The Petroleum Oil and Gas Corporation of South Africa (Pty Ltd)
Reg. No. 1970/008130/07

~~DRAFT~~

ENVIRONMENTAL MANAGEMENT PROGRAMME

F-O PRODUCTION AREA

DOCUMENT DATE	REVISION
May 2011	00
March 2026	01

PREFACE AND ACKNOWLEDGMENTS

This Environmental Management Programme (EMPr) has been prepared for the development of the F-O Gas Field in terms of the Environmental Impact Assessment (EIA) Regulations 2006 and the transitional arrangements of the EIA Regulations 2010 in terms of the National Environmental Management Act, 1998 (No. 107 of 1998) (NEMA), as amended, and the Mineral and Petroleum Resources Development Act, 2002 (No. 28 of 2002) (MPRDA), as amended, and Regulations thereto.

In order to maintain consistency between PetroSA's various oil and gas operations, this EMPr has as its basis PetroSA's existing EMPrs for exploration well drilling and production in Block 9. Where necessary, they have been updated in light of the findings and recommendations of the EIA undertaken by CCA Environmental (Pty) Ltd for the development of the F-O Gas Field. All significant changes to the Environmental Protection Activities for well drilling (see Section 3) and production (see Section 5) are underlined and in a different font (Times New Roman) to the rest of the text.

TEAM: SUMMARY OF QUALIFICATIONS AND EXPERIENCE

Jonathan Crowther – CCA Environmental (Pty) Ltd, Cape Town.

RESPONSIBILITY ON PROJECT	Project leader and quality control.
Qualifications	B.Sc. Hons (Geol.), M.Sc. (Env. Sci.)
PROFESSIONAL REGISTRATION	Pr.Sci.Nat., CEAPSA
EXPERIENCE IN YEARS	23
EXPERIENCE	Jonathan Crowther has been involved in environmental consulting since 1988 and is currently the Managing Director of CCA Environmental (Pty) Ltd. He has expertise in a wide range of environmental disciplines, including Environmental Impact Assessments (EIA), Environmental Management Plans / Programmes, Environmental Planning & Review, Environmental Auditing & Monitoring, Environmental Control Officer, Public Consultation & Facilitation. He has project managed a number of offshore oil and gas EIAs for various exploration and production activities in South Africa and Namibia. He also has extensive experience in projects related to roads, property developments and waste landfill sites.

Jeremy Blood – CCA Environmental (Pty) Ltd, Cape Town.

RESPONSIBILITY ON PROJECT	Project management, report writing and specialist study review.
QUALIFICATIONS	B.Sc. Hons (Bot.), M.Sc. (Cons. Ecol.)
PROFESSIONAL REGISTRATION	Pr.Sci.Nat., CEAPSA
EXPERIENCE IN YEARS	12
EXPERIENCE	Jeremy Blood has been working as an environmental assessment practitioner since 1999 and has project managed a number of large-scale projects covering a range of environmental disciplines, including Environmental Impact Assessments (EIA), Environmental Management Plans / Programmes, Environmental Auditing & Monitoring and Environmental Control Officer related work in South Africa, Mozambique and Kenya. He has expertise in a wide range of projects relating to mining (gas, heavy mineral mining and borrow pits), housing / industrial developments and infrastructure projects (e.g. roads, railway line, power lines, pipelines).

Revision 1 Team- EIMS

Revisions to the EMPr undertaken for Revision #01 were undertaken by Liam Whitlow form EIMS. Liam Whitlow is an experienced Environmental Scientist with a B.Sc. Honours in Environmental Management and over 25 years of professional experience. Liam is a registered Environmental Assessment Practitioner and Professional Natural Scientist. His expertise includes environmental impact assessments, project management, and environmental monitoring, with significant experience in the oil and gas, mining and infrastructure sectors.

DOCUMENT CONTROL, REVISION AND REVIEW

DOCUMENT CONTROL	***DOCUMENT NO:***

DOCUMENT REVISION CONTROL		
REVISION DATE ~~PAGE NUMBER/S~~	***REVISION # ~~CHANGE LOCATED~~***	***DESCRIPTION OF REVISION ~~DATE OF ISSUE~~***
2011/05	***00***	***EMPr prepared CCA Environmental (Pty) Ltd (CCA)***
2026/03/05	***02***	***EMPr Amendment prepared by Environmental Impact Management Services (Pty) Ltd (EIMS)- based on 2025 Environmental Audit EMPr – Amendments in blue text***

ROUTING SLIP FOR LAST REVISION NUMBER			
ROLE	***NAME***	***POSITION***	***REVIEW DATE***
REVIEWER 1	*Jessica Courtoreille*	*Environmental Leader*	*31 May 2011*
Reviewer 2	*Renay Pillay*	*PetroSA HSEQ: Environment*	*March 2026*
Reviewer 3	*Patrick Malahe*	*Upstream Reliability Manager*	*March 2026*
Reviewer 4	*Dian John*	*Environmental Leader*	*March 2026*

TABLE OF CONTENTS

ACTIVITIES 3.4	POLLUTION PREVENTION
ACTIVITY 3.5	RIG ESTABLISHMENT AND REFUELLING
ACTIVITY 3.6	DRILL CUTTINGS AND DRILL FLUIDS
ACTIVITIES 3.7-3.9	GENERAL WASTE MANAGEMENT, EFFLUENT DISCHARGE AND GASEOUS EMISSIONS
ACTIVITY 3.10	INCIDENTS AND EMERGENCY REPORTING AND MANAGEMENT
ACTIVITY 3.11	WELL SUSPENSION AND ABANDONMENT
ACTIVITY 3.12	SYSTEM ADMINISTRATIVE REQUIREMENTS
SECTION 4.	***TABLE OF ENVIRONMENTAL PROTECTION ACTIVITIES FOR CONSTRUCTION***
	LAYOUT OF THE TABLE
ACTIVITIES 4.1	PLANNING PHASE
ACTIVITY 4.2	STAKEHOLDER ENGAGEMENT
ACTIVITY 4.3	ENVIRONMENTAL TRAINING AND AWARENESS
ACTIVITIES 4.4	POLLUTION PREVENTION
ACTIVITY 4.5	INFRASTRUCTURE POSITIONING & REFUELLING
ACTIVITIES 4.6-4.8	GENERAL WASTE MANAGEMENT, EFFLUENT DISCHARGE AND GASEOUS EMISSIONS
ACTIVITY 4.9	INCIDENTS AND EMERGENCY REPORTING AND MANAGEMENT
ACTIVITY 4.10	SYSTEM ADMINISTRATIVE REQUIREMENTS
SECTION 5	***TABLE OF ENVIRONMENTAL PROTECTION ACTIVITIES FOR PRODUCTION***
	LAYOUT OF THE TABLE
ACTIVITIES 5.1-5.3	POLLUTION PREVENTION UNDER NORMAL OPERATING CONDITIONS

ACTIVITIES 5.4-5.6	WASTE MANAGEMENT
ACTIVITY 5.7	INCIDENTS AND EMERGENCY REPORTING AND MANAGEMENT
ACTIVITY 5.8	STAKEHOLDER ENGAGEMENT
ACTIVITY 5.9	ENVIRONMENTAL TRAINING AND AWARENESS
ACTIVITY 5.10	SYSTEM ADMINISTRATIVE REQUIREMENTS
ACTIVITY 5.11	DECOMMISSIONING

ACRONYMS & ABBREVIATIONS USED IN THE EMPR

µg chl*a*/litre	micrograms of chlorophyll 'a' per litre
mg C/m^2/hr	milligrams of carbon per square meter per hour
BOP	Blow Out Preventer
CALM	Catenary Anchor Leg Mooring
DAFF	Department of Agriculture, Fisheries and Forestry
DEA	Department of Environmental Affairs
DMR	Department of Mineral Resources
DNV	Det Norske Veritas
EEZ	Exclusive Economic Zone
EMPrs	Environmental Management Programmes
E&P	Exploration and Production
EXCO	PetroSA Executive Committee
FPF	Floating Production Facility
FPSO	Floating Production Storage and Off-loading vessel
GTL	Gas to Liquid
ICMA	Integrated Coastal Management Act (24 of 2008)
JOC	Joint Operations Centre
MANCO	PetroSA Management Committee
MARPOL	International Convention for the Prevention of Pollution from Ships 73/78
MPAs	Marine Protected Areas
MEG	Mono Ethyl Glycol
MPCCLA	Marine Pollution (Control and Civil Liability) Act (6 of 1981)
MPRDA	Minerals and Petroleum Resources Development Act 28 of 2002
MPRDAA	Minerals and Petroleum Resources Development Amendment Act 49 of 2008
MSDS	Material Safety Data Sheet
NADF	Non Aqueous Drilling Fluid
NEMA	National Environment Management Act 107 of 1998 (as amended)
OHS	Occupational Health and Safety 85 of 1993 (as amended)
OIM	Offshore Installation Manager
PASA	Petroleum Agency of South Africa
PLEM	Pipeline End Manifold – connection system
PPE	Personal Protective Equipment
ROV	Remote Operated Vehicle
SABS	South African Bureau of Standards
SAHRA	South African Heritage Resources Agency
SAMSA	South African Maritime Safety Authority
SCG	South Coast Gas
SHEQ	Safety, Health, Environment and Quality
UCT	University of Cape Town
UNFCC	United Nations Framework Convention on Climate Change
UNCLOS	United Nations Law of the Sea Convention
UTA	Umbilical Termination Assembly – control system
WBDF	Water Based Drilling Fluid

Section 1: Introduction

1.1 NAME OF PRODUCTION AREA

F-O production area

1.2 CONTACT DETAILS

~~*1.2.1 Construction (including well drilling) Phase*~~

~~Manager: Kevin Robson~~
~~Address: PetroSA (No. 1970/008130/07)~~
~~Private Bag X5 151 Frans Conradie Drive~~
~~PAROW PAROW~~
~~7499 7500~~

~~Telephone: +27 (0)21 929 3338~~
~~Facsimile: +27 (0)21 929 3681~~
~~Cell: +27 (0)71 941 0022~~
~~E-mail: kevin.robson@petrosa.co.za~~

1.2.2 Production Phase

Manager: Ms Nombuso Gumede, Mine Manager ~~Anthony Meyer~~
Address: PetroSA (No. 1970/008130/07)
Private Bag X14 PetroSA Refinery Site
MOSSEL BAY Duinzicht Avenue
6500 6500

Telephone: +27 (0)44 606 6198
Facsimile: +27 (0)44 606 6194
~~Cell: +27 (0)82 396 5211~~
E-mail: NOMBUSO.Gumede@petrosa.co.za ~~anthony.meyer@petrosa.co.za~~

1.3 PRODUCTION AREA AND LOCATION

This EMPr covers the F-O production area in Petroleum License Block 9, located approximately 110 km off the South Coast of South Africa, within what is known as the Bredasdorp Basin.

PetroSA's Block 9 licence area covers a surface area of 22 756 km^2 and currently includes four other production lease areas: FA-EM, South Coast Gas (SCG), Sable and Oribi/Oryx (see Figure 1.1). Each of these production lease areas has its own EMPr. The FA-EM, SCG and Sable lease areas currently produce gas from about 19 wells. The gas flows to the FA Platform where it is processed; condensate is separated out and the gas and condensate are pumped ashore, in two separate lines, to the Gas-to-Liquid (GTL) manufacturing refinery in Mossel Bay. The Oribi/Oryx field currently produces oil from four production wells which flows to and is processed at the ORCA, a floating production facility, from where it is pumped to a buoy for loading onto a shuttle tanker for onward shipment.

The F-O production area covers an area of approximately 275 km^2 with water depths ranging from 125 m to 250 m (see Figures 1.2 & 1.3). The co-ordinates of the F-O production area boundary are provided in Table 1.1.

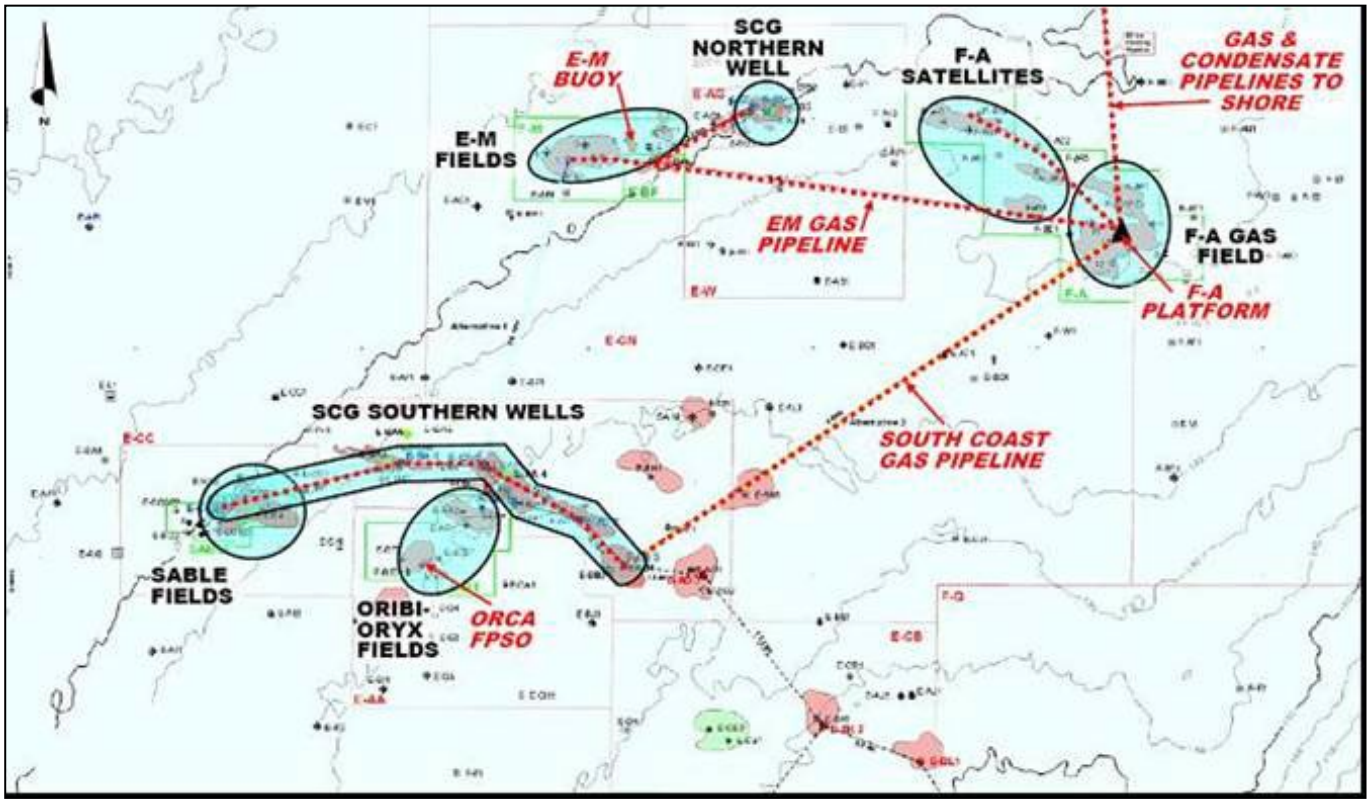


Figure 1.1: Location of all hydrocarbon production areas in Block 9 (source, PetroSA).

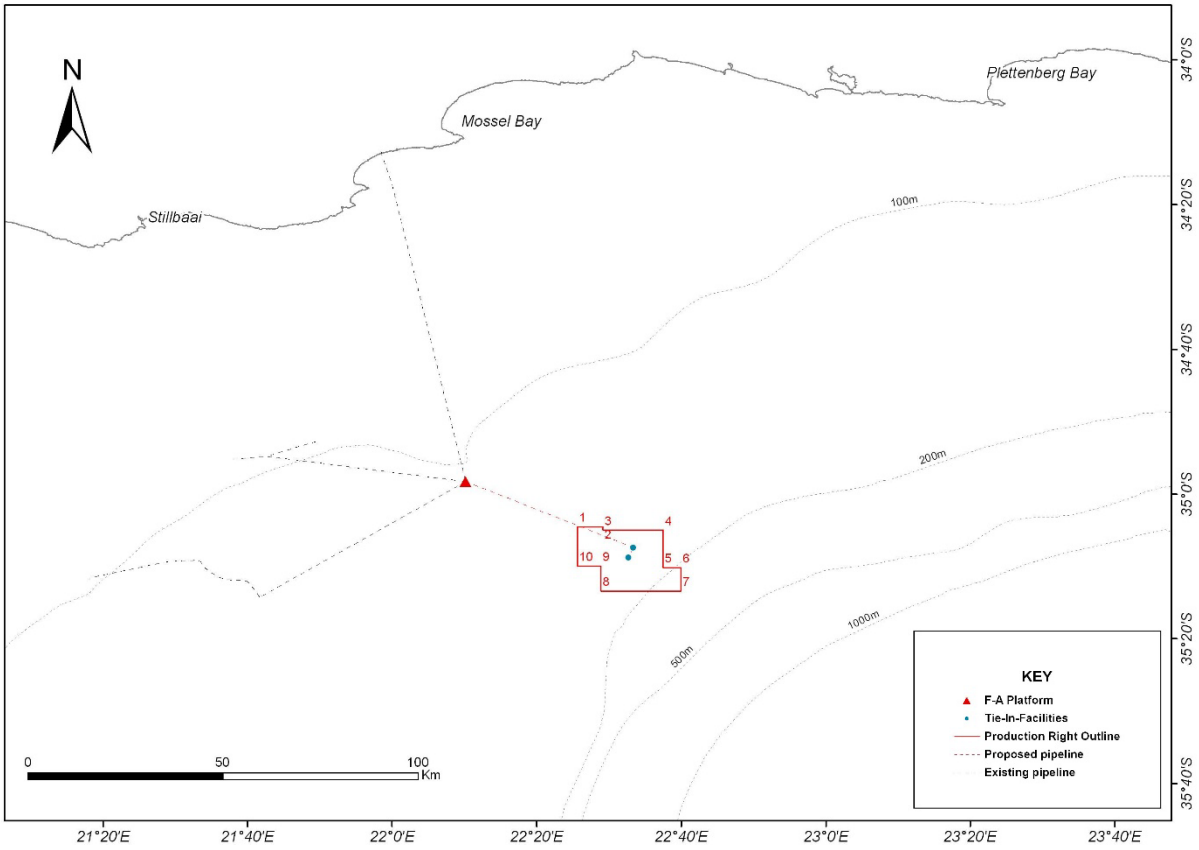


Figure 1.2: Production Right Area for the F-O Gas Field.

Table 1.1: Co-ordinates of the F-O production area.

Points	Co-ordinates (Spheroid WGS 84, Datum Hartbeeshoek 91)	
	Latitude (S)	Longitude (E)
1	35° 04′ 30″	22° 25′ 39″
2	35° 04′ 30″	22° 29′ 09″
3	35° 04′ 57″	22° 29′ 09″
4	35° 04′ 57″	22° 37′ 29″
5	35° 10′ 08″	22° 37′ 29″
6	35° 10′ 08″	22° 39′ 59″
7	35° 13′ 23″	22° 39′ 59″
8	35° 13′ 23″	22° 28′ 54″
9	35° 09′ 55″	22° 28′ 54″
10	35° 09′ 55″	22° 25′ 39″

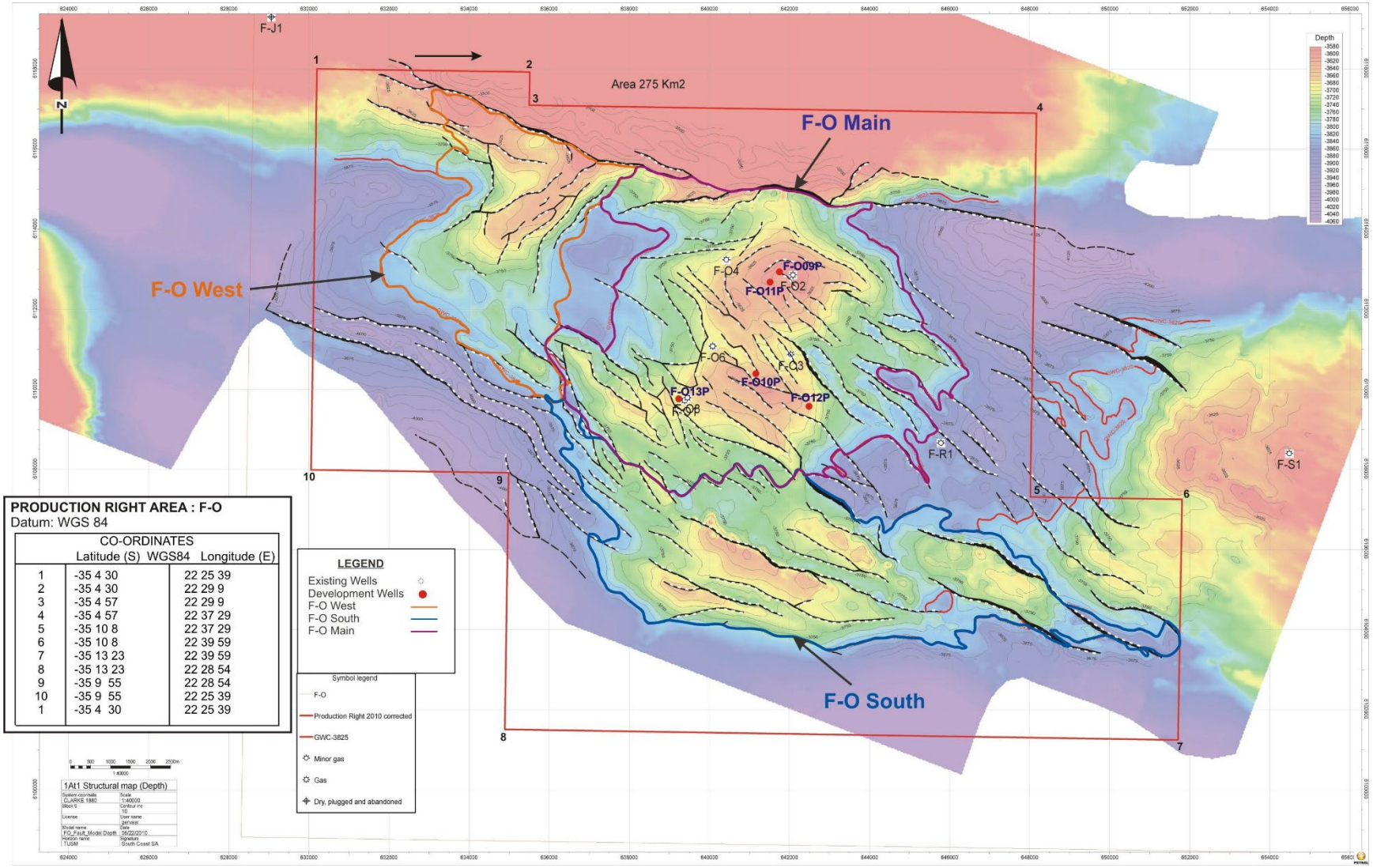


Figure 1.3: F-O production Area showing the tie-in facilities and the anticipated location of five of the Phase 1 wells (Source, PetroSA).

1.4 BRIEF DESCRIPTION OF PROJECT

1.4.1 Introduction

This project involves drilling and collecting gas and condensate (collectively termed "gas") from wells in the F-O Gas Field via a new approximately 39 km subsea production pipeline that will connect each well and route the gas to the existing F-A Platform for processing.

The development of the F-O Gas Field is based on exploratory work undertaken in the area under PetroSA's existing Exploration License and approved EMPr for prospect well drilling in Petroleum Licence Block 9. Six vertical exploration and appraisal wells have been drilled in the F-O Gas Field to date (see Figure 1.3 and Table 1.2). The most recent two wells, F-O6 and F-O8, successfully appraised the field and informed Phase 1 of the field development plan. It is estimated that Phase 1 will extend the operational life of the GTL refinery to at least 2020.

Table 1.2: Existing well location co-ordinates within the F-O Production Right area.

Wells	Operator	Year	Well status	Co-ordinates (Spheroid WGS 84, Datum Hartbeeshoek 91)	
				Latitude	Longitude
F-O1	Soekor	1989	Abandoned	35° 08' 54.05'' S	22° 31' 48.45'' E
F-O2	Soekor	1991	Suspended	35° 07' 10.99'' S	22° 33' 33.34'' E
F-O3	Soekor	1994	Suspended	35° 08' 15.54'' S	22° 33' 32.46'' E
F-O4	Mossgas	2000	Suspended	35° 06' 59.48'' S	22° 32' 27.48'' E
F-O6	PetroSA	2008/09	Suspended	35° 08' 10.16'' S	22° 32' 13.50'' E
F-O8	PetroSA	2008	Suspended	35° 08' 52.13'' S	22° 31' 49.29'' E

1.4.2 Well drilling

PetroSA will drill up to 14 production wells in the F-O Gas Field in two phases. Phase 1 development will consist of four to eight production wells. An additional four to six wells are envisaged as a Phase 2 development, some of which may in fact be exploration wells in the F-O West and F-O South fields. The final number of wells is dependant on the success of the initial four wells and production experience gained during the initial field operation.

The anticipated location of the first four wells is shown in Figure 1.3 and the co-ordinates are presented in Table 1.3. The location of all the remaining wells will be within the F-O production area with the targeted reservoirs identified on Figure 1.3, but the final location is not yet known. The final well location will be based on a number of factors, including geological target; anchoring obstacles; subsea facilities optimisation, etc. The drilling of Phase 1 production wells is expected to commence in the first quarter of 2012.

Table 1.3: Well location co-ordinates for the first four wells in the F-O Production Right area.

Wells	Co-ordinates (Spheroid WGS 84, Datum Hartbeeshoek 91)	
	Latitude	Longitude
F-O2ML 5 and 6	35° 07' 19.8762'' S	22° 33' 23.8903'' E
F-O2ML 2 and 3	35° 07' 20.5752'' S	22° 33' 23.0657'' E
F-O1ML 5 and 6	35° 08' 42.7277'' S	22° 32' 43.8654'' E
F-O1ML 3 and 4	35° 08' 43.4267'' S	22° 32' 43.0405'' E

Note: The well positions are only indicative at this stage and the location could change.

Drilling of the exploration wells will be undertaken with a semi-submersible drilling unit. The drilling unit will be on location for as long as it takes to drill a well before moving on to the next well location. It is anticipated that it will take in the order of 100 days to drill a vertical well to a depth of approximately 4 000 m and up to 200 days to drill a horizontal well up to a depth of 6 000 m. A temporary 500 m statutory safety zone, with a total area 0.8 km^2, will be in force around the drilling unit while it is operational at a well location (i.e. no other vessels except the drilling unit's support vessels may enter this area). A larger safety zone will be required for certain activities (e.g. demersal trawling), as the anchor chains and anchors extend out for some 1 500 m from the drilling unit. The safety zone will be described in a Notice to Mariners as a navigational warning.

During initial drilling (riserless stage) the drill string, with a large bit, is lowered from the drilling unit to initiate hole drilling on the seafloor. All cuttings from this initial drilling are deposited directly onto the seafloor. Following this initial drilling stage, a wellhead is then run on the conductor pipe and cemented in the hole. A marine riser connects the drilling unit to the wellhead. A blow-out preventer (BOP) is run on the riser and connected to the wellhead. Drilling is continued by lowering the drill string, with a smaller bit, through the marine riser into the hole and rotating the drill string, causing the drill bit to crush the rock into small particles called "cuttings".

The cuttings are removed from the bottom of the hole in a drilling fluid or "mud", a specially formulated mixture of natural clays, polymers, weighting agents and/or other materials suspended in a fluid medium. PetroSA has indicated that they will use both a water-based fluid (WBF) and a Group III non-aqueous drilling fluid (NADF) as part of the drilling procedure. The NADF will be used to drill the 12-1/4" and 8-1/2" hole sections.

While drilling is in progress, drilling fluid is continuously pumped down the inside of the hollow drill string. The fluid emerges through holes in the drill bit and then rises (carrying the rock cuttings with it) up the annular space between the sides of the hole (the casing and riser pipe) and the drill string, to the drilling unit floor. Drill cuttings are separated from the drilling fluid by solids control equipment before the mud is re-circulated.

During the drilling of a well, the primary discharge from the drilling vessel is the drilling cuttings. Cuttings range in size from clay to coarse gravel. The composition of the rock particles reflects the types of sedimentary rocks penetrated by the bit. Although most of the drilling fluids are mechanically separated from the drilling cuttings, the discharged cuttings may contain up to 10% drilling fluid. In the event that NADF is

used, the drill cuttings will be treated to reduce their oil content to less than 5% by weight before discharge into the sea. NADF remaining at the end of the well drilling programme will be shipped to the drilling and completions fluids plant in the Mossel Bay Harbour for re-use by PetroSA on future wells or projects, sold for re-use or disposed of through an approved waste disposal company. The drilling and completions fluids plant will allow for the mixing of base fluid, brine and solids to obtain the desired density and rheological properties of the fluid required, as well as the storage and re-use of drilling fluids and completion brines. The plant capacity will comprise of approximately 1 600 to 2 225 m^3 of liquid storage and 200 to 600 metric tonne of dry bulk storage.

Although the probability of a well blow-out is extremely low, it nonetheless provides the greatest environmental concern (biophysical and socio-economic) during drilling operations. The primary safeguard against a blow-out is the drilling fluid. The density of the fluid can be controlled to balance any abnormal formation pressures. Abnormal formation pressures are detected by primary well control equipment. The likelihood of a blow-out is further minimised by employing a BOP, which is a secondary control system. The BOP is installed on the wellhead and is designed to close in the well if flow from the wellbore is detected. It can usually be operated from a number of stations on the drilling unit. This equipment is thoroughly inspected prior to installation and subsequently pressure and function tested on a regular basis.

When a well encounters hydrocarbons, it may be flow-tested to determine its economic potential before the well is either completed or decommissioned. If flow-testing is required, hydrocarbons will be burned at the well site. A high-efficiency flare is used to maximise combustion of the hydrocarbons.

If a well is successful in terms of gas production, a structure containing well control valves commonly called a “Subsea Xmas Tree” (SSXT) will be installed on top of the associated wellhead on completion of drilling. If a well is unsuccessful, it will be decommissioned. The wellhead will be removed with casings cut-off below the seafloor. The well will be plugged with cement and tested for integrity.

1.4.3 Subsea infrastructure

The final form and architecture of the subsea facilities required for the development of the F-O Gas Field are currently under investigation by PetroSA. The details of the subsea facilities are subject to the ongoing Front End Engineering Design, and although the exact details of the subsea facilities are not presently known, it is expected to include the facilities listed below:

- Production, Mono-Ethylene Glycol (MEG) and umbilical risers on the F-A Platform: This will include flexible risers up existing J-tubes (MEG and umbilical) and a new conductor in an existing platform conductor slot (production only);
- A Subsea Isolation Valve (SSIV) structure and pipework assembly at the junction between the platform production riser and the main production pipeline adjacent to F-A Platform;
- An approximate 39 km long production pipeline from the F-A Platform to a TIF located in the northern area of the F-O Gas Field. Its eventual length will be determined by the final location of the northern TIF and the actual routing of the pipeline;

- An approximate 39 km long main control umbilical running the length of the production pipeline from the F-A Platform to the north metering skid (NMS) adjacent to the northern TIF;
- An approximate 39 km long MEG pipeline running the length of the production pipeline (and probably attached to it as a piggybacked line) from the F-A Platform to the northern TIF;
- A northern TIF structure located in the northern area of the F-O Gas Field, to which the two northern wells F-O9 and F-O11 will be tied back, containing production and MEG distribution pipework and valves, and control and instrumentation hardware. During Phase 2 additional wells may be tied back to the northern TIF;
- A southern TIF structure located in the southern area of the F-O Gas Field, to which the three southern wells F-O10, F-O12 and F-O13 will be tied back, containing production and MEG distribution pipework and valves, and control and instrumentation hardware. During Phase 2 additional wells may be tied back to the southern TIF;
- A south metering skid (SMS) structure located adjacent to the southern TIF. The SMS, which is essentially similar to the NMS, contains umbilical termination items and electric, hydraulic and chemical distribution facilities, as well as production metering and associated valving;
- An approximately 3.4 km long infield production and MEG flowline linking the northern and southern TIFs. The eventual lengths of these flowlines will be determined by the final locations of the northern and southern TIFs and the actual routing of the flowlines;
- An approximately 3.4 km long infield control umbilical running the length of the infield flowlines, and linking the NMS and SMS;
- A well production and MEG flexible flowline and control umbilical for each well in the field, linking the well to its associated TIF and metering skid structure. The lengths of these infield flowlines and umbilicals will depend on the final locations of the wells, the subsea structures and their routing, and are currently anticipated to be in the range of approximately 0.4 km to 2.4 km; and
- A SSXT at each well location. The control module for each SSXT will be located on the SSXT.

A diagrammatic representation of the anticipated Phase 1 of the F-O Gas Field development concept is presented in Figure 1.4.

It is anticipated that the installation of the subsea facilities will be performed concurrently with drilling. The current project schedule is based on installing the pipelines between F-O Gas Field and the F-A Platform during the drilling of the second development well with the remainder of the subsea infrastructure (umbilicals, platform risers, jumper tie-ins, etc.) being installed during the drilling of the third well.

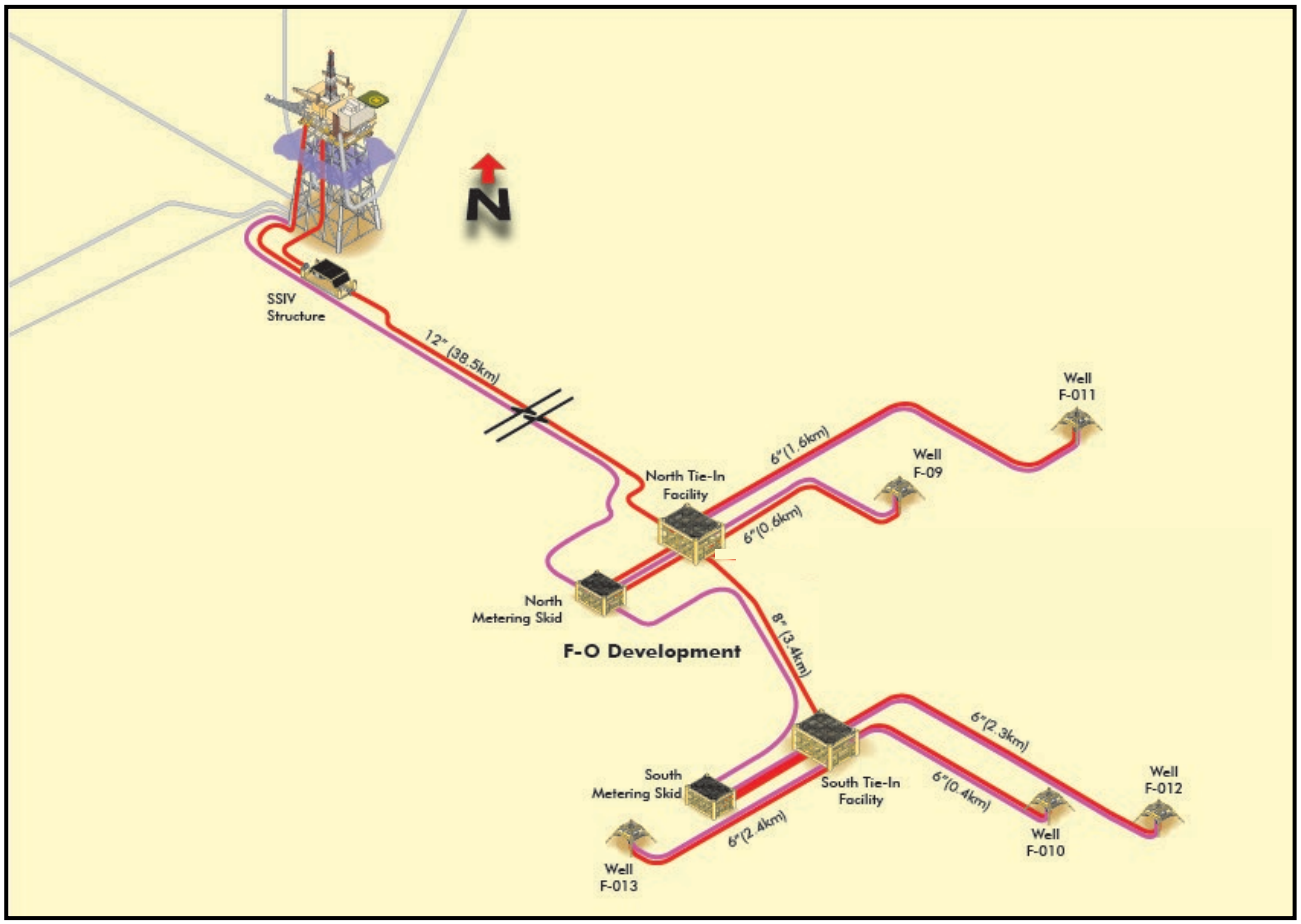

N
SSIV
Structure
12" (38.5km)
North Tie-In
Facility
6"(1.6km)
6"(0.6km)
Well
F-011
Well
F-09
North
Metering Skid
F-O Development
8" (3.4km)
6"(2.3km)
6"(0.4km)
South
Metering Skid
South Tie-In
Facility
6"(2.4km)
Well
F-012
Well
F-010
Well
F-013

Figure 1.4: Diagrammatic representation of the overall F-O Gas Field development concept (Source, JP Kenny).

1.4.4 F-A Platform

Modifications to the F-A Platform systems will be necessary to accommodate the F-O development, although the exact extent of these modifications will only be determined during detailed design. The F-A Platform will, however, need to accommodate the new risers.

1.4.5 Production

With the implementation of the F-O Gas Field, the flow rate of gas from the F-A Platform to shore is expected to remain unchanged at around 200 million standard cubic feet per day (MMscfd). Gas and condensate production will be separated at the F-A Platform and transported to the GTL refinery through two existing separate approximately 90 km long subsea pipelines. The total volume of gas in place for the F-O development is estimated to be approximately 914 billion standard cubic feet (Bscf).

All operations and identified impacts at the F-A Platform will be managed and monitored in accordance with existing methodologies / procedures set out in PetroSA's integrated SHEQ system and the FA-EM production area EMPr (see Chapter 4). A list of existing PetroSA operating procedures are presented in Appendix 1.

1.4.6 Decommissioning

On completion of the economic life of the F-O Gas Field, the wells (including the two appraisal wells, F-O6 and F-O8) and facilities installed for the project will be decommissioned. The decommissioning strategy will be consistent with that of other PetroSA gas production areas in Block 9.

Within the defined F-O Production Right area all SSXT and wellheads (with casings cut-off below the seafloor) will be removed. The wells will be plugged with cement and tested for integrity. The SSIV assembly, TIFs, metering skids, flowlines, MEG pipelines and umbilicals will be removed as far as is practicable. The process of determining the practicability of removing this infrastructure is presented in Section 5 (see Activity 5.11.2.2).

Concrete mattresses and concrete blocks (less than 0.5 m high) used to stabilise the pipelines and other overtrawlable structures will be left behind on the seafloor. The production pipeline will be thoroughly flushed, plugged off and left on the seabed. This approach was selected by PetroSA based on the evaluation of the following criteria:

- environmental impact (particularly biodiversity effects, implications for fisheries and fate of materials (e.g. potential for re-cycling, disposal in land fill site, etc);
- complexity and associated technical risk;
- safety risks/ risks to personnel;
- possibilities for environmental offsets; and
- financial costs.

Safety zone around the subsea infrastructure will then be removed.

1.5 EMPr CONTEXT

As noted earlier this EMPr has been prepared to meet the requirements of the EIA Regulations 2006[1] and the transitional arrangements of the EIA Regulations 2010 in terms of NEMA, as amended, and the Mineral and Petroleum Resources Development Act, 2002 (No. 28 of 2002) (MPRDA), as amended, and Regulations thereto.

[1] The EIA Regulations 2006 were amended and the amended regulations were published on 18 June 2010 in Government Gazette No. 33306 and were effected on 2 August 2010. The EIA Regulations 2010 makes provisions for "transitional arrangements" in order to accommodate applications, which commenced prior to the promulgation of the EIA Regulations 2010 and were still pending at the time the EIA Regulations 2010 took effect.

The development of the F-O Gas Field is a listed activity in terms of the EIA Regulations 2006 and a Scoping Study and EIA are required in order for the Department of Environmental Affairs (DEA) to consider the application in terms of NEMA. Regulation 32(2)(o) of Government Notice R385 requires that the Environmental Impact Report must contain an EMPr that complies with Regulation 34 of the EIA Regulations 2006. This EMPr has been prepared to meet the requirements of Regulation 34.

In addition, in terms of the MPRDA a Production Right must be approved prior to commencement of development activities. A requirement for obtaining a Production Right is that an EMPr must be compiled and submitted to the Petroleum Agency South Africa (PASA) for approval. This EMPr has also been prepared to meet the requirements of Regulation 51 and Section 39 of the MPRDA.

Section 2: General Context

2.1 KEY LEGISLATIVE REQUIREMENTS

This section outlines the key legislative requirements and guiding principles underpinning the EMPr and the associated Scoping Study and EIA process. This is not intended to be an exhaustive list and should be verified against PetroSA's legal register, which is continually updated.

2.1.1 National Environmental Management Act, 1998

The development of the F-O Gas Field is a listed activity in terms of the EIA Regulations ~~2006~~ promulgated in terms of Chapter 5 of NEMA, as amended, and a Scoping Study and EIA are required in order for DFFE ~~DEA~~ to consider the application in terms of NEMA.

~~Regulation 32(2)(o) of Government Notice R385 requires that the Environmental Impact Report must contain an EMPr that complies with Regulation 34 of the EIA Regulations 2006.~~ This EMPr has been prepared to meet the requirements of the NEMA EIA Regulations ~~Regulation 34~~.

2.1.2 Mineral and Petroleum Resources Development Act, 2002

In terms of the MPRDA a Production Right must be approved prior to commencement of development activities. A requirement for obtaining a Production Right is that an EMPr for the operation must be compiled and submitted to PASA for approval. As part of the compilation of the EMPr an EIA must also be conducted in terms of Section 83(4)(b) of the MPRDA.

A single Scoping Study and EIA process was undertaken to meet the requirements of both NEMA and MPRDA. This EMPr has as its basis the information presented in the Environmental Impact Report prepared as part of the Scoping Study and EIA process, as well as PetroSA's existing EMPr for the FA-EM Production area.

This EMPr has been prepared to meet the requirements of Regulation 51 and Section 39 of the MPRDA.

2.1.3 National Heritage Resources Act, 1999

The National Heritage Resources Act (No. 25 of 1999) (NHRA) provides for the protection of South Africa's natural heritage. The development of the F-O Gas Field is a listed activity in terms of Section 38(1) of the NHRA and requires authorisation by the responsible heritage resources authority. However, in terms of Section 38(8) of the NHRA where the proposed activity is subject to a Scoping Study and EIA process in terms of NEMA, the responsible heritage resources authority becomes a commenting authority. The decision-making authority should take into account in its decision-making any comments and recommendations made by the relevant heritage resources authority.

2.1.4 Other relevant legislation

In addition to the foregoing, PetroSA must also comply with the provisions of other relevant international and national legislation and conventions, which includes, amongst other, the following:

International Marine Pollution Conventions

- International Convention for the Prevention of Pollution from Ships, 1973/1978 (MARPOL);
- Amendment of the International Convention for the Prevention of Pollution from Ships, 1973/1978 (MARPOL) (Bulletin 567 – 2/08);
- International Convention on Oil Pollution Preparedness, Response and Co-operation, 1990 (OPRC Convention);
- United Nations Convention on Law of the Sea, 1982 (LOSC);
- Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972 (the London Convention) and the 1996 Protocol (the Protocol);

Other International Legislation

- International Commission on Radiological Protection (ICRC);
- International Atomic Energy Agency (IAEA) Regulations for the Safe Transport of Radioactive Material, 1984;

Other South African legislation

- Carriage of Goods by Sea Act, 1986 (No. 1 of 1986);
- Dumping at Sea Control Act, 1980(No. 73 of 1980);
- Hazardous Substances Act, 1983 and Regulations (No. 85 of 1983);
- Integrated Coastal Management Act, 2008 (No. 24 of 2008);
- Marine Living Resources Act, 1998 (No. 18 of 1998);
- Marine Traffic Act, 1981 (No. 2 of 1981);
- Marine Pollution (Control and Civil Liability) Act, 1981 (No. 6 of 1981);
- Marine Pollution (Prevention of Pollution from Ships) Act, 1986 (No. 2 of 1986);
- Marine Pollution (Intervention) Act, 1987 (No. 65 of 1987);
- Maritime Safety Authority Act, 1998 (No. 5 of 1998);
- Maritime Safety Authority Levies Act, 1998 (No. 6 of 1998);
- Maritime Zones Act 1994 (No. 15 of 1994);
- Merchant Shipping Act, 1951 (No. 57 of 1951);
- Mine Health and Safety Act, 1996 (No. 29 of 1996);
- National Environmental Management: Air Quality Act, 2004 (No. 39 of 2004);
- National Environmental Management: Biodiversity Act, 2004 (No. 10 of 2004;
- National Environmental Management: Integrated Coastal Management Act, 2008 (No. 24 of 2008);
- National Environmental Management: Waste Act, 2008 (No. 59 of 2008);
- National Heritage Resources Act, 1999 (No. 25 of 1999)

- National Nuclear Energy Regulator Act, 1999 (No. 47 of 1999);
- National Ports Act, 2005 (No. 12 of 2005);
- Nuclear Energy Act, 1999 (No. 46 of 1999);
- Occupational Health and Safety Act, 1993 (No. 85 of 1993) and Major Hazard Installation Regulations;
- Sea-Shore Act, 1935 (No. 21 of 1935);
- Sea Birds and Seals Protection Act, 1973 (No. 46 of 1973);
- Ship Registration Act, 1998 (No. 58 of 1998);
- Water Act, 1998 (No. 36 of 1998); and
- Wreck and Salvage Act, 1995 (No. 94 of 1995).

2.2 SUMMARY DESCRIPTION OF THE AFFECTED ENVIRONMENT

The following is a summary of the affected environment as presented in the Environmental Impact Report prepared as part of the EIA undertaken for the development of the F-O Gas Field.

2.2.1 Physical oceanography

The F-O production area falls within the offshore area of the South Coast region of South Africa. The region is dominated by the Agulhas Bank, which represents a transition zone between the warm Agulhas Current waters to the east and the cool waters of the Benguela system to the west.

The coastline is characterised by a number of Capes separated by sheltered sandy embayments. The oceanography of the coastal strip is largely dependent on the orientation of the local coastline and bathymetry in relation to prevailing easterly and westerly wind regimes.

The majority of waves arrive from the south-west, having been generated in the Southern Ocean, particularly during winter and spring. Tides along the South Coast are semi-diurnal. Although the tidal range on the Agulhas Bank is around 1.5 m, it increases slightly from west to east.

The bathymetry drops steeply at the coast to approximately 50 m, with depth then increasing gradually outwards to the shelf break at a depth of 140 m off Port Elizabeth and 300 m south of Cape Agulhas. Depth outside the shelf break increases rapidly to more than 1 000 m. Water depths in the F-O production area range from 125 m to 250 m. The seafloor in the area consists predominantly of scattered hard rock outcrops with patches of thin sediment accumulations between the individual outcrops.

Wind-driven upwelling occurs in the nearshore along the South Coast, especially when easterly winds blow during summer.

2.2.2 Biological oceanography

The F-O Gas Field lies within the Agulhas subphotic biozone. This biozone lies within the 'minimal protected category' (1 to 5 %) and is defined as vulnerable, with extractive utilisation of marine resources identified as the greatest threat.

The benthic habitat type within the F-O production area is largely unconsolidated sediments with an average amount of bioturbation activity (which is the displacement and mixing of sediment particles by benthic fauna and flora), indicating a rich infaunal community. Several rocky outcrops supporting a diverse range of hard ground species are also present (e.g. gorgonians, bryozoans and sponges). The combination of habitat types (soft sediments and rocky formations) results in a highly diverse benthic environment.

Squid and the South Coast Rock Lobster are two commercially important invertebrate species. Squid forms dense spawning aggregations (at depths ranging from 20 to 130 m) in sheltered bays along the eastern half of the South Coast, especially between Plettenberg Bay and Algoa Bay. These aggregations of adults reach a peak in November and December. The South Coast Rock Lobster occurs on rocky substrate in depths of 90 to 170 m.

Many of the fish species inhabiting the South Coast are also found on the West and/or East Coasts, highlighting the location of the South Coast as a transition zone between two different current systems. The Agulhas Bank is an important spawning area for a number of species, including anchovy, pilchard, horse mackerel, Cape hake, kingklip and squid. The shallower inshore areas (<100 m) along the South Coast comprise a varied habitat of rocky reefs and soft-bottom substrates, which support a high diversity of endemic sparid and other teleost species. Many of these species form an important component of the commercial and recreational linefishery. An important fishing ground, popularly known as *The Blues* is situated an estimated 70 km west of the F-O production area.

The marine mammal fauna of the South Coast comprises between 35 and 38 species of cetaceans (whales and dolphins) and one seal species, the Cape fur seal. The majority of migratory cetaceans in South African waters are large baleen whales. Blue, fin, sei, minke and humpback whales make winter migrations through the South Coast region en route from Antarctic summer feeding grounds to winter breeding grounds. While blue, fin and sei whales migrate off or along the continental shelf edge (and are thus distributed in deeper waters), humpback whales migrate over the continental shelf and along the coast. Southern Right whales migrate into the near-shore region of the South Coast between June and November each year.

Three species of turtles (the green, leatherback and loggerhead) are found in the South Coast region, probably associated with the Agulhas Current. The leatherback turtle is described as "critically endangered", and the loggerhead and green turtles are "endangered". The green turtle is a non-breeding resident along the east coast of South Africa and together with loggerhead turtles are expected to occur only as occasional visitors along the South Coast. The abundance of adult turtles and hatchlings within the F-O Production Right area is expected to be low.

Overall, 60 species of seabirds are known, or thought likely to occur, along the South Coast. Thirteen species breed within the South Coast region. These include Cape gannets (Algoa Bay islands), African penguins (Algoa Bay islands), Cape cormorants (a small population at Algoa Bay islands and mainland sites), white-breasted cormorant, Roseate tern (Bird and St Croix Islands), Damara tern (inshore between Cape Agulhas and Cape Infanta), Swift tern (Stag Island) and kelp gulls. Figure 2.1 provides a map depciting the delineated cionsrevtaion and protected areas.

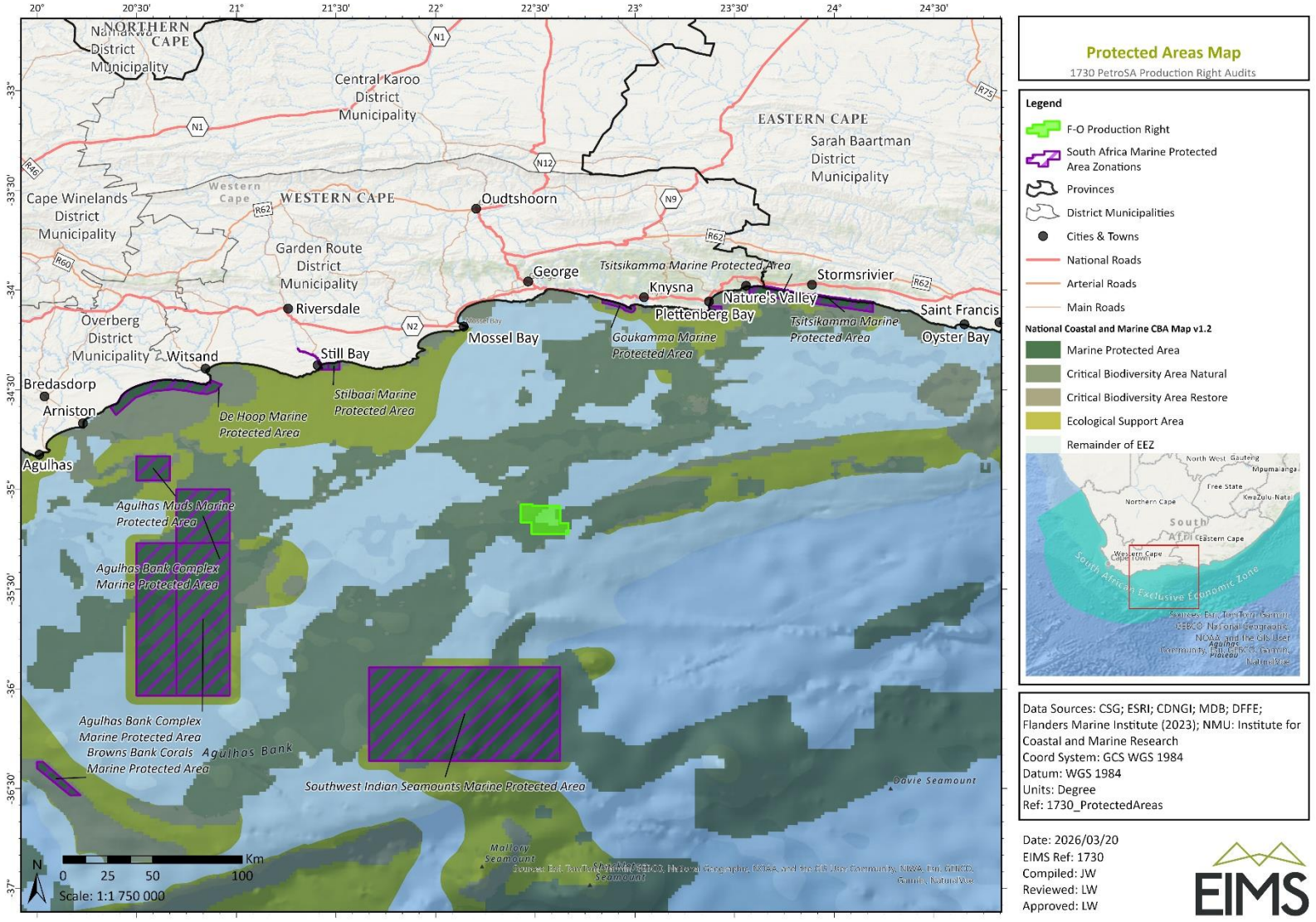


Figure 2.1: Protected areas and biodiversity areas in relation to the Production Right boundary.

2.2.3 Human utilisation

There are five fisheries active in the vicinity of the project:

- Demersal trawl: The closest trawling grounds are located approximately 30 km to the south-east of the F-O Gas Field wells.
- Midwater trawl: There is evidence of midwater trawl activity in the south-eastern area of the F-O production area.
- Demersal longline: The F-O Gas Field development coincides with the western extent of heavily longlined grounds.
- Pelagic longline: There is no historical evidence that pelagic longline gear has been set within the F-O production area.
- South Coast Rock Lobster longline: The main fished grounds lie to the south-west and north / north-east of the F-O Gas Field Development area and there is no evidence of fishing activity in the vicinity of the development area rock lobster.

The shipping traffic on the South Coast is high. This traffic is located relatively close to shore, and includes commercial and fishing vessels. North- and south-bound cargo vessels usually remain over the mid-shelf (100 m isobath), while tankers and bulk carriers usually remain further offshore.

2.3 SOCIO-ECONOMIC GOALS AND OBJECTIVES

The goals and objectives presented in this section is a summary of those identified in the Social and Labour Plan, which has been submitted to PASA as part of the current application process for a Production Right.

The key needs activities identified in the area include:

- Education and Training;
- Employment opportunities;
- Skills development; and
- Infrastructural development in relation to sports fields, play parks, clinics, etc.

The development of the F-O Gas Field is aimed at supplementing the feedstock to the GTL refinery thereby sustaining the current socio-economic benefits associated with PetroSA operations in the Mossel Bay area. These include:

- direct and indirect employment;
- supplier development;
- preferential procurement in line with the Preferential Procurement Policy Frameworkd Act (No. 5 of 2000); and
- construction of a home of safety for abuse woman and children which will offer a range of services to the community.

2.4 SUMMARY OF THE POTENTIAL IMPACTS OF RELATED TO THE DEVELOPMENT OF THE F-O GAS FIELD

2.4.1 Well drilling

A summary of the assessment of potential environmental impacts associated with the well drilling in the F-O Gas Field is provided in Table 2.1.

The majority of the impacts associated with well drilling would occur in the immediate vicinity of each drilling location, would be of short- to medium-term duration (i.e. reversible) and of low to medium intensity, and are considered to be of VERY LOW to LOW significance after mitigation.

The key impact, although unlikely, associated with drilling operations relates to the introduction of non-indigenous invasive marine species through vessels and equipment transfer and ballast water discharge. The improbable introduction of non-indigenous invasive species (e.g. the anemones, *Metridium senile* and *Sagartia elegans*) due to vessels and equipment transfer and the discharge of ballast water could result in an impact of high to very high significance. This impact is not unique to the project, but rather a threat common to the South African offshore environment from the numerous vessels that pass through South African coastal waters daily. Mitigation would only serve to reduce the probability of occurrence. However, if the impact did occur it could remain of HIGH to VERY HIGH significance.

The main risk relating to the drilling and completion fluids plant, which would be located on Pier 9 in the Mossel Bay Harbour, relates to the unlikely event of a tank or bund fire. Of all the material stored on site, the base fluid (Mosspar H) is the only material with the potential to ignite and cause a tank or bund fire. As the probability of ignition is extremely low, the risks of a fire at the plant would be less than $1x10^{-10}$ fatalities per person per year, resulting in the individual and societal risks being classified as trivial (i.e. an acceptable risk). Provided no other hazardous materials are stored or produced at the drilling and completion fluids plant, it would not be classified as a MHI. The significance of this improbable impact is assessed to be of VERY LOW significance with and without mitigation.

2.4.2 F-O Gas Field Development

A summary of the significance of the potential impacts associated with the development of the F-O Gas Field (excluding well drilling) is presented in Table 2.2.

Table 2.1: Summary of the significance of the potential impacts associated with the well drilling in the F-O Gas Field.

Potential impact		Significance	
		Without mitigation	With mitigation
1. Normal drilling unit, support vessel and helicopter operation:			
Emissions to the atmosphere		VL	VL
Deck drainage into the sea		VL	VL
Machinery space drainage into the sea		VL	VL
Sewage effluent into the sea		VL	VL
Galley waste disposal into the sea		VL	VL
Solid waste disposal into the sea		Insig.	INSIG.
Noise from drilling unit and support vessel operation		VL	VL
Noise from helicopter operation		L-M	VL
2. Impact of well drilling on marine fauna:			
Physical damage and sediment disturbance		L	L
Smothering by cuttings and drilling fluid and plume turbidity		L	L
Biochemical effects of discharged drilling fluid and contaminated cuttings	Water-based fluids	L	L
	Non-aqueous drilling fluids	L	L
Drilling noise		VL	VL
Faunal attraction to drilling units		VL	VL
Vessel & equipment transfer and discharge of ballast water		H-VH	H-VH
Cumulative impact		L	
3. Impact on cultural heritage material:			
Impact on historical shipwrecks		M	INSIG.
4. Impact on other users of the sea:			
Marine transport routes		L	L
Fishing industry		See Table 2	
5. Risk associated with drilling and completion fluids plant:			
Thermal radiation associated with a tank or bund fire		VL	VL
6. Accidental release of gas or hydrocarbons:			
Impact on water column and sea bottom from an uncontrolled release of natural gas		L	L
Impact on the atmosphere from an uncontrolled release of natural gas		VL	VL
Impact on marine fauna, fishing and coastal environments from a small hydrocarbon spill		VL	VL

VH=Very High	H=High	M=Medium	L=Low	VL=Very low	Insig = Insignificant	N/A= Not applicable

Table 2.2: Summary of the significance of potential impacts associated with the development of the F-O Gas Field.

Impact			Alternative (where applicable)	Significance	
				Without mitigation	With mitigation
1. Construction					
Emissions to air			-	VL	VL
Effluent and waste disposal	*Deck drainage*		-	VL	VL
	Machinery space drainage		-	VL	VL
	Sewage		-	VL	VL
	Galley wastes		-	VL	VL
	Solid waste		-	Insig.	INSIG.
Impact on benthic communities	*Physical damage*		Any subsea infrastructural layout and vessel type	L	L
Disturbance of fauna by helicopter operations			-	L-M	VL
Interference with shipping			All subsea layouts	L	VL
Impact on cultural heritage			All subsea layouts	M	INSIG.
2. Production					
2.1 Normal operation					
Impact on benthic communities	*Physical presence of infrastructure*	*Effect on biodiversity and biomass*	Pipeline abandonment	L (+ve)	L (+ve)
			Pipeline retrieval	VL (+ve)	VL (+ve)
		Effects on migrating species	Pipeline abandonment	M	M
			Pipeline retrieval	L	L
Impact on fishing	*Increased fishing effort and loss of catch*	*Demersal longline*	All subsea infrastructural layouts and both pipeline decommissioning alts	L	L
		South Coast Rock Lobster longline	All subsea infrastructural layouts and both pipeline decommissioning alts	L	L
		Demersal trawl	All subsea infrastructural layouts and pipeline abandonment	L	L
			All subsea infrastructural layouts and pipeline retrieval	VL	VL
		Midwater trawl	All subsea infrastructural layouts and pipeline abandonment	L	L
			All subsea infrastructural layouts and pipeline retrieval	VL	VL
2.2 Accidental gas leak					
Impact on water column and sea bottom			-	VL	VL
Impact on the atmosphere			-	VL	VL

Impact			Alternative (where applicable)	Significance	
				Without mitigation	With mitigation
3. Decommissioning					
Emissions to air			-	VL	VL
Effluent and waste disposal	*Deck drainage*		-	VL	VL
	Machinery space drainage		-	VL	VL
	Sewage		-	VL	VL
	Galley wastes		-	VL	VL
	Solid waste		-	N/A	N/A
Impact on benthic communities	*Physical damage*		Both pipeline decommissioning alts and vessel type	VL	VL
Disturbance of fauna by helicopter operations			-	L-M	VL
Interference with shipping			-	L	VL
4. Cumulative Impact					
Impact on benthic communities in Block 9			Both pipeline decommissioning alts and vessel type	L	
Impact on fishing	*Increased fishing effort and loss of catch*	*Demersal longline*		L	
		South Coast Rock Lobster longline		L	
		Demersal trawl		M	
		Midwater trawl		L	
5. No-Go Alternative					
Lost opportunity to further explore and utilise gas reserves on the South Coast and possible abandonment of the GTL refinery in Mossel Bay in 2013/2014			-	VH	

VH=Very High	H=High	M=Medium	L=Low	VL=Very low	Insig = Insignificant	N/A= Not applicable

2.4.2.1 Construction phase

The construction phase would include the installation of the production pipeline between the F-A Platform and the F-O Gas Field and associated infrastructure (e.g. umbilicals, MEG pipeline, SSIV, TIFs, flowlines, tie-in spool pieces, concrete mattresses, etc.) using installation and support vessels. All impacts associated with the construction phase would be short-term and are considered to range from INSIGNIFICANT to LOW significance with the implementation of mitigation measures regardless of what final subsea infrastructural layout configuration is selected and what type of vessel is used (namely anchored or dynamically positioned).

2.4.2.2 Production

It is estimated that the project would extend the operational life of the GTL refinery to at least 2020. Therefore, production or operational impacts are generally considered to take place over the medium-term within the project area (i.e. localised). However, some impacts are considered to take place over the long-term where these relate to the abandonment of the production pipeline on the seafloor.

The most significant impact relates to the effect on benthic migrating species due to the physical presence and the abandonment of the production pipeline (MEDIUM significance with and without mitigation). The alternative of retrieving the production pipeline during decommissioning, which was assessed for comparative purposes, would result in the impact taking place over the medium term, which would lower the significance of the impact to LOW with and without mitigation. Although pipeline abandonment would result in a more significant impact on migrating species, it is reasonable to suggest that adult lobsters would be able to move over the production pipeline, which would be only approximately 32 cm in diameter. In addition, the pipeline is likely to settle into the substrate in some areas and lift above it in others, thereby reducing the potential to restrict the movement of this species.

A potential key issue at the onset of the EIA was the impact of the infrastructure and associated 500 m safety zone on the fishing industry during the production phase in terms of increased fishing effort and loss of catch. The only two fishing sectors that could potentially be impacted by the safety zone around the subsea infrastructure are demersal longlining and South Coast Rock Lobster longlining. The impact on these sectors due to the safety zone is considered to be of LOW significance regardless of the decommissioning alternative, as these fisheries would be able to set their lines over the abandoned pipeline. If demersal trawling and midwater trawling move into the area in the future there could be an impact on these sectors as well. The unlikely impact on the demersal trawling and midwater trawling sectors ranges from LOW (pipeline abandonment) to VERY LOW (pipeline retrieval) significance. Pipeline abandonment would increase the duration of the impact from medium-term to long-term should these fishing sectors move into the area.

Gas from the F-O Gas Field would be routed to the existing F-A Platform for processing. Although the development of the F-O Gas Field would increase the gas resource, the throughput of gas at the F-A Platform would be kept constant at around 200 MMscf per day. PetroSA would continue to operate as at present under their existing emission permits and licenses. All operations and identified impacts at the F-A Platform would be managed and monitored in accordance with existing methodologies set out in PetroSA's integrated SHEQ system and FA-EM production area EMPr. The production-related aspects of the FA-EM production area EMPr have been included in the EMPr prepared for the F-O production area. The development of the F-O Gas Field would not result in any additional production-related impacts.

2.4.2.3 Decommissioning

On completion of the economic life of the F-O Gas Field, the wells (including the two appraisal wells, F-O6 and F-O8) and infrastructure installed for the project would be decommissioned. PetroSA propose to remove all SSXT and wellheads from the seafloor. The wells would be plugged with cement and tested for integrity. The SSIV assembly, TIFs, metering skids, flowlines, MEG pipelines and umbilicals would be removed as far as is practicable. Concrete mattresses and concrete blocks (less than 0.5 m high) used to stabilise the pipelines and other overtrawlable structures would be left behind on the seafloor. The production pipeline would be thoroughly flushed, plugged off and left on the seabed.

All impacts associated with the decommissioning phase are considered to be of **VERY LOW** significance with the implementation of mitigation measures regardless of whether or not the production pipeline is retrieved or abandoned.

2.4.3 Cumulative impact

The main impact from historic oil and gas development in the South Coast offshore region has been on the trawling fishery, specifically within and around the Blues trawling ground. To date there has been an approximately 108 km^2 reduction in trawling grounds on the South Coast amounting to a loss of 0.34% of the trawlable area. Although the proposed F-O Gas Field development project is located to the east of the Blues trawling ground and away from the high intensity trawling grounds, there could be an impact on the demersal and midwater trawling sectors if trawling moves into the area in future. The likely future cumulative impact of the proposed project on the trawling fishery is considered to range from LOW (midwater trawl) to MEDIUM (demersal trawl) significance.

The two fishing sectors that could potentially be directly impacted by the proposed safety zone associated with the F-O Gas Field development include demersal longlining and South Coast Rock Lobster longlining sectors. To date there has been no reduction to the demersal longline sector on the South Coast, while the South Coast Rock Lobster longlining sector has been reduced by approximately 7 km^2 by existing oil and gas development (i.e. a 0.014% reduction). The proposed development of the F-O Gas Field would reduce the demersal longlining sector by approximately 53 km^2 (0.27 %) and would further reduce the South Coast Rock Lobster longlining by an approximately 7 km^2 resulting in a total loss of 0.03%. The cumulative impact on both the demersal longline and South Coast Rock Lobster longline sectors is considered to be of LOW significance. It should be noted that the significance of the cumulative impact would decrease when the proposed project is decommissioned and when the economical life of the existing fields (e.g. South Coast Gas, E-M, F-A, Sable and Oribi/Oryx) have been reached and PetroSA commence with decommissioning activities.

The cumulative impact on the marine benthic environment relates to both well drilling and the presence of physical infrastructure (existing and proposed). The total area impacted as a result of the existing PetroSA oil and gas infrastructure in the Agulhas Bioregion is approximately 0.18 km^2 representing 0.0006 % of the Agulhas Bioregion (note: this area excludes the area impacted by the deposition of drill cuttings as these

areas are expected to have recovered). The proposed well drilling programme (specifically the discharge of cuttings) would impact an additional approximately 3.5 km^2 representing 0.012 % of the Agulhas Bioregion. The proposed subsea infrastructure would impact an additional approximately 0.05 km^2 representing 0.0002 % of the Agulhas Bioregion. Combined, the area affected by the developments (existing and proposed) would be approximately 3.73 km^2 representing 0.013 % of the Agulhas Bank resource, which is considered to be negligible. Therefore, it is reasonable to suggest that considering the current status of the developments in the area, the cumulative impact associated with the proposed development of the F-O Gas Field is considered to be of LOW significance. This assessment does not take into consideration the impact caused by demersal trawling on the South Coast, which can cause considerable damage to marine benthic habitat in the estimated 31 736 km^2 trawling grounds and probably has the single most significant impact on the benthic environment on the South Coast.

The impacts relating to emissions to the atmosphere and discharges to the sea during well drilling, construction and decommissioning are considered to be of VERY LOW significance. Cumulatively, these are considered to remain of VERY LOW significance.

2.4.4 No-Go Alternative

The implications of not going ahead with the development of the F-O Gas Field relate to the lost opportunity to further explore and utilise gas reserves on the South Coast and possible abandonment of the GTL refinery. The possible abandonment of the GTL refinery would have negative impacts on employment, GDP, household income and government revenue. Thus the potential impact of the No-Go Alternative is considered to be of VERY HIGH significance.

2.5 MANAGEMENT OF POTENTIAL ENVIRONMENTAL IMPACTS

Potential impacts associated with the project were identified and assessed as part of the EIA. A summary of the significance of potential impacts is presented in Tables 2.1 and 2.2. Impact management, which includes all mitigatory measures listed in the Environmental Impact Report, is set out in this EMPr in the following sections:

- Section 3: Well drilling;
- Section 4: Construction (including infrastructure installation); and
- Section 5: Production (including decommissioning).

2.6 ENVIRONMENTAL POLICY

A copy of PetroSA's Health, Safety and Environmental Policy is presented in Appendix 2. This policy sets out PetroSA's commitment to ensure successful implementation of the project and EMPr.

2.7 FINANCIAL PROVISION

In terms of the MPRDA, PetroSA is required to make financial provision to meet its obligations as described in this EMP.

2.7.1 Operational Phase

The operational phase includes drilling, construction and gas field development (as applicable) up to the closure or abandonment phase.

PetroSA will make provision for the requirements of the EMPr such as monitoring, reporting or specialist studies as part of the normal budgeting process.

Environmental management actions required as a result of an incident or accident would be covered by PetroSA's insurance[1], as described below:

- Third Party liability, which includes personal injury, property damage, seepage and pollution as a result of any offshore exploration and production operations, is covered up to USD150 000 000 (one hundred and fifty million US Dollars) per occurrence;
- Well control insurance, which includes blowouts, seepage and pollution, is covered up to USD 150 000 000 (one hundred and fifty million US Dollars) per occurrence;
- Production infrastructure such as the FA Platform, wellheads and pipelines are covered per occurrence as described below:

FA Platform	Physical damage	USD 550,000,000
FA Platform	Removal of wreck and/or sue and labour	USD 90,000,000
FA Platform	Total loss	USD 200,000,000
Wellheads, pipelines, CBM & SPM buoys, umbilicals and risers	Removal of wreck and/or sue and labour	25% of value

In addition, as a condition of contract PetroSA requires a Contractor to carry the following insurance and will not permit any of its Contractors to undertake any work until certificates of insurance are provided:

- *Workmen's compensation insurance* as required in terms of the provisions of the Compensation for Occupational Injuries and Diseases Act, 1993 (No. 130 of 1993);
- *Employer's liability insurance* with a limit of liability at all times of not less than USD 1 000 000 (one million US Dollars) for each occurrence or such larger amounts for which Contractor already have cover;
- *Non-ownership aviation liability* with a limit of liability at all times of not less than USD 50 000 000 (fifty million US Dollars) for each occurrence or such larger amounts for which Contractor already has cover;

[1] All figures as for 2010/11 insurance.

- *Comprehensive general public liability insurance including pollution* with a limit of liability of not less than USD 1 000 000 (one million US Dollars) per occurrence;
- *Motor vehicle liability insurance* including passenger liability indemnity;
- *Physical Damage Insurance* for loss or damage to Contractor's equipment and machinery. Such coverage shall be on *All Risks Insurance basis or its equivalent* for full value of Contractor Group material and equipment;
- *Hull and Machinery Insurance* in the form of Full Form Hull and Machinery Insurance, including collision liability, with limits of liability at least equal to the full value of the vessel; and
- *Standard Protection and Indemnity Insurance*, at least equal to the value of each vessel owned or chartered (including Tower's Liability, where applicable).

2.7.2 Closure or Abandonment Phase

PetroSA makes provision for its closure commitments in the form of a liability provision, which is reflected in the balance sheet as the best estimate of the expenditure required to settle the obligation at the projected end of life of the field. The abandonment costs are presented in Table 2.3. This provision would only come into effect once any infrastructure has been installed and takes the form of an asset, e.g. a well is drilled and completed.

2.7.3 Financial Provision reporting

Proof of Financial Provision will be provided to PASA in the following manner:

- Construction/Drilling Phase:
  - Copies of the insurance cover carried by the Contractors and PetroSA will be provided together with the environmental notification submitted to PASA at least 7 days prior to the commencement of any gas field drilling or development activity.
- Operational Phase:
  - A copy of the insurance certificate for the year will be provided on the renewal date; and
  - The annual revision of the closure provision will be submitted together with the annual Performance Assessment reports.

Table 2.3: Abandonment costs for Phase 1.

ACTIVITY	UNIT	QUAN-TITY	RATE PER UNIT	TOTAL	NOTES
MOBILISATION					
Mobilisation of personnel, rig and support vessel	Sum	1	$200 000	$200 000	Assumes rig is already mobilised to Block 9 for other well abandonment.
WELL PLUGGING EQUIPMENT					
Drill Rig	days	10.9	$170 000	$1 853 000	F-O8
	days	10.9	$170 000	$1 853 000	F-O6
	days	29.1	$170 000	$4 947 000	F-O01P
	days	29.1	$170 000	$4 947 000	F-O02P
	days	29.1	$170 000	$4 947 000	F-O03P
	days	29.1	$170 000	$4 947 000	F-O04P
	days	29.1	$170 000	$4 947 000	F-O05P
Support Vessel	days	10.9	$20 000	$218 000	F-O8
	days	10.9	$20 000	$218 000	F-O6
	days	29.1	$20 000	$582 000	F-O01P
	days	29.1	$20 000	$582 000	F-O02P
	days	29.1	$20 000	$582 000	F-O03P
	days	29.1	$20 000	$582 000	F-O04P
	days	29.1	$20 000	$582 000	F-O05P
Well head removal, cutting if casings, plugging, etc.	Sum	1	included above	included above	
CLEAN UP OF SPILLAGES					
Oil recovery equipment and absorbent material hire/purchase. Remediation of negative effects on marine environment			n/a	n/a	F-O is a dry gas. No oil pollution potential. Spills from rigs/vessels. Will use established spill contingency plans
WASTE MANAGEMENT					
Handling, Storage and final disposal at licensed landfill site onshore. Appointment of registered waste management contractor.	Sum	1	$50 000	$50 000	
THIRD PARTY LIABILITIES					
Marine mining, fishing industry, marine transport routes. Compensation, damage claims, etc.			n/a	n/a	Covered by insurance
PROJECT MANAGEMENT COSTS					
Hiring of divers, follow up monitoring, disbursements, etc.	Sum	1	$400 000	$400 000	
REMOVAL OF MISCELLANEOUS OBJECTS FROM SEA FLOOR					
Retrieval of lost equipment/items through the use of divers and specialist contractors	Sum	1	$100 000	$100 000	
FLUSHING CLEANING OF PIPELINES AND UMBILICALS					
Cleaning all residual hydrocabons and chemicals		1	$750 000	$750 000	
REMOVAL OF JUMPERS and MISCELLANEOUS SEABED EQUIPMENT					
Removal of loose and hazardous items in accordance with EIA and EMPr	Sum	1	$1 700 000	$1 700 000	
SUBTOTAL				**$34 987 000**	
Contingency (10%)				**$3 498 700**	
TOTAL				**$38 485 700**	

2.8 MONITORING AND EMPr PERFORMANCE ASSESSMENT

PetroSA would undertake appropriate monitoring, auditing and reporting on an ongoing basis during drilling, construction, production (including decommissioning) (see Sections 3.12, 4.10 and 5.10). PetroSA would track performance against objectives and targets specified in this EMPr. Audits would generate a list of recommended corrective actions, which would be used as a tool to document all corrective actions taken and how they were performed.

In order to comply with the MPRDA and its relevant Regulations, PetroSA would undertake annual performance assessments in order to ensure compliance with the EMPr and to assess the continued appropriateness and adequacy of the EMPr. Performance assessment reports shall be submitted to PASA for consideration.

PetroSA would also comply with any monitoring or auditing requirements of the relevant competant authority ~~DEA~~.

2.9 PLANS AND PROCEDURES FOR ENVIRONMENTAL RELATED EMERGENCIES AND REMEDIATION

All offshore emergencies would be managed in terms of PetroSA's current procedures, *Oil Spill Contingency and Response Plan* (EP/SHE/PR/001) and *General Onshore Plan for Offshore Emergencies* (EP/SHE/PR/006).

Where necessary, a bridging document would be drawn up between these procedures and the emergency response procedures and plans of the selected contractor(s)

2.10 UNDERTAKING BY THE APPLICANT

PetroSA undertakes to comply with the provisions of the MPRDA and Regulations thereto (see Appendix 3).

Environmental Protection Activities

Activities 5.1 - 5.3: Pollution prevention under normal operating conditions

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.1. LEAK/ SPILL PREVENTION

5.1.1 Subsea Infrastructures Maintenance and Monitoring

Rationale:

Gas and oil is transported from wellheads to the surface in pipelines via valves and other equipment. In a saline and turbulent environment if the pipe work and associated connectors and valves are not maintained regularly they could deteriorate and result in their contents leaking to the sea. Scheduled maintenance and regular inspections are essential to maintain the integrity of the system of pipelines and risers used to convey the oil or gas. Since the contents of the pipeline are a valuable product there are procedures in place to maintain and inspect the system to limit losses. The focus of this programme is to ensure that environmental issues are adequately addressed.

Objectives:

- To check the integrity of all pipe work and equipment on the platform and sea bed in a systematic and scheduled manner to minimise the risk of rupture or leakage which could cause pollution of the sea.
- To replace, repair and maintain all pipe work and equipment on the platform and sea bed in a systematic and scheduled manner to minimise the risk of rupture or leakage which could cause pollution of the sea.
- To detect any leaks or ruptures so that they can be repaired speedily.
- To formally and critically evaluate the circumstances of any ruptures and leaks in order to plan for prevention of recurrence.

5.1.1.1 All undersea structures including pipe works and valves shall be subject to scheduled inspection and maintenance as per the flow diagram below.	***Subsea Manager***	***Max interval 5 years***

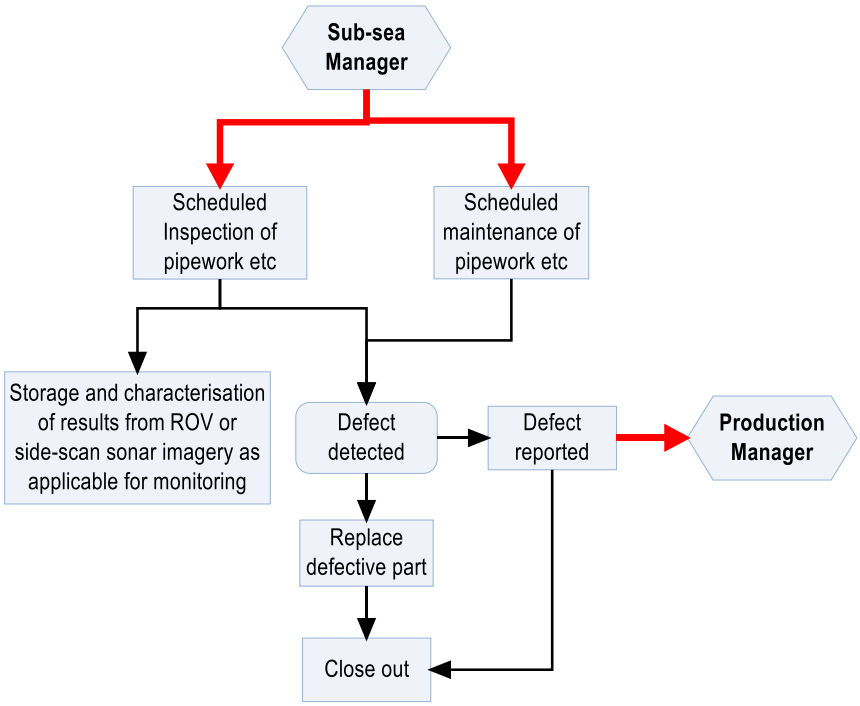


Figure 5.1.1: Pipeline maintenance and inspection

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.1.1.2 The results of the scheduled inspections surveys shall be subject to systematic, documented review.	***Subsea Manager***	***Within 2 months of survey***
5.1.1.3 Any repairs shall be reported in Quarterly ~~Monthly~~ Report	***Subsea Manager***	***Quarterly ~~Monthly~~***
*5.1.1.4 Any leak or spill of liquids, be they on the surface or sub-sea, shall be regarded as an incident and/ or emergency and dealt with according to the incident procedure below (see **Activity 5.7.1**).*	***Subsea Manager***	***Immediately***
5.1.1.5 Ensure that all well interventions and workovers at the wellfields are planned and executed under approved procedures that include defined activity scope, verified well barriers, controlled management and disposal of fluids, certified well control equipment (including BOPs), pre- and post-operation ROV seabed surveys, issued navigational notices, and documented environmental monitoring and reporting.	***Environmental Manager***	***Prior to commencement of activity. During activity.***
5.1.1.6 Audit guidelines (maintenance) ▪ Audits should, through examination of records retained by the facility, visual inspections and targeted interviews, verify that: ○ The maintenance schedule was adhered to; ○ The inspection schedule was adhered to; ○ Any defects were repaired; ○ Incidents were recorded in the incident reports; ○ The response time to incidents is appropriate to their significance; ○ Environmental Incidents were subject to comprehensive evaluation by management; ○ Requisite changes were made to operational procedures to ensure that the incident is not repeated; ○ Incidents arising from the same root cause(s) are not repeated; ○ Trial runs and/or drills for major incidents are conducted at least annually; and ○ The response for major contingencies are formally reviewed by management annually.	***SHEQ Manager***	***Annually***
5.1.2 Interaction with Shipping		
5.1.2.1 Service Vessels		
Rationale: Vessels carrying personnel or supplies to and from the offshore installations may negatively impact on the environment through reckless behaviour, negligence and/or accidents. PetroSA may be jointly responsible for the immediate response and remediation of any such environmental damage. Furthermore, any residual environmental damage resulting from actions by the supply vessels may increase the costs and extent of PetroSA's decommissioning rehabilitation. It is therefore important that the supply vessels are operated by competent personnel, are seaworthy and appropriate for their tasks, and managed in such a way as to minimise the risk of any environmental damage occurring. In the event that damage does occur, the correct and appropriate response is undertaken by the Master(s) of the vessel(s) concerned.		
Objective: • To ensure that professional and seaworthy certification is appropriate to requirements. • To inform the Masters of the supply and transport vessels of the actions to be taken to minimise environmental damage and the actions to be taken in the event of such damage occurring. • To check that the requisite actions are taken and that they are effective in minimising environmental damage.		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.1.2.1.1 All contracts with service providers shall require compliance by the service provider with the EMPrs. The contracts shall specifically require that the service provider complies with all relevant legislation and indemnifies PetroSA of any shared liability in the event that the service provider contravenes legislation in spite of being required to adhere to the EMPr. PetroSA reserves the right to inspect operations on the service-provider's vessel to assess compliance. Deviations from the PetroSA procedures shall be deemed breach of contract.	***Logistics Base Manager***	***Ongoing***
5.1.2.2 Other Shipping in the Area		
Rationale: The offshore structures are potential hazards to all marine traffic. A collision between a ship and any structure or PetroSA service vessel may result in marine pollution through the release of oils and fuels and the deposition of objects on the sea bed. Various measures need to be taken to minimise the risk of collisions through alerting shipping to the presence of the structures and/or operations.		
Objectives: • To ensure that provisions prescribed by SAMSA to ensure that the structures and associated vessels are "visible" to marine traffic and aircraft have been implemented. • To ensure that the provisions are effective in maintaining "visibility" of the structures and associated vessels.		
5.1.2.2.1 All measures prescribed by SAMSA to minimise the risks of collision of marine traffic with the offshore structures must be implemented and maintained.	***OIM***	***Ongoing***
5.1.2.2.2 Measures to be implemented include: • Maintenance of safety and exclusion zones; • Maintenance of standard watch procedures; • Issue navigational warnings if visibility of structures is diminished (e.g. power outages or failure of fog horn); • Radio communication to alert approaching vessels; • Use of Flares and Sirens where necessary; • Recording of interactions with vessels in the installation log book; and • Collisions, near misses or other transgressions with associated pollution risks will be treated as incidents and handled according to the procedure detailed under **Activity 5.7.**	***OIM***	***Ongoing***
5.1.3 Workshops and Repairs		
Rationale: The platforms and vessels contain workshops of various descriptions and sizes in which machinery containing oils and fuels are repaired and serviced. Furthermore, the workshops store oils and fuels and other potentially polluting substances. The workshop and repair operations do not always take place in a defined workshop area but may take place anywhere on the platform or vessel. While drainage mechanisms exist, there is a risk of polluting substances leaking or spilling into the sea and/ or solid objects falling overboard (see **Activity 5.7**). Procedures are already implemented to minimise loss of equipment or personnel. The focus of this programme is to ensure that environmental issues are adequately addressed.		
Objectives: ▪ To manage the workshops in a manner that minimises the risk of liquids polluting the sea and to expedite clean up of any such spillages that do occur. ▪ To minimise the risk of polluting the environment during repairs and maintenance on the vessel or platform.		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
*5.1.3.1 All fuels, greases, oils and other chemicals shall be stored and handled as per chemical handling procedures specified in PetroSA standard operating procedures and summarised in the chemical handling procedures below (see **Activity 5.3**).*	***SHEQ Officer***	***Ongoing***
5.1.3.2 Repair and servicing of loose equipment or machinery shall be undertaken only in the workshops or within areas of the vessel or installation which has drainage dedicated to containing spilled liquid and suspended debris.	***SHEQ Officer***	***Ongoing***
5.1.3.3 Where repair of equipment or machinery must take place in situ, precautions appropriate to the location must be taken to minimise the risk of spills or loss of objects overboard.	***SHEQ Officer***	***Ongoing***
*5.1.3.4 Any spills of liquids shall be treated as an incident and handled according to the procedure detailed under **Activity 5.7.1** below.*	***SHEQ Officer***	***Immediately***
*5.1.3.5 Any loss of objects overboard shall be treated as an incident and handled according to the procedure detailed under **Activity 5.7.2** below.*	***SHEQ Officer***	***Immediately***
5.1.3.6 Audit Guidelines • Audits should, through examination of records retained by the facility, visual inspections and targeted interviews, verify that: ○ Repair and servicing of mobile equipment and machinery takes place in the workshops or within areas which drain to the effluent tanks. ○ Where such repair is not possible, that the measures taken to minimise spillage or loss of objects overboard were appropriate to the situation and location. ○ Incidents were managed as per the incident procedure under **Activity 5.7.**	***SHEQ Manager***	***Annually***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.2. POLLUTION PREVENTION - SUPPORT SERVICES

5.2.1 Support Services

Rationale:

The platforms and vessels are serviced by other vessels and helicopters which load and off-load equipment personnel and materials. Such operations may disturb marine life, solid objects and liquids may fall into the sea which could pose a risk to shipping or the fisheries, while certain articles and liquids may also be detrimental to marine life and could pollute the sea. Since all such cargo has a monetary value procedures exist to limit any such loss and to retrieve objects falling overboard wherever possible. The focus of the Environmental Management Programme is to ensure that the procedures adequately address environmental issues.

Objectives:

- To minimise the risk of objects being lost overboard during transit or transfer.
- To retrieve objects which have fallen overboard before they pose a risk to the environment or shipping.
- To log the existence and location of fallen objects for future reference/ action.
- To notify interested parties of the existence and location of un-retrieved fallen objects.
- To minimise disturbance to large marine fauna from helicopter flights.

5.2.1.1 Existing PetroSA and aviation service providers' procedures, such as the Materials Handling & Transport and Marine Support Services procedures, shall be implemented to minimise the risk of objects and chemical substances being dropped overboard, during cargo transfer, leaking from storage containers and during handling.	***Logistics Base Manager***	***Ongoing***
5.2.1.2 Helicopter transfers to and from offshore installations shall fly at a minimum height of 500m (or as instructed by the Relevant National Airport Air Traffic and Navigation Services) above sea level and shall not hover or circle over whales, dolphins, sharks, turtles or aggregations of seabirds.	***Logistics Base Manager***	***Ongoing***
5.2.1.3 Helicopter flight logs will be kept to demonstrate compliance with set flight paths.	***Logistics Base Manager***	***Ongoing***
5.2.1.4 Audit guidelines • Audits should, through examination of records retained by the facility, verify that: ○ Incidents were recorded in the incident reports; ○ The response time of incidents is appropriate to their significance; ○ The decision whether or not to retrieve objects was environmentally appropriate; ○ Incidents were subject to comprehensive evaluation by management; ○ Requisite changes were made to operational procedures to ensure that the incident is not repeated; ○ Incidents resulting from the same root cause(s) are not repeated; ○ Trial runs and/or drills for major incidents are conducted at least annually; and ○ The response for major contingencies are formally reviewed by management annually.	***SHEQ Manager***	***Annually***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.3. CHEMICAL STORAGE AND HANDLING

Rationale:

Vessels and platforms store and use a range of chemicals (both solid and liquid) which could potentially contaminate the marine environment. The activities of all personnel dealing with chemicals must minimise the risk of spillage. Not only do spillages constitute waste but they also pose a risk to the environment. Thus the first line of prevention is behavioural. Workshop management has been dealt with above under **Activity 5.1.3**. Even with effective plans in place, accidents do still occur. To this end the vessels and platforms have dedicated drainage systems which channel onboard spillages to tanks for treatment and / or disposal if required. Measures are required to contain any leaks and spillages to avoid the development of a hazardous cocktail in the bilge which could not be discharged to the sea and would require treatment and removal as hazardous waste.

Many of the procedures for chemical handling and storage are legislated under the Occupational Health and Safety Act 85 of 1993 as amended but the focus of the Environmental Management Programme is to ensure that environmental issues are adequately addressed.

Objectives:

- To handle and store chemicals in such a way as to minimise the risk of spillage or leakage.
- To dispose of expired chemicals in an environmentally responsible and legal manner.
- To respond to any spills and or leaks in such a way that environmental damage does not occur.
- To formally evaluate any spills or leaks in order to plan for prevention of recurrence.

5.3.1 Measures for Chemical Storage and Handling		
5.3.1.1 A chemical register shall be maintained by the facility which will detail: • All chemicals used and stored by the facility; • Chemical characterisation of each chemical including SABS class and hazard rating; • Specific storage handling or disposal requirements for each chemical including Personal Protective Equipment; • Emergency response actions for each chemical; and • The process used to verify the information contained in the register.	***SHEQ Officer***	***Ongoing***
5.3.1.2 All containers of hazardous liquids shall be stored inside impermeable bunds (portable or fixed) which have a total capacity of 110% of the total amount liquid stored inside them. This shall apply both in store-rooms and in situations where containers have been temporarily moved from the store room to a position close to where the contents are being used for convenience.	***SHEQ Officer***	***Ongoing***
5.3.1.3 All chemicals shall have current Material Safety Data Sheets (MSDS) prominently displayed at the location of storage and use.	***SHEQ Officer***	***Ongoing***
5.3.1.4 Incompatible chemicals shall not be stored in the same location.	***SHEQ Officer***	***Ongoing***
5.3.1.5 Personnel using chemicals shall be trained in their use, disposal and clean-up.	***SHEQ Officer***	***Annually***
5.3.1.6 Any chemicals which are used at a location distant from their storage shall be transported in drip trays.	***SHEQ Officer***	***Ongoing***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.3.1.7 Expired chemicals shall be labelled as waste and treated in accordance with the disposal requirements specified in their MSDS.	***SHEQ Officer***	***Immediately***
*5.3.1.8 Any liquid spills of more than 5 litres shall be treated as an incident and handled according to the incident procedure detailed under **Activity 5.7.1** below.*	***all staff***	***Immediately***
*5.3.1.9 Any loss of chemicals overboard shall be treated as an incident and handled according to the procedure detailed under **Activity 5.7.1**.*	***SHEQ Officer***	***Immediately***
5.3.1.10 Audit Guidelines • Audits should, through examination of records retained by the facility, verify that: ○ The chemical register is current and verified; ○ Storage accords with legal requirements and the details contained in the MSDS; ○ All liquids were stored inside bunds of requisite capacity; ○ The bunds are sealed and the containment integrity is checked regularly; ○ All hazardous chemicals were labelled as such and the emergency procedures to be adopted in the event of a spill clearly are detailed on MSDS at the site of storage; ○ All MSDS are current and accurate; ○ Mobile liquid chemical dispensers or drums are positioned on / or over drip trays; ○ Spills are reported and handled according to the liquid incident management procedure under **Activity 5.7.1;** ○ Spill absorbents are available at the location of use and that they are appropriate to the nature of the chemical being used; and ○ Expired chemicals are labelled as expired and handled as waste.	***SHEQ Manager***	***Annually***

Environmental Protection Activities

Activities 5.4 - 5.6: Waste Management

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.4. SOLID WASTE MANAGEMENT

Rationale:

Globally there is a recognition that wastage of resources must cease. A major concern is that final disposal to landfill of potentially renewable resources will unnecessarily use up landfill airspace and also wastes resources that still have value. Since the enactment of the National Environmental Management: Waste Act (No 59 of 2008) there is now a positive obligation on waste generators to assess their resource usage and attempt to eliminate or reduce waste production and where this is not possible, to develop ways of re-using or recycling waste. Disposal to landfill is then only adopted as a final resort. This requires an active and ongoing assessment of waste production to identify creative ways of satisfying the objects of this Act. The procedure below provides an overview of the steps which should be taken.

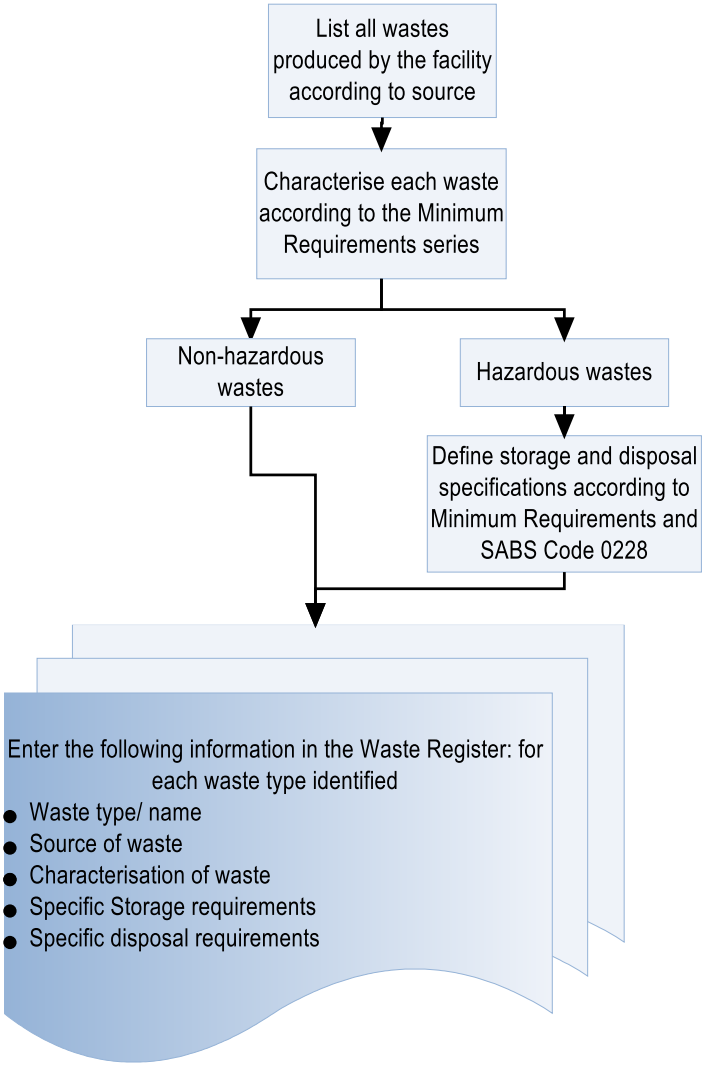
Objectives:

- To prevent any waste from entering the marine environment except for macerated galley waste and macerated and treated sewage waste.
- To reduce the amount of waste disposed to landfill by reducing waste generation and maximising recycling and reuse.
- To comply with waste management legislation.
- To dispose of all solid waste in an environmentally responsible manner.

5.4.1 Solid Waste Management Measures		
5.4.1.1 *The facility shall review its waste management on an annual basis using the waste management hierarchy depicted below. This shall be a documented, and targets for reduction/ reuse/recycling provided.* ~~*The facility shall review its waste management on an annual basis using the hierarchy depicted below (source http://www.envirowise.gov.uk/uk/our-services/resource-efficiency.html). This shall be a formal, documented review of all wastes, and results shall be reported to MANCO. The program shall document waste reduction targets for the forthcoming year.*~~	***SHEQ Manager***	

5.4.1.2 Waste Management Hierarchy

Figure 5.4.1: Waste Management Hierarchy

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.4.1.3 The facility shall develop and maintain a Waste Register which shall detail: • Each waste produced by the facility; • Their source; • Their SABS class and hazard rating; • Their disposal methods; and • Any specific precautions or legislative requirements.	***SHEQ Officer***	***Ongoing***
5.4.1.4 Waste Register  *Figure 5.4.2: Waste Register*		
5.4.1.5 The Waste Register shall be reviewed and updated annually.	***SHEQ Officer***	***Annually***
5.4.1.6 Waste shall be segregated into the following categories. Recyclables shall be stored separately as shall hazardous waste.	***SHEQ Officer***	***Ongoing***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

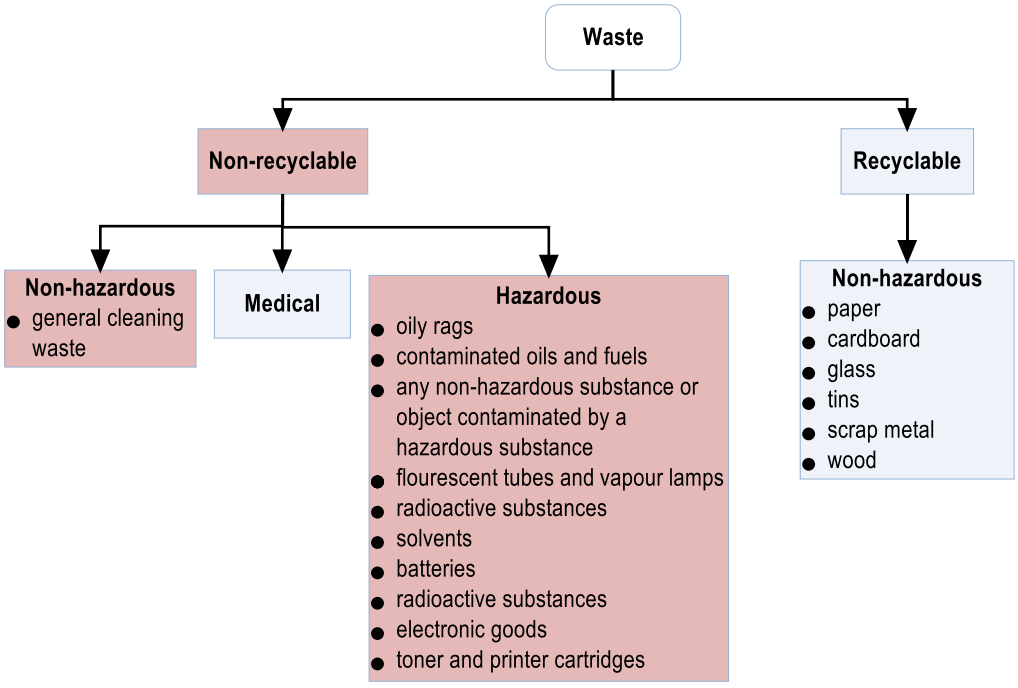


Figure 5.4.3: Possible waste segregation categories

5.4.1.7 All wastes shall be handled according to the flow diagram below while awaiting transport to disposal sites.	***SHEQ Officer***	***Ongoing***

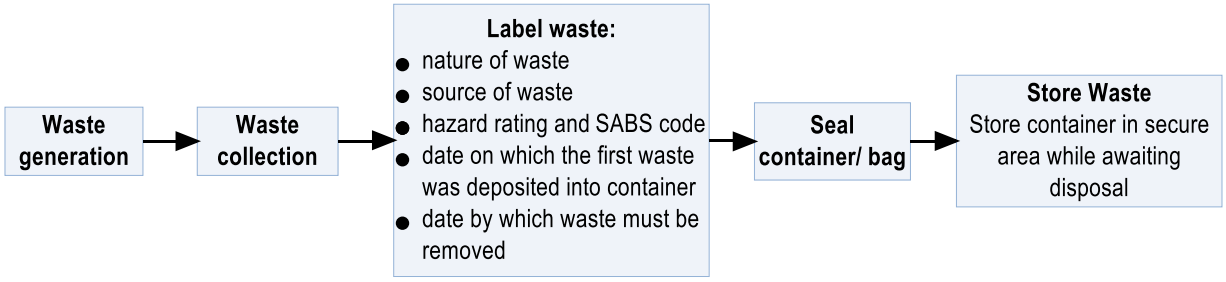


Figure 5.4.4: Waste Handling

5.4.1.8 No waste may be stored for more than 30 days on any facility without formal permission from DEA.	***SHEQ Officer***	***Ongoing***
5.4.1.9 Wastes shall be stored in sealed containers or bags and protected from the environment according to specifications for storage in the Minimum Requirements for the Handling, Classification and Disposal of Hazardous Waste published by Department of Water Affairs and Forestry in 1998.	***SHEQ Officer***	***Ongoing***
5.4.1.10 Comply with the National Norms and Standards for the storage of waste under the Waste Act, 2008. If non-compatible wastes are to be stored, care should be taken to adequately separate them, to prevent possible interactions in the event of fire or spillage. Flammable or combustible	***SHEQ Officer***	***Ongoing***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
wastes must in any event be stored separately from other waste materials. ~~Incompatible waste may not be stored in the same location (see the hazard ratings for wastes in the Minimum Requirements for the Handling, Classification and Disposal of Hazardous Waste published by Department of Water Affairs and Forestry in 1998 for compatibility).~~		
5.4.1.11 Galley waste shall be macerated at sea to pieces smaller than 25mm and deposited overboard in accordance with MARPOL requirements, or disposed to landfill onshore.	***SHEQ Officer***	***Ongoing***
*5.4.1.12 Sewage shall be treated as per **Activity 5.5.5.3**.*	***SHEQ Officer***	***Ongoing***
5.4.1.13 Waste removal from the platform or vessel shall be handled according to the following flow diagram.	***SHEQ Officer***	***Ongoing***

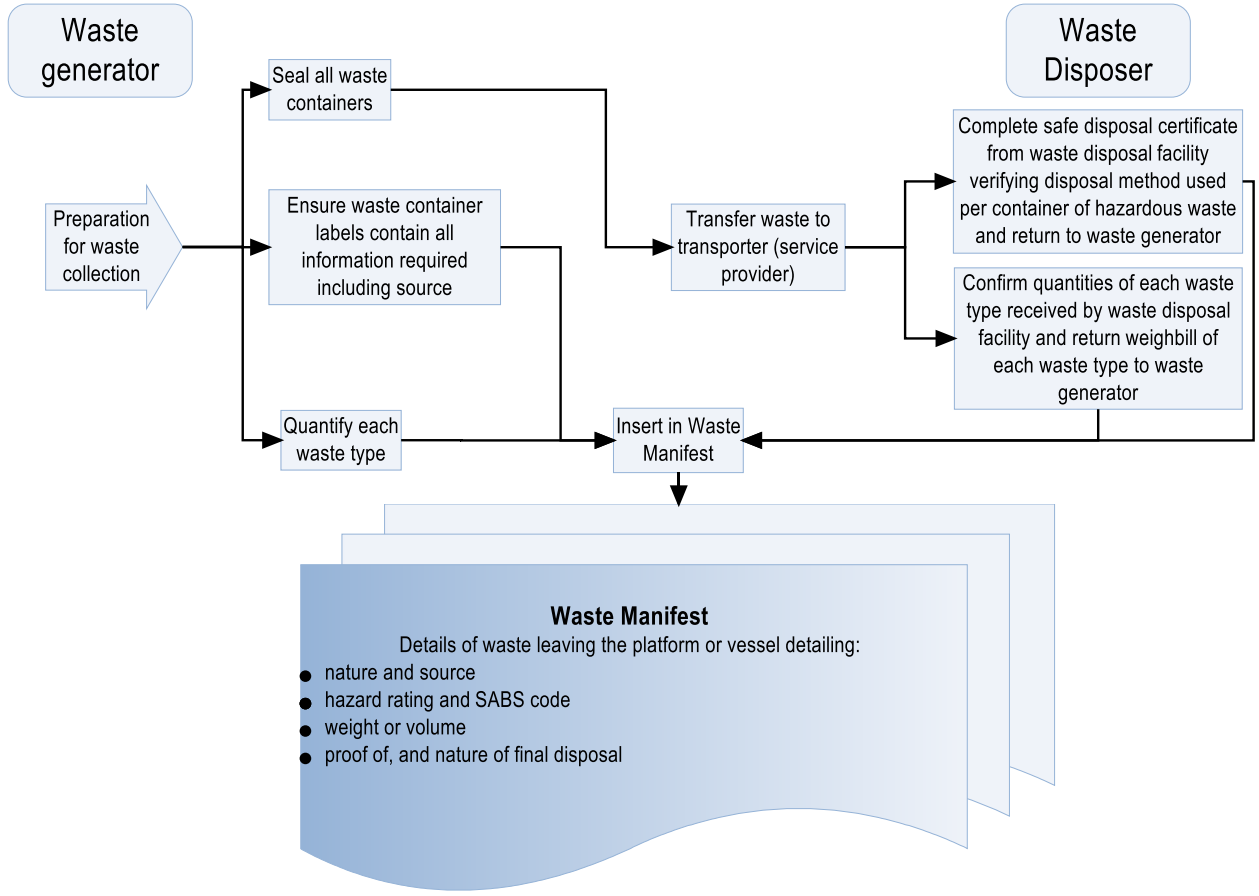


Figure 5.4.5: Waste removal

5.4.1.14 The offshore facility shall develop and maintain a waste manifest system which details: • The quantities of all wastes leaving the facility. • The date upon which they left. • The date upon which they were received by the disposal facility.	***SHEQ Officer***	***Ongoing***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
• Proof of correct disposal by the landfill site (safe disposal certificate for hazardous waste).		
5.4.1.15 A safe disposal certificate shall be issued for each load of hazardous waste, excluding hazardous wastes lawfully disposed of at the PetroSA Landfill. ~~A safe disposal certificate shall be issued for each load of hazardous waste.~~	***Landfill Manager***	***Ongoing***
5.4.1.16 The safe disposal certificate shall be kept on file in PetroSA's waste records. ~~The safe disposal certificate shall be filed in the waste manifest.~~	***SHEQ Officer***	***Ongoing***
5.4.1.17 The volumes of each waste type generated and disposed as well as the disposal site and method shall be reported in The Quarterly ~~Monthly~~ Report.	***SHEQ Officer***	***Quarterly ~~Monthly~~***
5.4.1.18 Waste disposal records shall be stored for submission to the PASA or other regulatory agencies should they ~~Waste Management Officer should the Officer at DEA~~ require it.	***SHEQ Officer***	***Ongoing***
5.4.1.19 All personnel shall receive regular training on the handling and management of waste.	***SHEQ Officer***	***Annually***
5.4.1.20 Audit Guideline • Audits should, through examination of records retained by the facility, verify that: ○ The waste characterisation register is current and verified; ○ The Waste Register has been reviewed within the last 12 months; ○ The waste management program has been reviewed within the last 12 months; ○ Waste reduction targets have been met; ○ Procurement practices have been reviewed with a view to avoiding and /or minimising waste through selective purchasing practices; ○ Storage accords with legal requirements and the details contained in the register; ○ All liquid wastes were stored inside bunds of requisite capacity. ○ The bunds are sealed and the containment integrity is checked regularly; ○ All hazardous wastes were labelled as such; ○ No wastes are stored by the facility for longer than 30 days without approval from DEA subject to the submission of a Basic Assessment Report; ○ The amount of general waste stored on site does not exceed 30 tonnes per day or does not exceed a throughput rate of 20m^3 per day without approval from DEA subject to the submission of a Basic Assessment Report; ○ The temporary storage of hazardous waste does not exceed 3 tonnes on any one day without approval. If the amount of hazardous waste generated exceeds 3 tonnes per day, this is a scheduled activity in terms of the Waste Act and requires approval from DEA via a scoping / Basic Assessment process; ○ Each container of waste is labelled with its source and contents;	***SHEQ Manager***	***Annually***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
○ Safe disposal certificates are obtained for every hazardous waste load; and ○ All personnel have received training in waste management and handling within the last 12 months.		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.5. DISCHARGE OF EFFLUENT

Rationale:

Bulk liquid wastes arise from cleaning the decks, from ablutions, from the bilges and from produced water. These are stored prior to discharge but the discharge has the potential to be detrimental to the marine environment if it does not meet MARPOL discharge standards.

Objectives:

- To contain any effluents which could pose a threat to the marine environment.
- To treat any effluents before discharge in order to minimise damage to the marine environment.
- To comply with legislative obligations for effluent discharge.

5.5.1 Produced Water		
5.5.1.1 No produced water may be discharged to the sea unless the oil concentration is below 40 ppm.[1]	***Production Superintendent / Marine Supervisor***	***Ongoing***
5.5.1.2 Oil concentration of produced water shall be monitored continuously automatically and concentrations logged daily. In the event of breakdown of automatic measurements, manual measurements shall be made at least twice daily until equipment is repaired.	***Production Superintendent / Marine Supervisor***	***Daily***
5.5.1.3 In the event that the oil concentration reaches or exceeds 40 ppm the root cause of exceedance shall be investigated and rectified.	***Production Superintendent / Marine Supervisor***	***Immediately***
5.5.1.4 The systems controlling the produced water discharges must be kept in good working order.	***Production Superintendent / Marine Supervisor***	***Ongoing***
5.5.1.5 The monitoring results shall be filed and retained for 5 years.	***SHEQ Manager***	***5 years***
*5.5.1.6 The concentration of oil in produced water as determined in **Activity 5.5.1.2** shall be reported in The Quarterly ~~Monthly~~ Report.*	***SHEQ Officer***	***Quarterly*** ***~~Monthly~~***
5.5.1.7 Any discharges of produced water at or exceeding 40 ppm oil concentration shall be treated as an incident, reported and investigated accordingly.	***SHEQ Officer***	***Immediately***
5.5.2 Deck & Bilge Water		
5.5.2.1 No deck or bilge water may be discharged to the sea unless the oil concentration is below 15 ppm (MARPOL standard).	***Marine Superviso r/ Production Superintendent***	***Ongoing***

[1] *Limit specified in a Pollution Safety Certificate issued by SAMSA on 23/01/2008. In contrast PARCOM 1/17/1 stipulates that no produced water may be discharged to the sea unless the oil concentration is below 100 ppm, further discharged produced water oil content should be managed such that the monthly mean concentration is equal to or less than 40ppm.*

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.5.2.2 Oil concentration of discharged bilge and deck water shall be monitored continuously automatically and concentrations logged daily. In the event of a breakdown of automatic measurements then manual measurements shall be made twice daily until equipment is repaired.	***Marine Supervisor/ Production Superintendent***	***Twice daily***
5.5.2.3 In the event that the discharged oil concentration exceeds 15 ppm the root cause of exceedance shall be investigated and rectified.	***Marine Supervisor/ Production Superintendent***	***Immediately***
*5.5.2.4 The concentration of oil in bilge water as determined in **Activity 5.5.2.2** shall be reported in The Quarterly ~~Monthly~~ Report.*	***SHEQ Officer***	***Quarterly*** ***~~Monthly~~***
5.5.2.5 The monitoring results shall be filed and retained for 5 years.	***SHEQ Manager***	***5 years***
5.5.3 Sewage		
5.5.3.1 Sewage shall be comminuted before discharge to the sea in accordance with MARPOL standards.	***Marine Supervisor/ Production Superintendent***	***Ongoing***
5.5.4 Audit Guidelines		
• Audits should, through examination of records retained by the facility, verify that: ○ The waste water streams were monitored at the specified frequency; ○ The laboratory equipment used for analysis was calibrated and maintained according to manufacturer's specifications; ○ Sewage macerators are maintained and fully functional; ○ Any elevated levels were investigated and the sources identified and appropriate action was taken; ○ Any such remedial action was documented and the effectiveness monitored; ○ No waste water was discharged from bilge tanks with a concentration of greater than 15ppm oil (MARPOL) and of produced water with an oil concentration of greater than 40 ppm; ○ Any discharges of concentrations greater than those specified were formally investigated, reported and remedial action taken; and ○ Any such remedial action was documented and the effectiveness monitored.	***SHEQ Manager***	***Annually***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.6. GASEOUS EMISSIONS

Rationale:

Gaseous emissions of concern on the offshore installations are escaped Freon from the refrigeration units and gases resulting from flaring. At present there are no legislated limits for the emissions produced by PetroSA. Should this change in future the performance criteria will be amended accordingly.

Objectives:

- To reduce the volumes of green house gases emitted.

5.6.1 Gaseous Emissions		
5.6.1.1 Maintain all refrigeration equipment in accordance with the scheduled maintenance program to minimise Freon release.	***Production Superintendent / Marine Supervisor***	***Ongoing***
5.6.1.2 Any accidental releases of Freon shall be treated as incidents, and in addition to normal incident reporting, shall be reported to DEA.	***Production Superintendent / Marine Supervisor***	
5.6.1.3 Incidents shall be reported to DEA.	***Operations Environmental leader***	***Quarterly***
5.6.1.4 The volume of gas flared on a daily basis shall be reported in The Quarterly ~~Monthly~~ Report.	***SHEQ Officer***	***Quarterly*** ***~~Monthly~~***
5.6.1.5 Greenhouse gas emissions must be reported in accordance with the requirements of the National Greehouse Gas Reporting Regulations, published under the National Environmental Management: Air Quality Act.	*SHEQ Officer*	*Annually*
5.6.1.6 Audit Guidelines • Audits should, through examination of records retained by the facility, verify that: ○ Emissions are monitored according to the specified schedule; ○ The laboratory equipment used for analysis was calibrated and maintained according to the manufacturer's specifications; and ○ Any elevated levels were investigated and the sources identified and rectified.	***SHEQ Manager***	***Annually***

Environmental Protection Activities

Activity 5.7: Incidents and Emergency Reporting and Management

ACTIVITY 5.7. INCIDENTS & EMERGENCY REPORTING & MANAGEMENT 2

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.7. INCIDENTS & EMERGENCY REPORTING & MANAGEMENT

Rationale:

An incident is an unplanned event which could or does result in harm/ loss to people, property, process or environment and covers every incident from minor spills and leaks to large-scale releases and emergencies. This includes well blow-outs, ruptures of pipelines, collision between vessels and the platforms, spills during fuel bunkering or any other operation, and loss of objects overboard.

The single biggest environmental incident risk, given the nature of PetroSA operations, is of oil and chemical spills to the sea from a variety of sources. Not only is this prohibited by a range of different national and international laws and regulations but any product spillage constitutes a financial loss. Thus, PetroSA has a number of standard operating procedures which not only aim to prevent spills during normal operations and emergency situations but also to manage the response in the event of a spill. The incident management procedure is employed as the first stage of a spillage, which includes an assessment of the magnitude and severity of the spill in order to determine whether the incident constitutes an emergency and if the oil spill contingency plan must be activated.

Objectives:

- To provide a coherent, planned response to any incident which could adversely affect the environment.
- To improve response time and efficiency of the plans and the activities of staff members through drills and test runs.
- To provide a process for the management of an incident or emergency depending upon the severity of the occurrence.
- To minimise the risk of loss of solid objects overboard and to expedite the retrieval (if possible) of any objects which fall overboard.
- To log the existence and location of fallen objects for future reference/action.
- To notify interested parties of the existence and location of un-retrieved fallen objects.
- Through post-emergency evaluations, minimise the risk of a recurrence of the incident.

5.7.1 Liquid Spills or Leaks

5.7.1.1	~~*Any incident shall be managed according to the procedure outlined in the flow diagram below. This diagram summarises the PetroSA procedures specified for incident management and oil spill contingency management. PetroSA documents should be consulted for more details on procedures and reporting instructions.*~~ *All incidents, including liquid spills, shall be managed in accordance with the PetroSA Incident Management Procedure (QAL/PR/COR/002), and/or the approved OSCP, depending on the nature of the incident.*	***All staff***	***Immediately***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

5.7.1.2 *Liquid Incident Reporting & Management*

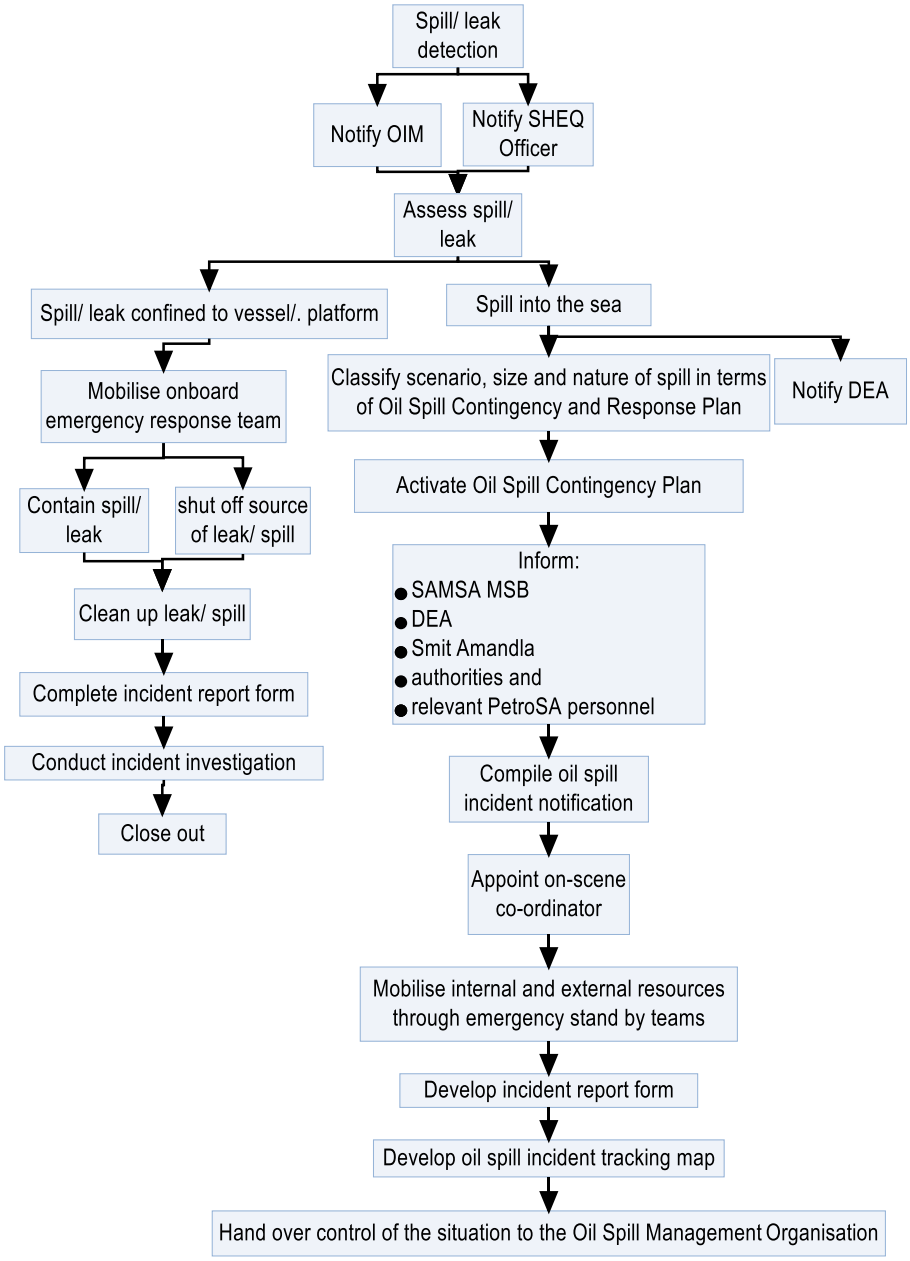


Figure 5.7.1: Liquid Incident Reporting & Management

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.7.1.3 *The incident and the results of the investigation shall form part of The Quarterly ~~Monthly~~ Report.*	***OIM***	***Quarterly*** ***~~Monthly~~***
5.7.1.4 *The plan should be aligned to the National Oil Spill Contingency Plan (NOSCP) and updated every five years or sooner if significant changes occur, such as new developments, or emergency incidents that alter the risk of marine pollution. Check and update the contact details in the OSCP every 6 months or on notification by government or other key organisations. ~~Check and update the contact details in the oil spill contingency plan every 6 months or on notification by government or other key organisations.~~*	***OIM***	***5 yearly*** ***6 months***
5.7.2 Materials and Equipment Lost Overboard		
5.7.2.1 *If a solid object falls overboard, the incident shall be managed according to the flow diagram below.*	***All staff***	***Immediately***
5.7.2.2		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

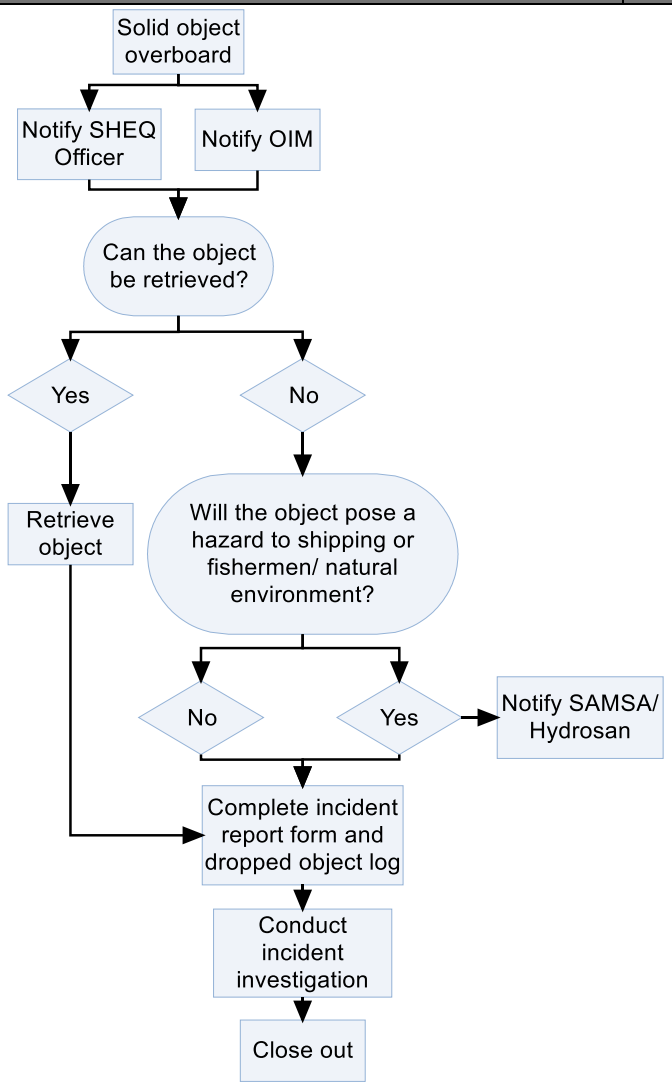


Figure 5.7.2: Dropped Object Incident Response

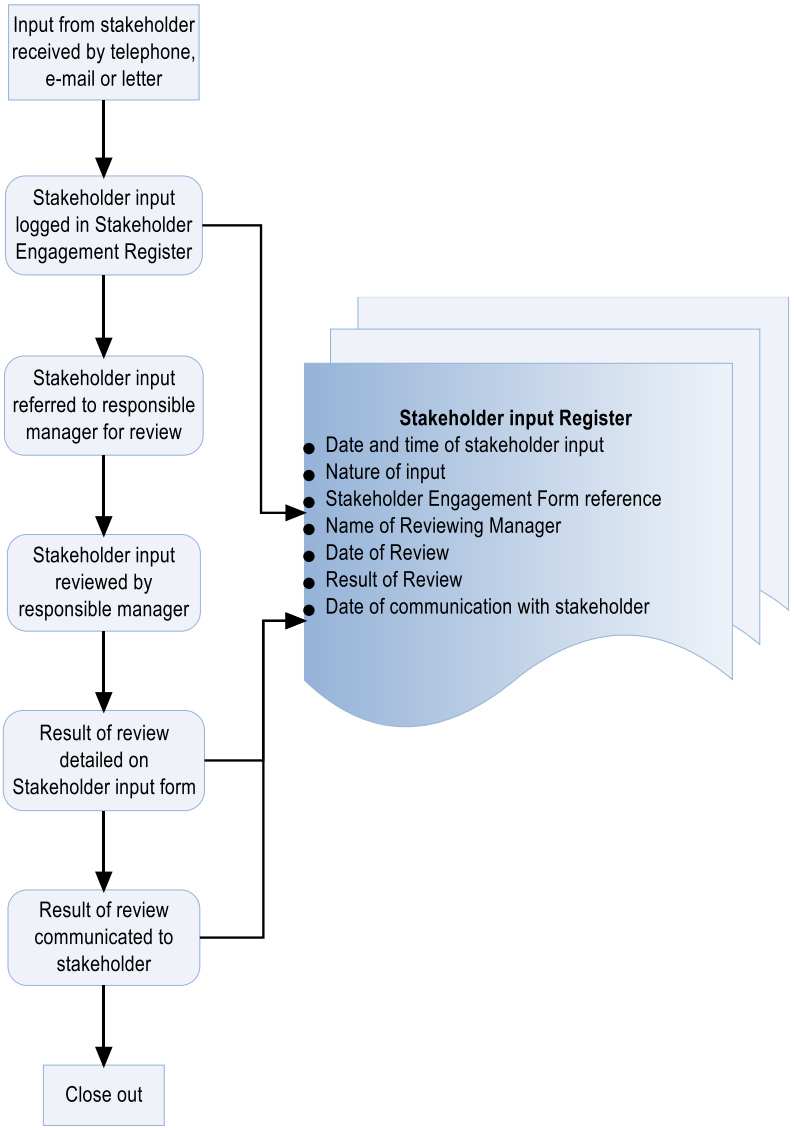
5.7.2.3 *Any incidents shall be reported in The Quarterly ~~Monthly~~ Report.*	***SHEQ Officer***	***Quarterly ~~Monthly~~***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
5.7.2.4 *Audit Guidelines* • Audits should, through examination of records retained by the facility, verify that: ○ All incidents have been reported and recorded as per specification in the flow diagram above; ○ All incidents have been comprehensively investigated to identify root causes; ○ The incident reports detail the results of the investigations into root causes and advises on amendments to procedures or equipment as needed; ○ The advised changes are implemented; ○ A trend analysis on incidents is conducted monthly; ○ Incidents are reported weekly and monthly along with the root cause analyses; ○ Sufficient oil and chemical spill containment and absorbent equipment is stored in sufficient quantities in areas where spills are considered most likely; and ○ The oil spill contingency plan is current.		

Environmental Protection Activities

Activity 5.8: Stakeholder Engagement

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
ACTIVITY 5.8. STAKEHOLDER ENGAGEMENT		
Rationale: The activities of the offshore oil and gas production installations have or may have impacts upon a range of stakeholders. These impacts can range from positive job creation or second order income generation to negative impacts such as limitations on trawling efficiency and potential disruption of biodiversity. It is incumbent on PetroSA to engage with stakeholders in terms of the principles of NEMA and to this end the Agulhas Forum has been established, which meets every 6 months and includes representatives from the fishing industry, conservation NGOs, and government departments. The aim of the forum is to provide a mechanism for dissemination of information about PetroSA activities and to receive and answer stakeholder concerns. In so doing, the forum meetings seek to improve the level of transparency of the nature and timing of PetroSA operations.		
Objectives: • To provide regular feedback to the stakeholder forum. • To establish and maintain a register of stakeholders. • To receive, process and respond to inputs from external and internal stakeholders.		
5.8.1 Stakeholder Engagement		
5.8.1.1 A stakeholder feedback process as detailed in the flow diagram below shall be maintained	***Operations Environmental Leader***	***Ongoing***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
 *Figure 5.8.1: Stakeholder Feedback Management*		
5.8.1.2 Any feedback from stakeholders concerning offshore operations shall be reported in The Quarterly ~~Monthly~~ Report.	***SHEQ Officer***	***Quarterly*** ***~~Monthly~~***
5.8.1.3 Audit Guidelines • Audits should, through examination of records retained by the facility, verify that: ○ A stakeholder register has been maintained; ○ Any stakeholder inputs have been reviewed by the responsible manager; ○ The above stakeholder inputs have been responded to appropriately; and ○ The stakeholder has been informed of the outcome of the review by the responsible manager.		***Annually***

Environmental Protection Activities

Activity 5.9: Environmental Training and Awareness

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
ACTIVITY 5.9. ENVIRONMENTAL TRAINING AND AWARENESS		
Rationale: Poor staff awareness about resource efficiency, waste management and pollution control is common in many organisations. This can result in accidents or avoidable incidents through ignorance. It is important to raise environmental awareness to stimulate staff participation. To raise awareness and obtain commitment, staff need to be given the facts about the costs of waste and incidents which generate waste; how the programme applies to them as individuals, and the benefits of resource efficiency to the business. This can assist personnel to be appropriately equipped to conduct their duties in an environmentally responsible manner.		
Objectives: • To equip all personnel on the platform/ rig etc to perform their duties in an environmentally responsible manner through regular training. • To raise environmental awareness through feedback on environmental performance and any changes in legislation of best practices.		
5.9.1 Environmental Training and Awareness		
5.9.1.1 A matrix detailing environmentally related training shall be developed in consultation with the Operations Environmental Leader This shall detail elements of this Environmental Management Programme that are appropriate to each work area on the facility.	***Training Superintendent***	***Every 2 years***
5.9.1.2 Toolbox talks shall be used to discuss environmental awareness and to report back on environmental performance applicable to the specific work area.	***SHEQ Officer***	***2 monthly***
5.9.1.3 Deviations of procedure by staff members shall initiate a retraining exercise.	***SHEQ Officer***	***Immediately***
5.9.1.4 Repeated deviations from procedures after retraining shall result in disciplinary procedures being instituted against the offender(s).	***OIM***	***As required***
5.9.1.5 Audit Guidelines • Audits should, through examination of records retained by the facility, verify that: ○ The training matrix has been developed and is current; ○ The training matrix was used to plan training programs for all personnel; ○ All personnel have received appropriate training at least annually; ○ Deviations from procedures identified in incident investigations have resulted in retraining; and ○ Complete training records are maintained for 5 years.	***SHEQ Manager***	***Annually***

Environmental Protection Activities

Activity 5.10: System Administrative Requirements

ACTIVITY 5.10. SYSTEM ADMINISTRATIVE REQUIREMENTS 2

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 5.10. SYSTEM ADMINISTRATIVE REQUIREMENTS

Rationale:

Systems enable an organisation to:

- assure itself of its conformance with its own stated environmental policy.
- demonstrate conformance.
- ensure compliance with environmental laws and regulation amongst other things.

The ISO system model operates on the system of Plan – Do – Check – Act cycle.

Plan: establish objectives and make plans (analyze your organization's situation, establish your overall objectives and set your interim targets, and develop plans to achieve them).
Do: implement your plans (do what you planned do).
Check: measure your results (measure/monitor how far your actual achievements meet your planned objectives).
Act: correct and improve your plans and how you put them into practice (correct and learn from your mistakes to improve your plans in order to achieve better results next time).[1]"

This section summarises some key system requirements to ensure the effective implementation of the EMPr. Further details are available in PetroSA's EMS documentation.

Objectives:

- To provide a comprehensive and coherent system which accesses and stores information pertinent to environmental management from diverse sources to verify responsible environmental practices.
- To provide a formal platform for reporting on environmental performance.
- To monitor and audit environmental performance against pre-determined criteria.
- To use formal management reviews to continuously improve the system itself and thereby environmental performance as a whole.

5.10.1 Monitoring

The following parameters shall be monitored:		
*5.10.1.1 Produced water discharge: oil concentration to ensure <40 ppm (see **Activity 4.5.1.2**).* *5.10.1.2 Produced water discharge: volumes discharged.*	***SHEQ Officer***	***Continuous automatic, plus daily logging of monitoring data***
*5.10.1.3 Bilge water discharge: oil concentrations to ensure <15ppm (see **Activity 4.5.2.2**).*	***SHEQ Officer***	***Daily***
*5.10.1.4 Flare emissions: Gas volume flared (see **Activity 4.6.1.4**).*	***SHEQ Officer***	***Monthly***
*5.10.1.5 Solid waste production and disposal (refer **Activity 4.4.1.17**).*	***SHEQ Officer***	***Monthly***
5.10.1.6 Marine biodiversity – colonisation of structures by alien taxa: using existing	~~***Operations:***~~	***Every 5~~3~~***

[1] http://www.iso.org/iso/iso_catalogue/management_standards/understand_the_basics.htm

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
ROV footage and underwater photography surveys of biological communities on the offshore structures and sections of pipelines to monitor possible development of populations of large (>20 mm) alien species. (Biodiversity Convention). Any visual footage of marine growth / feature on infrastructure should be distributed to relevant marine ecologists for further investigation.	***Environmental Leader***	***years***
5.10.1.7 Monitoring results shall be retained for 5 years.	***SHEQ Manager***	***5 years***
5.10.1.8 Monitoring results shall be reported in The Quarterly ~~Monthly~~ Report.	***OIM***	***Quarterly*** ***~~Monthly~~***
5.10.2 Auditing		
5.10.2.1 The EMPr shall be subject to an internal audit on an annual basis. ~~This constitutes the annual performance report.~~	***~~Corporate:~~ Environmental Leader***	***Annually***
5.10.2.2 The EMPr shall be subject to an external verification audit on a three yearly basis.	***~~Corporate:~~ Environmental Leader***	***Every 3 years***
5.10.2.3 The audits shall review and report on the auditing requirements detailed in each section of this EMPr.	***~~Corporate:~~ Environmental Leader***	***As above***
5.10.2.4 Audit Guidelines • Audits should, through examination of records retained by the facility, verify that: o All records required by this EMPr have been retained and are stored in an accessible and logical manner; o All reports required by this EMPr have been completed and submitted to the designated recipient; o All monitoring has been completed and any deviances responded to accordingly; and o Management reviews have been conducted and were comprehensive and any action required has been implemented.		
5.10.3 Reporting		
5.10.3.1 The following reports shall be compiled and submitted: Quarterly Internal Report, Quarterly PASA Report (including a summary of all reportable incidents and stakeholder issues), Annual Performance Assessment Report (Internal Audit). • Internal Reports (Monthly during construction and operations; quarterly during Care and Maintenance): o Incidents. o Repairs. o Gas flared. o Volumes and quality of produced and bilge water discharged. o Waste generated. o Energy consumed i.t.o. fuel, diesel, gas, crude oil. • Quarterly PASA Reports: o Reportable incidents. o Consolidated from internal reporting (as per above). o Stakeholder issues. o Volumes and quality of produced and bilge water discharged.		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

Annual Performance Assessment Reports

Monthly Report (Internal)
Monthly
(all values are year-to-date)

Contents
- Incidents
- Repairs
- Gas flared
- Volumes and quality of produced and bilge water discharged
- Waste generated
- Energy consumed ito fuel, diesel, gas, crude oil
- Training
- Stakeholder issues arising to offshore installation
- ~~Any audit results~~
- Any other environmental studies

Department of Environmental Affairs
Quarterly
(all values are year-to-date)

Contents
- Reportable incidents
- Volumes and quality of produced and bilge water discharged
- Stakeholder issues arising to offshore installation
- Any audit results

PASA
Quarterly
(all values are year-to-date)

Contents
- Reportable incidents
- Consolidated values from Monthly Reports
- Stakeholder issues arising to offshore installation

PASA
Annually

Contents
- Annual Performance Assessment Report

PetroSA EXCO
Annually

Contents
- Annual Performance Assessment Report
- Results of Annual Management Review

Figure 4.10.1: Summary of Reports per Recipient and Frequency

5.10.4 Record keeping		
5.10.4.1 All records shall be retained for 5 years.	***SHEQ Manager***	***5 years***

5.10.4.2 The following records shall be maintained as part of the EMPr. The records may be filed in another system such as the SHEQ system. The requirements of this EMPr are satisfied if the required documents are cross-referenced for auditing purposes.

- Effluent discharge volumes;
- Effluent discharge quality results;
- Effluent quality exceedances;
- Incident reports;

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
• Air quality monitoring; • ROV imagery of subsea conditions; • Water manifests and waste characterisation; • Waste production and disposal analyses; • Training records; • Prosecutions/ notices of non-compliance; • Stakeholder inputs and the review thereof; • Audit reports; • Results of management reviews; • Weekly, monthly and annual internal reports; • Planned maintenance reports / logs; • All previous EMPrs; • All EIAs and application for environmental authorisations; and • Any correspondence with permitting authorities such as PASA, DEA, SAMSA, etc.		
5.10.5 EMPr Review and Revision		
5.10.5.1 The EMPr shall be subject to annual review by senior management. 1. The review shall consider the following information: • Monthly monitoring records; • Training records; • Audit reports; • Enforcement records; • Feedback from stakeholders; and • Revisions to system documents. 2. The management review shall consider whether: • All significant aspects of and risks to compliance have been identified, documented and assigned performance criteria; • There are any significant aspects of or risks to compliance which are no longer appropriate and can be removed; • Performance criteria are being met or whether other actions are required; and • The EMPr as implemented during the preceding year facilitates compliance with its' objectives and legal obligations, and if not what amendments are required.	***Senior Management***	***Annually***
5.10.5.2 The review by senior management shall be documented and the document retained for 5 years.	***Senior Management***	***5 yearly***

Environmental Protection Activities

decommissioning

ACTIVITY 11. DECOMMISSIONING 2

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing

ACTIVITY 11. DECOMMISSIONING

Rationale

The gas and oil fields will end their economic lives and the associated infrastructure on the seabed (up to high water mark) will become redundant and will need to be decommissioned in terms of South Africa's obligations under international conventions and domestic law.

Decommissioning herein is assumed to be a natural conclusion of production and is not a separate process, i.e. the "end of production" includes the decommissioning activities.

Offshore facilities/Infrastructure needing to be decommissioned include:

- subsea equipment on or in the seabed;
- ~~support structures and topsides for fixed and floating installations (Orca and FA production platforms, EM and Control Buoy);~~
- pipelines with PLEMs/ UTAs/ riser anchor bases;
- flow lines and umbilicals; and
- wells.

To decide on the best decommissioning option/s all activities involved in decommissioning need to be examined and compared, including:

- removal methods and disposal routes for all offshore facilities/ infrastructure components;
- cleaning methods and agents and disposal of hazardous residues
- application of the principles of the waste management hierarchy;
- catering for degradation and movement and stability of remains on the seabed;
- removal of seabed debris following decommissioning works; and
- post-decommissioning monitoring and maintenance, as well as other ancillary tasks.

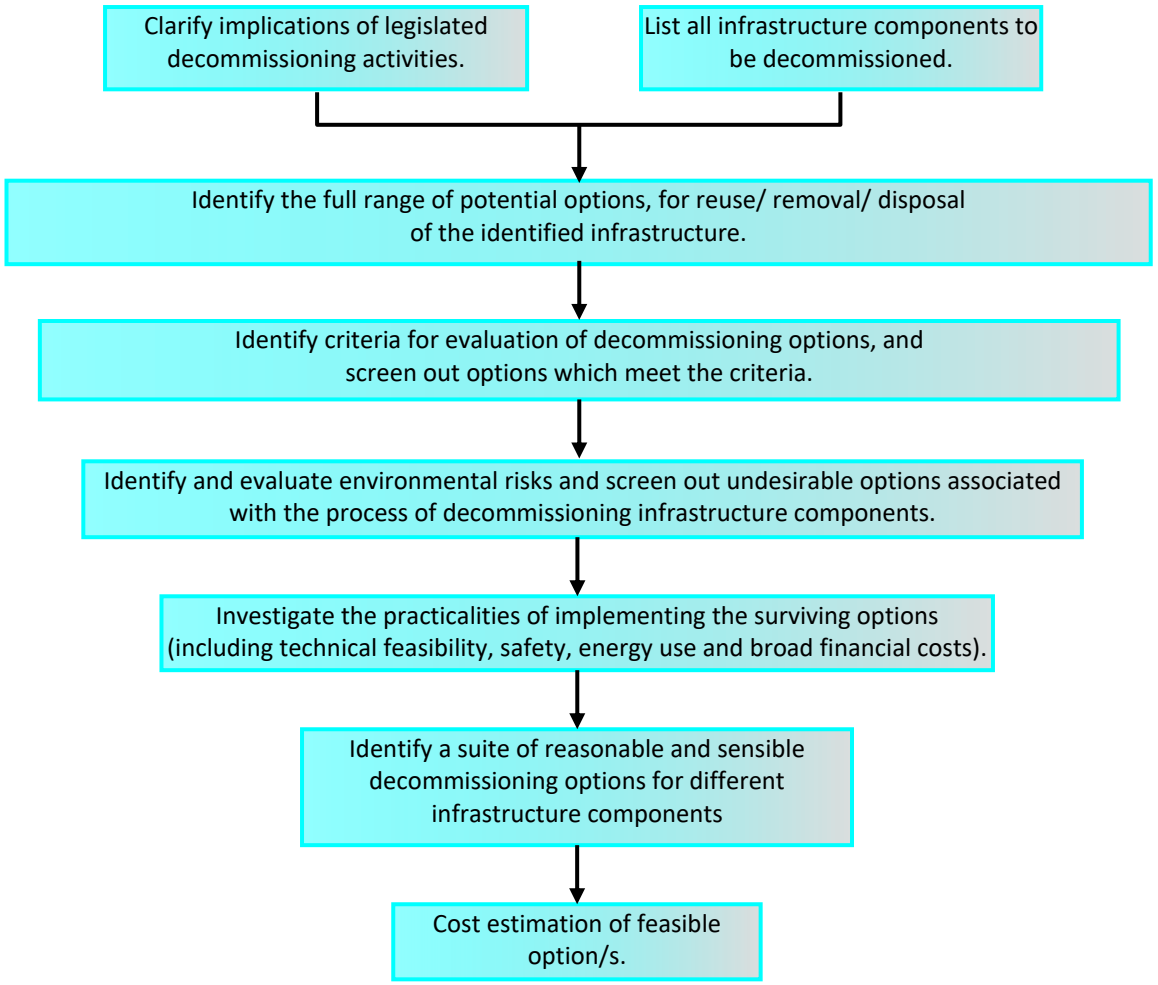
The overarching criteria that need to be used in the evaluation and selection of the optimal decommissioning option/s are:

- environmental impact (particularly biodiversity effects, implications for fisheries and fate of materials e.g. potential for re-use or re-cycling, disposal in land fill site, etc);
- complexity and associated technical risk;
- safety risks/ risks to personnel;
- possibilities for environmental offsets; and
- financial costs (including post-decommissioning).

Overall objective:

- To investigate options for the ultimate fate of all components of the offshore facility/ infrastructure in such a way as to cause no significant adverse effects on the marine (or terrestrial) environment while having a proper regard for safety, technical, social (other legitimate uses and users of the sea), and financial costs, and to meet national and international obligations. This is so as to be able to schedule and finance contracts for decommissioning, and where necessary and feasible to adjust the operational environmental management programme to make this easier to achieve.

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
11.1 Identification of Decommissioning Strategy		
11.1.1 The process followed to identify reasonable and sensible decommissioning solutions is illustrated in the diagram below.	***VP : Operations***	***Annually***



Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
11.2 Decommissioning Strategy for FA-EM Production Area & Framework for Annual Evaluation and Reporting to PASA.		

11.2.1 For each option detailed risk assessment is carried out using 5 main risk categories and a total of 18 sub-criteria are listed below:

- Safety risks: 1.1 Safety risk to offshore personnel, 1.2 Safety risk to onshore personnel, 1.3 Safety risk to other offshore users, and 1.4 Safety risk to other onshore users.
- Environmental risks: 2.1 Energy use and GHG emissions, 2.2 Soil and groundwater contamination, 2.3 Seawater and sediment contamination, 2.4 Impact on marine ecology, and 2.5 Impact on terrestrial ecology.
- Societal risks: 3.1 Health risk to local communities, 3.2 Impact on fisheries, 3.3 Impact on livelihoods of local communities, and 3.4 Stress on local public infrastructure.
- Technical risks: 4.1 Technical challenges, 4.2 Weather challenges, and 4.3 Logistical and regulatory challenges.
- Economic risks: 5.1 Decommissioning costs, and 5.2 Post decommissioning costs.

For each sub-criterion, risks are evaluated qualitatively or semi-quantitatively and the residual risk is represented using four risk levels, viz.,

- High risk,
- Medium-high risk,
- Medium-low risk, and
- Low risk.

An elaborate scoring system along with sensitivity analysis is used, in line with international practice, For sensitivity analysis, seven scenarios have been considered:

- Base case, where safety, environmental, societal, technical and economic risk categories are weighted 20% each;
- Safety bias case, where safety risk category is weighted 40% and all the other categories 15% each;
- Environmental bias case, where environmental risk category is weighted 40% and all the other categories 15% each;
- Societal bias case, where societal risk category is weighted 40% and all the other categories 15% each
- Technical bias case, where technical risk category is weighted 40% and all the other 15% each;
- Cost irrelevant case, where economic risks are disregarded; and
- Offshore bias case, where onshore risks are disregarded.

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
11.2.2 Preferred decommissioning options: ~~Based on the independent evaluation detailed in Report 10501209-REP-07, Rev. A~~Detailed comparative risk assessment report has been prepared to evaluate the risks associated with each option available and identify the best (least risk) option for decommissioning of each offshore facility/infrastructure component. Following this, a detailed environmental impact assessment has been prepared for the selected option. **T~~t~~he preferred decommissioning option~~s~~ for ~~the~~ each offshore facility/** infrastructure component~~s~~ of the **~~FA-EMF-~~O** production area ~~are~~ **is** summarised in the table below. ~~**These shall be revisited each year;**~~ Note: The options will be revisited at the time of decommissioning and re-evaluated, if necessary.		

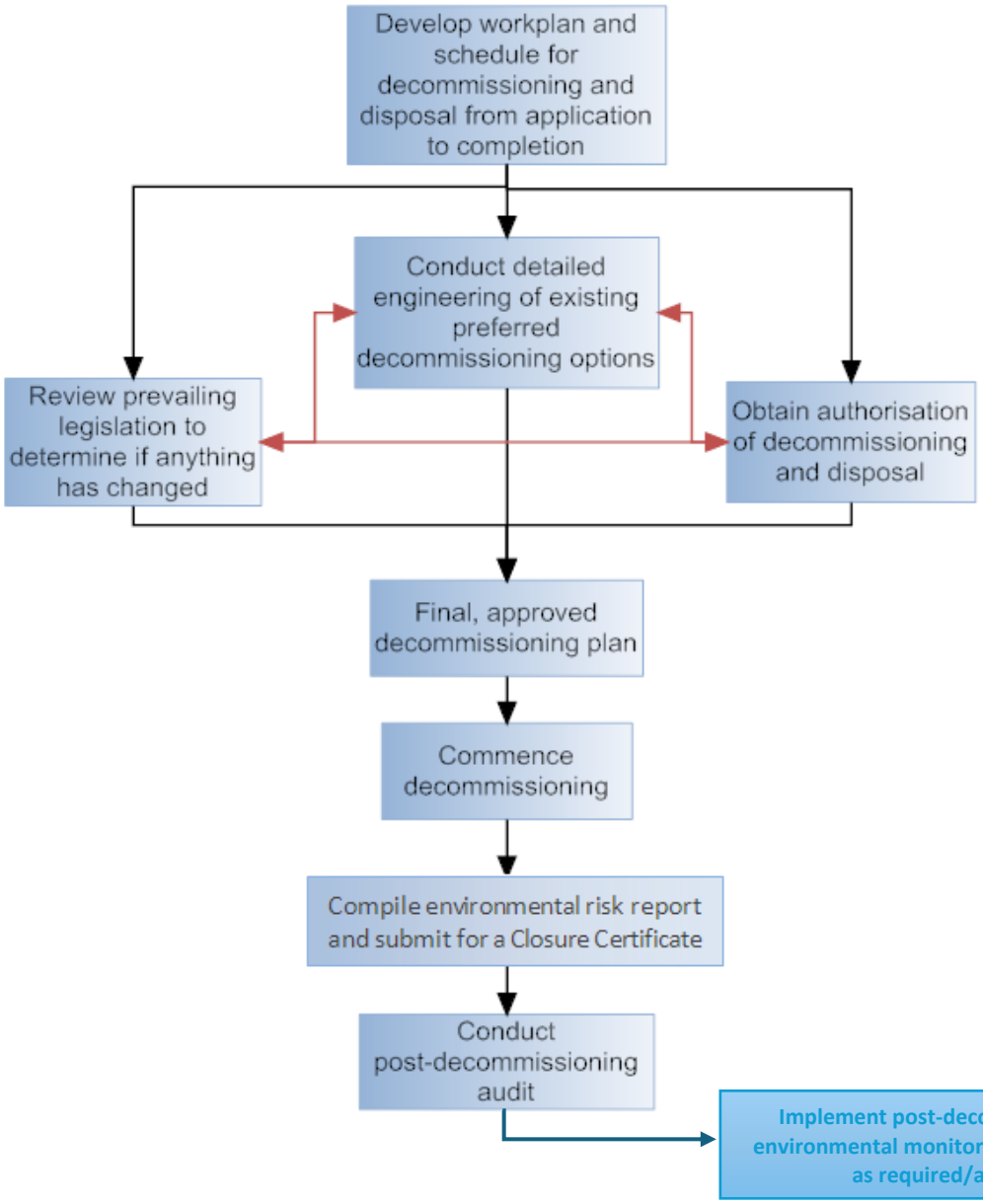
Asset type	Selected Option	Selected Strategy for Decommissioning and Disposal
~~Platform topsides~~	~~Option 2: Dismantle and remove the topsides piecemeal, and transfer to them to the shore for cleaning, and reuse, recycling or disposal.~~	• ~~The topsides will be removed 100% using a piecemeal approach where all modules except the MSF structure will be removed by replacement cranes.~~ • ~~The MSF structure will be stripped off all equipment so that only the structural steel remains.~~ • ~~The bare MSF structure will be disposed off by toppling into the sea along with the cut-off section of the jacket.~~ • ~~After removal, the dismantled equipment and parts will be transferred to the shore for disposal to external waste management facilities.~~ • ~~If necessary, the dismantled equipment and parts will be chemically cleaned at site (onshore) to remove the hazardous inventory (hydrocarbon and chemical residues) before they are transported to external waste management facilities, along with any cleaning waste generated.~~ • ~~Mostly of the waste is likely to be sold as scrap metal to local waste recycling plant or dealers.~~
~~Platform jacket and MSF structure~~	~~Option 3: Cut off the jacket to 55m below the seawater level and topple the cut off jacket along with the bare MSF structure on to the seabed.~~	• ~~The cut off jacket section along with the bare MSF structure will be toppled in place via a strategic subsea cutting program.~~ • ~~The jacket section from the seabed to 55 m depth will remain in place.~~ • ~~Any waste materials generated will be transferred to the shore for disposal to external waste management facilities.~~
Offshore wells	Cut off the wellheads (including the Xmas tree) at the mudline, plug the boreholes with primary and secondary barriers,	• The subsea Xmas trees, wellheads and associated wellhead platform structures will be cut off or dismantled and then transferred to the shore for disposal at external waste management facilities. • Kill fluid will be injected into the wellbore to stop the flow of well fluids. • The wellbores will be plugged with two back-to-back cement barriers and then the wells will be left in place (abandoned).

Operational Activities/ Aspects & Auditable Actions			Responsibility	Timing
	and then transfer the cut off well heads to the shore for cleaning and reuse, recycling or disposal.	• Waste material generated from the decommissioning of the offshore wells will be transferred to the shore for disposal to external waste management facilities for recycling (as scrap metal) or other means of disposal. • If necessary, the dismantled equipment and parts will be chemically cleaned at site (onshore) to remove the hazardous inventory (hydrocarbon and chemical residues) before they are transported to external waste management facilities, along with any cleaning waste generated.		
Offshore pipelines (~~export and~~ in-field pipelines)	Clean all the pipelines, stabilize and leave them in situ.	• All ~~the export pipelines and~~ the in-field will be cleaned in situ and abandoned in-situ, with the pipe ends being left open to the sea environment. • Blind flanges will be fitted at pipeline isolation points to seal the pipelines during the cleaning process. • The cleaning method for the export pipelines consists of pigging followed by flushing with treated seawater (with solvents added if necessary) so that the residual hydrocarbon content is ≤50 ppm. • Chemical or mechanical pigging will be employed for the export pipelines to strip the inside surfaces of hydrocarbon residues and other debris, using a pig launcher and pig receiver installed on a vessel/rig/platform used for this purpose. • The cleaning method for the in-field pipelines consists of flushing with treated seawater (with solvents added if necessary) so that the residual hydrocarbon content is ≤50 ppm. • The cleaning operations will be carried out on a vessel/rig/platform in a closed cycle where oil sludge is removed from the return seawater. Flushing will be repeated as many times and as long needed, so that the target residual hydrocarbon content is reached. • Where well characteristics permit, reverse flushing (known as bullheading) may be used so that the flushing medium may be injected into the wells rather than returning to the surface for oil sludge removal. • After the cleaning process is completed, additional grout bags will be placed on the pipeline sections with free span to prevent snagging of trawler fish nets. • Pigging waste and oil sludge generated from the cleaning process will be transported to external waste management facilities for treatment or disposal.		
Subsea pipelines structures (manifolds, isolation valves and rigid riser sections)	Clean all the pipeline structures, stabilize and leave them in situ.	• The subsea pipeline structures will be cleaned in situ by seawater flushing then left on seabed to act as additional subsea anchorage to the remaining pipelines. • Flushing will be carried out on a vessel/rig/platform in a closed cycle where oil sludge is removed from the return seawater. Flushing will be repeated as many times and as long needed, so that the residual hydrocarbon content is ≤50 ppm. • Oil sludge generated from the cleaning process will be transported to external waste management facilities for treatment or disposal.		
Subsea flexible items (flexible risers, jumpers,	Clean all trenched (buried) items in situ and leave them on the seabed but	• The main umbilicals ~~between the F-A- satellite, SCG and F-O fields~~ will be cleaned in situ by seawater flushing and then left on the seabed.		

Operational Activities/ Aspects & Auditable Actions			Responsibility	Timing
spools and umbilicals)	remove all un-trenched items and transfer them to the shore for cleaning and reuse, recycle or disposal.	• Flushing will be carried out on a vessel/rig/platform in a closed cycle where oil sludge is removed from the return seawater. Flushing will be repeated as many times and as long needed, so that the residual hydrocarbon content is ≤50 ppm • Untrenched short spools, control jumpers and short flexibles will be removed and transferred to the shore for cleaning and reuse, recycling, or disposal at external waste management facilities.		
~~Floating structures (buoys)~~	~~Remove all the floating structures from the sea and transfer them to the shore for reuse, recycling or disposal.~~	~~• The export buoy in Oribi-Oryx field was already disconnected and towed to the shore in 2025. Hence no further action is needed.~~ ~~• The control buoy in E-M field will be detached from the rigging system and transferred to the shore for reuse, recycle or disposal at external facilities.~~ ~~• The mooring chain will be detached from the buoy and slowly lowered onto the seabed.~~		
Seabed debris (gravity bases, concrete mattresses, grout bags etc.)	Reposition, where needed, and leave all debris on the seabed.	• Gravity base and mooring arrangements including chain and subsea rigging will be left on the seabed. • Concrete mattresses and grout bags will be repositioned and placed on the abandoned pipelines sections with free span (to prevent snagging of trawler fish nets) or left in place on the seabed.		
Drill cuttings	Leave all drill cutting in "as is" condition (do nothing).	• The drill cuttings lying on the seabed for over 30 years (with the more recent drilling carried out in 1992) will be undisturbed and left in situ.		
11.2.3 Decommissioning options including costs shall be updated annually for submission to PASA.			***GM : Decommissioning***	***Annually***

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
11.3 Financial Provision		
11.3.1 PetroSA shall provide for its closure commitments in the form of a liability provision, which is reflected in the balance sheet as the best estimate of the expenditure required to settle the obligation at the projected end of life of the field.	***PetroSA Financial Manager***	***Annually***
11.3.2 Reporting of Financial Provision • Proof of Financial Provision will be provided to PASA in the following manner: ○ A copy of the insurance certificate for the year will be provided on the renewal date of each year, and ○ The annual revision of the closure provision will be submitted together with the annual Performance Assessment reports.	***GM : Decommissioning***	***Annually***
11.4 Stakeholder Engagement		
11.4.1 Consult fishing communities and other offshore users for their feedback and comments on the proposed decommissioning plans and environmental management programmes so that their concerns and expectations are duly considered.	***PetroSA SHEQ Manager***	***Prior to finalising the plans and programmes***
11.4.2 Notify PASA, DFFE, fishing stakeholders and other marine users of the commencement of decommissioning activities.	***PetroSA SHEQ Manager***	***At least 1 month prior to start of decommissioning***
11.4.3 Communicate information regarding decommissioning activities to SA Navy Hydrographic office so that they can issue notices to fishing stakeholders and other offshore users to ensure all offshore users are kept informed of restrictions on fishing and other marine uses. Such a notice should provide: • the co-ordinates of decommissioning activities; • an indication of the decommissioning timeframes; • a special note on the hazards posed by decommissioning activities.	***PetroSA SHEQ Manager***	***At least 1 month prior to start of decommissioning***
11.4.4 Notify fishing stakeholders and other marine users of the completion of production activities and the location of abandoned infrastructure. Information regarding abandoned infrastructure should be communicated to the SA Navy Hydrographic office so that they can be indicated on Notices to all offshore users and marked on relevant charts.	***PetroSA SHEQ Manager***	***Immediately on cessation of decom-missioning***
11.5 Application for a Closure Certificate		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
11.5.1 Detailed **engineering specifications** shall be developed for decommissioning options	***GM : Decommissioning***	***To commence at least 12 months prior to planned cessation of production.***
11.5.2 A suite of **preferred decommissioning options** shall be selected based upon environmental and technical considerations.	***GM : Decommissioning***	***To commence at least 12 months prior to planned cessation of production.***
11.5.3 A **detailed environmental impact assessment** of the preferred decommissioning option(s) shall be undertaken for application for approval, consistent with the MPRDA and NEMA amongst others.	***Corporate Environmental Leader***	***To commence immediately on completion of 11.3.1 and 11.3.2***
11.5.4 A **detailed Closure Plan** shall be compiled and submitted to PASA.	***GM : Decommissioning***	***6 months before decommissioning starts***
11.5.5 A **seabed survey** shall be undertaken to validate the Closure Plan	***GM : Decommissioning***	***End of decommissioning***
11.5.6 A detailed **environmental risk assessment** shall be undertaken for submission **for approval and issuance of a Closure Certificate**, consistent with the MPRDA. This assessment shall contain at least the following information: • *Description and location of all abandoned infrastructure;* • *Results of seabed survey;* • *Results of Risk Assessment; and* • *Any further monitoring requirements.*	***Corporate Environmental Leader***	***Within 180 days post-production***
11.5.7 Submit a **Final Performance Report** to PASA including, inter alia: proof of environmental notification and communication with HydroSAN and other users of the sea; and the results of relevant quarterly reports.	***PetroSA SHEQ Manager***	***Within 180 days post-production***
Aspects of this process are iterative as a number of activities must inform each other as indicated in the figure below.		

Operational Activities/ Aspects & Auditable Actions	Responsibility	Timing
		
Auditing specifications ***1. The above steps have been completed*** ***2. The detailed performance criteria of the post decommissioning audit will be detailed in the environmental authorisations.***	***PetroSA SHEQ Manager***	***Post-decommissioning***