3. PROJECT DESCRIPTION

This chapter describes the need and desirability for the proposed project, provides general project information, an overview of the proposed exploration drilling programme and a description of the project alternatives.

3.1 NEED AND DESIRABILITY

Fossil fuels (including gas and oil) play a central role in the socio-economic development of South Africa, while simultaneously providing the necessary infrastructural economic base for the country to become an attractive host for foreign investments in the energy sector (Ministerial foreword of the White Paper on the Energy Policy 1998). The White Paper on the Energy Policy (1998) is the overarching policy document which guides future policy and planning in the energy sector. It states that the government will, *inter alia*, “promote the development of South Africa’s oil and gas resources…” and “ensure private sector investment and expertise in the exploitation and development of the country’s oil and gas resources”. The successful exploitation of these natural resources will contribute to the growth of the economy and relieve pressure on the balance of payments.

The National Development Plan (NDP) (2012) provides the context for all development in South Africa, with the overarching aim of eradicating poverty and inequality between people in South Africa. The NDP identifies the need to diversify the current energy mix and to reduce carbon emissions. There is a clear intention for gas to play a more significant role in the energy mix and the exploration of gas as an alternative to coal for energy production has been recognised as a planning priority.

The position of the NDP is reiterated in the Draft Integrated Energy Plan (IEP) (2013), which seeks to determine how current and future energy needs can be addressed efficiently. Key objectives outlined in the plan include security of supply, increased access to energy, diversity in supply sources and primary sources of energy and minimising emissions. The plan indicates that projected demand for natural gas between 2010 and 2050 would be second only to petroleum products, primarily due to increased growth in the industrial sector. It also identifies significant potential for natural gas in terms of power generation and direct thermal uses.

An increase in domestic natural gas reserves would also contribute to security of supply in the gas-to-liquids industry, which relies on feedstock from coal, oil and gas reserves. The Draft IEP points out the vulnerability of the liquid fuels industry and its economy to fluctuations in the global oil market, given that South Africa is a net importer of oil. Furthermore, existing gas stocks in the domestic offshore are declining, and new sources of feedstock are required to support and increase production in the gas-to-liquids industry (NDP, 2012). As such, exploration for additional domestic hydrocarbon reserves is considered important and any discoveries would be well received by the local market. The Department of Energy’s Integrated Resource Plan (2010-2030) supports this view, stating that regional and domestic gas options should be pursued. In essence, the government’s official position is that exploration and development of oil and gas fields should be encouraged.

In July 2014 the South African Government launched Operation Phakisa, which is an innovative, pioneering and inspiring approach that will enable South Africa to implement its policies and programmes better, faster and more effectively. Operation Phakisa aims to, *inter alia*, unlock the economic potential of South Africa’s oceans. In this regard four priority sectors have been selected as new growth areas in the ocean economy, including:

a) Marine transport and manufacturing activities, such as coastal shipping, trans-shipment, boat building, repair and refurbishment;

(b) Offshore oil and gas exploration;
(c) Aquaculture; and
(d) Marine protection services and ocean governance.

In terms of offshore oil and gas exploration the goal is to further enhance the enabling environment for exploration of oil and gas, resulting in an increased number of exploration wells drilled, while simultaneously maximising the value captured for South Africa. The proposal by Thombo provides an opportunity for the development of the Orange Basin, thereby meeting one of the aims of Operation Phakisa.

The Orange Basin is the largest of the South African offshore basins and is under-explored with approximately 1 well per 4 000 m^2 (PASA 2012). Two gas fields with significant potential have been discovered in the basin to date, namely the Ibhubesi Gas Field (Block 2A) and the Kudu Gas Field off southern Namibia. Some hydrocarbon exploration has taken place in Block 2B, which is adjacent to and inshore of Block 2A. In 1988 an exploration well (A-J1) was drilled by Soekor which resulted in an oil discovery. The well is located approximately 25 km offshore and was drilled to a depth of 3 250 m in Cretaceous lacustrine sediments typical of a graben system (i.e. a depression between geologic faults). In addition, as previously mentioned, Thombo undertook a 3D seismic survey over this area of primary interest. Based on these previous exploration activities, Thombo is now proposing to drill up to five possible exploration wells in the A-J graben, the primary area of interest, in order to fully appraise the hydrocarbon potential of the geological structure or “prospect”.

In summary, exploration success would result in long-term benefits for South Africa consisting of access to new energy sources, improved security of supply, major in-country investments in a development project and reduced dependence on the importation of hydrocarbons.

3.2 GENERAL PROJECT INFORMATION

3.2.1 EXPLORATION RIGHT HOLDER

Thombo is the operator of the Block 2B Exploration Right. Other licensees in the block include Simbo Petroleum and Afren.

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Managing Director:	Trevor Ridley	
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3.2.2 LICENCE AREA DETAILS

Licence Block 2B covers an area of approximately 4 359 km^2, and is located off the West Coast of South Africa roughly between latitudes 30ºS and 31ºS on the continental shelf in water depths of less than 200 m (see Figure 1.1). The co-ordinates of the licence block are provided in Table 3.1.

Table 3.1: Co-ordinates of Block 2B (WGS 84 Zone 33).

Point	Latitude (S)	Longitude (E)	Point	Latitude (S)	Longitude (E)
A	30º 00’ 01.23768”	16º 43’ 56.74699”	H1	30º 27’ 40.46670”	17º 18’ 14.36360”
B	30º 00’ 03.72755”	17º 06’ 53.43948”	J1	30º 29’ 22.18844”	17º 18’ 14.36360”
C	30º 01’ 04.98677”	17º 06’ 53.43948”	K1	30º 29’ 22.18841”	17º 19’ 17.86721”
D	30º 01’ 04.98677”	17º 07’ 07.67784”	L1	30º 30’ 51.19171”	17º 19’ 17.86717”
E	30º 03’ 12.10738”	17º 07’ 07.67780”	M1	30º 30’ 51.19171”	17º 20’ 21.41578”
F	30º 03’ 12.10738”	17º 07’ 52.11282”	N1	30º 32’ 45.63269”	17º 20’ 21.41578”
G	30º 05’ 44.65547”	17º 07’ 52.11282”	P1	30º 32’ 45.63265”	17º 21’ 37.63249”
H	30º 05’ 44.65547”	17º 08’ 36.54308”	Q1	30º 34’ 33.68582”	17º 21’ 37.63249”
J	30º 07’ 39.06872”	17º 08’ 36.54305”	R1	30º 34’ 33.68582”	17º 22’ 20.03380”
K	30º 07’ 39.06869”	17º 09’ 14.62921”	S1	31º 00’ 01.18980”	17º 22’ 20.03380”
L	30º 09’ 14.41771”	17º 09’ 14.62921”	T1	31º 00’ 01.21842”	16º 45’ 56.97522”
M	30º 09’ 14.41771”	17º 09’ 59.08147”	U1	30º 50’ 01.24642”	16º 45’ 56.94898”
N	30º 11’ 15.19476”	17º 09’ 59.08147”	V1	30º 50’ 01.20962”	17º 04’ 56.99510”
P	30º 11’ 15.19472”	17º 10’ 56.23478”	W1	30º 44’ 01.22449”	17º 04’ 56.97937”
Q	30º 13’ 15.95489”	17º 10’ 56.23475”	X1	30º 44’ 01.22568”	17º 03’ 56.97641”
R	30º 13’ 15.95489”	17º 11’ 21.60690”	Y1	30º 42’ 01.23008”	17º 03’ 56.97241”
S	30º 15’ 23.10628”	17º 11’ 21.60690”	Z1	30º 42’ 01.23412”	17º 00’ 56.96197”
T	30º 15’ 23.10628”	17º 12’ 44.18842”	A2	30º 38’ 01.24321”	17º 00’ 56.95218”
U	30º 17’ 42.93650”	17º 12’ 44.18842”	B2	30º 38’ 01.25459”	16º 55’ 56.93941”
V	30º 17’ 42.93647”	17º 13’ 28.62124”	C2	30º 33’ 01.26140”	16º 55’ 56.92472”
W	30º 20’ 02.76032”	17º 13’ 28.62124”	D2	30º 33’ 01.26331”	16º 54’ 56.92158”
X	30º 20’ 02.76032”	17º 13’ 53.95660”	E2	30º 30’ 01.26832”	16º 54’ 56.91708”
Y	30º 21’ 25.40970”	17º 13’ 53.95660”	F2	30º 30’ 01.27192”	16º 52’ 56.91018”
Z	30º 21’ 25.40970”	17º 14’ 44.76404”	G2	30º 17’ 01.28908”	16º 52’ 56.88818”
A1	30º 22’ 41.69579”	17º 14’ 44.76404”	H2	30º 17’ 01.29440”	16º 49’ 56.87990”
B1	30º 22’ 41.69579”	17º 15’ 35.59356”	J2	30º 15’ 01.29578”	16º 49’ 56.87792”
C1	30º 24’ 23.41505”	17º 15’ 35.59360”	K2	30º 15’ 01.29830”	16º 47’ 56.87210”
D1	30º 24’ 23.41505”	17º 16’ 39.10516”	L2	30º 09’ 01.26382”	16º 47’ 56.75420”
E1	30º 25’ 58.75525”	17º 16’ 39.10519”	M2	30º 09’ 01.24549”	16º 46’ 56.74768”
F1	30º 25’ 58.75525”	17º 17’ 23.56004”	N2	30º 04’ 01.22941”	16º 46’ 56.74822”
G1	30º 27’ 40.46670”	17º 17’ 23.56004”	P2	30º 04’ 01.22761”	16º 43’ 56.74141”

3.2.3 FINANCIAL PROVISION

In terms of Sections 41 and 89 of the MPRDA[4] and Regulation 51(b)(v), no exploration operation may commence unless the Exploration Right holder has provided for a financial provision acceptable to the designated agency guaranteeing the availability of sufficient funds to fulfil its obligations in terms of the Exploration Work Programme and EMPr Addendum.

[4] Although Section 41 of the MPRDA has been repealed by the MPRDAA, the financial provision falls under the transitional arrangements provided under NEMLA 3 (see Section 2.1.1). Thus the financial provision for this project would still be provided under Section 41 and 89 of the MPRDA.

Thombo would put in place the required financial provision for the proposed exploration activities prior to any work being undertaken in the Exploration Right area. The estimated cost for the management and remediation of any unlikely environmental damage that might be incurred as a result of the proposed exploration drilling programme or future removal of any suspended wellheads would be in the order of USD 5-8 million. A breakdown of the financial provision is provided in Appendix 4. Thombo's preferred method of providing for the financial provision is in the form of appropriate insurance. Thombo would discuss and conclude the nature and quantum of the financial provision with PASA prior to any drilling activity being undertaken.

3.2.4 THOMBO'S HEALTH, SAFETY AND ENVIRONMENTAL POLICY

A copy of Thombo's Health, Safety and Environmental (HSE) Policy is provided in Appendix 5. This policy sets out their commitment to ensure successful implementation of the proposed project.

3.2.5 ENVIRONMENTAL AWARENESS

The exploration drilling programme would be undertaken by an experienced drilling contractor (including vessel and staff). Environmental Awareness would be undertaken as part of Thombo's normal contract management, which includes the following:

1. The Final EIR and EMPr Addendum would be included in the contract documentation of the selected drilling contractor;
2. Contractors would prepare bridging documents to include provisions on compliance with the Final EIR and EMPr Addendum and with the HSE requirements of Thombo;
3. Drilling crew would undergo induction training, of which the relevant sections of the Final EIR and EMPr Addendum would form a part;
4. Tool box talks would be conducted. These talks would include environmental aspects such as waste management, spill prevention and clean-up, etc.; and
5. Place on the drilling unit a Thombo HSE representative that has undergone Environmental Awareness Training.

3.2.6 MONITORING AND PERFORMANCE ASSESSMENT

Thombo would ensure that the drilling contractor executes the work in accordance with the requirements of the Environmental Management Programme (EMP) (as per the Final EIR) and Mitigation and Management Plan (as per the EMPr Addendum). Thombo would undertake appropriate monitoring and track performance against specified objectives and targets as presented in the EMP and Mitigation and Management Plan. In this regard Thombo would appoint a HSE representative to undertake monitoring on an ongoing basis to ensure the protection of the environment and the safety of personnel and contractors. This monitoring / auditing would generate a list of any non-compliances, the recommended corrective actions, and how the corrective actions were performed. In addition, Thombo would conduct performance assessments as determined by PASA and / or DEA.

The contractor would also be required to periodically perform self-audits, reviews and inspections to determine the implementation of and adherence to the specified objectives and targets presented in the EMP and Mitigation and Management Plan.

At the completion of each well a "close-out" report would be prepared, which would outline the implementation of the specified objectives and targets, and highlight any problems and issues that arose during well drilling.

3.2.7 PLANS AND PROCEDURES FOR ENVIRONMENTAL RELATED EMERGENCIES AND REMEDIATION

An Emergency Response Plan specific to the proposed activities within Block 2B would be compiled during the detailed design stage. This plan would describe Thombo's Emergency Response Organisation. In the event of an emergency arising during activities associated with Thombo's exploration drilling operations, a Thombo Emergency Response Team, liaising as appropriate with contractor representatives, would provide the primary emergency response. The plan would also provide guidance for the Emergency Response Team members in the execution of their responsibilities. It would be used in conjunction with the project Oil Spill Contingency Plan for all environmental incidents.

In addition, Thombo and the selected drilling contractor would compile the following plans and procedures to ensure that operations are conducted in a manner that minimises the risks to the environment and enhances the safety of employees and contractors:

- Project-specific Oil Spill Contingency Plan and Shipboard Oil Pollution Emergency Plan (SOPEP): These plans would instruct employees as to the correct response procedure for oil spills that arise during the exploration drilling operation. All employees who are affected by the plan would be trained before commencement of drilling and at least one exercise would be held during drilling to confirm preparedness of people and equipment; and
- Waste Management Plan: This plan would instruct employees as to the correct handling and disposal of waste generated during exploration well drilling. All employees who are affected by the plan would be provided with appropriate training and awareness to ensure they fulfil the legal and any other requirements of the plan.

Note:
An integrated subsea well intervention system is available in Saldanha Bay for deployment in the event of a subsea well control incident. This unique piece of equipment is operated by Oil Spill Response Limited (OSRL) and provides for swift subsea incident response around the world.

The integrated subsea well intervention system includes four capping stacks to shut-in an uncontrolled subsea well and two hardware kits to clear debris and apply subsea dispersant at a wellhead. The equipment can be used for the majority of known subsea wells in water depths up to 3 000 m.

It is recommended that Thombo becomes a member of or subscribe to OSRL for the duration of the exploration drilling programme.

3.2.8 UNDERTAKING BY THE APPLICANT

As required in terms of the MPRDA Regulations, Thombo undertakes to comply with the provisions of the MPRDA and Regulations thereto (see Appendix 6).

3.3 PRE-DRILLING SITE SURVEYS

3.3.1 SHALLOW HAZARD ASSESSMENT

Shallow hazard assessment would be undertaken to identify and delineate any geo-hazards that may impact the proposed exploration drilling operations. Such hazards could include:

- Seabed hazards:
  - Seafloor geologic features such as slumps or faults extending up to the seabed;
  - Synthetic objects, for example, wrecks, mines, pipelines, etc.; and
  - Poor anchoring conditions such as very soft clay or cemented sand.

- Sub-seabed hazards:
  - > Shallow gas or shallow water flow reservoirs;
  - > Gas hydrates;
  - > Layers of boulders;
  - > Unconsolidated formations; and
  - > Shallow prospects.

Several data sources would be used to identify geo-hazard occurrences. Conventional and reprocessed 3D seismic data may be used to improve the understanding of the deposition characteristics and sedimentological units while high resolution 3D data may be used to depict "vivid images" of the seafloor. Analogue site survey data (including high frequency data acquired from echo sounding, side-scan sonars and sub-bottom profiling) may be used to produce accurate bathymetry maps and seafloor mosaics, and provide an indication of seafloor gas and shallow faults.

3.3.2 SEDIMENT SAMPLING

If deemed necessary by Thombo, sediment sampling would be undertaken to determine the geotechnical properties of the seabed in the proposed drilling area(s).

Where conditions permit, a gravity corer would be used to obtain a continuous core of the upper 6 m of the seabed (see Figure 3.1a). A gravity corer uses a set of heavy weights to lower a steel tube towards the seabed. At approximately 10 m above the seabed the steel tube is released and penetrates the underlying sediments. The tube is then recovered and lifted to the surface for analysis.

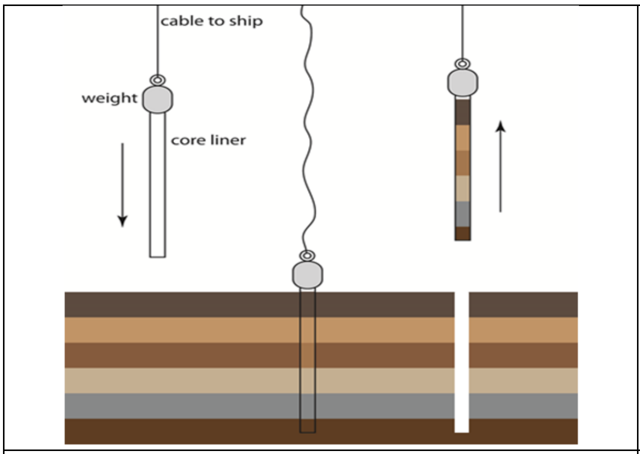


Figure 3.1a: Gravity corer (Source: http://chemwiki.ucdavis.edu).

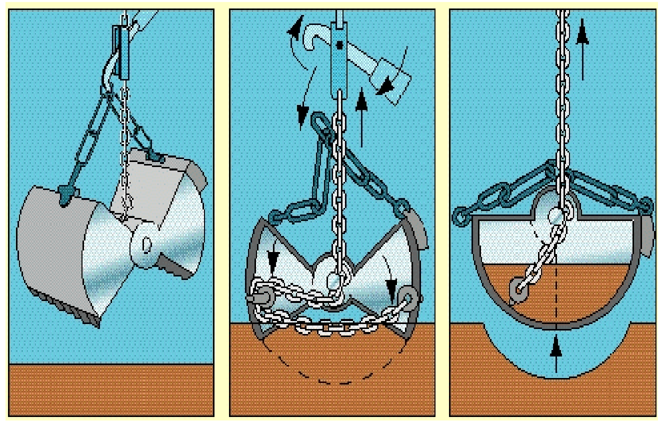


Figure 3.1b: Grab sampler (Source: http://www.jochemnet.de).

In areas where the seabed consists of sand, gravel or other hard soils more comprehensive equipment such as a push sampler or Cone Penetration Test (CPT) device would be used. The equipment is mounted on a weighted platform (approximately 5 m x 5 m) and surface supplied hydraulics force a test pipe into the seabed.

If the seafloor is sufficiently soft, grab samples may also be taken (see Figure 3.1b). Grab sampling is the simple process of bringing up surface sediments from the seafloor. This method, however, cannot be used to characterise different sedimentary layers since it is unable to penetrate the ground to depth and a mixture of sediments is produced. Once the grab sampler is launched, the jaws open and it descends to the seafloor. A spring closes the jaws and they trap sediments or loose substrate. The grab sampler is then brought up to the surface where its contents are analysed.

In the event that sediment sampling is undertaken, it is anticipated that up to 50 samples would be collected at each drill location. Each individual sample would have a maximum disturbance area and volume of approximately 0.01 m^2 and 0.07 m^3, respectively, resulting in a total disturbance area and volume of approximately 0.5 m^2 and 3.5 m^3, respectively.

3.4 EXPLORATION DRILLING

3.4.1 WELL LOCATION AND DRILLING PROGRAMME

Thombo proposes to drill an exploration well in the area of primary interest (i.e. the A-J graben), which is located in water depths ranging between 130 m and 160 m (see Figure 1.1). The co-ordinates of the area of primary interest are provided in Table 3.2. The well location would ultimately be based on a number of factors, including further detailed analysis of the seismic data, the geological target, pre-drilling site surveys and seafloor obstacles.

The earliest that drilling is expected to take place is in the 2016 / 2017 summer period. The expected final depth of the well would be up to 4 500 m below the seafloor and drilling with its associated testing is expected to take up to approximately three months to complete per well.

Based on the results of the first well, it is envisaged that up to four additional wells could be drilled.

Table 3.2: Co-ordinates of the area of primary interest (i.e. the A-J graben) (WGS 84 Zone 33).

Point	Latitude (S)	Longitude (E)	Point	Latitude (S)	Longitude (E)
A	30º 23’ 55.75”	17º 00’ 35.98”	L	30º 40’ 15.47”	17º 15’ 07.26”
B	30º 22’ 03.69”	17º 03’ 22.39”	M	30º 41’ 43.09”	17º 14’ 14.78”
C	30º 20’ 50.03”	17º 07’ 16.94”	N	30º 42’ 28.87”	17º 13’ 45.38”
D	30º 24’ 58.59”	17º 09’ 14.60”	O	30º 43’ 13.92”	17º 13’ 34.07”
E	30º 28’ 31.19”	17º 10’ 14.81”	P	30º 43’ 40.64”	17º 12’ 30.97”
F	30º 31’ 43.63”	17º 11’ 38.66”	Q	30º 42’ 48.50”	17º 11’ 35.69”
G	30º 33’ 34.62”	17º 13’ 10.50”	R	30º 42’ 08.09”	17º 11’ 05.61”
H	30º 34’ 35.47”	17º 14’ 08.06”	S	30º 39’ 55.10”	17º 09’ 09.27”
I	30º 35’ 36.40”	17º 14’ 51.62”	T	30º 39’ 03.50”	17º 07’ 20.97”
J	30º 36’ 40.05”	17º 15’ 05.97”	U	30º 37’ 07.26”	17º 06’ 19.55”
K	30º 38’ 25.75”	17º 15’ 17.27”	V	30º 35’ 27.73”	17º 05’ 24.89”

3.4.2 DRILLING UNIT OPTIONS

Various types of drilling technology can be used to drill an exploration well depending on, *inter alia*, the water depth and marine operating conditions experienced at the well site, e.g. platform rigs, jack-up rigs, semi-submersible drilling units (rigs), and drill ships (see Figure 3.2a). Thombo is currently considering two alternative drilling units, most likely a semi-submersible drilling vessel (rig) (see Figure 3.2b) or possibly a jack-up rig (see Figure 3.2c).

3.4.2.1 Semi-submersible drilling unit (rig)

The most likely choice would be a semi-submersible drilling unit, which is essentially a drilling rig with auxiliary drilling and marine support equipment located on a floating structure comprised of one or a number of pontoons. A semi-submersible rig may be self-propelled or would require a tow vessel or transport barge to transport the unit to its drilling location.

When at the well location, the pontoons are partially flooded (or ballasted), to submerge the pontoons to a pre-determined depth below the sea level where wave motion is minimised. This gives stability to the drilling unit thereby facilitating drilling operations. In shallow water, such as in Block 2B, the drilling unit would be anchored in position.

A riser pipe on compensated hydraulic tensioners (which keep the tension of the riser pipe constant during wave motion) connects the drilling unit to the seabed during the drilling operation. The riser acts as a conduit through which drilling operations can proceed and drilling fluid can be circulated.

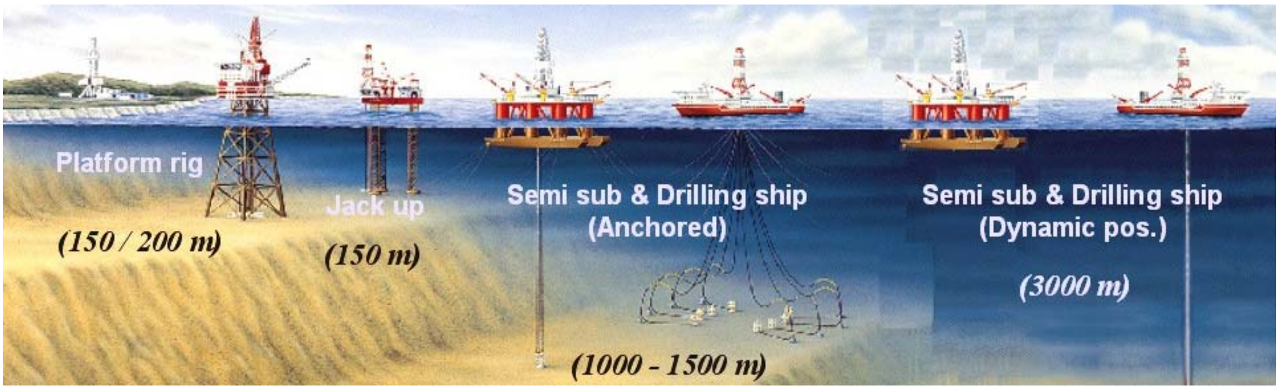


Figure 3.2a: Drilling unit types (Source: www.sos-hotlo.nl).

Figure 3.2b: Semi-submersible drilling vessel (Source: www.offshoreenergytoday.com).

Figure 3.2c: Jack-up rig (Source: www.offshoreenergytoday.com).

3.4.2.2 Jack-up rig

A jack-up rig consists of a buoyant hull fitted with a number of movable legs, capable of raising its hull over the surface of the sea. The buoyant hull enables transportation of the unit and all attached machinery to a desired location. Generally jack-up rigs are not self-propelled and are towed to location with their legs elevated.

Once on location the legs are jacked down onto the seafloor thereby raising the hull to the required elevation above the sea surface. The legs may be designed to penetrate the seabed or may be fitted with footings (or spudcans).

Jack-up rigs have certain advantages over a semi-submersible drilling unit, including a stable work platform, good availability and relatively lower mobilisation costs.

3.4.2.3 Safety standards

The drilling unit would be classified for seaworthiness through an appropriate marine classification programme (e.g. Det Norske Veritas, American Bureau of Shipping, etc.). The Department of Mineral Resources regulates safety of offshore operations by application of the Mine Health and Safety Act,1996 (No. 29 of 1996) and associated regulations. This Act provides for health and safety requirements for operations and includes hazard and risk assessments, monitoring and awareness training.

3.4.2.4 Exclusion zone

Under the Convention on the International Regulations for Preventing Collisions at Sea (COLREGS, 1972, Part B, Section II, Rule 18), a drilling unit that is engaged in underwater operations is defined as a “vessel restricted in its ability to manoeuvre” which requires that power-driven and sailing vessels give way to a vessel restricted in her ability to manoeuvre. Vessels engaged in fishing are required to, so far as possible, keep out of the way of the well drilling operation.

Furthermore, under the Marine Traffic Act, 1981 (No. 2 of 1981), an “exploration platform” or “exploration vessel” used in prospecting for or mining of any substance falls under the definition of an “offshore installation” and as such it is protected by a 500 m safety zone. It is an offence for an unauthorised vessel to enter the safety zone.

The temporary 500 m safety zone around the drilling unit would be enforced at all times. A bigger safety zone would be required for certain activities (e.g. demersal trawling) in order to take into consideration any anchor array around the drilling unit. A support vessel equipped with appropriate radar and communications would be kept on 24-hour standby near the drilling unit and would be used to patrol the area to ensure that other vessels adhere to the safety zone. The safety zone would be described in a Notice to Mariners as a navigational warning.

3.4.3 DRILLING EQUIPMENT AND PROCEDURE

Thombo is committed to sustainable development, including the promotion of the use of “best available and safest technologies” in order to minimise operational risks and potential impacts on the environment. In determining whether a set of processes, facilities or methods of operation constitute the “best available and safest technologies”, consideration would be given to the following:

- Comparable processes, facilities and / or methods of operation which have recently been successfully implemented;
- Technological advances and changes in scientific knowledge and understanding;
- The economic feasibility of such techniques;
- Time limits for installation in proposed or existing operations; and
- The nature and volume of discharges and emissions.

Thus, what are currently considered to be the “best available and safest technologies” for a particular operation may change with time in light of technological advances, changes in scientific knowledge and understanding, economic and social factors, and standard industry practice. The sections below provide a description of current industry practice.

3.4.3.1 Equipment

The essential elements of a drilling unit are: hoisting, rotating, circulating, safety equipment, power supply and storage. These are described below (see Figure 3.3).

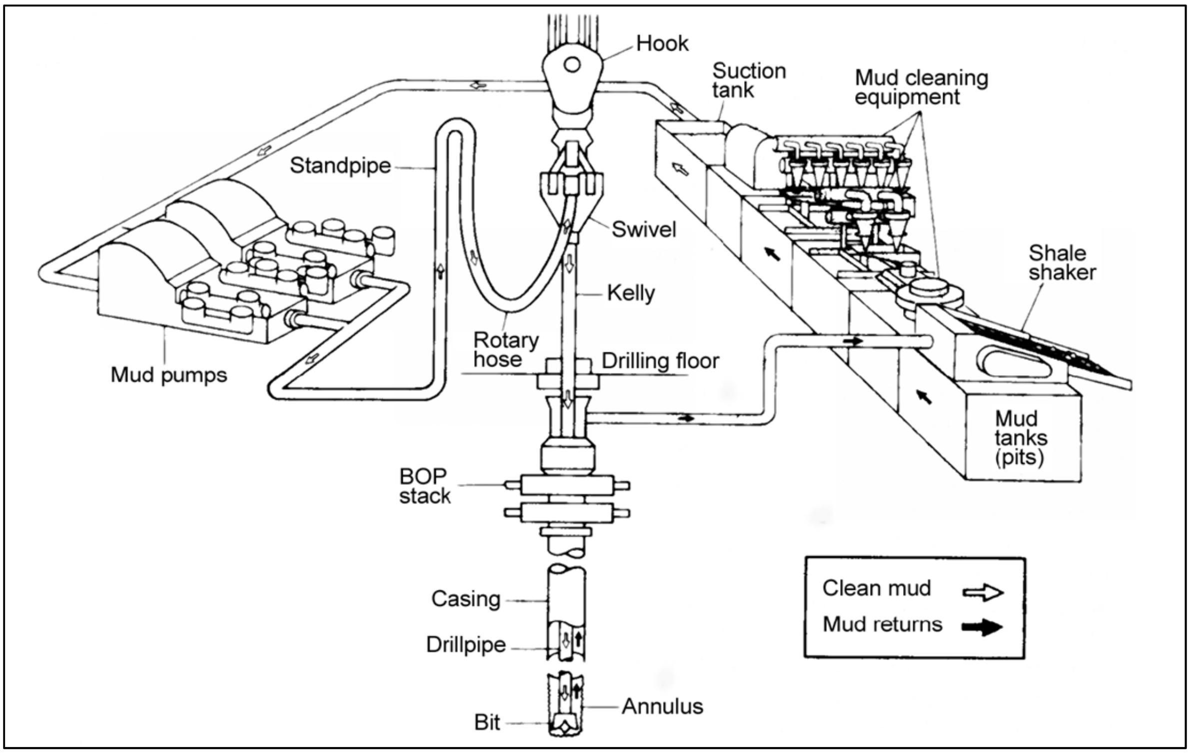


Figure 3.3: Schematic of a typical fluid circulation system used on floating drilling units (from www.petrowiki.org).

Hoisting System

The hoisting system is used to raise and lower drill pipe in and out of the hole and to support the drill string to control the weight on the drill bit during drilling. The hoisting system consists of the derrick, traveling and crown blocks, the drilling line and the draw works. The drilling unit uses a derrick, which is a steel tower that is used to support the traveling and crown blocks and the drill bit and pipe (string). The crown and traveling blocks are a set of pulleys that raise and lower the drill string. The crown block is a stationary pulley located at the top of the derrick. The traveling block moves up and down and is used to raise and lower the drill string. These pulleys are connected to the drill string with a large diameter steel cable. The cable is connected to a winch or draw-works. The draw-works contain a large drum around which the drilling cable is wrapped. As the drum rotates one way or the other, the drilling cable spools on or off the drum and raises or lowers the drill string.

Rotating System

The rotating equipment turns the drilling bit. This equipment consists of the topdrive, the rotary table, the drill pipe and the drill collars (drill string) and the bit. The topdrive is attached to the bottom of the traveling block and permits the drill string to rotate. The topdrive consists of a strong motor that rotates the drill string. A hose, through which the drilling fluid enters the drill pipe, is connected at the top of the topdrive. The drill pipe is a round pipe about 9 to 9.5 m long with a typical diameter of 5 to 5 7/8 inch (approximately 13 to 15 cm). Drill collars are heavy thick pipes that are used at the bottom of the drill string to add weight to the bit. The drill pipe has threaded connections on each end that allow the pipe to be screwed together to form longer sections as the hole gets deeper. The drill bit is used to create the hole. Drill bit sizes typically range from 36 inches (91 cm) to 6 inches (15 cm) in diameter.

Circulating System

The drilling operation uses drilling fluids to reduce friction, to lubricate and cool the drill bit, remove the drilled rock fragments (cuttings), and to balance the pressure in the wellbore which prevents other fluids from flowing into the wellbore. The circulation system of drilling fluid consists of the suction pits, pumps, surface piping (flowlines and standpipe), rotary hose (or kelly hose) and swivel, which is connected to the topdrive.

Figure 3.3 shows the flow path of the drilling fluid. The circulating system pumps the drilling fluids (or drilling muds) down the inside of the drill pipe, out of the nozzles in the drilling bit and returns them up the annular space between the drill pipe and the wellbore / riser to the surface where the cuttings are separated from the drilling fluid.

The cuttings are separated from the mud by vibrating screens called shale shakers. The cuttings are trapped on the screens and the mud passes through the screens into the mud pits. The circulating pumps pick up this clean mud and pump it back down the hole.

Safety System

Although the probability of a well blow-out is extremely low, it nonetheless provides the greatest environmental concern 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, which generally consists of two sets of pit level indicators and return mud-flow indicators with one set manned by the drill crew and the other by the mud logger. The mud logger also has a return mud gas detector, which monitors gas content in the return mud. The mud logger also measures the return mud temperature, changes in shale density and other parameters for abnormal pressure detection. The drilling fluid is also tested frequently during drilling operations and its composition can be adjusted to account for changing downhole conditions.

The likelihood of a blow-out is further minimised by employing a specially designed item of safety equipment called a blow-out preventer (BOP), which is a secondary control system. The BOP is installed on the wellhead and is designed to close in the well to prevent the uncontrolled flow of hydrocarbons from the reservoir in case the pressure of the reservoir exceeds the pressure of the drilling fluid in the reservoir resulting in hydrocarbons entering the wellbore. If this cannot be controlled hydrocarbons could eventually exit the wellbore into the marine environment / atmosphere. Hence the BOP system plays a key role in preventing potential risks to people, the environment and equipment. The BOP would undergo a thorough inspection prior to installation and is subsequently pressure and function tested on a regular basis throughout the duration of the drilling operation.

A typical BOP stack is shown in Figure 3.4. The BOP stack usually consists of the following:

- Annular preventer: The annular-type blow-out preventer can close around the drill string, casing or a non-cylindrical object, such as a kelly. Drill pipe including the larger-diameter tool joints (threaded connectors) can be "stripped" (i.e. moved vertically while pressure is contained below) through an annular preventer by careful control of the hydraulic closing pressure. Annular BOPs are typically located at the top of a BOP stack, with one or two annular preventers positioned above a series of several ram preventers.
- Ram type preventers: Ram type preventers are similar in operation to gate valves but use a pair of opposing steel plungers or rams. The rams extend toward the centre of the wellbore to restrict flow or retract open in order to permit flow. There are four common types of rams or ram blocks used in a BOP stack (or combination thereof):
  - > Pipe rams close around a drill pipe, restricting flow in the annulus (ring-shaped space between concentric objects) between the outside of the drill pipe and the wellbore, but do not obstruct flow within the drill pipe. Variable-bore pipe rams can accommodate tubing in a wider range of

outside diameters than standard pipe rams, but typically with some loss of pressure capacity and longevity;

> Blind rams (also known as sealing rams), which have no openings for tubing, can close off the well when the well does not contain a drill string or other tubing and seal it;
> Shear rams cut through the drill string or casing with hardened steel shears; and
> Blind shear rams (also known as shear seal rams or sealing shear rams) are intended to seal a wellbore, even when the bore is occupied by a drill string, by cutting through the drill string as the rams close off the well.

In deeper offshore operations, there are four primary ways in which a BOP can be controlled, including (in order of priority):

- Electrical control signal, which is sent from the surface through a control cable;
- Acoustical control signal, which is sent from the surface based on a modulated / encoded pulse of sound transmitted by an underwater transducer;
- Remotely Operated Vehicle (ROV) intervention, which mechanically controls valves and provides hydraulic pressure to the stack (via "hot stab" panels); and
- Deadman switch / auto shear, which is a fail-safe activation of selected BOPs during an emergency, and if the control, power and hydraulic lines have been severed.

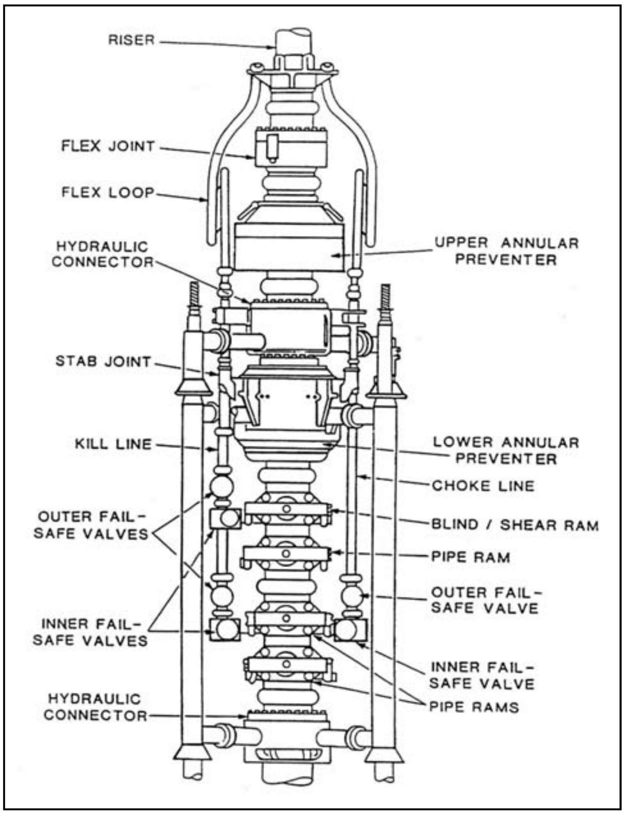


Figure 3.4: Schematic of a typical subsea BOP stack.

Power System

The drilling unit would need power to operate the circulating, rotating, hoisting and auxiliary systems onboard. Diesel engines are used to power generators which supply the electricity requirements of the drilling unit.

Storage Areas

The drilling unit would have dedicated storage for a variety of fluids and chemicals including:

- Fuel (diesel);
- Fresh (potable) water;
- Drilling water;
- Bulk mud and cement;
- Liquid mud;
- Mud chemicals; and
- Cementing chemicals.

3.4.3.2 Drilling method

Two drilling methods can be employed on a drilling unit, namely rotary or downhole motor drilling. The primary drilling method would be rotary drilling, where the whole drill string is rotated to penetrate the formations. However, a downhole motor may be included in the bottom hole assembly to provide additional power to the bit. The downhole motor is driven by the drilling fluid, which is pumped down the drill string.

The downhole motor drilling also allows a well to be directionally drilled to achieve any inclination from vertical to horizontal and to also change the azimuth direction in order to reach the geological target (see Figure 3.5). The direction of the well is changed by holding the drill string stationary and pointing the downhole motor, which has a slight bend in its body, in the direction required and slide drilling ahead.

Additionally, modern rotary steerable systems enable directional drilling while rotating the drill string, by utilising sophisticated downhole tools, controlled from surface by means of mud pulse telemetry.

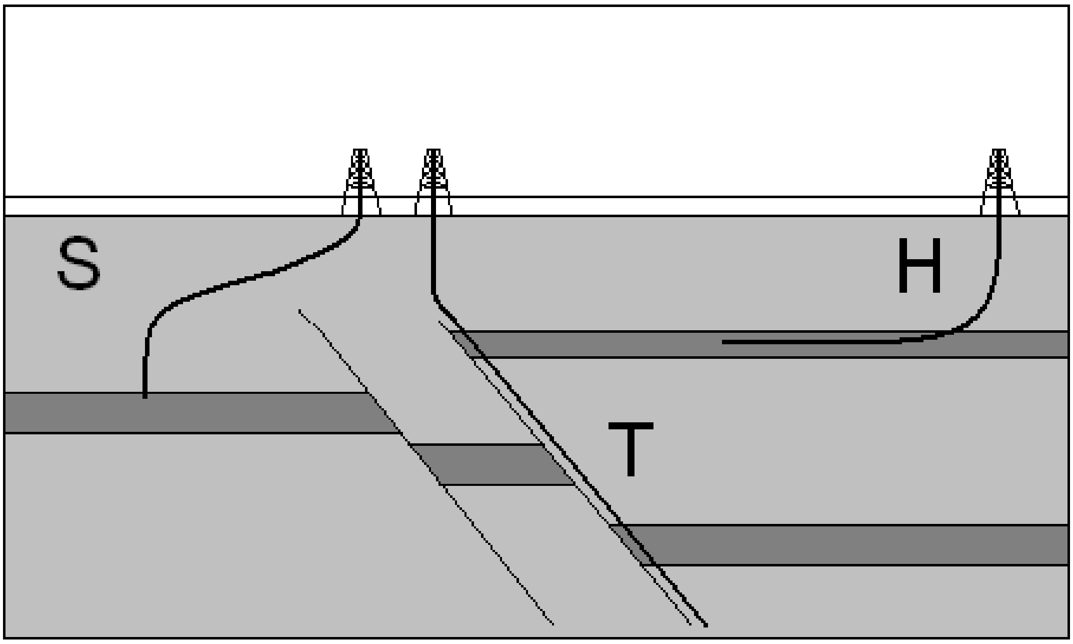


Figure 3.5: Tangent (T), Horizontal (H) or S shaped (S) drill trajectories.

3.4.3.3 Drilling sequence or stages

Each well would be created by jetting and drilling a hole into the seafloor with a drilling unit that rotates a drill string with a bit attached. After each borehole section is drilled, steel pipe (or casings), slightly smaller in diameter than the hole, is lowered into the hole and permanently cemented in place (cementing operations are described in Section 3.4.3.4). The borehole diameter progressively decreases with increasing depth as smaller diameter casings are inserted into the hole at various stages and cemented into place.

The casing provides structural integrity to the newly drilled wellbore, in addition to isolating potentially dangerous high pressure zones from each other and from the surface. With these zones safely isolated and the formation protected by the casing, the well would be drilled deeper with a smaller bit, and also cased with a smaller size casing. It is anticipated that up to four or five casing strings would be used in the wells.

Drilling is essentially undertaken in two stages, namely the riserless and risered drilling stages.

Initial (riserless) drilling stage (see Figure 3.6)
Sediments just below the seafloor are often very soft and loose, thus to keep the well from caving in and to carry the weight of the wellhead, a 30 inch (76 cm) diameter structural conductor pipe is either jetted or drilled (36 inch diameter hole) and cemented into place. Jetting of the conductor is preferred, however, if the shallow seabed properties do not allow for this, the conductor would be drilled and secured with cement. These two approaches are described below.

- **Jet:** The conductor pipe is assembled at the drilling unit floor and a drill bit, connected to a drill pipe, is run through the inside to the bottom of the casing. The entire assembly is lowered to the seafloor by the rig hoist. At the seafloor the driller spuds the assembly into the seafloor sediments and then turns on a pump, which uses water or drilling fluid to jet the pipe into place.
- **Drill and cement:** In the case where the nature of the seafloor sediments (hard sediments) necessitate drilling, a hole of diameter 40/42 inch would be drilled and the conductor pipe would be run into the hole and cemented into place. The cement returns would exit the bottom of the conductor and travel up the annular space between the conductor and the hole with some cement being deposited on the seabed around the conductor.

When the conductor pipe and wellhead are at the correct depth, in the order of 200 m deep depending upon soil strength, a new drilling assembly would be run inside the conductor pipe and the next hole section would be drilled by rotating the drill string and drill bit.

Below the conductor pipe, a 26 inch (66 cm) diameter hole would be drilled for a 20 inch (51 cm) surface casing, which would extend to approximately 345 m below the seabed. The rotating drill string causes the drill bit to crush rock into small particles, called “cuttings”. While the wellbore is being drilled, drilling fluid is pumped from the surface down through the inside of the drill pipe, the drilling fluid passes through holes in the drill bit and travels back to the seafloor through the space between the drill string and the walls of the hole, thereby removing the cuttings from the hole. At the planned depth the drilling is stopped and the bit and drill string is pulled out of the hole. A surface casing would then be permanently cemented into place. In the event of technical issues in the riserless section, intermediate liners could be required in order for the surface casing to be installed at a sufficient depth to support the drilling riser and BOP and to enable mud circulation during subsequent drilling operations.

These first two hole sections would be drilled using seawater and water-based fluid (WBF) or mud sweeps, to assist in transporting the cuttings out of the hole (see Section 3.4.4.1 below for a description of WBFs). All cuttings and WBF from this initial drilling stage would be discharged directly onto the seafloor adjacent to the wellbore.

Risered drilling stage (see Figure 3.6)
Following the initial drilling stage described above, a BOP and marine riser would be run and installed on the wellhead. The riser connects the drilling unit to the well and allows the drilling fluid and rock cuttings to be

circulated back to the drilling unit, thereby isolating the drilling fluid and cuttings from the marine environment.

Drilling is continued by lowering the drill string, with a smaller bit, through the riser to the 20 inch (51 cm) diameter casing shoe. During the risered drilling stage WBFs would continue to be used for as long as they provide the necessary characteristics. If the use of WBFs is no longer possible, a low toxicity non-aqueous drilling fluid (NADF), would be used to (a) obtain critical reservoir parameters, (b) provide a greater level of lubrication, and (c) provide more tolerance to high temperatures (see Section 3.4.4.2 below for a description of NADFs).

While drilling is in progress, drilling fluid is continuously recirculated to the drilling unit. The returned drilling fluid is treated to remove solids and drill cuttings from the re-circulating mud stream (see Section 3.4.3.5). Where NADF is used, the cuttings are also treated before being discharged overboard. Waste management is discussed further in Section 3.4.9.

The hole diameter progressively decreases in steps with depth as smaller diameter casings are inserted into the hole at various stages and cemented into place. As indicated previously, the expected final depth of the well is approximately 4 500 m below the seafloor.

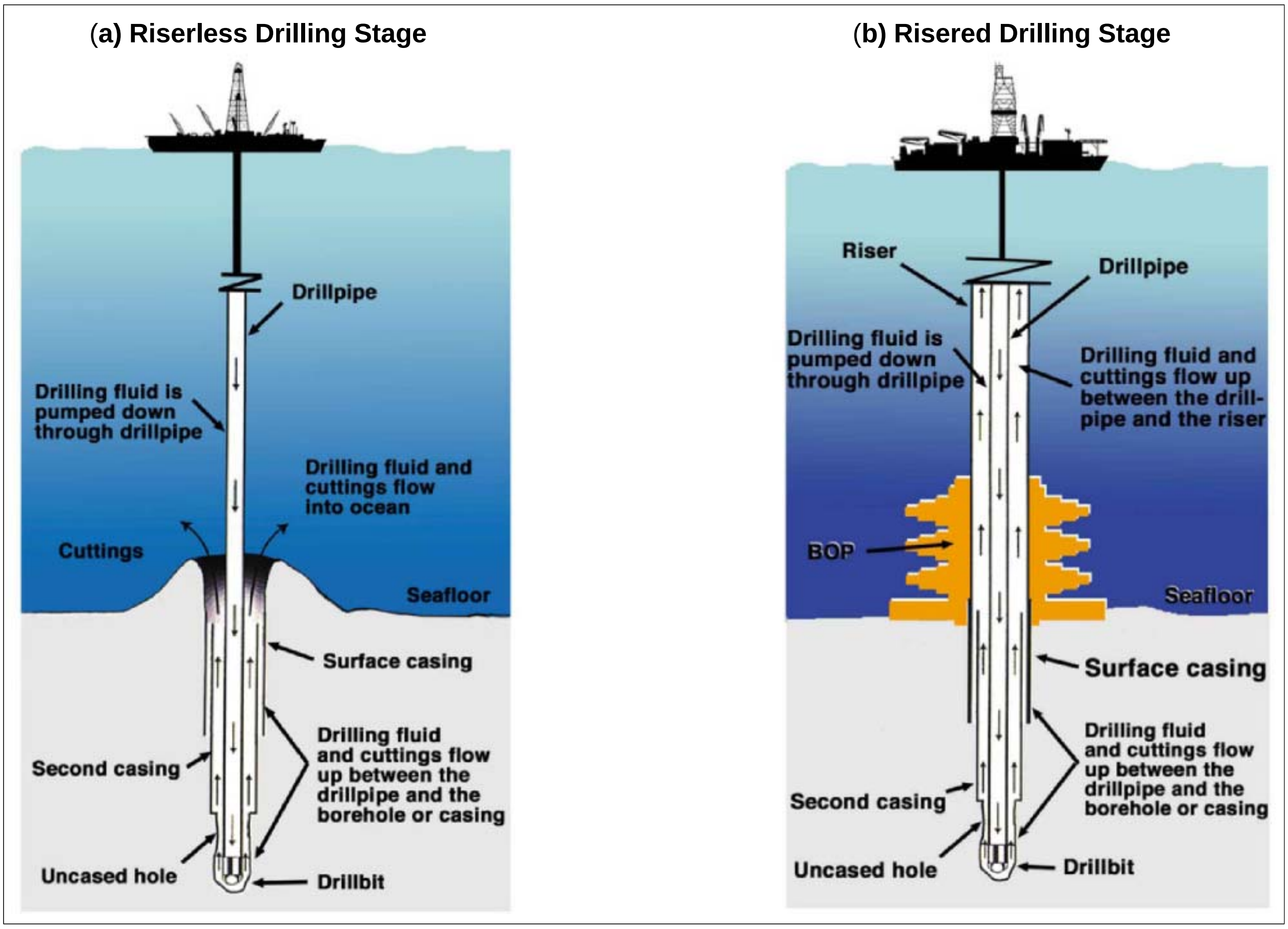


Figure 3.6: Illustrations showing the (a) riserless drilling and (b) risered drilling stages (Source: http://www.geoscienceletters.com/content/figures/2196-4092-1-2-2-l.jpg).

3.4.3.4 Cementing operation

The casings are permanently secured into place by pumping cement slurry, followed by drilling fluid, through the drill pipe and/or cement stinger at the bottom of the hole and back up into the space between the casing and the borehole wall (annulus). To separate the cement from the drilling fluid in order to minimise cement contamination a cementing plug and/or spacer fluids are used. The plug is pushed by the drilling fluid to ensure the cement is placed outside the casing filling the annular space between the casing and the borehole wall.

To ensure effective cementing, an excess of cement is often used. Until the marine riser is set, some of this excess emerges out of the top of the well onto the seafloor. This cement does not usually set and is slowly dispersed into the seawater (see Section 3.4.9 for operational discharges).

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

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

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

3.4.3.5 Drilling fluid circulation system and solids control equipment

While drilling is in progress during the risered drilling stage, drilling fluid is continuously pumped down the inside of the hollow drill string. The fluid emerges through ports (“nozzles”) 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. The returned drill mud is treated to remove the cuttings from the re-circulating mud stream (see Figure 3.3).

The solids control system sequentially applies different technologies to remove the cuttings from the drilling fluid and to recover drilling fluid so that it can be reused. A typical solids control system consists of the following main components:

- Shale shakers (removes large-sized cuttings);
- Degasser (removes entrained gas);
- Desanders (removes sand-sized cuttings);
- Desilters (removes silt-sized cuttings); and
- Centrifuge (recovers fine solids and weighting materials such as barite).

The components of the solids control system depends on the type of drilling fluid used, the formations being drilled, the available equipment on the drilling unit and the specific requirements of the disposal option. Solids control may involve both primary and secondary treatment steps.

3.4.3.6 Anticipated well design

The well design ultimately depends upon factors such as planned depths, expected pore pressures and anticipated hydrocarbon-bearing formations. The various components of the anticipated well design are shown in Table 3.3.

Table 3.3: Estimated well design and cutting volumes.

Drill Section	Hole diameter (in)	Pipe diameter (in)	Hope depth (m)	Section depth (m)	Drilling duration (days)	Type of drilling fluid used	Volume of cuttings (m^3)	Volume of drilling fluid discharged (m^3)	Drilling fluid and cuttings discharge location
Riserless drilling stage									
1	36	30	200	200	0.4	Seawater, viscous sweeps & WBF	144.5	1 000 *	Seabed
2	26	20	345	145	0.3		54.6	500 *	Seabed
Risered drilling stage									
3	17.5	13-3/8	1 235	890	3.7	WBF and / or NADF	151.9	7.6 **	Surface
4	12.25	9-5/8	2 990	1 755	14.6		146.8	7.3 **	Surface
5	8.5	7-1/2	4 500	1 510	31.5		60.8	3.0 **	Surface

Note: * = The majority of the drilling fluid in these particular sections would most likely be seawater.
** = Treated to 5% of cuttings volume.

3.4.4 DRILLING FLUIDS OR MUDS

An important component in the drilling operation is the drilling fluid or drilling mud, which is used for:

- Maintaining a stable wellbore and preventing the open hole from collapsing;
- Providing sufficient hydrostatic pressure to control subsurface pressures and prevent kicks or blow-outs;
- Transport of the cuttings to the surface;
- Cooling and lubrication of the drill bit and drill string (reduce friction);
- Powering mud motors / downhole tools during the drilling process;
- Regulation of the chemical and physical characteristics of returned mud slurry on the drilling unit; and
- Displacing cements during the cementing process.

Drilling fluid is a complex mixture of fluids, solids and chemicals that are carefully tailored to provide the correct physical and chemical characteristics required to safely drill the well.

3.4.4.1 Water-based fluids

Due to the variability in conditions that can be encountered drilling fluid mixtures vary to some extent. Typically, the major ingredient making up 85 to 90% of the total volume of a WBF is fresh and / or seawater, with the remaining 10 to 15% of the volume being barite, cellulose-based polymers, xanthan gum, bentonite clay, soda ash, caustic soda and salts (these are usually either potassium chloride [KCl] or sodium chloride [NaCl]).

Barite (barium sulphate) is an inert compound used as a weighting agent. Cellulose-based polymers are used to control the rate of filtration of water in the mud into the formation being drilled by forming a thin filter cake on the borehole wall. Xanthan gum (XC polymer) and minor amounts of bentonite clay are used to provide viscosity and impart rheological properties to the mud for cuttings transport, as well as to provide gel strength for cuttings suspension. Caustic soda (sodium hydroxide) is used to maintain the required pH in the drilling fluid. KCl or NaCl are used to reduce the swelling tendencies of clays being drilled and help to maintain a stable wellbore. Glycol is also added to WBF to avoid hydrate formation. Other minor additives may be used in special circumstances. A listing of the WBF chemicals used on a typical well, their functions and comments on their ecotoxicity are provided in Table 3.4.

Table 3.4: Main components of water-based fluid.

Material	Use	Ecotoxicity
Aluminium stearate	Defoamer	Non-toxic, insoluble
Barite	Weighting agent	Non-toxic, insoluble, non-biodegradable
Bentonite	Viscosifer	Non-toxic, insoluble, non-biodegradable
Calcium carbonate	Bridging, loss of circulation	Non-toxic, insoluble
Caustic soda	pH and alkalinity control	Soluble, corrosive
Cellulose based polymers	Fluid loss control	Insoluble, non-toxic
Citric acid	pH control	Soluble, low toxicity, irritant
Diesel oil pill (< 0.1 % mud volume)	Stuck pipe spotting fluid	Slightly soluble, 96 hr LC_{50} >0.1-1000 ppm
Gilsonite (asphalt based)	Lubricant, fluid loss reducer	Low toxicity, slightly soluble
Gluteraldehyde (0.01% mud vol)	Bactericide (biocide)	Noted for its toxic properties, irritant
Lime	Carbonate and CO_2 control	Slightly soluble, non-toxic, irritant
Organic synthetic polymer blends	Filtrate reducing agent	Non-toxic, 96 hr LC_{50} >500 ppm
Palm oil ester	Lubricant, stuck pipe pills	Slightly soluble, biodegradable
Potassium chloride	Shale / clay inhibitor	Soluble, non-toxic
Soda ash	Alkalinity, calcium reducer	Soluble, non-toxic
Sodium bicarbonate	Alkalinity, calcium reducer	Soluble, non-toxic
Xanthan gum	Viscosity, rheology	Soluble, non-toxic

3.4.4.2 Non-aqueous drilling fluids

NADF are used to:

- Provide optimum wellbore stability and enable a near gauge hole to be drilled;
- Reduce torque and drag in high angle to horizontal wells;
- Minimise damage to reservoirs that contain clays that react adversely to WBF; and
- Obtain irreducible water saturation log data for gas reservoirs.

The main chemicals used in a NADF are presented in Table 3.5.

Table 3.5: Main chemicals used in a non-aqueous drilling fluid (adapted from OGP 2003).

Material	Description
Base oil	Non-aqueous drilling fluids use base fluids with significantly reduced aromatics and extremely low polynuclear aromatic compounds. New systems using vegetable oil, polyglycols or esters have been and continue to be used.
Brine phase	$CaCl_2$, NaCl, KCl.
Gelling products	Modified clays reacted with organic amines.
Alkaline chemicals	Lime e.g. $Ca(OH)_2$.
Fluid loss control	Chemicals derived from lignites reacted with long chain or quaternary amines.
Emulsifiers	Fatty acids and derivatives, rosin acids and derivatives, dicarboxylic acids, polyamines.

The three types of NADF that are used for offshore drilling can be defined as follows:

- **Group I NADF (high aromatic content)**
  These base fluids were used during initial days of oil and gas exploration and include diesel and conventional mineral oil based fluids. They are refined from crude oil and are a non-specific collection of hydrocarbon compounds including paraffins, olefins and aromatic and polycyclic aromatic hydrocarbons (PAHs). Group 1 NADFs are defined by having PAH levels greater than 0.35%.
- **Group II NADF (medium aromatic content)**
  These fluids are sometimes referred to as Low Toxicity Mineral Oil Based Fluids (LTMBF) and were developed to address the rising concern over the potential toxicity of diesel-based fluids. They are also developed from refining crude oil but the distillation process is controlled such that the total aromatic hydrocarbon concentration is less than Group I NADFs (0.5 – 5%) and the PAH content is less than 0.35% but greater than 0.001%.
- **Group III NADF (low to negligible aromatic content)**
  These fluids are characterised by PAH contents less than 0.001% and total aromatic contents less than 0.5%. They include synthetic based fluids (SBF) which are produced by chemical reactions of relatively pure compounds and can include synthetic hydrocarbons (olefins, paraffins and esters). Using special refining and/or separation processes, base fluids of Group III can also be derived from highly processed mineral oils (paraffins, enhanced mineral oil based fluid (EMBF)). PAH content is less than 0.001%.

Drill cuttings derived from the reservoir section would contain residual base fluids, which cannot be removed easily. The disadvantage of using a NADF is that base fluid and other chemicals would result in an increase in toxicity. However, the trend in the industry has been a move towards Group III NADFs with a low to negligible aromatic content, that were developed to be more readily biodegradable in order to not persist in the long-term, and less toxic than other NADFs.

Thombo would endeavour to use a Group III NADF during the second phase of drilling, should WBFs no longer provide the necessary characteristics to maintain wellbore stability. In order to minimise the impact on the environment, Thombo is proposing to treat the cuttings onboard to reduce the residual cuttings oil content to < 5% of dry cuttings weight. The treated cuttings would then be released overboard at a depth of at least 5 m below the sea surface.

3.4.5 WELL EVALUATION

3.4.5.1 Mud logging

Mud logging involves the examination of the drill cuttings brought to the surface by the drilling fluid.

Mud logging also monitors for hydrocarbon gases that relate to changes in formation pressure and the volume or rate of returning fluid, which is imperative to catch "kicks" early. A "kick" is an influx of formation fluid into the wellbore which occurs when the formation pressure at the depth of occurrence is more than the hydrostatic head of the mud above, which if not controlled temporarily by closing the BOP and ultimately by increasing the density of the drilling fluid would allow formation fluids and mud to come up through the drill pipe uncontrollably.

3.4.5.2 Downhole formation logging

Electrical logging and logging while drilling (LWD) are the two most widely used downhole formation evaluation methods. The use of wireline logging tools requires the drill string to be removed from the well so these logs are generally run at casing points. LWD on the other hand consists of special robust logging tools being placed in the drill string a short distance behind the bit and by means of mud pulse telemetry enables the transmission of the log readings to surface in real time. The advantage of LWD logging is that results are obtained early, before significant invasion of the rock by drilling fluid filtrate can affect readings. It also insures against the failure of wireline logging due to problems such as borehole degradation or tool failures. Usually both methods are employed to varying degrees, with a comprehensive wireline logging programme being employed to confirm and supplement the LWD results.

In wireline logging the logging tools are lowered into the borehole on the end of an armoured steel cable within which lie a number of individual electrical conduits. The length of the cable is accurately measured which enables the determination of the results against depth in the well. The logging tools use various methods, such as instrumented pads and calipers that press against the rock formation, to measure different properties or centralise the tools. The continuous measurements are transmitted through the electrical conduits to a computer in the logging control cabin where they are transformed into real time logs of the different physical rock properties being measured.

The logs can be broadly classified into three classes, namely Electrical, Nuclear and Mechanical. They can also be further classified into passive or active measuring type. The passive type directly measures the properties of the rocks (e.g. the electrical potential in the formation fluids). The active types transmit from the tool into the rock and measure the response (e.g. measuring current induced magnetic fields in the rock caused by the emission of electromagnetic waves from the tool).

Mechanical logging tools can typically take samples of the rock or formation fluids and directly measure the pore pressure in permeable formations. The various responses can be correlated to the properties of the rocks or formation fluids. From this data, different rock and fluid types, their thickness, depths and properties can be determined during the petrophysical evaluation (see Section 3.4.5.4)

Radioactive sources may be used for certain types of data acquisition (see Section 3.4.5.3). The source can be mounted in the wireline tool, where it generates a radioactive field that interacts with the rocks penetrated at the wellbore. The measured response is directly related to the physical properties of the rocks. Radioactive sources are also used for calibrating wireline tools that measure either natural or induced radioactivity.

3.4.5.3 Radioactive sources

There are two standard types of wireline tools that use radioactive sources and measure formation porosity, namely:

1. The density log, which measures the electron density of a formation (this is a function of porosity); and
2. The neutron log, which measures the hydrogen ion concentration in a formation.

The radiation levels of the density and neutron tool activity are very low.

Radioactive calibration tools

Calibration tools generate a known level of low radioactivity, which is used to calibrate the receiver response for the neutron logging tool and for calibrating tools that measure the natural radiation of formations. The measurements are used for correlating zones between wells and for identifying lithologies, particularly volcanic ashes, organic rich shales, potassium feldspars, micas and glauconite. The radiation from the calibration tools is similar to the natural radiation from rocks.

Radiation level

The radioactive sources used in wireline logging would be stored in sealed containers. The radioactive material is encapsulated in ceramic cylinders and then sheathed in several layers of stainless steel. The size of the sealed sources is approximately 4 in (length) x 1 in (diameter) for the density tool and 7 in (length) x 1.5 in (diameter) for the neutron source.

The radiation levels are very low. The density tool activity can range from 0.1-2 curies (Ci) with a 0.5–200 milliroentgens per hour (mR/hr) maximum radiation level at the source surface. The neutron tool activity can range from 3-20 Ci with a 50-200 mR/hr maximum radiation level at the surface. The neutron tool, however, does not emit any external radiation at the tool surface when it is not energised.

The radiation from the calibration tools is similar to the natural radiation from rocks. Activities range from 0.000002–0.5 mR/hr maximum radiation levels.

Specific safety procedures would be established by the wireline logging contractor to handle the sources. In addition, the contractor has to set up incident and emergency reporting procedures for actual or suspected individual over-exposure, theft or loss, logging tools stuck downhole in wells and release or spillage into the environment. The contractor routinely tests the sources according to industry requirements to document leak levels.

Transport, storage and handling of radioactive devices

Radioactive devices are transported from the wireline contractor’s base to a drilling unit in specially designed secured (locked) storage containers. The tools are inventoried upon arrival and tested for leaks. A detailed log is kept of any access to the storage container and tools.

Drilling units would have a special storage location designated for radioactive containers. The storage location would be specifically chosen to minimise the danger of fire, explosion and exposure, and are clearly identified by yellow radioactive warning signs.

Only certified wireline logging engineers would be allowed to handle the radioactive devices. Whenever the radioactive sources are used, the area between and around the storage containers and the drill floor would be secured and only key personnel would be allowed in the area. Long handling sticks would be used to transfer the density and neutron sources between the storage containers and the logging tools on the drill floor, but the calibration tools, being very low-level radioactive devices, would be hand-held.

The engineers handling the devices would follow strict approved procedures. They would also wear personal monitoring devices to measure any unusual exposure. The equipment would be handled as little as possible by the engineers and returned immediately to the storage containers upon completion of the logging run.

3.4.5.4 Petrophysical evaluation

Evaluation of the physical and chemical properties of the rocks in the sub-surface, and their component minerals, including water, oil and gas, is undertaken during the drilling operation using wireline log and core data from the well. Information from engineering and production logs, as well as mud logging, may also be used.

Petrophysical evaluation typically includes the following activities:

- Distinguishing between reservoir and non-reservoir rock, thickness intervals, etc.;
- Determining the water saturation in reservoir rocks (for the reservoir intervals);

- Calculating oil and gas saturation in reservoir rocks to determine the hydrocarbon fraction; and
- Calculating petrophysical properties of rocks e.g. porosity, permeability, density, etc.

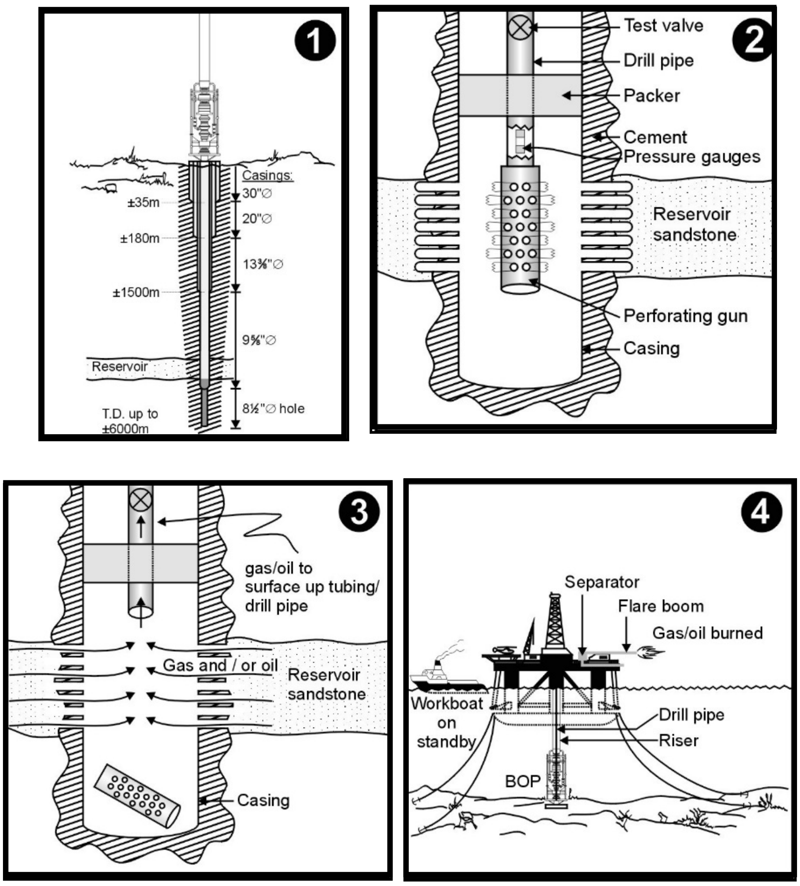
The findings of the evaluation provide an indication of the level of difficulty that would be associated with the extraction of the hydrocarbons in place and enable the design of reservoir management strategies to optimise long-term hydrocarbon recovery.

3.4.6 WELL (FLOW) TESTING

Should an exploration well encounter hydrocarbons, it may be flow-tested (also called production testing) to determine the economic potential of the discovery before the well is either abandoned or suspended for later re-entry and completion (see Figure 3.7). In the event that a discovery is made, four further wells may be drilled to appraise the field.

If flow testing is required, hydrocarbons would be flared at the well site. A high-efficiency flare is used to maximise combustion of the hydrocarbons. The amount of hydrocarbons produced would depend on the quality of the reservoir but is kept to a minimum to avoid wasting potentially marketable oil and/or gas. Thus the final well test programme would be prepared when the detailed geology and fluids are defined.

No produced water is anticipated. However, if water does flow with the hydrocarbons to the surface, it would be flared off. Any water remaining would either be stored and brought to shore for treatment and disposal or treated and discharged offshore, both in accordance with regulatory requirements.



The purpose of the drill stem testing is to gain pressure, flow rate and fluid composition data to determine whether the prospect can be commercially produced.

1. Geophysical logs are interpreted to determine the exact position of the reservoir and its characteristics. Casing is run and cemented into place. Any open hole below the casing may be isolated, if necessary, with cement plugs.

2. Perforating gun (usually 12 shots/ft) at the end of the drill pipe is positioned over the interval being tested. Packer is set. Detonation of shaped charges perforates holes through casing and cement to open channels into the reservoir.

3. Gun may be dropped from drill string. Reservoir fluids (oil and/or gas) enter ports in the bottom of the drill pipe and flow to the surface under carefully controlled conditions.

4. On the rig, oil and/or gas passes a separator. Flow rates of oil and/or gas are measured. All oil and gas produced is efficiently burned through special burner heads.

Flow rates and down-hole reservoir pressures are carefully measured in a series of flow and shut-in periods. Samples of oil and gas are collected for analysis.

Figure 3.7: Diagrammatic presentation of a well test (drill stem test) (after Crowther Campbell & Associates and Centre for Marine Studies, 1999).

3.4.7 WELL SUSPENSION OR ABANDONMENT

Based on the results of the drilling, logging and possible testing of the well, a decision would be made as to whether to suspend or abandon the well, before the drilling unit is moved off location. The options are described below.

(a) *Suspended wells*: If it is verified that a well is commercially viable, it could be suspended. This would entail the following

- Cement plugs would be set inside the wellbore and tested for integrity;
- The BOP would be removed before the drilling unit is moved off location;
- The wellhead (up to 5 m high) would remain on the seafloor; and
- A corrosion cap would be placed over the wellhead to facilitate re-entry.

The discovery of a viable hydrocarbon reserve could result in an oil and/or gas production project, which could result in significant future benefits to South Africa. Any future proposed production project would be subject to a separate environmental authorisation process.

(b) *Abandoned wells*: If a well is unsuccessful, it would be permanently abandoned in a safe and stable condition. This would entail the following:

- Cement plugs would be set inside the wellbore and tested for integrity;
- The BOP would be removed before the drilling unit is moved off location;
- The casings would be cut approximately 3 m below the seafloor; and
- All the wellhead equipment would be removed to leave the seafloor clear.

The decision on whether to abandon an unsuccessful well would determine the way forward, which may include the relinquishment of the entire licence area or a portion thereof. This would require the application for a closure certificate.

3.4.8 SEA- AND LAND-BASED SUPPORT

3.4.8.1 Onshore logistics base

An onshore logistics base would be provided for the storage of materials (including wellbore materials, diesel, water and drilling fluids) and equipment that would be transported from/to the drilling unit by support vessels. The shore base would also be used for bunkering vessels. The onshore logistics base would be located in either Cape Town or Saldanha Bay. The final decision on its location would ultimately be based on discussions with Transnet and where the project can be accommodated in terms of space and proposed activities.

It is anticipated that space and equipment requirements to service the operation at the shore base would consist of the following:

- Yard space (3 000 to 5 000 m^2);
- Covered warehouse (500 m^2);
- Office space;
- 45 t crane (yard operations);
- 80 to 100 t crane (quay side operations);
- 8 t forklift equipped with certified pipe clamp;
- Trucks and flatbed trailers;
- Fuel supply;
- Potable water supply; and
- Liquid and dry mud plant.

The service infrastructure required to provide the necessary onshore support is currently in place at both the Cape Town and Saldanha Bay harbour precincts and no additional onshore infrastructure would be necessary for this project. Likewise, no new facilities or construction would be needed for helicopter support.

3.4.8.2 Support and supply vessels

The drilling unit would be supported by several vessels, which would facilitate equipment and material transport between the drilling unit and the port. It is envisioned that a supply vessel would call into port every week during the campaign.

A standby vessel would also be available to support any potential emergency need, including fire fighting, oil containment/recovery and rescue and to supply any specialised equipment necessary in case of an emergency. The standby vessel would also be used to patrol the area to ensure that other vessels adhere to the 500 m safety zone around the drilling unit.

3.4.8.3 Crew transfers

Transportation of personnel to and from the drilling unit would most likely be provided by helicopter operations from either Kleinzee or Hondeklipbaai. Transportation to Kleinzee or Hondeklipbaai would likely be provided from Cape Town.

The drilling unit would accommodate in the order of 100 - 150 personnel. Crews would work in 12-hour shifts in 4-5 week cycles. Crew changes would be staggered, and in combination with ad hoc personnel requirements. Thus helicopter operations to and from the drilling unit would occur on an almost daily basis.

3.4.9 OPERATIONAL DISCHARGES

This section provides a brief description of the types of emissions and discharges that are expected from the activities relating to drilling a typical well. Normal emissions and discharges from an offshore drilling unit include emissions to air, discharges to sea and return of waste to shore. The management of these emissions and discharges will be included in a project-specific waste management plan.

Abnormal discharges such as spills or losses of oil and / or chemicals are possible, but unlikely with the safety systems in place. Any such spills would be handled in accordance with procedures set forth in the operator’s contingency plan (see “Plans and Procedures for Environmental Related Emergencies and Remediation” in Section 3.2.7).

3.4.9.1 Emissions to air

A range of air emission types would be generated from a variety of sources during well drilling. These would include exhaust emissions from vessels and machinery, including the combustion of diesel fuel and gas product to power the drilling unit, as well as fugitive emissions from a wide variety of sources.

Combustion

Emissions to the air would be generated by combustion of diesel fuel in generators and other machinery used to power the drilling operation. Fuel consumption of a semi-submersible drilling unit is estimated to be between 75 and 100 bbl (barrels) of diesel per day. Typical emissions resulting from this consumption are as follows (note: these levels are based on standard fuel emission factors for each compound):

- CO_2 = 32 tons/day;
- NO_2 = 0.6 tons/day;
- CO = 0.015 tons/day;
- SO_2= 1.2 tons/day[5]; and
- Particulates = 0.05 tons/day[6].

Additional air emissions would be generated by vessels used to tow the drilling unit, operating support / supply vessels and helicopter operations. The air emissions from the support or supply vessels would be no greater than that from any other vessel of a similar tonnage.

Incineration of operational waste

The incineration of non-toxic combustible wastes (e.g. galley waste) on the drilling unit and support / supply vessels would require an Atmospheric Emission Licence (see Section 2.1.5). Thombo has indicated that there would be no offshore incineration of waste. Waste would either be treated and discharged overboard (see Section 3.4.9.2) or taken to shore for disposal (see Section 3.4.9.3).

Flaring

During well testing it may be necessary to flare off oil and gas. The amount of hydrocarbons produced would depend on the quality of the reservoir but is kept to a minimum to avoid wasting potentially marketable oil and/or gas. It is anticipated that the duration of flaring would be in the order of 2 days per test.

Other emissions to air

Additional air emissions would be generated by ventilation from mud pits and shakers and during refuelling operations.

3.4.9.2 Discharges to sea

Drilling cuttings and mud

Drill cuttings, which range in size from clay to coarse gravel and reflect the types of sedimentary rocks penetrated by the drill bit, are the primary discharge during well drilling. There is, however, no standard practice for the treatment and disposal of drill cuttings that is applied around the world, including South Africa. In most countries in early exploration development phases drill cuttings are discharged to sea (OGP 2003). In South Africa historically over 300 wells have been drilled with the accepted disposal method being cuttings discharge to sea. The rationale for this is based on the low density of drilling operations in the vast offshore area and the high energy marine environment.

During the riserless drilling stage for each well, all cuttings and WBF would be discharged directly onto the seafloor. It is estimated that approximately 200 m^3 of cuttings and approximately 1 500 m^3 of seawater and WBM (the majority of which would be water) would be discharged per well onto the seafloor for the initial 345 m of drilling for each well (refer to Table 3.3). The cuttings dispersion modelling study (see Appendix 3.2) indicates that the seabed release of cuttings during the riserless drilling stage would result in a roughly circular shaped deposition pattern around the proposed well, owing to the low seabed currents and small settling distance (5 m). The results indicate that deposition thicknesses greater than 0.1 mm are expected to extend up to a maximum of approximately 300 m from the wellhead and cover a maximum area of approximately 7 ha in both summer and winter. Deposition thicknesses greater than 10 mm and 100 mm would, however, be confined to a maximum area of approximately 0.6 ha and 0.1 ha, respectively. The maximum thickness of deposited cuttings is not expected to exceed 200 mm.

[5] This assumes sulphur content of diesel fuel is approximately 500 ppm.
[6] For particulates with an aerodynamic diameter of less than 10 µm.

Once the marine riser is connected (risered drilling stage), the drilling fluid and cuttings are circulated up to the drilling unit where the mud is cleaned and the cuttings discharged into the sea. In the case of a NADF being used, the drill cuttings would be treated to reduce their oil content to less than 5% of dry cuttings weight prior to discharge overboard. Surface released cuttings would be dispersed by the current and settle to the seafloor. The rate of cuttings discharge decreases with increasing well depth because the hole diameter becomes smaller and penetration rates decrease (refer to Table 3.3). The total volume of surface released cuttings during the risered drilling stage is estimated to be approximately 360 m^3 for each well, and is dependent on the well design. These cuttings would contain up to 5% of residual NADF (i.e. approximately 18 m^3) in the event such a mud is used for drilling purposes. Discharge is intermittent as actual drilling operations occur only about one-third to one-half of the total time the drilling unit is on location. The cuttings dispersion modelling study (see Appendix 3.2) indicates that the surface release of cuttings during the risered drilling stage results in deposition over a larger area than the seabed release due to the larger settling depth. The results indicate that the deposition thicknesses greater than 0.1 mm are expected to extend up to a maximum of approximately 1 000 m from the wellhead and cover a maximum area of approximately 54 ha in summer and winter. Deposition thicknesses greater than 5 mm would, however, be confined to a maximum area of less than 2 ha in both summer and winter. The maximum thickness of deposited cuttings is not expected to exceed 10 mm.

The maximum modelled cumulative deposition thickness (from both the riserless and risered drilling stages) over all simulations occurring during summer and winter is presented in Figure 3.8. Table 3.6 presents the maximum modelled areal extent of the deposition footprint for a number of deposition thicknesses.

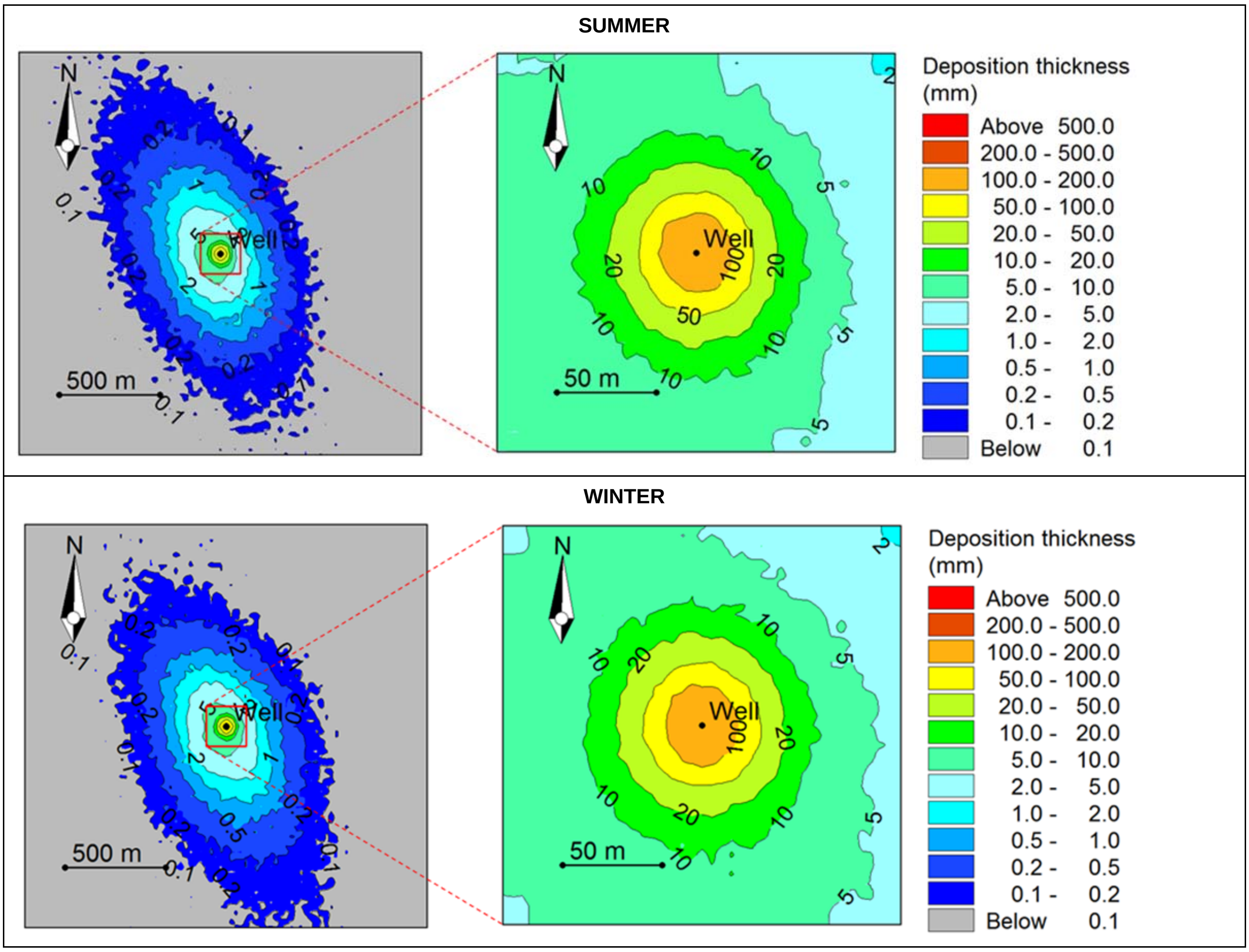


Figure 3.8: Maximum modelled cumulative deposition thickness (riserless and risered) over all simulations occurring during summer and winter.

Table 3.6: Maximum areal extent of cuttings deposition footprint.

Deposition thickness (mm)	Maximum areal extent of deposition footprint (ha)					
	Seabed release		Surface release		Cumulative	
	Summer	Winter	Summer	Winter	Summer	Winter
> 0.1	7.1	7.1	53.6	53.6	53.6	53.8
> 0.2	5.0	5.0	35.7	35.3	35.8	35.4
> 0.5	2.9	2.9	19.9	20.3	20.3	20.8
> 1	2.0	2.0	11.9	11.9	12.6	12.3
> 2	1.4	1.3	6.4	6.4	6.9	7.1
> 5	0.8	0.9	1.1	1.1	2.2	2.3
> 10	0.6	0.6	0.0	0.0	0.8	0.8
> 20	0.4	0.4	0.0	0.0	0.6	0.6
> 50	0.2	0.2	0.0	0.0	0.3	0.3
> 100	0.1	0.1	0.0	0.0	0.1	0.1

Alternative methods for NADF drill cuttings disposal, and their viability, are discussed below.

a) Onshore disposal (OGP 2003)

This alternative involves the processing of drill cuttings on the drilling unit, storage and transportation to shore for final disposal. Disposal options include:

> Landfill disposal: Depending on the level of treatment and residual NADF, the cuttings would more than likely need to be disposed of at a hazardous landfill site.

> Onshore injection: Onshore injection requires the presence of a suitable injection formation with appropriate properties for the disposal and containment of the cuttings and associated NADFs.

> Land-spreading: Land-spreading involves spreading untreated cuttings evenly over an area followed by mechanical tilling with addition of nutrients, water, air and or oxygen as necessary to stimulate biodegradation by naturally occurring oil-degrading bacteria. Land-spreading is generally limited to one application.

> Land-farming: Land-farming is similar to land-spreading except material is applied several times at the same location. Depending upon the location of the land-farm, a liner, over liner, and/or sprinkler system may be required.

> Re-use (e.g. road construction). Treated cuttings may be used for construction or other alternative uses. If necessary or optimal, cuttings could be further treated prior to disposal biologically (e.g. composting) or thermally (e.g. thermal desorption or incineration).

Although the onshore disposal option has the advantage that it does not leave an accumulation of cuttings on the seafloor, it has several disadvantages (e.g. additional pressure on existing landfill sites and potential impacts on vegetation and groundwater) and involves a substantial amount of additional equipment, transportation, facilities and cost. Since there are currently no sites identified for land-spreading and -farming and landfill sites in the Western Cape are already under enormous air-space availability pressure, this disposal alternative is not being considered for the proposed project.

b) Re-injection (OGP 2003)

Drill cuttings could be injected under pressure into a subsurface geological formation at the drill site. Cuttings could either be injected into the annulus of the well being drilled or into a dedicated or dual-use disposal well.

Cuttings re-injection is not a viable option for all drilling operations and is ultimately dependent on a suitable geological formation capable of accepting and containing the waste on a long-term basis. This method of disposal is also only practical and economic where a large number of wells are being drilled from a single location.

Since the suitability of the subsurface geological formations at the drill site is unknown and would require the drilling of an additional well with the similar need to dispose of drill cuttings, this disposal alternative is not being considered for the proposed project.

The advantages and disadvantageous of both offshore and onshore disposal methods discussed above are summarised in Table 3.7.

Table 3.7: Advantages (+) and disadvantages (-) of the three drill cuttings disposal alternatives (OGP 2003).

Economics	Operational	Environmental
1. Offshore treatment and discharge		
+ Very low cost per unit volume treatment. + No potential liabilities at onshore facilities. - Potential future offshore liability. - Cost of analysis of discharges and potential impacts (e.g. compliance testing, discharge modelling, field monitoring programmes).	+ Simple process with little equipment needed. + No transportation costs involved. + Low power requirements. + Low personnel requirements. + Low safety risk. + No shore-based infrastructure required. + No additional space or storage requirements. + Little weather restrictions. - Management requirements of fluid constituents (namely oil content).	+ No incremental air emissions. + Low energy usage. + No environmental issues at onshore sites. - Potential for short-term localised impacts on seafloor biology.
2. Onshore treatment and disposal		
+ Waste can be removed from drilling location eliminating future liability at the drill site. - Transportation cost can be high for vessel rental and vary with distance of shore base from the drilling location. - Transportation may require chartering of additional supply vessels. - Additional costs associated with offshore transport equipment (cuttings boxes or bulk containers) and personnel. - Operational shut-down due to inability to handle generated cuttings would make operations more costly. + On land transportation costs. – Potential future liabilities. – Process required to obtain approval from a number of onshore regulatory authorities.	- Safety hazards associated with loading and unloading of waste containers on workboats and at the shore base. - Increased handling of waste is necessary at the drill site and at shore base. - Additional personnel required. - Risk of exposure of personnel to aromatic hydrocarbons is greater. - Efficient collection and transportation of waste are necessary at the drilling location. - May be difficult to handle logistics of cuttings generated with drilling of high rate of penetration large diameter holes. - Weather or logistical issues may preclude loading and transport of cuttings, resulting in a shutdown of drilling or need to discharge. – Onshore transport to site. – Safety risk to personnel and local inhabitants in transport and handling. – Disposal facilities require long-term monitoring and management. Landfill – Requires appropriate management and monitoring may have requirements on	+ No impacts on benthic community + Avoids impacts to environmentally sensitive areas offshore. - Fuel use and consequent air emissions associated with transfer of wastes to a shore base. - Increased risk of spills in transfer (transport to shore and offloading). - Disposal onshore creates new problems (e.g. potential groundwater contamination). - Potential interference with shipping and fishing from increased vessel traffic and increased traffic at the port. + Reduces impacts to seafloor and biota. - Potential for onshore spills. - Air emissions associated with transport and equipment operation. Landfill - Potential groundwater and surface water impacts. - Air emissions associated with earthmoving equipment. - May be restrictions on oil content of wastes.

Economics	Operational	Environmental
Landfill - Additional pressure on existing landfill sites (air-space availability). Land-spreading + Relatively inexpensive if land is available. Land-farming + Inexpensive relative to other onshore options. – Requires long-term land lease.	maximum oil content of wastes. – Land requirements. Land-spreading + Simple process with little equipment needed. – Cannot be used for wastes with high salt content without prior treatment. Land-farming - Limited use due to lack of availability of and access to suitable land - Requires suitable climatic conditions (unfrozen ground) - cannot be used for wastes with high salt content without prior treatment	- May be limited by local regulations. Land-spreading + Degradation of hydrocarbons. - Must be done within concentration constraints or could damage crop production. Land-farming + If managed correctly minimal potential for groundwater impact. + Biodegradation of hydrocarbons. - Air emissions from equipment use and off-gassing from degradation process. - Runoff in areas of high rain may cause surface water contamination. - May involve substantial monitoring requirements.
3. Re-injection		
+ Enables use of a less expensive drilling fluid. + No offsite transportation needed. + Ability to dispose of other wastes that would have to be taken to shore for disposal. - Expensive and labour-intensive. - Shutdown of equipment can halt drilling activities.	+ Cuttings can be injected if pre-treated. + Proven technology. - Extensive equipment and labour requirements. - Application requires receiving formations with appropriate properties. - Casing and wellhead design limitations. - Over-pressuring and communication between adjacent wells. - Variable efficiency. - Difficult for exploration wells due to lack of knowledge of formations. - Limited experience on floating drilling operations and in deep water. - Temporary shutdown if there are problems with injection equipment or well operations.	+ Elimination of seafloor impact. + Limits possibility of surface and groundwater contamination. - Increase in air pollution due to large power requirements. - Possible breach to seafloor if not designed correctly.

Cement and cement additives

Typically, cement and cement additives are not discharged from drilling units. However, during the initial cementing operation, excess cement would emerge out of the top of the well and onto the seafloor in order to ensure the conductor pipe is cemented all the way to the seafloor. During this operation some of the required cement volume would be pumped into the space between the casing and the borehole wall (annulus) and small quantities cement would be discharged onto the seafloor. In the worst case scenario approximately 20 m^3 of cement could be discharged onto the seafloor. It should, however, be noted that if cement returns are observed on the seafloor cementing would be terminated.

BOP hydraulic fluid

As part of routine opening and closing operations the subsea BOP stack elements would vent hydraulic fluid into the sea at the seafloor. It is anticipated that approximately 500 – 1 000 litres of oil-based hydraulic emulsion fluid would be vented per month during the drilling of a well. Concentrated BOP fluids are mildly toxic to marine crustaceans and algae (LC_{50} 102-117 ppm), but they are diluted with fresh water 50-100:1 for application. BOP fluids are completely biodegraded in seawater in 28 days.

Vessel machinery spaces (bilges), ballast water and deck drainage

The concentration of oil in discharge water from any vessel (bilge and ballast) would comply with the MARPOL Regulation 21 standard of less than 15 parts per million (ppm) oil in water. Any oily water would be processed through a suitable separation and treatment system to meet the MARPOL standard before discharge overboard. To ensure MARPOL compliance all machinery space and deck drainage would be collected and piped into a sump tank on-board the drilling unit for treatment prior to discharge.

Sewage

Sewage discharge would meet the requirements of MARPOL Annex IV. MARPOL Annex IV requires that sewage discharged from vessels be comminuted and disinfected and that the effluent must not produce visible floating solids in, nor cause discoloration of the surrounding water. The treatment system must provide primary settling, chlorination and dechlorination. The treated effluent is then discharged into the sea, as is the practice aboard ocean-going vessels.

Food (galley) wastes

The disposal into the sea of food waste is permitted, in terms of MARPOL Annex V, when it has been comminuted or ground to particle sizes smaller than 25 mm and the vessel is located more than 3 nautical miles (approximately 5.5 km) from land. Disposal overboard without macerating can occur greater than 12 nautical miles (approximately 22 km) from the coast; however, Thombo would not permit discharge of any food waste without maceration. The daily discharge from a drilling unit is typically about 0.2 m^3.

Detergents

Detergents used for washing exposed marine deck spaces would be discharged overboard. The toxicity of detergents varies greatly depending on their composition. Water-based detergents are low in toxicity and are preferred for use. Preferentially biodegradable detergents, e.g. Teepol, should be used. Detergents used on work deck space would be collected with the deck drainage and treated as described under deck drainage above.

3.4.9.3 Land disposal

A number of other types of wastes generated during the exploration activities would not be discharged at sea but would be transported to shore for ultimate disposal. These wastes would be disposed at a licensed municipal landfill facility or at an alternative approved site. Operators would be required co-operate with local authorities to ensure that waste disposal is carried out in an environmentally acceptable manner.

A summary of these waste types generated by a drilling unit during a typical drilling operation, their expected amounts per well, environmental properties, and destination is given below. Typical volumes are presented in Table 3.8.

Table 3.8: Average monthly volume of wastes produced during a 2014 drilling campaign off the coast of South Africa.

Waste Type	Average monthly volume produced during drilling
Solid hazardous waste	5 m^3
Non-hazardous waste (metals)	15 m^3
Non-hazardous waste (plastics)	17 m^3
Non-hazardous waste (card / paper)	20 m^3
Non-hazardous waste (glass)	1 m^3
Non-hazardous waste (electronic)	1 m^3
Non-hazardous waste (wood)	30 m^3
Non-hazardous waste (general / other)	25 m^3

Garbage
This includes wastes originating from offshore accommodation, workshops, etc., including waste paper, plastics, wood, metal, glass, etc. All waste would be disposed of at an approved onshore landfill site.

Scrap metal and other materials
Surplus material would be re-used. Non-usable material (e.g. oiled machine cuttings) would be stored and disposed of at an approved onshore landfill site.

Drums and containers
Empty drums containing residues, which may have adverse environmental effects (solvents, lubricating/gear oil, etc.), would be rinsed before disposal. If carried out on-board the vessel, the rinse water would be stored and transported to shore. Rinse water would be disposed of in a manner acceptable to the local authorities regardless of whether rinsing is carried out on board the drilling unit or onshore. Rinsed and non-rinsed drums brought ashore would be disposed of in a local landfill site after crushing to reduce volume.

Used oil
Examples include used lubricating and gear oil, solvents, hydrocarbon-based detergents, possible drilling fluids and machine oil. Toxicity varies depending on oil type. All non-recycled waste oils would be securely stored, transported to shore and disposed of at a licensed site acceptable to the relevant authorities.

Chemicals and hazardous wastes
Disposal of any unexpected chemical and hazardous substance (e.g. radioactive devices/materials, neon lights, fluorescent tubes, toner cartridges, batteries etc.) would be done on a case-by-case basis and in a manner acceptable to appropriate regulatory authorities.

Laboratory wastes
Minor quantities of laboratory wastes would be generated (from water quality testing and retort analysis) that would be discharged to sea.

Infectious wastes
Infectious wastes include bandages, dressings, surgical waste, tissues, medical laboratory wastes, needles, and food wastes from persons with infectious diseases. Only minor quantities of medical waste are expected. Prevention of exposure to contaminated materials is essential, requiring co-operation with local medical facilities to ensure proper disposal.

Filters and filter media
This includes air, oil and water filters from machinery. Oily residue and used media in oil filters that may contain metal (e.g. copper) fragments, etc. are possibly toxic. Filters and media would be transported ashore and disposed of at a licensed landfill facility.

Drilling fluid
Bulk volumes of NADF remaining at the end of well drilling, would be shipped ashore and returned to the supplier, treated and disposal through an approved waste disposal company or re-used during the drilling of the subsequent well.

3.4.10 SUMMARY OF PROJECT ALTERNATIVES

Table 3.9 provides a summary of the project alternatives that have been considered during the EIA.

Table 3.9: Summary of project alternatives.

No.	Alternatives	Description
1. Site / location alternatives		
1.1	Drill site	Thombo is the operator and holder of an existing Exploration Right for Block 2B. Thus the proposed exploration well drilling would occur within this licence area. Thombo is, however, proposing to limit the well drilling to an area of primary interest (i.e. the A-J graben) in the licence area (refer Section 3.4.1). This area of interest is based on an understanding of the geological information for the area from an analysis of the existing seismic data. Thus the drilling area is more or less fixed by the location of the area of highest geological interest. Although the final well location would be based on a number of factors, including further analysis of the seismic data, the geological target and seafloor obstacles, this EIA assumes that the wells could be drilled anywhere within the area of primary interest.
1.2	Onshore logistics base	The main onshore logistics base would be located in either Cape Town or Saldanha Bay (refer to Section 3.4.8.1). The final decision on its location would ultimately be based on discussions with Transnet and where the project can be accommodated in terms of space and proposed activities. Another onshore base would also be established in either Kleinzee or Hondeklipbaai in order to facilitate the transportation of personnel by helicopter to and from the drilling unit. This EIA assesses the potential impacts related to all onshore logistics base alternatives.
2. Activity alternatives		
2.1	Exploration well drilling	Thombo has to date undertaken a 3D seismic survey over the area of primary interest. Since exploration well drilling is the next logical step in the exploration process no other activity alternatives are being considered in the EIA process. It should, however, be noted that certain pre-drilling activities may be undertaken prior to drilling, e.g. shallow hazard assessment and sediment sampling (refer to Section 3.3). This EIA assesses the potential impacts related well drilling and the associated pre-drilling activities.
3. Design or layout alternatives		
3.1	Number of wells	Thombo is proposing to drill up to five wells in the area of primary interest. The exact number of wells would ultimately be based on the success of the initial exploration well (refer to Section 3.4.1). This EIA assumes that all five wells would be drilled anywhere within the area of primary interest.
3.2	Scheduling	Although Thombo is proposing to commence drilling a summer window period (see Section 3.4.1), this EIA considers both a summer and winter drilling scenario.
4. Technology alternatives		
4.1	Pre-drilling sediment sampling	Pre-drilling sediment sampling would be undertaken to determine the geotechnical properties of the seabed in the proposed drilling areas. Various sampling methods may be used, e.g. gravity corer, push sampler, cone penetration test or grab samples (refer to Section 3.3.2). This EIA assesses the potential impacts related to all proposed sampling methods.

No.	Alternatives	Description
4.2	Drilling unit and anchoring / positioning	Thombo is currently considering two alternative drilling units, either a semi-submersible drilling vessel or a jack-up rig (refer to Section 3.4.2). This EIA assesses the potential impacts related to both drilling unit options.
4.3	Drilling method	Two drilling methods can be employed on a drilling unit, namely rotary or downhole motor drilling (refer to Section 3.4.3.2). This EIA assesses the potential impacts related to both drilling methods.
4.4	Drilling fluid	Two types of drilling fluid may be used during drilling (refer to Section 3.4.4). During the initial riserless drilling stage WBF would be used. However, during the risered drilling stage, a low toxicity NADF may be used, if the use of WBFs is no longer possible (refer to Section 3.4.3.3). This EIA assesses the potential impacts related to both types of drilling fluids.
4.5	Drill cuttings disposal methods	Alternative drill cuttings disposal methods include: • Discharge to sea; • Onshore disposal; and • Re-injection into well. These alternative methods, and their viability, are discussed in Section 3.4.9.2. Since only the disposal of cuttings to sea alternative is considered viable for the proposed project, only this alternative is being assessed in the EIA.
4.6	Well completion	Based on the results of the drilling, logging and possible testing of the wells, a decision would be made as to whether to suspend or abandon the wells before the drilling unit is moved off location (refer to Section 3.4.7). This EIA assesses the potential impacts related to both well suspension and abandonment.