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) 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[4], 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:

[4] Address by President Jacob Zuma at the launch of Operation Phakisa, 19 July 2014; http://www.thepresidency.gov.za/pebble.asp?relid=17739)

(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 Shell provides an opportunity to meet one of the aims of Operation Phakisa.

Shell has a strategic vision to support future energy demands in South Africa by building a robust and successful integrated energy business in the country. The Orange Basin Deep Water Licence Area is part of this strategy, and is focussed on one of the key themes within Shell, namely deep water exploration and development. Shell acquired the licence area after it was promoted by PASA in the 2009 Bid Round. As previously mentioned, Shell undertook a 3D seismic survey in a portion of the licence area, which identified potential geological structures or “prospects”.

If the proposed exploration drilling is successful, this presents an opportunity to develop a South African oil and gas industry resulting in long-term benefits 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. There is also potential in the long-term for local economic stimulation through direct employment, future business opportunities, royalties and tax revenues.

3.2 GENERAL PROJECT INFORMATION

3.2.1 EXPLORATION RIGHT HOLDER

Shell is the Exploration Right holder of the Orange Basin Deep Water Licence Area.

Address:	Shell South Africa Upstream B.V.	
	PO Box 2231	10 Rua Vasco da Gama Plain
	CAPE TOWN	CAPE TOWN
	8000	8000

General Manager:	Jan Willem Eggink
Telephone:	+27 (0)21 408 4610
Facsimile:	+27 (0)21 413 1700
E-mail:	j.eggink@shell.com

3.2.2 LICENCE AREA DETAILS

The Orange Basin Deep Water Licence Area is located off the West Coast of South Africa and covers an area of approximately 37 290 km^2. The eastern border of the licence area is located between approximately 150 km and 300 km off the coast roughly between Saldanha Bay (33ºS) and Kleinzee (30ºS), with water depths ranging from 500 m to 3 500 m (see Figure 1.1). The co-ordinates of the licence area are provided Table 3.1.

Table 3.1: Co-ordinates of the Orange Basin Deep Water Licence Area (Co-ordinate system: WGS 84 Zone 33).

Point	Latitude (S)	Longitude (E)	Point	Latitude (S)	Longitude (E)
1	30º 00’ 01.41”	14º 25’ 59.41”	12	31º 15’ 01.30”	14º 59’ 56.53”
2	30º 00’ 04.41”	14º 41’ 56.43”	13	32º 00’ 01.23”	14º 59’ 56.77”
3	30º 40’ 01.36”	14º 41’ 56.44”	14	32º 00’ 01.18”	15º 29’ 56.85”
4	30º 40’ 01.33”	14º 54’ 56.46”	15	32º 15’ 01.15”	15º 29’ 56.88”
5	30º 42’ 01.32”	14º 54’ 56.46”	16	32º 15’ 01.13”	15º 44’ 56.90”
6	30º 42’ 01.31”	15º 02’ 56.47”	17	32º 45’ 01.08”	15º 44’ 56.99”
7	30º 52’ 01.31”	15º 02’ 56.48”	18	32º 45’ 01.03”	16º 14’ 57.07”
8	30º 52’ 01.29”	15º 24’ 56.53”	19	33º 00’ 00.99”	16º 14’ 57.11”
9	31º 00’ 01.29”	15º 24’ 56.55”	20	33º 00’ 01.19”	13º 59’ 56.70”
10	31º 00’ 01.33”	14º 44’ 56.47”	21	30º 16’ 04.79”	13º 59’ 56.31”
11	31º 15’ 01.32”	14º 44’ 56.49”			

3.2.3 FINANCIAL PROVISION

In terms of Sections 41 and 89 of the MPRDA[5] 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.

It is Shell's policy to ensure appropriate financial provision is in place prior to any work being undertaken in the exploration right area. Shell will discuss and conclude the nature and quantum of the financial provision required for the management of and remediation of environmental damage with PASA during their second exploration right renewal period prior to any drilling activity being undertaken.

3.2.4 SHELL’S HEALTH, SAFETY, SECURITY AND ENVIRONMENTAL POLICY

Shell follows a systematic approach to health, safety, security and environmental (HSSE) management in order to achieve high standards of operation and continuous performance improvement. Shell manages these matters as critical business activities by setting standards and targets for operation and improvement, and by measuring, appraising and reporting on its performance. Shell continuously looks for ways to reduce potential environmental effects from their operations.

Shell’s general operating principles are underpinned by a deliberate focus on safety and environmental protection. Shell’s safety record is built on strict company standards, multiple safety barriers to prevent incidents from occurring and to enable a quick and effective response should it be necessary, extensive safety competence assurance, and a culture that requires workers, contractors and visitors to stop any unsafe activities. Shell’s company-wide Goal Zero programme and established 12 Life Saving Rules capture its aim to operate with no harm to people and no significant incidents in its daily operations.

[5] 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.

The proposed project would be conducted within the framework of Shell's internal standards and Business Principles, as well as the environmental, health and safety policies and procedures of its contractors. Environmental, Health and Safety management of the proposed project would follow procedures and requirements described in Shell's Health, Safety, Security, Environment and Social Performance Control Framework and Corporate Standards (see Table 3.2). These policies and management procedures would be bridged to the appointed contractors' own HSSE management system.

In this way Shell aims to have an HSSE performance they can be proud of, to earn the confidence of customers, shareholders and society at large, to be a good neighbour and to contribute to sustainable development.

In addition, offshore exploration projects are carried out within a framework of national regulations, international conventions, corporate policies and procedures, and recognised third party guidelines, all of which have different applications, remits, requirements and implications. Standards and guidelines have been identified using the following sources:

- Shell HSSE and Social Performance Control Framework;
- International Finance Corporation (IFC) Performance Standards;
- World Bank Environmental, Health and Safety (EHS) Guidelines; and
- Topic-specific conventions that are not restricted to a specific geography, such as the 1973 International Convention for the Prevention of Pollution from Ships (MARPOL).

Table 3.2: Shell's commitment and policy on health, safety, security, environment and social performance.

Commitment	Policy
Shell is committed to: • Pursue the goal of no harm to people; • Protect the environment; • Use material and energy efficiently to provide our products and services; • Develop energy resources, products and services consistent with these aims; • Publicly report on its performance; • Play a leading role in promoting best practice in our industries; • Manage Health, Safety and Environmental matters as any other business activity; and • Promote a culture in which all Shell employees share this commitment.	Every Shell Company: • Has a systematic approach to Health, Safety and Environmental management designed to ensure compliance with the law and to achieve continuous performance improvement; • Sets targets for improvement and measures, appraises and reports performance; • Requires contractors to manage Health, Safety and Environmental in line with this policy; • Requires joint ventures under its operational control to apply this policy and uses its influence to promote it in its other ventures; and • Includes Health, Safety and Environmental performance in the appraisal of all staff and rewards accordingly.

3.2.5 ENVIRONMENTAL AWARENESS

The exploration drilling would be undertaken by a drilling Contractor (including vessel and staff) and environmental awareness training would form part of Shell's HSSE requirements, which includes the following:

1. The Final EIR and EMPr Addendum would be included in the contract documentation of the selected drilling Contractor;
2. Drilling crew would undertake induction training, of which the relevant sections of the Final EIR and EMPr Addendum would form a part;

3. Tool box talks would be conducted. These talks would include environmental aspects such as waste management, spill prevention and clean-up, etc.; and
4. A Shell HSSE representative would monitor and report on the implementation of and compliance with the Environmental Management Programme (as per the Final EIR) and Mitigation and Management Plan (as per the EMPr Addendum).

3.2.6 MONITORING AND EMP PERFORMANCE ASSESSMENT

Shell would ensure that the drilling contractor executes the work in accordance with the requirements of the Environmental Management Programme in the Final EIR and Mitigation and Management Plan in the EMPr Addendum.

The Contractor would be required to demonstrate its commitment to these documents through leadership and action planning. Contractor would monitor and report on their performance. Contractor would have the resources, equipment and materials needed to implement the specifications of the Environmental Management Programme / Mitigation and Management Plan, as well as to ensure compliance with the regulatory requirements and laws. The Contractor would implement a training programme that includes induction, ongoing awareness (through toolbox talks) and rewarding understanding of the requirements of the Environmental Management Programme / Mitigation and Management Plan. The Contractor would establish and implement a documented system to monitor and report performance that meets the requirements of the Environmental Management Programme / Mitigation and Management Plan. The Contractor would periodically perform self-audits, reviews and inspections to determine the effectiveness of the implementation of the Environmental Management Programme / Mitigation and Management Plan.

Shell's HSSE representative would periodically review the Contractor's compliance with the Environmental Management Programme / Mitigation and Management Plan. Findings from these reviews, including non-compliance and areas of improvement would be formally communicated to the Contractor. The responses and actions by the Contractor would be recorded and tracked in a register to monitor areas of improvement.

After well completion a "close-out" EMPr performance report would be prepared. This report 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 the Orange Basin Deep Water Licence Area would be compiled during the detailed design stage. This plan would describe the Emergency Response Organisation for Shell. In the event of an emergency arising during activities associated with Shell operations, a Shell Emergency Response Team, liaising with Contractor representatives, as appropriate, 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, Shell and the selected 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: This plan would instruct employees as to the correct response procedure for oil spills that arise during the exploration drilling operation. All employees who are responsible for the execution of the plan would receive the appropriate training; 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 would be responsible for implementing the plan would ensure that it is integrated as part of the HSSE resources, training and awareness.

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.

Shell is a member of OSRL, which gives them ready access to this equipment.

3.2.8 UNDERTAKING BY THE APPLICANT

As required in terms of the MPRDA Regulations, Shell undertakes to comply with the provisions of the MPRDA and Regulations thereto (see Appendix 4).

3.3 EXPLORATION DRILLING

3.3.1 WELL LOCATION, PRE-DRILLING SITE SURVEY AND DRILLING PROGRAMME

As mentioned above, Shell is proposing to drill one or possibly two wells in the northern portion of the licence area. An area of interest has been defined for the well locations (see Figure 3.1), which is approximately 900 km^2 in extent with water depths ranging between 1 500 m and 2 100 m. The final well location will be based on a number of factors, including further analysis of the 3D seismic data, the geological target and seafloor location obstacles. The area of the proposed drill location would be analysed for hazards on a special high definition seismic dataset, which is a subset of the acquired 3D data. A Remotely Operated Vehicle (ROV) may be used to identify any seafloor obstacles.

The expected final depth of the well is between 2 700 m and 3 000 m below the seafloor and is expected to take in the order of three months to drill and complete. For safe operational reasons (i.e. optimal sea state and weather conditions), drilling is expected to take place in a future summer window period in the second (2017 - 2018) or third (2019 – 2020) exploration right renewal period.

Depending on the success of the first well, a second well may be drilled to establish the quantity and potential flow rate of the hydrocarbons. The “appraisal” well would be drilled in a location and to a depth determined by the results of the first well. It is anticipated that the appraisal well would be drilled at least one year after completion of the first well in order to allow sufficient time for data analysis and planning.

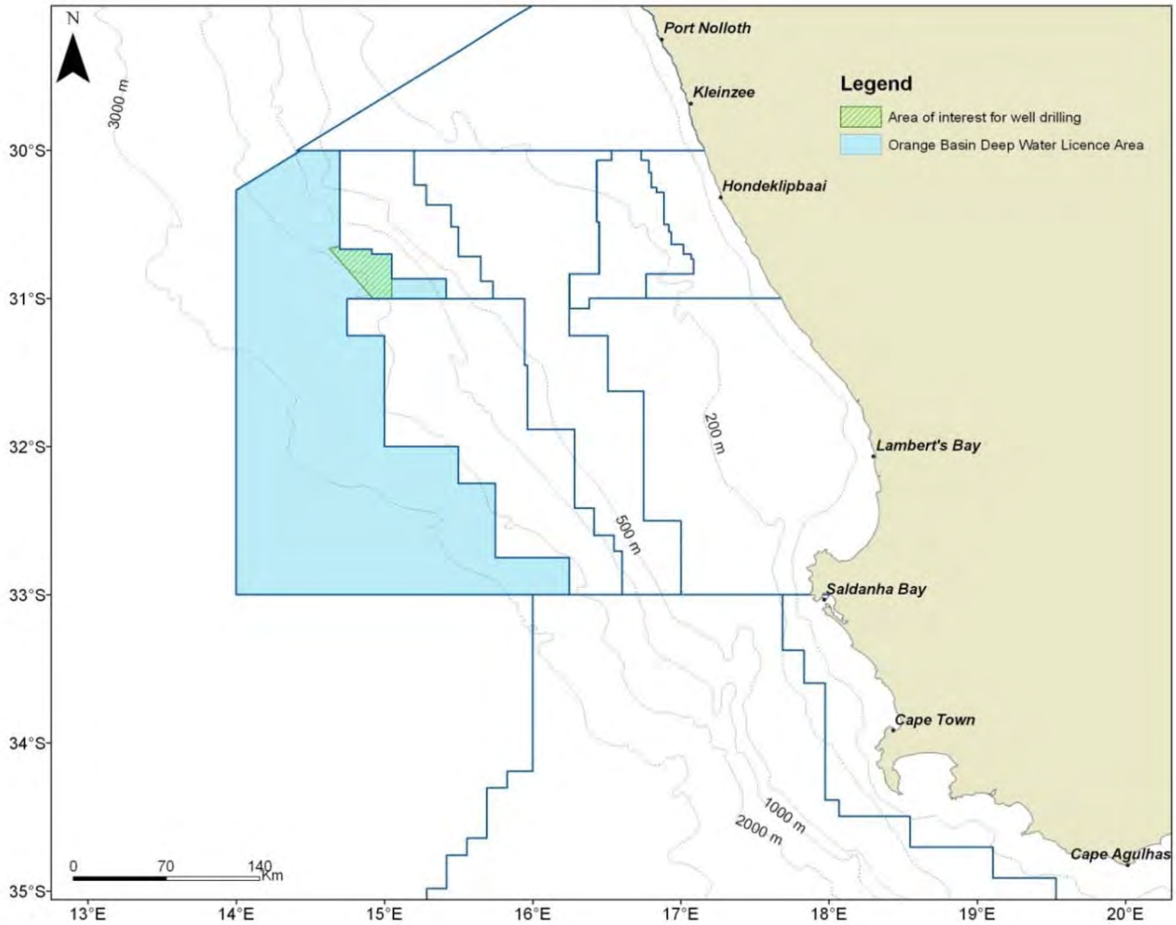


Figure 3.1: Locality of the area of interest for well drilling within the Orange Basin Deep Water Licence Area.

3.3.2 DRILLING UNIT OPTIONS

Various types of drilling technology can be used to drill an exploration well (e.g. barges, platform rigs, jack-up rigs, semi-submersible drilling units (rigs), drill ships and tension leg platform units) depending on, *inter alia*, the water depth and marine operating conditions experienced at the well site. Shell is currently considering two alternative vessel types for the proposed well drilling operation, these being either a semi-submersible drilling unit (see Figure 3.2a) or a drill-ship (see Figure 3.2b).

3.3.2.1 Semi-submersible drilling unit (rig)

A semi-submersible drilling unit 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. The semi-submersible drilling unit identified for the proposed project would be self-propelled and would not require a tow vessel or barge to transport it to the 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 deeper water where anchoring is not practical (such as in the area of interest), the drilling unit would be held in position by dynamic positioning thrusters. On-board computers are locked onto the well location and activate bow and stern thrusters to maintain the drilling unit on location with a high degree of precision.

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.

3.3.2.2 Drill ship

A drill-ship is essentially a self-sufficient ship with a drilling rig attached, normally located at the centre of the ship where drilling operations are conducted. The advantage of a drill ship over the majority of semi-submersible units is that the drill ship is independently mobile.

The drill ship identified for the proposed project would be held in position by dynamic positioning thrusters. The drill-ship, similar to the semi-submersible drilling unit, uses a riser pipe on compensated hydraulic tensioners to connect the vessel to the seabed and to act as a conduit through which drilling operations can proceed.

Figure 3.2a: Photograph of a semi-submersible drilling unit (Source: Shell).

Figure 3.2b: Photograph of a drill ship (Source: Shell).

3.3.2.3 Safety standards

The drilling unit would be classified for seaworthiness through an appropriate marine classification programme (e.g. American Bureau of Shipping). Shell would ensure safety standards using the following sources:

- International Convention for Safety of Life at Sea. IMO/SOLAS consolidated edition 1997 plus ISM Code. ISBN 92-801-1433-6;
- Loading of Lifeboats during Drills. Report Step Change in Safety Committee 2003;
- Service Vessel Marine Safety Guidelines. Report OGP 213 Applicable to the extent referenced in Article 5 of Section VI;
- International Convention on Standards of Training, Certification and Watch-keeping for Seafarers. Report IMO 2001 Edition;
- International Maritime Dangerous Goods Code (IMDG). Report IMO 2008 edition;
- Convention on the International Regulations for Preventing Collisions at Sea. (COLREGS). Report IMO Consolidated edition 2003;
- Guidelines for Vessels with Dynamic Positioning Systems. Report IMO Circular MSC 645;
- Code of Safe Practices for Merchant Seamen. Report UK Maritime and Coastguard Agency. Consolidated Edition 2009;
- International Code of Practice for Offshore Diving. Report IMCA D014 Rev 1, 2007; and
- Diving Recommended Practices. Report OGP 411, 2008.

3.3.2.4 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 (approximately 0.8 km^2 in extent) would be enforced around the drilling unit at all times. A support vessel equipped with appropriate radar and communications would be kept on 24-hour standby near the drilling unit and is 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.

3.3.3 DRILLING EQUIPMENT AND PROCEDURE

Shell 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.

3.3.3.1 Equipment

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

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 engine 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 m long with a diameter of 5 inch (13 cm). Drill collars are heavy thick pipes that are used at the bottom of the drill string to add weight on the bit. The drill pipe has threaded connections on each end that allow the pipe to be joined together to form longer sections as the hole gets deeper. The drilling bit is used to create the hole. Drilling 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 (lubricate and cool drill bit), remove the drilled rock fragments (cuttings), and to equalise pressure in the wellbore and prevent 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 hole, out of the nozzles in the drilling bit and returns them 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.

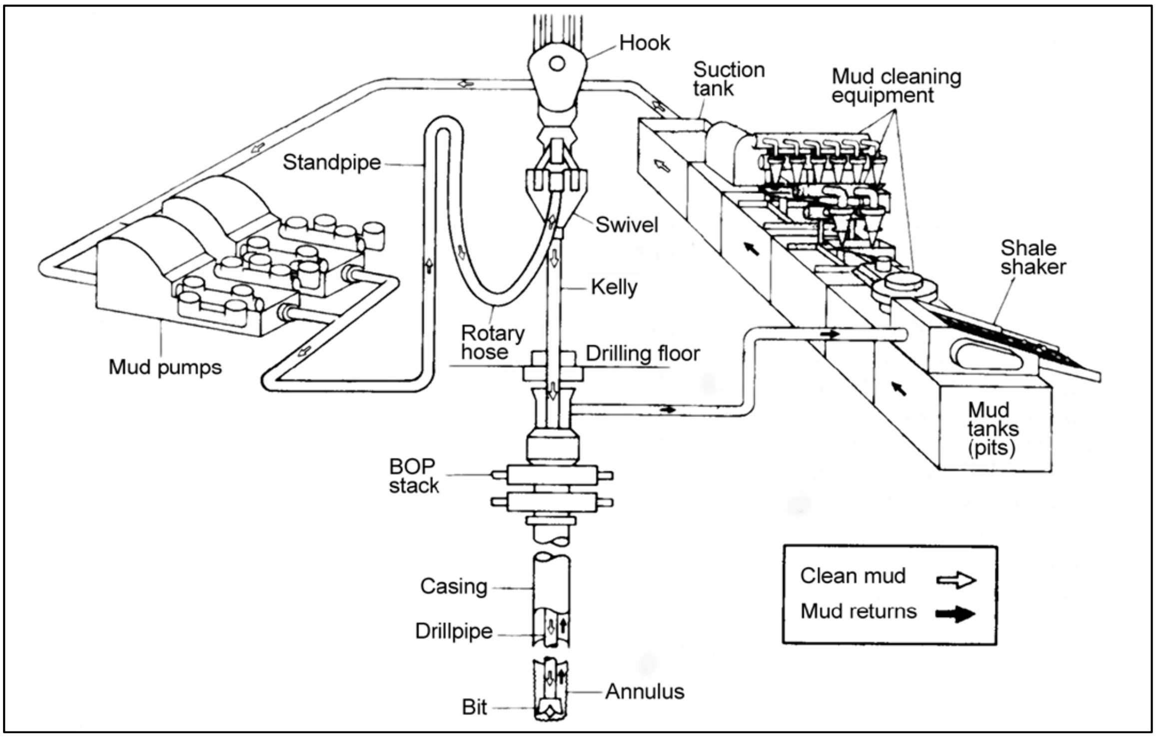


Figure 3.3: **Schematic of a typical fluid circulation system used on floating drilling units (from www.petrowiki.org).**

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 return mud temperature and changes in shale density 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 subsequently pressure and function tested on a regular basis.

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.

In addition to the above, advanced well intervention and capping equipment is available in Saldanha Bay for deployment in the event of a subsea well control incident. The 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. This unique piece of equipment is only stored in four international locations, namely Norway, Brazil, Singapore and South Africa, and is maintained ready for immediate mobilisation in the event of an incident.

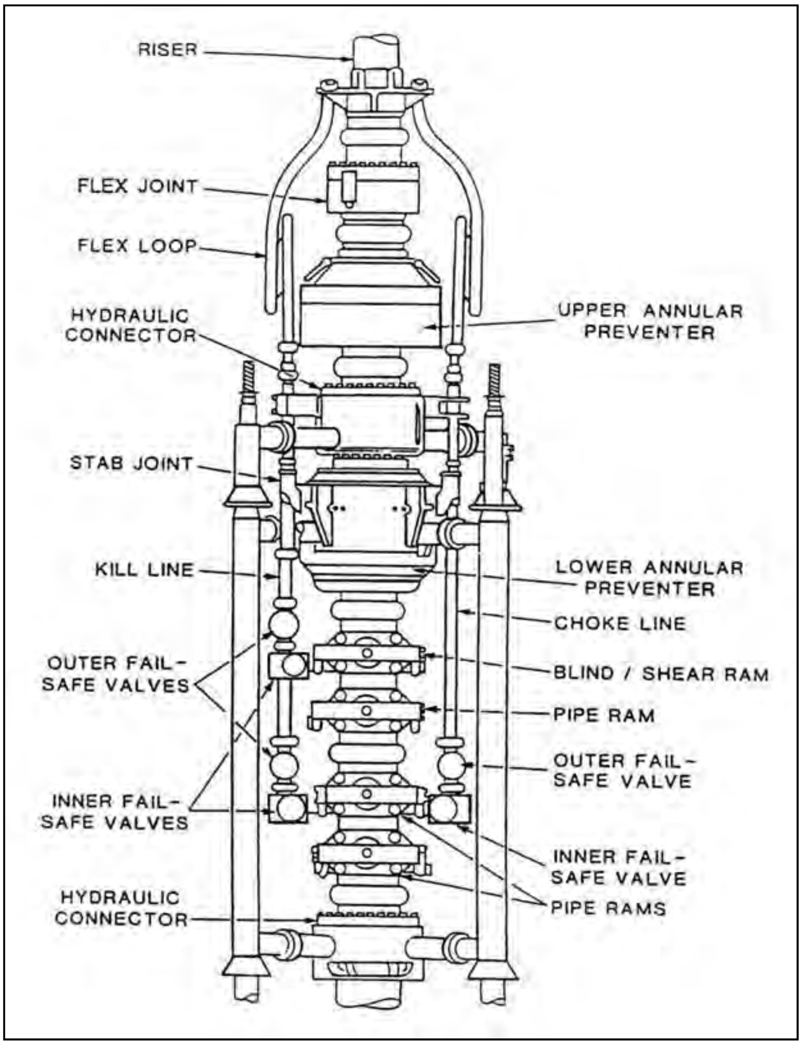


Figure 3.4: Schematic of a typical subsea BOP stack.

Power System

The drill unit would need power to operate the circulating, rotating and hoisting systems. This power is generated from diesel engines that power generators which transmit electricity to 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 (or liquid) mud and cement; mud chemicals; and cementing chemicals.

3.3.3.2 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 (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.

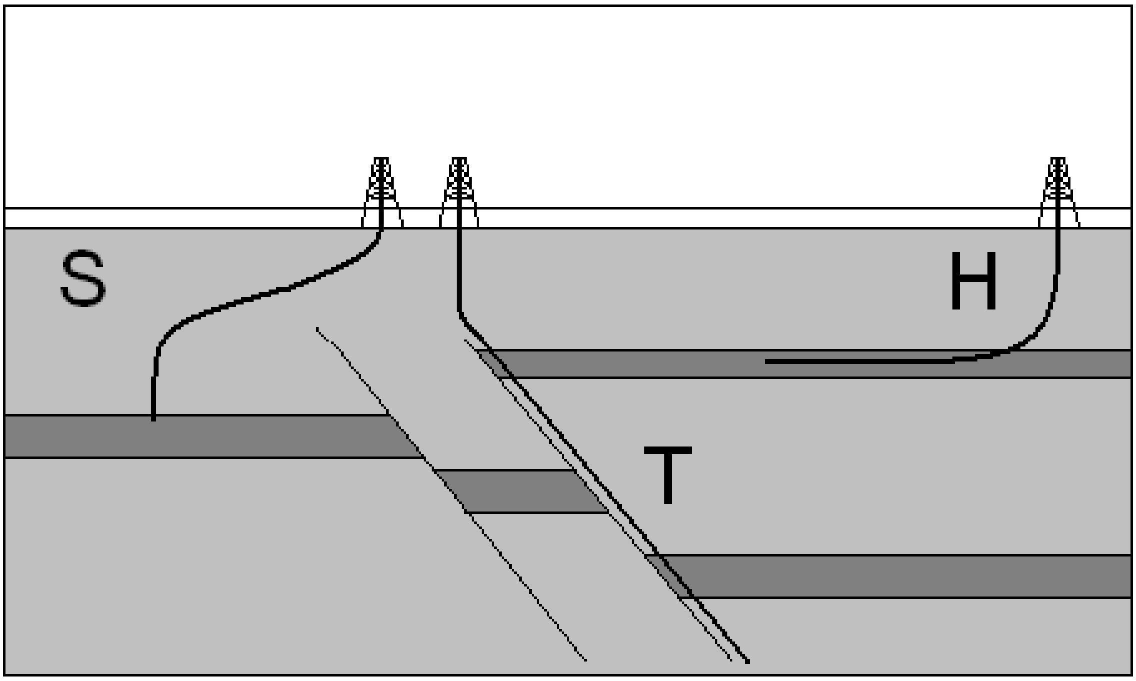


Figure 3.5: Tangent (T), Horizontal (H) or S shaped (S) drill trajectories.

3.3.3.3 Drilling sequence or stages

The well would be created by jetting or drilling a hole into the seafloor with a drill bit attached to a rotating drill string. After the hole is drilled, sections of steel pipe (or casings), slightly smaller in diameter, are placed in the hole and permanently cemented in place (cementing operations are described in Section 3.3.3.4). The hole diameter decreases with increasing depth as progressively 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 (see Figure 3.6). Shell is proposing to have four to nine sets of subsequently smaller hole sizes drilled inside one another, each cemented with casing.

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

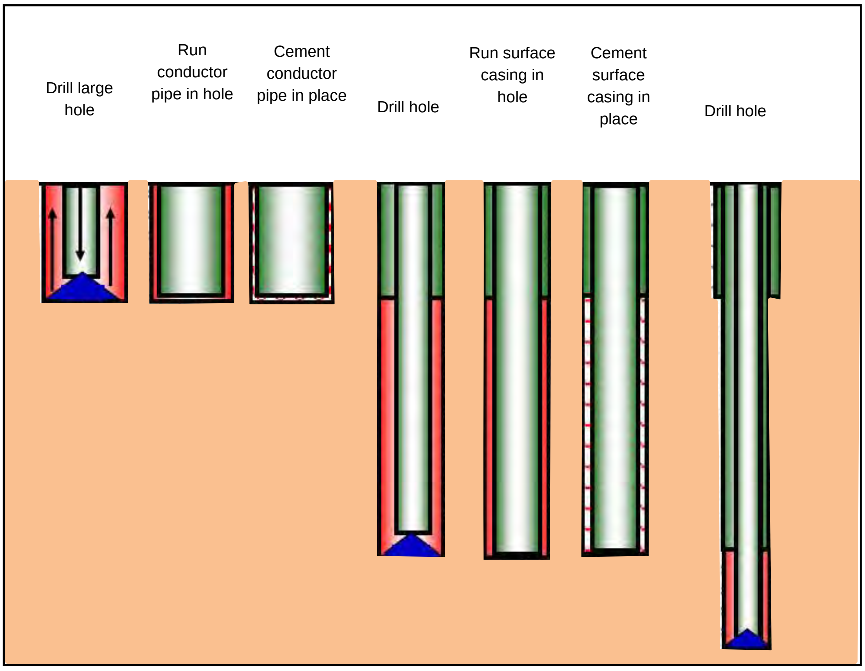


Figure 3.6: Simplified view of well drilling.

Initial (riserless) drilling stage

Sediments just below the seafloor are often very soft and loose, and to keep the well from caving in and to carry the weight of the wellhead a 36 inch (91 cm) diameter structural conductor pipe is jetted and / or drilled and cemented into place depending on the shallow seabed properties.

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.

When the conductor pipe and wellhead are at the correct depth the drill bit and drill string are released in order to commence with drilling operations. 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, and a conductor pipe is run and cemented in place. This hole would be approximately 70 m deep.

Below the conductor pipe, typically a 26 inch (66 cm) diameter hole would be drilled for a 20 inch (51 cm) surface casing, which would extend to approximately 1 000 m below the seabed. The surface casing would 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 accommodate the drilling riser and BOP.

These initial hole sections would be drilled using seawater (with viscous sweeps) and water-based mud (WBM) (see Section 3.3.4.1 below for a description of WBMs). All cuttings and WBM from this initial drilling stage would be discharged directly onto the seafloor adjacent to the wellbore.

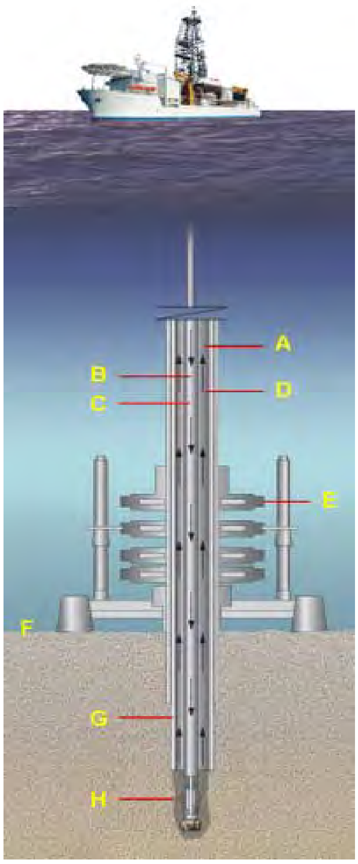
Risered drilling stage

Following the initial drilling stage described above, a BOP and marine riser (see Figure 3.7) is 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 and rotating the drill string. During the risered drilling stage when WBMs cannot provide the necessary characteristics, a low toxicity synthetic-based mud (SBM), which is a type of non-aqueous drilling fluid, 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 3.3.4.2 below for a description of SBMs).

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 3.3.3.5). The cuttings are also treated before being discharged overboard. Waste management is discussed further in Section 3.3.9.

The hole diameter decreases in steps with depth as progressively smaller diameter casings are inserted into the hole at various stages and cemented into place. As indicated previously, the expected final depth of the well is between 2 700 m and 3 000 m below the seafloor.



A	-	Riser
B	-	Drill pipe
C	-	Drilling fluid is pumped down through drill pipe
D	-	Drilling fluid and cuttings flow up between the drill pipe and the riser
E	-	Blow-out preventer
F	-	Seafloor
G	-	Casing
H	-	Open hole

Figure 3.7: Typical drilling operation (Source: http://www.planetseed.com).

3.3.3.4 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 hole wall.

To ensure effective cementing, an excess of cement is often used. Until the marine riser is set, this excess emerges out of the top of the well onto the seafloor. This cement does not set and is slowly dissolved into the seawater (see Section 3.3.8 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, 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.

3.3.3.5 Drilling fluid circulation system and solids control equipment

While drilling is in progress, 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.

3.3.3.6 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. It should be noted that several contingency strings are typically made available depending on the geological uncertainties of a well.

Table 3.3: Notional well design and cutting volumes.

Drill Section	Hole diameter (in)	Pipe diameter (in)	Depth of section (m)	Drilling duration (days)	Type of drilling fluid used	Volume of drilling fluid discharged	Volume of cuttings (m^3)	Drilling fluid and cuttings discharge location
Riserless drilling stage								
1	36	30	70	1	Seawater, viscous sweeps & WBM	69 m^3	46.0	Seabed
2	26	20	1 000	2		480 m^3	342.5	Seabed
Risered drilling stage								
3	17.25	13 5/8	800	4	SBM	223 mT	120.6	Surface
4	12.25	9 7/8	450	4		10 mT	34.2	Surface
5	8.5	-	400	8		2.5 mT	14.6	Surface

3.3.4 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.

3.3.4.1 Water-based muds

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 WBM is fresh and / or seawater, with the remaining 10 to 15 % of the volume being barite, potato or corn starch, 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. Potato or corn starch and other 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 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. Other minor additives may be used in special circumstances. A listing of the WBM 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 (adapted from CCA & CSIR, 1997).

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

3.3.4.2 Non-aqueous drilling fluids

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 WBM; 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 Swan *et al.* 1994).

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 disadvantage of using a NADF is that base fluid and other chemicals would result in an increase in toxicity. Drill cuttings that derive from the reservoir section contain residual base fluids, which cannot be removed easily. The trend in the industry has been to move towards low toxicity NADF (Group III NADF) that are biodegradable and will not persist in the long-term. There are three types of NADF that are used for offshore drilling and 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 SBM 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%. Shell is proposing to use a SBM during the risered drilling stage.

3.3.5 WELL EVALUATION

3.3.5.1 Mud logging

Evaluation of the petro-physical properties of the formations that have been penetrated is carried out routinely during the drilling operation. 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 when the formation pressure at the depth of the bit 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.

3.3.5.2 Downhole formation logging

Electrical logging and measurement while drilling logging 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. Radioactive sources may be used for certain types of data acquisition (see Section 3.3.5.3).

There are two fundamentally different uses of radioactive devices in wireline logging. In the first, the source is 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. The other usage is for calibrating wireline tools that measure either natural or induced radioactivity.

3.3.5.3 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.

3.3.5.4 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.

3.3.5.5 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 inches (length) x 1 inch (diameter) for the density tool and 7 inches (length) x 1.5 inches (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 (see Section 3.3.5.6). 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.

3.3.5.6 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.

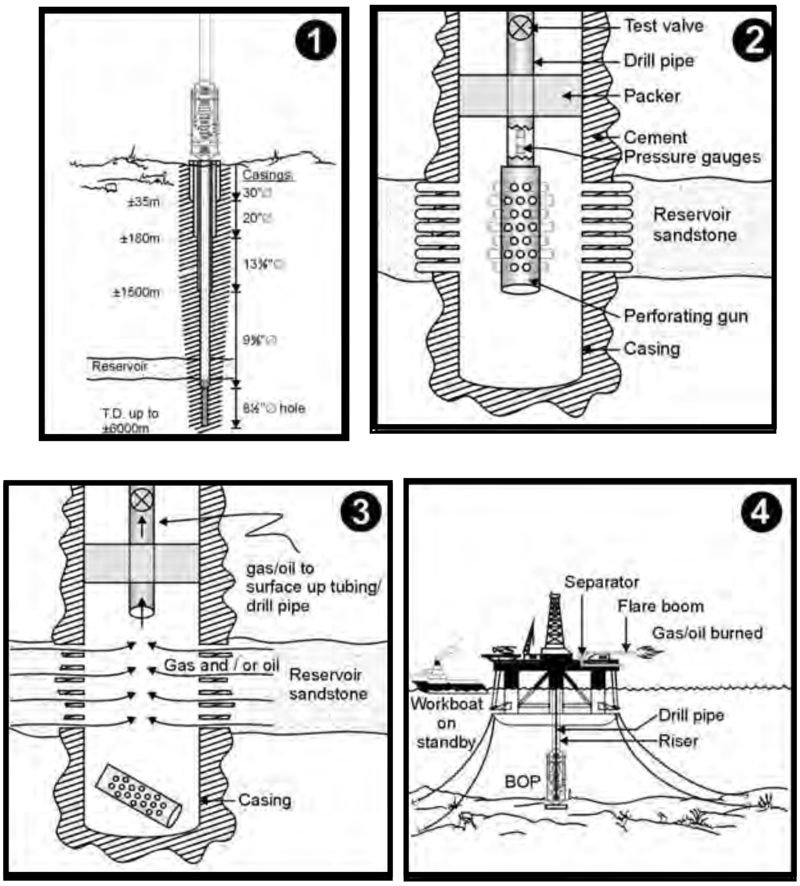
The engineers handling the devices would follow strict approved procedures. They would also wear personal monitoring devices to measure any unusual exposure. The equipment would be handled as little as possible by the engineers and returned immediately to the storage containers upon completion of the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

3.3.6 WELL (FLOW) TESTING

Should the exploration well encounter hydrocarbons, an "appraisal" well may be drilled, which would 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 3.8).

If flow testing is required, hydrocarbons would be burned 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 3.8: Diagrammatic presentation of a well test (drill stem test) (after Crowther Campbell & Associates and Centre for Marine Studies, 1999).

3.3.7 WELL SUSPENSION OR DECOMMISSIONING

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

(a) *Suspended well*: 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 (total 3 to 4 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 development project would be subject to a separate environmental authorisation process.

(b) *Decommission well*: If a well is unsuccessful, it would be decommissioned 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; and
- The wellhead (total 3 - 4 m high) would either remain on or be removed from the seafloor. At the proposed drilling depths, the preferred option would be to leave the wellhead on the seafloor.

The possible abandonment of wells may result in a decision by Shell to relinquish the licence area or a portion thereof, which would require the application for a closure certificate.

3.3.8 SEA- AND LAND-BASED SUPPORT

3.3.8.1 Onshore logistics base

An onshore logistics base would be located in either the Cape Town or Saldanha Bay harbour precincts. The shore base would provide 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 sea. The shore base would also be used for bunkering vessels.

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 and no additional onshore infrastructure is necessary for this project.

3.3.8.2 Support and supply vessels

The drilling unit will be supported by at least three vessels, including one standby and two supply vessels. The standby vessel would provide support for firefighting, oil containment / recovery, rescue and any equipment that may be required 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. The supply vessels would provide 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.

3.3.8.3 Crew transfers

It is anticipated that transportation of personnel to and from the drilling unit would most likely be provided by helicopter operations (e.g. Eurocopter EC225, S92 or AW 139/189) from the Kleinzee airport, which is located approximately 250 km from the proposed area of operation. Transportation to Kleinzee would be provided by fixed-wing flights (e.g. ATR42/72, B1900 or Embrear 120) from Cape Town, which is approximately 500 km to the south.

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 and fixed wing operations between Kleinzee and Cape Town would occur on an almost daily basis.

A second helicopter would be kept on standby for rescue operations. This helicopter is kept in a high state of readiness, i.e. fuelled, setting on pad, pilot and crew at base in Kleinzee.

3.3.9 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 waste management plan once the choice of drilling unit (either a semi-submersible drilling unit or drill ship) has been made.

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

3.3.9.1 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 = 0.32 tons/day;
- NO_2 = 0.6 tons/day; and
- CO = 0.015 tons/day.

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

Certain non-toxic combustible wastes (e.g. galley waste) may be incinerated on the drilling unit and support / supply vessels, creating smoke (particulate matter) emissions. If these wastes are not incinerated, they would either be treated and discharged overboard (see Section 3.3.9.2) or taken to shore for disposal (see Section 3.3.9.3).

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 2-5 days per test.

Other emissions to air

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

3.3.9.2 DISCHARGES TO SEA

Drilling cuttings and mud

Drill cuttings are the primary discharge during well drilling, which range in size from clay to coarse gravel. The composition of the rock particles reflects the types of sedimentary rocks penetrated by the drill bit. There is no standard practice for the treatment and disposal of drill cuttings applied around the world, including South Africa. However, 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 WBM would be discharged directly onto the seafloor. It is estimated that 300 to 400 m^3 of cuttings and approximately 550 m^3 of WBM would be discharged onto the seafloor for the initial 1 000 m of drilling (refer to Table 3.3). The cone created by the cuttings is predicted to be in the order of 80 cm thick close to the wellbore, thinning outwards to a thickness of 3 cm at a radius of 120 m. The total predicted area affected by the discharges would thus be in the order of 0.045 km^2. The cuttings themselves would deposit out within the cone of WBMs at average thicknesses of 15 to 25 cm.

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. The drill cuttings would be treated to reduce their oil content to 6.9% or less of dry cuttings weight using shakers, a centrifuge and a vertical cuttings dryer. The treatment of drill cuttings may include thermal treatment, which use high temperatures to destroy hydrocarbon-contaminated material and is the most efficient treatment for destroying organics, in order to reduce the residual oil content to as low as possible. Although most of the drilling fluids are mechanically separated from the drilling cuttings, the discharged cuttings would contain some residual SBM.

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 in the order of 150 to 200 m^3 for each well, and is dependent on the well design. These cuttings would contain approximately 235 mT of residual SBM. 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 (National Research Council 1985). The results of the cuttings dispersion modelling study (see Appendix 2.2) show that the large depths at the well site (1 800 m to 2 040 m) combined with the moderate to strong current speeds (at 200 m depth the median speed is 0.12 m/s and the maximum 0.56 m/s) and relatively low mass of cuttings discharged (1 042 t) result in the drill cuttings being spread over a large area area (between 25.9 and 29.8 km^2), with relatively low deposition thicknesses of less than 1 mm predicted for distances greater than about 150 m from the location of the well.

An alternative to the offshore disposal of SBM drill cuttings is onshore disposal. This alternative involves the processing of drill cuttings on the drilling unit, storage and transportation to shore for final disposal. Disposal options include (OGP 2003):

- Landfill disposal: Depending on the level of treatment and residual SBM, 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 SBMs.
- 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.

The advantages and disadvantageous of both offshore and onshore disposal methods discussed above are summarised in Table 3.6.

Table 3.6: 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 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.	- 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 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.	+ 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. - 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.

Economics	Operational	Environmental
	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	- 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.

Cement and cement additives

Typically, cement and cement additives are not discharged from drilling units. However, during the initial cementing operation, excess cement emerges 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 a maximum of 150% of the required cement volume would be pumped into the space between the casing and the borehole wall (annulus). Thus in the worst case scenario approximately 210 m^3 of cement would be discharged onto the seafloor. It should, however, be noted that if cement returns are observed on the seafloor pumping 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) must 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. Drainage from marine (weather) deck spaces would wash overboard.

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 grinded to particle sizes smaller than 25 mm and the vessel is located more than 3 nautical miles (nm) (approximately 5.5 km) from land. Disposal overboard without macerating can occur greater than 12 nm (approximately 22 km) from the coast. 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.

3.3.9.3 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 of at a licensed municipal landfill facility or at an alternative approved site. Operators would be required to 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 3.7 (note: these quantities should be viewed as estimates based on experience).

Bulk volumes of SBM remaining at the end of well drilling, would either be shipped for onshore treatment and disposal through an approved waste disposal company or re-used during the drilling of the subsequent well.

Table 3.7: Estimated volume/mass of wastes produced during a drilling operation of 100 days (adapted from CSIR 1999).

Waste Type	Description	Volume / Mass produced per day	Total Volume / Mass produced during drilling
Rubbish/trash	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 onshore landfill site.	200 kg	20 000 kg
Scrap metal	Surplus material would be re-used. Non-usable material (e.g. oiled machine cuttings) would be stored and disposed of on land.	50 kg	5 000 kg
Drums/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.	5-10 units	500 – 1 000 units
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.	0.1 m^3	10 m^3
Chemicals/hazardous water	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.	0.05 m^3	5 m^3

Waste Type	Description	Volume / Mass produced per day	Total Volume / Mass produced during drilling
Laboratory waste	Minor quantities of laboratory wastes would be generated (from water quality testing and retort analysis) that would be discharged to sea.	negligible	negligible
Infectious waste	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.	negligible	negligible
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.	10 kg	1 000 kg

3.3.10 SUMMARY OF PROJECT ALTERNATIVES

Table 3.8 provides a summary of the project alternatives that have been considered during the S&EIA.

Table 3.8: Summary of project alternatives.

No.	Alternatives	Description
1. Site / location alternatives		
1.1	Drill site	Shell is the operator and holder of an existing Exploration Right for the Orange Basin Deep Water Licence Area. Thus the proposed exploration well drilling would occur within this licence area. Shell is, however, proposing to limit the well drilling to the northern portion of the licence area (refer Section 3.3.1). 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 geological interest. Although the final well locations within the area of interest 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 interest.
1.2	Onshore logistics base	An onshore logistics base would be located in either the Cape Town or Saldanha Bay harbour precincts (refer to Section 3.3.8.1). The location of the onshore logistics base would ultimately be based on discussions with the relevant Ports Authority and where there is sufficient space to accommodate the proposed onshore logistics. This EIA assesses the potential impacts related to a logistics base located in either Cape Town or Saldanha Bay.

2. Activity alternatives		
2.1	Exploration well drilling	Shell has to date undertaken a 3D seismic survey over a portion of the licence area. 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, including ROV survey (refer to Section 3.3.1). This EIA assesses the potential impacts related well drilling and the associated pre-drilling activities.
3. Design alternatives		
3.1	Number of wells	Shell is proposing to drill one or possibly two wells in the area of interest. The drilling of the second well would be dependent on the success of the first well (refer to Section 3.3.1). This EIA assumes that both wells would be drilled.
3.2	Scheduling	Although Shell is proposing to drill in a future summer window period from November to April in the second (2017 - 2018) or third (2019 – 2020) exploration right renewal period (see Section 3.3.1), this EIA considers both a summer and winter drilling scenario.
4. Technology / process alternatives		
4.1	Drilling unit	Shell is currently considering two alternative drilling units, either a semi-submersible drilling vessel or a drill-ship (refer to Section 3.3.2). This EIA assesses the potential impacts related to both drilling unit options.
4.2	Drilling method	Two drilling methods can be employed on a drilling unit, namely rotary or downhole motor drilling (refer to Section 3.3.3.2). This EIA assesses the potential impacts related to both drilling methods.
4.3	Drilling fluid	Two types of drilling fluid would be used during drilling (refer to Section 3.3.4). During the initial riserless drilling stage WBM would be used. However, during the risered drilling stage, a low toxicity SBM would be used, when WBMs cannot provide the necessary characteristics (refer to Section 3.3.3.3). This EIA assesses the potential impacts related to both types of drilling fluids.
4.4	Drill cuttings disposal methods	Alternative drill cuttings disposal methods include: • Discharge to sea; and • Onshore disposal. These alternative methods, and their viability, are discussed in Section 3.3.9.2. 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.
4.5	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. During well abandonment the wellheads would either remain on or be removed from the seafloor. At the proposed drilling depths, the preferred option would be to leave the wellhead on the seafloor. This EIA assesses the potential impacts related to both abandonment alternatives.