact, the associated indicators and proposed closure targets. In summary the proposed relinquishment criteria include:

- Well Sealing and Plugging: Effective zone isolation within the well bore and no hydrocarbon or fluid releases from the well bore.
- Other Uses: no obstacle to ongoing use (e.g. fishing or marine traffic).

4.5 CLOSURE COST

This section provides details on the proposed closure cost. The assumptions and limitations stated in Section 3.5.5 and Section 4.5.3, also underpin the basis of this closure cost determination.

4.5.1 CLOSURE COST METHODOLOGY

The closure cost has been calculated through the following steps:

- Applicable exploration activities are listed;

- Applicable closure actions listed for each activity;
- Cost items are listed for each action;
- Cost units and rates determined for each item (where possible on the basis of actual quotations); and
- Total cost is calculated.

4.5.2 CLOSURE COST ESTIMATION

This closure cost is based on 2023 values and will require annual reassessment, revision and escalation. The preliminary estimate of the closure cost is (inclusive of contingencies and VAT in Unites States Dollar) per well is provided in Table 7[2].

4.5.3 CLOSURE COST ASSUMPTIONS AND LIMITATIONS

Abandonment operations will be executed at the declaration by the Joint Venture is satisfied that the well has been completed, that is following the drilling results evaluation process and agreement on the forward plan. The estimated costs in the following narrative will not include any emergency measures (unplanned events described in the EIA Report) which will be entirely covered by separate comprehensive insurance cover. The overall costs assumptions will include all rig related expenditures plus all the logistical and service support related costs to carry out the abandonment program as per International Best Practice Code and comply with all the South African Regulatory requirements.

The drillship/rig which will be used for the drilling operation is set at a contractual day rate and the program will be over a few days to finally complete the abandonment program. The most likely scenario for the well is that the well head will be removed after the required plugs are set and that is the assumption made in the costing estimates, which are as follows:

- Drillship/rig costs with a day rate of $400 000.00 to $550 000.00 per day which is included in the full spread rate of approximately ~$1 000 000.00 per day and equates to 5 days for the abandonment operation to be completed;
- Requirement for Engineering completion design studies and the selection of the chemical additives required for the abandonment program;
- Support vessels which will be contracted for the drilling activities which will be utilised during the abandonment program and costed accordingly;
- Additional staff will be sent offshore therefore additional helicopter flights will be required and reflected in the cost estimate; and
- Additional expenditure is required for service company who operate and support ROV work to confirm well completion/ wellhead removal and certify the well closure.
- Included is a 10% contingency to allow for any variances in the cost estimates.

Based on the operational requirements for the abandonment program estimated costs have been categorised into activities associated with the exploration.

- Offshore operational costs which includes all operations on the drillship/rig;
- Operational execution costs, those which will be expensed on the abandonment programme; and
- The Onshore support component for the abandonment programme.

Table 7: Costs estimates for Well Abandonment Programme

Category	Activity/Item	Cost (USD)
Offshore Operational Costs	Drill Ship	$3 900 000.00

[2] The Closure Costs and all related assumptions have been provided by the Applicant.

Category	Activity/Item	Cost (USD)
	Support Vessels	$650 000.00
	Logistics and Services	$500 000.00
Operation Execution Costs	Consumables (Cement and Plugs)	$650 000.00
	Services	$1 000 000.00
	Engineering Studies	$500 000.00
	Fluid Studies	$100 000.00
Onshore Support Costs	Logistics Base	$200 000.00
	Helicopters	$50 000.00
	Waste Management	$100 000.00
Contingency @10%		$765 000.00
Total Cost Per Well		**$8 415 000.00**

4.6 MONITORING, AUDITING AND REPORTING

The requirement to monitor and audit should be carried through all phases of the proposed exploration activities. Please refer to the EMPr for the details regarding the monitoring of compliance and the specific monitoring tools and outcomes specified.

In accordance with Regulation 11 of the NEMA Financial Provisioning Regulations the Applicant must ensure annual review of the annual rehabilitation plan, the final rehabilitation decommissioning and closure plan, as well as the environmental risk assessment. This annual review must be audited by an independent auditor.

It is critical to continue monitoring through to the post- closure phase of the exploration activities. The aim of this being to ensure that the objectives of the rehabilitation and closure plan are met. In this regard it is recommended that the environmental auditing requirements of the NEMA EIA Regulations, 2014, as amended by followed.

5 ANNUAL REHABILITATION PLAN

The annual rehabilitation plan aims to:

a) review concurrent rehabilitation and remediation activities already implemented;

b) establish rehabilitation and remediation goals and outcomes for the forthcoming 12 months, which contribute to the gradual achievement of the post-exploration use, closure vision and objectives identified in the holder's final rehabilitation, decommissioning and closure plan;

c) establish a plan, schedule and budget for rehabilitation for the forthcoming 12 months;

d) identify and address shortcomings experienced in the preceding 12 months of rehabilitation; and

e) evaluate and update the cost of rehabilitation for the 12 month period and for closure, for purposes of supplementing the financial provision guarantee or other financial provision instrument.

Considering that well abandonment will be undertaken immediately, it is anticipated that an annual rehabilitation plan will not be required.

6 ENVIRONMENTAL RISK ASSESSMENT – LATENT AND RESIDUAL ENVIRONMENTAL IMPACTS

According to the Financial Provisioning Regulations (2015) the objective of the environmental risk assessment report that relates to latent and residual impacts is to:

- ensure timeous risk reduction through appropriate interventions;
- identify and quantify the potential latent environmental risks related to post closure;
- detail the approach to managing the risks;
- quantify the potential liabilities associated with the management of the risks; and
- outline monitoring, auditing and reporting requirements.

This section of the report aims to address these objectives separately in cases where they have not been considered in previous sections.

6.1 THE ASSESSMENT PROCESS USED AND DESCRIPTION OF LATENT ENVIRONMENTAL RISK

Section 9 of the EIA Report provides a detailed description of the environmental impact/risk identification and assessment (including the methodology and findings) undertaken for the proposed exploration activities. The EIA Report and EMPr have identified mitigation measures which, once implemented successfully, will result in the avoidance or acceptable reduction of the associated impact.

Latent risks include potential well leaks in the future as a result of well failure. Monitoring of potentially future production wells has been included and it is recommended that the Applicant should put in place the relevant insurances to deal with potential well failure.

Residual risks include:

- Potential impact on hardground communities as a result of the deposition of drill cuttings and sediment. This risk can be mitigated through the mitigation measures included in the EIA Report and EMPr.
- Damage to fishing equipment as a result of well infrastructure on the seafloor. This risk can be mitigated through the mitigation measures included in the EIA Report and EMPr.

6.2 MANAGEMENT ACTIVITIES, COSTING AND MONITORING REQUIREMENTS

New international best practice guidelines that may be developed in the future, other than those already referred to in the EIA Report and EMPr, and would need to be considered at such time. In addition, monitoring results and auditing reports, will inform the risk assessment further. No management activities or monitoring requirements were identified for the closure and post closure phase.