1 Introduction

1.1 General

BP is committed to conducting its business in a manner which ensures that wells are designed, drilled, completed and maintained to high and consistent standards. BP's minimum drilling and well operations standards are defined in this policy document. BP will comply with all relevant laws and regulations, and will be sensitive to the balanced economic and environmental needs of the community. Sound engineering judgement and governmental regulations may require that operations be carried out to standards exceeding these policy statements.

To ensure that we meet these objectives, BP has adopted Getting HSE Right (GHSER), which defines our expectations for identifying and managing safety, health, environmental and operational risks. Business Units are responsible for ensuring that their management and control systems satisfy the 13 elements:

- Leadership and accountability
- Risk assessment and management
- People, training and behaviours
- Working with contractors and others
- Facilities design and construction
- Operation and maintenance
- Management of change
- Information and documentation
- Customers and products
- Community and stakeholder awareness
- Crisis and emergency preparedness

1.6 Exception to Policy Statements

Dispensations from the Drilling and Well Operations Policy shall only be considered in exceptional circumstances. Dispensations from policy may only be granted with the documented permission of the appropriate Business Unit Leader.

Dispensation should be requested by documenting the reasons why the dispensation is being sought and the implications contravention of the policy may have for BP. A dispensation shall be endorsed by the Head of Discipline, or their delegate and approved by the Business Unit Leader or their delegate; delegate signatories for these two positions must not be the same person. A dispensation may be requested and approved either for a single well or a number of wells in the same area. A dispensation shall not be assumed to apply to other situations unless a similar specific dispensation has been sought and approved. In critical situations, urgent verbal approval shall be backed up with written confirmation as soon as practicable.

The Policy Dispensation Process Flow Map is shown in Addendum 3. The format for policy dispensation includes the following items:

- Which policy is to be contravened
- The reason for the request
- The proposed departure from policy
- Additional risks so incurred and actions taken to minimise those risks
- The duration of the dispensation
- Documented approval

Note that there may be minor variations on the exact process due to local management structure and legislative environment. Clarification should be sought from the appropriate Head of Discipline if required.

An approved copy of the dispensation shall be retained and accessible within the Business Unit filing system. Electronic copies of all dispensations shall also be sent by the Business Unit Wells Manager to the Document Controller in EPT who will make such authorised policy dispensations globally available.

1.7 Compliance

Periodic audits shall be undertaken in order to ensure compliance with this policy. It is acceptable to incorporate this requirement within GHSER audits, other audits, and incident investigations.

1.8 Risk Management

All drilling and well operations shall have a risk management process which will include identification, analysis, response and control. A risk register and action tracking system shall be maintained. Risk acceptance criteria will be agreed between line and function.

The Business Unit Leader is accountable to ensure that any deviation from policy and established procedures, and all non-routine operations have undergone a formal risk assessment and that appropriate measures are taken to manage the risks prior to performing the operation.

It is the responsibility of all involved in drilling and well operations to utilise prudent judgement and seek guidance from line management when there is a concern that compliance with any policy statement increases the risk of an incident.

2 General

2.1 All drilling and well operations shall be planned and performed in compliance with applicable BP and Business Unit (BU) policies. These may include, but are not limited to, policies on health, safety and the environment; ethical conduct; employees; relationships; and control and finance.

2.2 All drilling and well operations shall be planned and performed in compliance with all applicable legislation and regulations. All applicable governmental permits shall be obtained (air quality, annular injection, drilling, etc) prior to the commencement of operations.

2.3 Priorities for safety when planning and undertaking drilling and well operations shall be, in order of importance:

(1) Personnel.

(2) Environment.

(3) The installation.

(4) Reservoir integrity.

(5) Well delivery.

2.4 Clear roles, responsibilities and accountabilities shall be established for all positions within the drilling and well operations organisations.

2.5 During well construction and maintenance activities, operations shall be conducted with one active barrier and one contingent barrier installed, to address the critical operational risks and contain the well.

During conventional drilling, completions and work-over activities the active barrier

will normally be a stable fluid column and the contingent barrier will be the blowout preventer (BOP) equipment. During underbalanced drilling, wireline, snubbing and coil tubing intervention activities, the active barrier will normally be a dynamic mechanical seal device and the contingent barrier will be the BOP or tree.

Systematic documented risk assessments and procedures are required to confirm the suitability of all contingent barriers other than BOPs and trees.

2.6 A well handover system formalising the transfer of responsibility for the control of a well between different organisational units, and that documents well conditions, shall be in place.

2.7 Transportation services in support of drilling and well operations shall be in accordance with the relevant BU and BP policies.

2.8 Detailed policy statements are contained elsewhere within this document for specific activities.

2.9 Detailed policy requirements for certain specialised non-routine activities, such as underbalanced drilling, snubbing and certain developing technologies are specifically not included in this policy. Such specialised non-routine activities shall only be considered in context with the policy, and shall not be undertaken without a thorough review of industry experience and best practice, full application of drilling and completion common process and project planning methodology, and a detailed EPT review of the planned operations and contingencies.

3 Health, Safety and the Environment

3.1 General Requirements

3.1.1 All staff and contractor personnel involved in the management and supervision of drilling and well operations for BP shall be knowledgeable of the Drilling and Well Operations Policy.

3.1.2 Everyone involved in BP's drilling and well operations at the wellsite shall be knowledgeable in, and comply with, the relevant safety management system which shall be defined as part of the contractual relationship between BP and the primary contractors. The relevant safety management system will incorporate, or be supplemented to address, the requirements of Getting HSE Right.

3.1.3 The contractors' safety management system shall incorporate a behaviour-based safety observation programme, task-based risk assessment, job safe analysis, toolbox talks and inspection and audit programmes, including appropriate action-tracking processes, covering all aspects of the rig equipment, systems and personnel training and competencies.

3.1.4 Designated company representatives at every wellsite, whether BP employees,

consultants or contractors' people employed in the capacity of company representatives, are accountable for the application of the Drilling and Well Operations Policy (BPA-D-001) and the relevant safety management system by all involved in the operation.

3.1.5 Designated company representatives are accountable for the execution of the approved drilling and well operations programmes in compliance with BP's health, safety and environmental (HSE) requirements.

3.1.6 Designated company representatives and key third-party service contractors will participate in the primary contractor's routine weekly safety meetings.

3.1.7 Designated company representatives will have an up-to-date HSE training record, curriculum vitae and documented personal safety objectives. Performance will be subject to regular formal review.

3.1.8 Incident response plans will be maintained at every wellsite, and emergency drills will be regularly conducted and reported. These plans should address the availability of a means of quickly evacuating injured personnel at all drilling and well operations sites.

3.1.9 Every Business Unit shall have standards in place addressing critical elements of drilling and well operations work including but not limited to standards of HSE leadership, HSE support, equipment, audit, safety critical systems and dropped objects prevention.

3.1.10 Specialist BP and contractor HSE resources will be available at the wellsite, as required, to effectively support and assure compliance with the safety management system and the environmental and waste management systems.

3.1.11 Specialist HSE resources will assist wellsite management by promoting HSE matters, advising and coaching the workforce, supporting the application of safety observation and risk assessment systems and maintaining the emergency response plans.

3.1.12 Specialist HSE resources will conduct regular audits of critical elements of the safety management system and actively participate in incident investigations.

3.1.13 All temporary and permanent changes to personnel, systems, procedures, programmes, safety critical data, equipment, facilities, materials or substances should be evaluated using the management of change process to ensure that HSE risks arising from the changes are assessed, managed, documented and remain at an acceptable level.

3.1.14 All vehicles involved in BP operations shall be fitted with seat belts and passengers shall wear them when the vehicle is in motion. Vehicles shall be properly maintained. Drivers shall be properly trained for the work. Mobile

phones shall not be used by the driver when the vehicle is in motion.

3.2 Safety Critical Software

3.2.1 Standards for safety critical software shall be maintained in every BU to address the key areas of implementation, fault tracking and the use of software. Such standards may originate at the stream or corporate level, however each BU shall maintain them and implement a management process to assure specifications, design, programme changes, documentation, testing and acceptance requirements are met.

3.2.2 In particular, safety critical software includes well control, directional collision avoidance, casing and tubing design and pore and fracture pressure prediction software. BUs shall be able to demonstrate that all well engineering software has been assessed for safety criticality prior to use.

3.2.3 Before the release and distribution of any new or revised safety critical software, a defined plan shall be in place addressing the business case and responsibilities for implementation. A system shall be in place to report, categorise, prioritise and resolve software bugs, as well as properly record and track critical faults.

3.2.4 BUs shall maintain a written life-of-field management plan for all safety critical data. Security and back-up processes shall be tested prior to implementation. Safety critical data shall only be created, edited or deleted in accordance with the management plan. The production and interpretation of all safety critical results shall be subject to an assurance process with an audit trail.

3.2.5 Contractors' safety critical software shall be managed by them to ensure appropriate standards are maintained for installation, operation and disaster recovery.

Contractors' safety critical software shall include such software as used in integrated pipe-handling systems, deepwater BOP control systems, ballast control systems and dynamic positioning systems.

3.3 Workplace Environment

3.3.1 Lighting systems shall be installed to provide illumination of all working areas to appropriate standards such as NIOSH and NEC. All safety egress paths and assembly areas shall be provided with emergency lighting at the level of 5 lux or better.

3.3.2 Noise levels and the duration of exposure to high noise levels shall be reduced to the lowest level reasonably practicable. Areas where noise levels are between 83 and 88 db(A) shall be identified and ear protection shall be used. Noise levels above 88 db(A) shall be managed by noise reduction at source, engineering controls, barriers, reduced exposure time as well as hearing protection.

3.3.3 Controls shall be in place to protect people who use high vibration tools on a regular or prolonged basis from damage to their hands and arms. All tools and equipment used at the wellsite shall be designed to minimise vibration levels to as low as reasonably practicable.

3.3.4 The engineering complexities of mechanised and automated systems shall be fully evaluated on the basis of risk assessment and managed through effective development and application of rigorous inspection, maintenance and operating procedures, and personnel competencies. New installations or upgrades shall have a systematic management of change process applied prior to commissioning.

3.3.5 Means shall exist to control exposure to airborne pollutants, such as dust, gases and vapours, and stressful thermal environments. These may include initial and repeat assessments of the workplace, engineering controls, administrative controls and personal protective equipment provided by the contractor.

3.3.6 Each BU shall have a standard and a control process in place to manage the transportation, storage and use of hazardous materials. The permit to work system shall be employed to control the handling of explosives and radioactive materials.

Personnel who may be exposed to hazardous materials shall be made aware of the hazards and provided with training to manage the risks of exposure, the limitations of and proper use of personal protective equipment, other precautions to be taken, emergency procedures to be followed and any required additional measures such as exposure monitoring.

3.3.7 Each wellsite shall have a waste management plan. The plan shall include storage facilities which provide containment, materials safety data sheets, contingency plans to respond to spills, control processes for transfer and disposal of waste, reporting protocols and a mechanism to ensure that personnel are properly trained.

3.4 Workplace Practices

3.4.1 All risks shall be managed to a level, which is as low as reasonably practicable. Risk management at the wellsite shall include the HSE issues arising from the selection of resources, the design and operation of working systems, the control and disposal of waste and the delivery of services.

3.4.2 Manriding is a safety critical activity. Routine manriding operations shall not be permitted on BP wellsites. Manriding shall only take place under the permit to work system after a full risk assessment has been conducted. Any permit for manriding operations shall be authorised by the senior wellsite contractor’s representative.

The work shall be performed under the direct control of the supervisor in charge of the area. All personnel conducting and supervising manriding operations shall be trained and assessed as competent for the work. All equipment used in manriding

operations shall incorporate appropriate safety features, be maintained as required by the manufacturer, be upgraded as required by manufacturers' product bulletins and be inspected prior to and after the work.

3.4.3 Excessive working hours leads to fatigue and impairment of mental alertness. Each BU shall have a work time standard in place which describes normal shift pattern rotation schedules, routine work periods, control process and contingency arrangements to deal with the occasional circumstances when the standard cannot be complied with.

Personnel engaged in BP's drilling and well operations shall not work in excess of 16 hours during a 24-hour period nor 28 days at the wellsite during a 42-day period without the written authority of the designated company representative. Travel arrangements and pre-arrival work time demands shall be considered as part of the work time control process.

3.4.4 Dropped objects prevention at the wellsite shall be a key element of the contractor's safety management system. Dropped objects standards and controls shall be in place at each facility to raise awareness, define secondary fastening requirements, specify inspection protocols and manage key risks such as control of tools and equipment taken aloft.

3.4.5 All lifting operations shall be planned and properly supervised consistent with the safety management system. A risk assessment or job safe analysis shall be conducted prior to each job and risks shall be eliminated or properly controlled. Detailed standards for lifting activities shall be in place and complied with at every wellsite. Crane operations shall only be conducted under the direct control of a banksman who shall not otherwise be involved in the lifting operation.

Fixed and mobile cranes and integrated protective systems shall be maintained in accordance with the manufacturer's recommendations. Lifting gear and lifting appliances shall be certified or successfully load tested and documented prior to use. Hand-spliced wires and slings are not permitted.

3.4.6 Primary drilling, workover and well operations contractors shall have a maintenance management system in place for their equipment. All safety critical equipment shall be included in the maintenance management system, including electrical equipment for use in hazardous areas, load-bearing, lifting, hoisting and pressure containing equipment. The system shall be rigorously applied and any overdue items shall be reported to contractors' and operators' senior site representatives on a regular basis.

Third-party equipment on hire at the wellsite for a period in excess of 3-months shall be subject to a formal system of maintenance management. Equipment on short-term hire at the wellsite shall be subject to formal maintenance and inspection checks prior to transport to the wellsite.

3.5 Audit and Assurance

3.5.1 HSE responsibilities and performance standards for BP and contractor supervisory and management staff at the wellsite shall be defined within the BU. Targets shall be set and monitored for each individual to support delivery of their personal contribution to the application of the safety management system.

3.5.2 The designated company representative shall manage delivery of an assurance process to confirm that the safety management system has been effectively applied at the worksite. The process shall assure the application of hazard identification and risk assessment process, competency assessment, job safety analyses, toolbox talks, operating procedures, permit to work system and the safety observation process.

3.5.3 All drilling and well operations safety and integrity management accidents, incidents and significant near misses will be investigated to determine the root causes and identify actions that will prevent a recurrence.

3.5.4 The primary contractor shall implement a system to internally assess the effectiveness of the application of the safety management system at the wellsite to maintain and improve HSE performance.

3.5.5 The BU shall put in place a system to externally assess the implementation of and compliance with the HSE management processes at the wellsite at commencement of the contract and on a periodic basis. The schedule of wellsite HSE assurance shall form part of the BU audit programme.

4 Hazardous Material, H_2S and Waste Management

4.1 All onshore and offshore operations shall be carried out in accordance with BP's Environmental Expectations.

4.2 Any drilled cuttings or waste fluids injection programme must be conducted in a manner that assures long-term containment of the material within the targeted formation.

4.3 Risk assessments shall be conducted on each and every well treatment activity where diesel, hazardous materials or chemicals are involved. Current Material Safety Data Sheets, or equivalent, shall be available at the wellsite.

4.4 No work shall be carried out which is liable to expose the wellsite operation to hydrogen sulphide (H_2S) until a risk assessment of the potential impact of H_2S is conducted. Where the risk of H_2S occurrence cannot be effectively assessed, short-term exposure shall be assumed and an appropriate level of detection shall be put in place.

4.5 The materials selection process for wells expected to contain H_2S shall comply with NACE standards wherever practicable. The BOP shall always be designed for an H_2S environment, ie 'H_2S trim'.

4.6 In areas where the presence of H_2S is anticipated, an H_2S contingency plan with appropriate operating and emergency procedures shall be available prior to commencing all drilling and well operations.

4.7 Personnel on BP operated installations that risk exposure to H_2S shall be properly protected from the effects of H_2S, and shall receive proper training in the hazards of H_2S and in the protective measures required.

4.8 Where there is a perceived risk of low level or naturally occurring radioactive material (LLRM or NORM) contamination, completion jewellery, tubing and samples retrieved from a well shall be checked for LLRM scale. An approved method of handling and disposal of LLRM scale shall be in place.

4.9 On installations where pyrophoric scale deposition is prevalent or anticipated, procedures for safe handling and disposal shall be prepared.

5 Planning, Materials and Services

5.1 All BUs will adopt Drilling and Completions Common Process (Drilling Value Assurance, Right Scoping, No Drilling Surprises and Technical Limit) as the standard methodology for well planning and execution.

5.2 All drilling and well operations shall have plans to cover emergency management, spill contingency and blowout response. These plans shall be specifically designed for application in the local environmental and operating conditions and be approved by the appropriate Business Unit Leader or delegate.

5.3 A well programme shall be in place and adhered to for all drilling and well operations. Well programmes shall have the appropriate level of approval within the Business Unit.

5.4 Any significant changes to a well programme shall be documented and approved via a formal process which includes those on the original approval list.

5.5 All drilling and workover units shall be subject to a formal rig audit to an appropriate level to ensure compliance with policy prior to commencement of contract.

5.6 Rig selection shall ensure that the operating capability of the rig is suitable for the environmental conditions that will prevail at the wellsite.

5.7 An investigation shall be made with the appropriate authorities or outside parties to identify and manage the risks associated with subsurface services or other hazards (pipelines, cables etc) either prior to selection and construction of the location onshore or mobilisation of a mobile rig onto an offshore location.

5.8 Simultaneous drilling, well operations, production and other operations shall

undergo a risk assessment to assess potential influence and overlap, to identify mitigating actions, and to develop specific procedures.

5.9 The well design should take account of the need to effectively and safely abandon the well at the end of well or field life. It should assure the long-term containment of any injected cuttings within the target interval.

5.10 All equipment, materials and services shall be fit for the purpose intended and in compliance with local legislative, BP, and industry (eg API, NACE, ANSI, ASME, ISO etc) standards and specifications as required.

5.11 All contractors engaged in drilling and well operations shall be capable of demonstrating technical, operational, quality, HSE and commercial integrity in respect of their organisation, logistics, planning, procurement, execution, and performance evaluation.

6 Preparing for Operations

6.1 Offshore

6.1.1 A shallow hazard assessment of proposed drilling locations shall be conducted and interpreted to determine the suitability of the location as a safe drilling site. This shall include a baseline seabed survey indicating physical conditions of the seabed. The appropriate techniques should be applied in keeping with the Offshore Site Investigation Manual (BPA-D-005).

6.1.2 For bottom supported drilling unit operations, a soils analysis and foundation risk assessment shall be carried out. The risk assessment shall consider the following as minimum criteria:

- Rig foundation
- Adjacent infrastructure
- Drilling and well control procedures
- Impact of shallow gas

6.1.3 A mooring analysis, a wellhead bending stress analysis and riser analysis shall be performed for floating drilling operations in the following circumstances:

- Prior to drilling with a new rig or in a new area
- Prior to using a wellhead or riser configuration not previously used in an area
- When the expected environmental conditions dictate this as being prudent

The wellhead bending stress analysis shall take account of wellhead stick-up. Limits on allowable wellhead angle commensurate with equipment in use shall be set. The analysis shall not be limited to drilling operations only but shall consider potential future use of the well for development operations if such use is considered a possibility.

6.1.4 A riser stress analysis and conductor analysis shall be performed for bottom supported operations taking into account all local environmental factors under the following circumstances:

- Prior to drilling in a new area
- Prior to using a mud line suspension system/conductor/riser/BOP configuration not previously used in an area

The bending stress analysis shall not be limited to drilling operations only but shall consider potential future use of the well for development operations should such use be considered a possibility.

6.1.5 At least one communication link shall be operating between the drilling unit and the operations office at all times.

6.1.6 An offshore installation shall have man overboard procedures and the means to effect such rescue during drilling and well operations.

6.1.7 All offshore installations shall have procedures in place for full evacuation in the event of an emergency.

6.1.8 Any vessel working in the support mode shall have direct communication with helicopters and the drilling unit.

6.1.9 Appropriate meteorological and oceanographic data pertaining to the area of the proposed well shall be available and taken into consideration prior to spud in, and for the duration of the well operation. Current sea state and weather forecasts shall be available both at the drilling rig and at the operations office whilst operations are in progress.

6.2 Onshore

6.2.1 A communication link shall be operating between the wellsite and the operations office at all times.

6.2.2 Access to the wellsite shall be restricted to authorised personnel only.

6.2.3 Accommodation camps shall be sited at as safe a distance as practicable from the wellbore taking the prevailing wind conditions into account.

6.2.4 Reliable and safe water supplies shall be provided prior to spud.

6.2.5 Appropriate assessments of shallow hazards of the proposed drilling location shall be conducted eg to identify any buried cables or pipelines and to determine the suitability of the site for drilling.

6.2.6 Fuel storage shall be at a safe distance from the wellbore and should include appropriate spill protection.

7 Operational Readiness

7.1 A pre-operational meeting with the rig contractor, service company personnel and relevant BP personnel shall be held at the wellsite or operations office prior to the commencement of drilling or well operations. This meeting shall focus on the HSE and operational performance expectations, operational objectives, differences from previous operations, hazards and contingencies.

7.2 The designated company representative shall be satisfied that the rig, equipment and site are in a safe operating condition, and that personnel are trained and competent, prior to commencing drilling and well operations.

7.3 An emergency evacuation drill, and for offshore locations, a man overboard drill, shall be carried out prior to commencement and at periodic intervals during a drilling or well operations campaign.

7.4 The final position of all spud locations shall be verified by a qualified and competent independent surveyor. The verified final position shall be added to a database of well position co-ordinates maintained by the BU.

7.5 On floating drilling units, there shall be a demonstrable standard for stability and ballast control. Stability and ballast control drills shall be conducted.

7.6 The rotary table elevation, relative to seabed and water depth at mean sea level for offshore drilling units, or the rotary table elevation relative to ground level for land drilling rigs, shall be determined and formally recorded and communicated.

7.7 On moored floating drilling units, the mooring system shall be pre-tensioned to a value, and for a time as agreed with the rig contractor.

7.8 When carrying out floating drilling and well operations from a dynamically-positioned unit:

- Well-specific operating guidelines and emergency disconnect contingency plans shall be in place prior to running the BOP stack

- Drive-off drills shall be held at intervals agreed by the rig contractor. Drills are to be reported

7.9 An independent leg jack-up drilling unit shall be pre-loaded to a value and for a time as agreed with the rig contractor prior to jacking up to operating elevation.

7.10 Where the risks of scouring cannot be discounted, facilities for subsea visual or manual inspection shall be available. The frequency of these inspections shall be mutually agreed with the rig contractor.

7.11 Completion of these requirements shall be formally documented in the relevant rig or operational logs.

8 Wellsite Equipment

8.1 All drilling and well intervention units shall be fitted with sufficient instrumentation to continuously monitor and record all data appropriate for conducting the operation in a safe and efficient manner.

8.2 For critical exploration and appraisal drilling operations, an independent means of monitoring wellbore conditions shall be used such as a mudlogging service.

8.3 A Crown-o-Matic or equivalent safety brake shall be installed on the drawworks and be operational at all times, and shall be subject to regular testing. Procedures shall be in place to manage routine and non-routine collision risks.

8.4 All drillpipes shall have either:

- No hard banding
- Hardfacing of casing-friendly wear resistant alloy overlays to a standard, finish and type approved by EPT

8.5 Drillpipe and bottomhole assembly components shall be inspected and graded in accordance with requirements laid down by the BU. These inspections should be commensurate with operating conditions. API RP7G is the industry standard for drillstring design, operating limits and classification. Use of proprietary guidelines for inspection such as DS1 may be appropriate provided that results remain in compliance with API RP7G.

8.6 Dedicated and correctly rated equipment shall be used for riser handling on all floating drilling units. Where an alternative non-dedicated component is to be used, it shall be inspected to an appropriate level immediately prior to use.

8.7 As a minimum, hazardous area designations shall reflect API RP 500B, or applicable regulations, whichever is the more stringent.

8.8 All equipment shall be classed and certified as suitable for any hazardous areas in which it may be operated.

8.9 All pressure vessels, and pumps shall be fitted with an independent pressure relief mechanism. Relief lines shall be designed for the potential pressures and flowrates and have an adequate restraining mechanism.

8.10 When conducting offshore drilling and well operations an emergency powered or diesel black start firefighting pump capable of supporting two fire hoses or one foam branch shall be available. The emergency power arrangements shall also be set up to enable operation of the cement unit, the BOP control panel and associated critical services for well control contingency purposes.

8.11 Eyewash stations or safety (drench) showers shall be provided at the:

- Mud mixing hoppers
- Mud pump area
- Rig floor
- Cement unit
- Any acid or hazardous chemical mixing or pumping area

8.12 A system shall be in place to ensure that all drilling and well operations equipment that requires certification has the correct certification and that it is valid.

8.13 All items of BP owned, contractor owned and third party owned lifting and load bearing, pressure containing and safety critical equipment shall be covered by a maintenance management system, that allows safe operation and technical integrity for the intended operating envelope.

8.14 Only replacement parts that meet or exceed the original equipment manufacturer's design, specifications and manufacture shall be used in safety critical equipment (except for well control equipment, refer to Section 9 Paragraph 9.2.2).

8.15 All high-pressure pipework assemblies equipped with hammerlock unions shall be manufactured to a recognised specification and be subjected to a routine inspection, testing and maintenance programme.

9 Well Control Equipment

9.1 Introduction

9.1.1 These policies apply to all well control equipment used in drilling and well operations. They represent the minimum requirements that, based on sound engineering judgement, may need to be exceeded to accommodate specific well circumstances or location conditions.

9.2 Modifications, Changes and Repairs

9.2.1 All modifications, design changes or weld repairs to well control equipment shall comply with appropriate API Specifications or government regulations, whichever is more stringent.

9.2.2 Only original equipment manufacturers' spares shall be used for BOP replacement parts.

9.2.3 Ring joint gaskets with metal-to-metal sealing are preferred, but suitably qualified alternatives with elastomer backup are permissible where a risk assessment reveals no life-of-well integrity issues.

9.3 Diverter Equipment

9.3.1 The diverter control system shall be sequenced to ensure that a side outlet is open and the shaleshaker valve is closed prior to the diverter element closing.

9.3.2 On closing the diverter element, flow shall be confined to the designated diverter lines only.

9.3.3 In cases where rupture discs exist, the diverter line valve, if installed, shall remain locked open.

9.3.4 The diverter control system shall operate all necessary valves and close the diverter element within 30 seconds for systems with a nominal bore of 20in or less. For systems of greater than 20in bore, the operating time shall not exceed 45 seconds.

9.3.5 The diverter control panel shall be located adjacent to the driller's position, with a second control panel located in a designated safe area.

9.3.6 Diverter lines shall be designed or audited to API RP-64. Diverter lines on offshore units shall have a minimum internal diameter of 12in. Diverter lines for onshore drilling operations shall have a minimum internal diameter of 8in. All diverter line valves shall be full opening.

9.3.7 On installation, and prior to drilling hole sections where diverting is the planned means of well control, the diverter system shall be function tested and, subject to local environmental constraints, the diverter lines flushed. Thereafter the diverter system shall be function tested at least once each seven days. Diverter lines with rupture discs shall be inspected only.

9.3.8 Offshore rigs shall have dual diverter line systems.

9.3.9 On land wells, where combustible liquids may flow from the well, the diverter vent line shall terminate in a safe location.

9.4 Configuration: Surface Drilling, Completion and Workover BOP Stacks

9.4.1 As arranged from top to bottom, the minimum BOP configuration required for wells where a wellhead pressure up to and including 5000psi is possible, is:

- One annular preventer
- Two ram type preventers, one of which must be blind or shear

9.4.2 As arranged from top to bottom, the minimum BOP configuration required for wells where a wellhead pressure of over 5000psi is possible, is:

- One annular preventer
- Two ram type preventers, one of which must be blind or shear
- Outlets for choke and kill lines
- One pipe ram

9.4.3 For offshore operations sealing shear rams shall be installed.

9.4.4 All surface stacks shall incorporate at least one choke line and one kill line which enter the stack above the lowermost set of pipe rams.

9.4.5 Kill and choke lines, installed below the lowermost set of rams, shall be used for pressure testing or monitoring the well only.

9.4.6 The BOP stack shall contain a pipe ram that can close on every size of drillpipe, and tubing that comprises a significant length of the total string. Where tubular accessories (eg cables, clamps, screens etc) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies are to be in place to mitigate this risk.

9.4.7 Where three rams are fitted, the lowermost ram shall be preserved as a master valve and shall only be used to close in the well when no other ram is available for this purpose.

9.4.8 Dual, full-opening valves shall be provided on each choke and kill line for all stacks. The outer valve on the choke line shall be remotely activated. The outer valve on the kill line shall either be a remotely operated or a non-return valve.

9.4.9 Each ram type preventer shall have a functional ram locking device available onsite.

9.4.10 Both the standpipe manifold and cement manifold shall have double valve isolation from the kill line.

9.5 Configuration: Subsea Drilling, Completion and Workover BOP Stacks

9.5.1 As arranged from top to bottom, the minimum BOP configuration required for wells where a wellhead pressure up to and including 5000psi is possible, is:

- One annular preventer that is retrievable on lower marine riser package
- Three ram type preventers

There shall be a minimum of one kill line and one choke line connected to the BOP stack.

9.5.2 As arranged from top to bottom, the minimum BOP required for wells where a wellhead pressure of over 5000psi is possible, is:

- Two annular preventers, one of which is retrievable on lower marine riser package
- Four ram type preventers

There shall be a minimum of three inlets/outlets. Where there are four inlets/outlets, one shall be below the lowermost ram. Where there are three inlets/outlets, the single kill or choke line connection shall not be below the lowermost ram.

9.5.3 A sealing shear ram is required. The limitations of its shearing capacity should be known and understood, and a documented risk assessment should be in place to address any such limitations.

9.5.4 Kill and choke lines installed below the lowermost set of rams shall be used for pressure testing and monitoring the well only.

9.5.5 The BOP stack shall contain a pipe ram that can close on every size of drillpipe and tubing that comprises a significant length of the total string. Where tubular accessories (eg cables, clamps, screens etc) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies are to be in place to mitigate this risk.

9.5.6 The lowermost ram shall be preserved as a master valve and shall only be used to close in the well when no other ram is available for this purpose.

9.5.7 Ram type preventers shall have remotely operated ram lock systems fitted.

9.5.8 Both the standpipe manifold and cement manifold shall have double valve isolation from the kill line.

9.6 Other Well Control Equipment

9.6.1 A full-open safety valve shall be available and ready to install on the drillfloor at

all times. Crossovers shall be available such that the full-open safety valve can be attached to any string of pipe to be run in the well. Contingencies for circulating casing at any time shall also be available.

9.6.2 On surface wellheads during the drilling and well operations, a minimum of one casing spool side outlet to the casing string being drilled through or worked in shall be equipped with double full-opening valves, companion flange and needle valve to allow installation of a pressure gauge.

The principle of two full-opening valves is based upon using one as a master valve and one as a working valve when conducting pumping and circulating through the outlet.

The other side outlet(s) to this wellhead shall have either a valve removal (VR) plug or a full-opening valve. Either should be equipped with a companion flange and needle valve installed to enable the installation of additional valves, if necessary.

9.6.3 On surface wellheads during the drilling and well operations, a minimum of one casing spool side outlet of any casing annulus shall be equipped with a single full-opening valve, companion flange and needle valve to allow installation of a pressure gauge.

This single valve shall not be used to pump or flow through.

The other side outlet(s) to this wellhead shall have either a VR plug or a full-opening valve. Either should be equipped with a companion flange and needle valve installed to enable the installation of additional valves, if necessary.

9.6.4 All drilling units shall have a BOP control system located away from the rig floor area, in an accessible and protected location, with two independent and operational hydraulic charging systems.

9.6.5 There shall be at least two operational control panels for all BOP functions one of which shall be located adjacent to the driller’s position, with a second located in a designated safe area. The primary hydraulic control unit, which may be considered as the second control panel, will be located in a safe place.

9.6.6 The working fluid volume of BOP accumulators and the BOP closing times shall comply with API RP 53.

9.6.7 Choke manifolds shall incorporate a minimum of two adjustable chokes, one of which is preferred to be capable of remote operation.

9.6.8 Choke lines, valves and the inlet side of manifolds shall be sized 3in minimum internal diameter for subsea stacks and 2in minimum internal diameter for surface

stacks.

9.6.9 All discharge lines from permanent and temporary choke manifolds shall be properly secured.

9.6.10 There shall be calibrated choke manifold and standpipe gauges in close proximity to the choke controls.

9.6.11 Gauges suitable for accurately reading low drillpipe and casing pressures shall be available along with a suitable manifold arrangement.

9.6.12 A pressure gauge shall be mounted on the standpipe and choke manifolds. The gauge shall be of the same nominal pressure rating as the equipment on which it is installed.

9.6.13 For conventional rotary drilling and workover operations, a means of accurately monitoring fill-up and displacement volumes shall be available to the driller. It is preferred that a low volume trip tank is installed and equipped with a volume indicator easily read from the driller's position.

9.6.14 In rotary operations it shall be possible at all times to disconnect from the string leaving a manually operated, full opening valve on the string.

9.6.15 Prior to installing the BOP, a non-ported float valve shall be run in the drillstring bottomhole assembly (BHA) as a protection against shallow gas influx up the drillstring.

9.6.16 Connections rated 3000psi and above shall not be threaded except as permitted in API RP53.

9.7 Configuration: Wireline Pressure Control Equipment

9.7.1 This section applies to well service operations performed with slickline, braided line or conductor line with an xmas tree in service. As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5000psi is possible, is:

- High-pressure pack-off, stripper, or greasehead with linewiper, stripper or pack-off
- Lubricator requirements as defined in Section 19
- One set of wireline valve rams for slickline, or dual wireline valve rams for braided and conductor line, suitable or sized for each diameter wire passing through the wireline valve
- Pump-in sub or other means to kill well while wireline valves are closed

9.7.2 Where a surface pressure of over 5000psi is possible, the following additional equipment is required:

- A second wireline valve ram
- And, if the tree valve cannot cut and seal, a shear-seal BOP

9.8 Configuration: Coiled Tubing Pressure Control Equipment

9.8.1 This paragraph applies to well service operations with a coiled tubing service unit with an xmas tree in service. As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5000psi is possible, is:

- One high-pressure pack-off, stripper or annular type preventer
- Lubricator requirements as defined in Section 19
- Hydraulically-operated (with manual backup) triple, quad or combination BOPs with equivalent capacity and sized for the tubing to be used

Hydraulic BOPs shall have the following top down configuration:

- Blind rams
- Shear rams
- Slip rams
- Pipe rams

9.8.2 Where a surface pressure of over 5000psi is possible:

- Combi BOPs shall not be used
- A riser evaluation shall be undertaken to ensure that the combined mechanical and pressure loadings are within the operating limits of the supplied equipment

10 Drilling Practices

10.1 A detailed ongoing assessment of the pore and fracture pressures shall be conducted during drilling operations on exploration and appraisal wells.

10.2 Formation leak-off or integrity tests shall be performed after drilling out each casing or liner shoe prior to drilling the new hole section, except for conductors. Corrective measures shall be performed if the open hole pressure integrity fails to

meet predetermined standards.

This requirement for formation leak-off or integrity test may be relaxed after a documented risk assessment, conditional upon indications of a good cement job, under the following conditions:

- Casing string is not a pressure containment string
- Exposed formations are very vulnerable to damage and such damage will subsequently increase the level of risk
- Casing shoe is set by design within the target reservoir
- Where air or underbalanced fluids are the primary circulating medium

10.3 For conventional drilling operations, the kick tolerance of the weakest known point of the hole section being drilled shall be updated continuously while drilling and reported on all BP daily drilling reports. This requirement for kick tolerance calculation applies to drilling of all hole sections after the first pressure containment string has been set.

Kick tolerance is defined as the maximum volume of kick influx that can be circulated out of the well without breaking down the formation at the open hole weak point. Kick tolerances are to be calculated as described in the Well Control Manual (BPA-D-002).

On all wells the design kick tolerance shall be greater than 25bbl based on maximum anticipated pore pressure and planned mud weights.

At all stages during the drilling of a well it shall be assured that assumptions made during the casing design are not violated.

10.4 All drilling breaks shall be flow-checked and reported.

10.5 For conventional rotary drilling operations, as a minimum flowchecks shall be performed whilst tripping out of hole:

- When pulling off bottom
- After pulling into the casing shoe
- Before the BHA enters the BOP stack

10.6 For conventional rotary drilling operations, trip sheets shall be filled out by the driller on every trip in and out of the hole. Any deviation from expected hole fill up volumes shall be investigated.

10.7 Choke line pressure losses shall be determined and recorded on floating drilling units:

- Prior to drilling out casing
- On any significant change in mud weight

10.8 A full dimensional check of all drilling, testing or completion tools shall be carried out and the results recorded prior to running tools in the hole. The record shall be available at the drilling site.

10.9 Bore protectors or wear bushings shall be installed in the wellhead during all rotary drilling operations. The wellhead design shall take this into account.

10.10 All coring toolstrings shall be equipped with a circulating sub above the core barrel.

10.11 When coring high pressure high temperature (HPHT) wells, the inner barrel will have provision for venting trapped pressure at regular intervals and a pump-out sub shall be positioned above the core barrel.

10.12 A coring task risk assessment shall be conducted to identify hazards and mitigating procedures to cover handling procedures, H_2S potential, wellbore fluids and cutting tools as a minimum.

11 Wellbore Trajectory Control

11.1 Survey programmes for all wellbores shall be designed such that the wellbore location is known with sufficient accuracy to:

- Meet local government regulations
- Penetrate the geological target(s) set in the well's objectives
- Minimise the risk of intersection with any nearby wellbore
- Drill a relief well
- Avoid location of shallow hazards

11.2 Survey programmes shall be executed by the contractor in accordance with a predefined quality assurance procedure. This procedure shall be available at the wellsite.

11.3 The survey programme shall be executed in accordance with its design. Where operational problems occur, any modifications to the programme shall be shown to fulfil the same requirements as the original design.

11.4 A database of well trajectories (planned and actual) and all project data (slots, targets, locations and projections) shall be maintained. This safety critical database shall be the subject of a written plan that describes how it shall be managed throughout the life of the field.

11.5 On multi-well locations an anti-collision scan shall be performed on the planned well trajectory and, where necessary, a close approach monitoring plan will be written to describe the special procedures required during execution.

11.6 Procedures for assessing tolerable risks of collision, defining minimum well separations and ensuring compliance with such criteria while drilling should be referenced to the Directional Survey Handbook (BPA-D-004).

11.7 Directional drilling and surveying procedures used by contractors working on behalf of BP during the planning, execution and evaluation of wells shall be subject to a formal assessment to demonstrate technical integrity.

12 Drilling Fluids

12.1 Every well shall have a drilling fluids programme. The programme shall, as a minimum, provide information on mud types, and property ranges for mud weight, rheology and filtration control. Contingency plans as a minimum should be included for minor and serious lost circulation, differentially stuck pipe and wellbore instability.

12.2 Every well shall have a programme that covers the processes to be followed to handle and dispose of anticipated waste drilled cuttings, waste mud, and any fluids contaminated by the drilling or well operation process.

12.3 Basic API testing of the active drilling fluids system shall be conducted and reported at least once daily during drilling operations.

12.4 A minimum quantity of weighting material shall be readily available onsite during all phases of the well, to weigh up the circulating volume by 1 pound per gallon. Individual programmes should define acceptable stock levels based on the nature of the operation and the supply logistics.

13 Casing and Tubing

13.1 A casing and tubing design shall be performed for all wells and should incorporate foreseeable life-of-well requirements. Where wells are to be produced, tested, fracced or injected, a design check shall be performed for the as-drilled configuration, unless as part of the BU assurance process a previous existing design is demonstrated to be adequate.

13.2 Design should follow the recommendations in the Casing Design Manual (BPA-D-003) and provide justification for deviation from its recommendations.

13.3 Rigorous application of the standards contained within the Casing Design Manual is required for the casing programme basis of design. The basis of design will address parameters within which it is acceptable to plan further wells in a programme, campaign or area without further detailed design. When these parameters are exceeded, a detailed reassessment of the design is required.

Casing design shall be performed using the BP approved casing design applications and methods. Exceptions to this on technical grounds shall be subject to EPT review. Design data shall be retained.

13.4 Casing designs shall be subject to assurance review as a minimum as follows:

Well Category		Review Level
(1)	All wells	Within BU
(2)	SITHP >10,000psi or SBHT >300°F, or H_2S, or water depth > 1000ft	BU plus independent review
(3)	Well using material with specified yield >125ksi, or sealed or potentially sealed annuli, or reduced well control loading	BU plus EPT review

13.5 Casing and liner setting depths shall be selected to provide a sufficient safety margin between formation fracture pressure and well control or casing cementing operations. Limitations on allowable well control operations shall be detailed in the design.

13.6 All casing and liner shall be designed to withstand reasonably foreseeable well control burst loadings.

The starting point for well control burst loading shall be gas to surface from casing shoe, or lower open hole fracture pressure. Casing designs using lesser well control loadings shall be subject to review as in Well Category 3 above. Casing designs shall include definition of the well control scenarios they accommodate and their rationale based on subsurface information, local experience and operational well control capabilities.

13.7 All production casing and liners shall be designed for burst, to withstand the

maximum pressure resulting from a tubing leak at the wellhead applied over the packer fluid.

13.8 Only seamless grades of tubulars are acceptable for casing and tubing which may be exposed to H_2S or NACE defined sour environments.

13.9 Casing and tubing shall be manufactured, inspected and tested in accordance with API or ISO, and BP specifications; where requirements differ the BP specification shall be used.

13.10 Field welding of tubulars is permitted on API 5L grade line pipe and K55 tubulars, and shall conform to the guidelines laid out in API RP 5CI Section 9. Welding operations on other grade pipe will require specific qualifications and procedures.

13.11 All casing, tubing and handling strings shall be drifted as close to the point of use as necessary to detect any handling damage that could impact well operations.

13.12 At least one downhole float valve shall be included on any casing string run through a hydrocarbon-bearing formation.

13.13 Differential fill float equipment shall not be used on casing strings which are to be run through potential hydrocarbon-bearing zones.

13.14 Auto fill float equipment shall be tripped prior to running through any hydrocarbon bearing zone.

14 Cementing

14.1 Every well shall have a cementing programme.

14.2 Prior to cementing operations, representative samples of cement, additives and mixing water shall be taken for testing of each programmed cement slurry, in accordance with API as minimum specifications.

14.3 In locations where supplies are intermittent, a minimum supply of cement and cement additives shall be kept on the drilling site. The volumes shall be at least enough to set appropriate isolation plugs in the current hole size.

14.4 The top of cement for casing and liner jobs shall be determined and recorded to an appropriate level of accuracy. In all cases the volumes pumped, volume returned and the differential pressure shall be measured and recorded.

15 Well Control Training

15.1 All BP drilling and well operations personnel, and personnel acting on behalf of

BP, who are directly involved in the planning and execution of BP drilling and well operations covered by this policy document shall have a valid and recognised well control certificate.

15.2 All drilling and well operations contractor toolpushers, subsea engineers, drillers, assistant drillers and others who may take control of the well activities, involved in BP operations covered by this policy document, shall have a valid and recognised well control certificate.

15.3 Well control certificates shall be renewed at periods not exceeding 24 months.

16 Well Control Practices

16.1 A BOP shall be installed for drilling operations below the surface casing shoe.

16.2 The BOP stack and wellhead in place at any point during the course of the well shall be of sufficient working pressure and temperature rating to contain the maximum anticipated surface pressure and temperature from the total depth of the current open hole section.

The maximum anticipated wellhead pressure shall take into account a gas column to surface for exploration and appraisal wells, whilst for development wells reservoir fluid shall be used.

16.3 The designated company representative shall be on the rig floor prior to each trip to flowcheck the well and then observe the trip until such time as they are satisfied that the hole fill volume is correct.

16.4 After completing all well kills or well testing operations, reasonable steps shall be taken to ensure that the hole is safe to trip prior to pulling out of the hole.

16.5 Kick detection, circulating, stripping, and shut-in drills shall be held regularly until the designated company representative is satisfied that each crew meets BP's established standards.

Thereafter kick detection and shut-in drills shall be performed at a minimum of once per week per crew and be reported in the Daily Drilling Report form.

16.6 A shut-in method shall be established, communicated and practised. The generally preferred method is the Fast Shut-in. The driller is responsible for and authorised to shut the well in. The designated company representative is the only one authorised to open the well.

16.7 A kick sheet shall be updated daily and at every change in mud weight, bottomhole assembly or formation integrity.

16.8 A well control incident report shall be completed immediately following all well control incidents.

16.9 The Well Control Manual constitutes BP group recommended practice.

17 Shallow Gas

17.1 General

17.1.1 The possibility of shallow gas shall be considered in the preparation of all drilling programmes.

17.1.2 A shallow hazards review shall always be performed for any offshore drilling location. The shallow hazards assessment produced for use in planning a drilling operation shall include a review of all seafloor conditions and geology to a penetration of at least 200m below the preferred setting depth of the first pressure containment string, or to a penetration of 750m below seabed, whichever is deeper.

The final assessment of site conditions shall be performed and produced by an in-house site investigation specialist making use of all facilities at the disposal of BP staff geoscientists and following protocol of the Offshore Site Investigation Manual.

17.1.3 The potential for shallow gas shall be classified in accordance with the following table in a shallow hazards assessment.

Classification	Description
High	An anomaly showing all of the seismic characteristics of a shallow gas anomaly, that ties to gas in an offset well, or is located at a known regional shallow gas horizon.
Moderate	An anomaly showing most of the seismic characteristics of a shallow gas anomaly but which could be interpreted not to be gas and, as such, reasonable doubt exists for the presence of gas.
Low	An anomaly showing some of the seismic characteristics of a shallow gas anomaly, but that is interpreted not to be gas although some interpretive doubt exists.
Negligible	Either there is no anomaly present at the location or the anomaly is clearly due to other, non-gaseous causes.

17.1.4 If any anomaly is classified with a potential shallow gas presence greater than negligible by shallow hazards assessment, then the surface position of the well

shall be relocated outside the anomaly to a location with negligible potential for shallow gas presence.

In the event that an acceptable location with negligible potential of shallow gas presence cannot be identified, then shallow gas shall be assumed present for purposes of well planning and risk mitigation. In such an event, a documented operational risk assessment shall be carried out, reviewed and approved. The document shall consider the following as a minimum:

- Potential presence of shallow gas
- Potential of shallow gas being abnormally pressured, if present
- Alternate location
- Possible use of pilot hole
- Rig type and capabilities
- Kill mud requirements
- Pump capacity
- Operational practices
- Riser or riserless configuration

17.1.5 Mutually agreed, rig-specific, shallow gas procedures shall be established between BP and the drilling contractor prior to the start of a well and shall cover foreseeable contingencies should shallow gas be encountered.

17.1.6 Shallow gas and diverter drills shall be held prior to spud of all wells and regularly until the first pressure containment string is set.

17.1.7 A shallow gas kick encountered prior to setting the first pressure containment string shall not be shut in. In such event of shallow gas flow, kill operations will immediately commence by pumping fluid into the well at the maximum sustainable pump rate.

17.2 Floating Drilling Operations

17.2.1 Wells shall be drilled riserless until the first pressure containment string has been set, unless:

- It is a government regulation to drill with a riser and diverter installed
- A recirculating mud system is required to drill the hole for surface casing

Prior to use of a riser to drill hole for surface casing, a documented risk assessment shall be performed to address associated risks of riser use.

17.2.2 The rig shall be maintained in a state of readiness to move off location whilst drilling surface hole. Where a riser is installed, procedures for well control and riser unlatch will be established in advance.

17.2.3 All floating drilling operations carried out with returns to the installation will be carried out with a diverter system installed.

17.3 Bottom Founded, Barge and Platform Drilling Operations

17.3.1 A high-resolution seismic survey shall be performed for all locations. New locations shall always be chosen to fall upon a high-resolution survey line.

17.3.2 Wells shall be drilled with a diverter system installed for all hole sections after setting structural conductor or drive pipe and before setting the first pressure containment string.

17.4 Land Drilling Operations

17.4.1 Prior to spud of any land drilling operation, a detailed review of historical data from offset wells will be performed to assess the potential for encountering shallow gas prior to setting the first pressure containment string on the planned well. In the absence of compelling data to substantiate shallow gas is not present, shallow gas shall be assumed present and a diverter system shall be used when drilling the hole section(s) between the structural casing and the setting depth of the first pressure containment string.

18 Well Management

18.1 All wells shall have a formally approved tubing/annulus communication and annulus monitoring procedure. This procedure should take full account of the specific well circumstances and clearly set out the specific requirements for annulus monitoring, allowable leakage rate and anomaly reporting criteria for both production and injection wells.

18.2 The BU shall approve the above procedure and include a formal dispensation process to allow the continued production or injection in the event of an anomaly.

18.3 Well start-up procedures shall be in place to prevent the possibility of any trapped fluid generating a pressure in excess of the equipment rating through an exposure to an increase in operating temperature. Monitoring of relevant areas shall take place until well conditions are stable.

18.4 Xmas tree and wellhead maintenance procedures shall be developed and implemented. Valve testing procedures shall be adopted to provide the means of monitoring xmas tree condition.

18.5 A downhole safety valve (DHSV) shall be fitted below the seabed as a minimum, in every offshore well capable of naturally flowing hydrocarbons to surface. Acceptable leak rates shall be defined in the BU well integrity procedures. Failed DHSVs shall be replaced or substituted by an item which provides an equivalent level of well integrity in a safe and timely manner, and as defined in the BU's field operating standards.

19 Well Intervention Operations

19.1 Preparation

19.1.1 Prior to handover and commencement of any well intervention operations, the work environment and well condition shall be inspected to ensure that they are safe for personnel and equipment during the planned operations.

19.1.2 Personnel and equipment shall be protected from exposed runs of wireline or coiled tubing and from any voids or hazards created by the removal of cellar covers, deck hatches and floor gratings.

19.1.3 The work environment shall be inspected regularly to check for potential hazards introduced by concurrent operations. Drilling and well operations personnel shall be required to identify and discuss all potential hazards between their respective operations with hazard mitigation plans in place.

19.1.4 During the period of well intervention, a single person shall be designated responsible for the intervention operation.

19.1.5 Clear emergency shutdown procedures shall be in place, with which all drilling and well operations personnel are familiar.

19.1.6 All equipment subject to operational loading (sheaves, units etc) shall be securely fastened or anchored to withstand the maximum expected forces during the operation of that equipment.

19.2 Pressure Control

19.2.1 If the lubricator connection is broken above an already fully tested riser and BOP, a retest of the lubricator connection above the BOP for 5 minutes, to the maximum anticipated wellhead pressure, is sufficient to confirm integrity.

19.2.2 The pressure control equipment rig-up, from the swab valve up, or from an installed downhole lubricator valve up, shall be long enough to allow retrieval of the whole toolstring, including items which may be retrieved from the well.

19.3 Well Intervention Operations

19.3.1 Prior to any swab cap well entry rig-up or rig-down, the pressure below the swab cap shall be bled off and monitored for at least 5 minutes for any pressure buildup.

19.3.2 On production wells fitted with more than one tubing string all strings should be shut in during wireline rig-ups. Once rigged-up and tested, the other strings may be opened up until such time as the operations are complete and the equipment required to be rigged-down.

19.3.3 A record of every wireline and coiled tubing toolstring (naming items, providing lengths, outside diameter thread type, fish neck sizes and any other salient points) shall be made prior to running in hole. This record shall be available at the wellsite throughout the time the toolstring is downhole.

19.3.4 Prior to the commencement of any wireline rig-up, the swab valve turns to open and close shall be physically checked and noted.

19.3.5 If any well safety valve is held open by a temporary local control unit, that unit shall never be left unattended.

19.3.6 Pressures in the tubing and annuli shall be regularly monitored and recorded during all well operational activities.

19.4 Fishing

19.4.1 On completion of every well operation any tools or part of tools left downhole shall be accurately recorded and reported.

19.4.2 The number of BOPs in the rig up shall be sufficient to close on both the fishing wire and the fished wire.

19.4.3 The pressure control equipment rig up, from the swab valve up, or from an installed downhole lubricator valve up, shall be long enough to allow retrieval of the whole toolstring, including items which may be retrieved from the well.

20 Pressure Testing

20.1 General

20.1.1 All tests shall include a low pressure test of 200 to 300psi for 5 minutes before proceeding to the full pressure test.

20.1.2 A satisfactory pressure test is represented by the test pressure held for a minimum of 5 minutes after the pressure has stabilised.

20.1.3 All tests shall be recorded on a chart.

20.1.4 Water is the preferred medium for pressure testing. However, once reservoir fluids have been produced to surface, consideration should be made to the use of a water/glycol mixture as the test/flushing fluid to avoid hydrate problems. Low temperature pressure testing shall utilise low freeze-point fluids.

20.1.5 The volume of test fluid pumped shall be monitored and recorded.

20.1.6 Pressure testing shall be performed by increasing the test pressure in a series of appropriate pressure increments.

20.1.7 The possibility of a test pressure leaking past a pack-off or test plug and being applied to a weaker element (eg casing collapse, lower rated ring gasket etc) shall always be considered. All reasonable steps shall be taken to monitor for, and eliminate, such an event.

20.1.8 Prior to any pressure testing, the area shall be isolated. Personnel shall be notified and/or evacuated.

20.2 Pressure Testing of Well Control Equipment

20.2.1 All subsea BOPs including annular BOPs shall be pressure tested on a test stump prior to deployment. The stump test will be to the maximum anticipated wellhead pressure expected in the well.

20.2.2 All well control equipment, except annular BOPs, shall be tested to the lowest of the following criteria:

(1) Maximum anticipated wellhead pressure to be encountered in the hole section.

(2) 90% of casing burst pressure.

(3) Wellhead rated pressure.

(4) BOP rated pressure.

In the event that the maximum anticipated wellhead pressure is not known with reliability, then the well control equipment should be tested to the lowest of the criteria (2), (3) or (4) above.

20.2.3 Annular BOPs shall be tested to a maximum of 70% of rated working pressure if not otherwise specified.

20.2.4 Pressure testing and full functional testing of the well control equipment shall be carried out to the pressures determined in Paragraphs 20.2.2 and 20.2.3 at intervals not normally exceeding 14 days. They shall be recorded on the Daily Drilling Report form.

This 14 day interval may be extended under exceptional circumstances, after an appropriate risk assessment and endorsement by the Head of Discipline or delegate.

20.2.5 All wellhead components and pressure-containing connections associated with the well control equipment shall be pressure tested in accordance with the requirements of this section upon installation or reinstallation.

20.2.6 The opening and closing volumes of all BOP functions shall be monitored and recorded on subsea stacks.

20.2.7 An accumulator test shall be carried out in accordance with the requirements of the Well Control Manual.

20.2.8 When testing wellhead components, due consideration shall be given to burst and collapse rating of relevant casing and components.

20.3 Pressure Testing of Tubulars

20.3.1 This section applies to all casing, testing and completion strings that may be used in a well.

20.3.2 All surface, intermediate and production casings/liners shall be pressure tested prior to drilling out the shoe track or perforating.

20.3.3 Pressure tests shall not give rise to loads exceeding the following:

- 90% of API burst rating
- Triaxial stress of 80% of nominal yield
- Connection pressure rating
- 75% of connection tensile rating

Due consideration must be given to the following:

- The density of fluid columns inside and outside the casing
- The burst rating for the weakest casing in the string
- The minimum design factors assumed for the casing
- The effect of pressure testing on casing tensile loads
- Casing wear if drilling has taken place before testing

If a pressure test is carried out during cementing when bumping the plug, the external load shall be assumed to be equal to the mud weight used to set the casing.

If a pressure test is carried out after waiting on cement, the external load shall be as defined in the Casing Design Manual Part 3 Section 6 Paragraph 4.

20.3.4 No pressure testing of structural/conductor casing is required unless a subsequent leak-off test will be necessary.

20.3.5 Surface and intermediate casings shall be pressure tested to the greater of that required for the anticipated leak-off test or formation integrity test (with appropriate test margin), or the surface pressure for the well control burst load case.

20.3.6 For development wells the minimum pressure test for production casing and liners shall be equivalent to the shut-in tubing pressure on top of the annulus completion fluids. Any additional loads that are to be placed on the casing string (eg operating annulus pressure controlled tools) must also be taken into account when planning pressure tests. If the completion fluid weight is lighter than that during the pressure test then surface pressure related to pressure controlled tools can be reduced to give an equivalent burst pressure at total depth. Unless ample data is available to support an alternative, dry methane shall be assumed in the calculation of surface pressure. For exploration wells the basic initial requirement is the same.

20.3.7 Production or test tubing should be tested to the maximum anticipated surface pressure. As a minimum, the pressure test for the production tubing should give an internal pressure at the lower section of tubing or packer assembly equivalent to the pressure load from the shut-in tubing head pressure and produced fluid.

Pressure testing of tubing is dependent of the completion design and should be considered as part of the running procedure. Consideration must be given to injection pressures and connection ratings.

20.3.8 Liner laps must be tested to a minimum of 500psi above the formation leak-off pressure (or sufficient to demonstrate pressure integrity if greater), at the casing shoe, unless there is no requirement to demonstrate the internal pressure integrity of the casing/liner hanger and cement. Where a drilling or completion operation is to be conducted that will impose a drawdown on the liner lap or previous casing shoe, a differential test must be conducted which imposes a drawdown equivalent to or greater than that expected.

21 Logging and Energy Sources

21.1 A person shall be designated in overall charge of, and responsible for, all logging and perforating operations. Logging operations shall only proceed when the designated person considers the hole conditions present minimal risk to the safety of personnel, the environment and the installation.

21.2 Logging and perforating operations conducted without the installation of wireline pressure control equipment shall only be carried out under conditions where:

- The hole can be contained, monitored and controlled and where the drilling/completion fluid provides the necessary overbalance
- The hole conditions are considered suitable for the tools that are to be run

21.3 In situations where a wireline riser and lubricator are used they shall be pressure tested as a minimum to the maximum anticipated wellhead pressure, prior to running a wireline tool into the wellbore.

21.4 Energy logging systems (perforating/radiation/chemical/explosive) shall have written operational and safety procedures on location to include live retrieval, misfire and fishing operations. Data sheets shall also be maintained on location for all energy and hazardous materials.

21.5 No matter the type of perforating gun or firing mechanism, all non-essential personnel shall be kept clear whilst the gun is being made up, retrieved or handled.

21.6 The procedures and responsibility for the safe use, handling and storage of all energy sources (explosive, radioactive etc) shall be documented for each operation.

21.7 Only the responsible contractor shall handle onsite energy sources.

21.8 Radio silence procedures approved by the appropriate local management shall be in place for all tools that use explosives and shall be adhered to at all times; procedures shall include the control of mobile phones. Examples of tools that use explosives are as follows:

- Wireline perforation guns (except approved radio-safe guns)
- Tubing conveyed perforating guns (electronically detonated)
- Formation sample tools (explosive types only)
- Back-off shots and chemical cutters
- Bridge plugs, cement retainers and packers run on wireline (except approved radio-safe setting tools)

21.9 Radioactive sources, detonators and explosives shall not be stored in close proximity to each other. Radioactive material shall not be jettisoned offshore.

21.10 All personnel handling radioactive sources shall have adequate training and wear approved film badges or dosimeters.

21.11 The loss of a radioactive source shall be reported to the appropriate regulatory agencies. Details shall be clearly recorded in the wellfile. The well shall be marked in accordance with local regulatory requirements.

21.12 If a wireline radioactive source becomes stuck downhole, attempts to retrieve the source using the reverse cut and thread method shall be made prior to pulling the weak point. The weak point shall not be pulled without explicit approval from both the designated company and the logging contractor’s senior site representative.

22 Testing and Completions

22.1 A detailed programme for any testing or completion operation shall be prepared.

22.2 A pre-job meeting shall be held onsite with all the relevant BP, drilling contractor and service company personnel present.

22.3 The test string shall include the facility to allow the string contents to be circulated or bullheaded prior to pulling out of hole.

22.4 Open hole testing operations where the packer is set in open hole shall not be conducted from floating drilling units.

22.5 Drillpipe shall not be used as the test string (nor the completion string) in a gas well or in a well where H_2S is present.

22.6 BOPs and associated equipment shall be pressure tested prior to running the test string.

22.7 All surface well testing or completion equipment upstream of the choke shall be pressure tested to the maximum anticipated pressure, plus an acceptable safety margin, prior to flowing the well. Equipment downstream of the choke shall be tested to rated working pressure. A full function test of all valves and automatic systems shall be conducted.

22.8 Test strings or completion strings with packers shall be pressure tested to the maximum anticipated pressure, plus a safety margin, prior to flowing the well.

22.9 All testing or completion operations shall be designed so as to conform with the principles outlined in Section 24.

22.10 The air supply to burners shall be independent of the rig air supply. Non-return valves should be fitted between the compressors and burner head.

22.11 Test lines and valves, including relief lines, shall be securely anchored at each end and along their length in accordance with safe practices. The relief lines shall be designed for the potential pressures and flowrates.

22.12 The operation of all gas detection and safety equipment held onsite shall be checked prior to the commencement of testing operations.

22.13 Nitrogen used to precharge annulus pressure response test tools shall be analysed for purity (ie oxygen content) prior to use.

22.14 Unlatch equipment used on floating operations shall be function tested immediately prior to running in the well.

22.15 Subsea test trees shall be capable of shearing all coil tubing and wireline to be run through the test string.

22.16 The capability for the BOP shear rams to shear the subsea test tree slick joint shall be assessed and mitigations put in place as required.

22.17 After completing well testing operations, reasonable steps shall be taken to ensure that the hole is safe to trip prior to pulling out of the hole.

22.18 During testing operations, sufficient main power, well control and installation

services shall be available, and on line, to service any unplanned or emergency conditions that may occur during the test.

22.19 Limited in-flow tests where fluids are not flowed to surface may be conducted using conventional drillpipe and procedures following a formal risk assessment.

23 Coiled Tubing Operations

23.1 All relevant sections of this Drilling and Well Operations Policy document shall apply to coil tubing operations.

23.2 All primary pressure-containing connections up to the hydraulic BOPs should be flanged. Threaded connects can be used, provided a proper risk assessment is conducted.

23.3 The coiled tubing BOPs shall be fully function tested on installation and pressure tested at least once every 7 days, after any BOP changes or after a coil changeout. Tests shall be recorded.

23.4 On any perforated well where a coiled tubing BHA shall be worked on bottom or where the coiled tubing is to be run without check valves, shear-seal BOPs shall be installed, to give a reasonable expectation that once cut, the coiled tubing shall drop to regain control of the tree valves. When shear-seal BOPs are employed, all connections between them and the tree or wellhead shall be flanged and double valve isolated, thereby excluding elastomers from connections beneath these BOPs.

23.5 Shear seal and shear ram preventers shall be capable of shearing the coil and any lines within it, at all pressures up to the preventer's maximum anticipated working pressure. When lower shear seal preventers are equipped with single needle valve pressure equalising capability, the valve shall be replaced with a plug.

23.6 To ensure that it will always be possible to unlatch the riser from a subsea well, the lower riser assembly must be capable of severing coiled tubing of the maximum wall thickness to be used as well as any wireline or control lines contained within, and provide a seal.

23.7 A choke manifold containing at least two adjustable chokes shall be installed, unless the normal production flowline is used through the tree and production manifold. In this case, the single production choke is sufficient.

23.8 Unless pressure deployment is used, the lubricator shall be of sufficient length to contain the BHA between the swab valve and the pack-off.

23.9 Active/live annulus outlets below the BOP shall be double valved on pressure deployment operations.

23.10 Dual flapper check valves shall be run above the BHA on all strings unless the planned operation precludes their use. When not utilised, the programme or local standard operating practice should refer to a detailed and current assessment of risks, mitigations and contingency responses.

23.11 When elastomer seals are used they shall be made of a material intended for exposure to wellbore conditions.

23.12 The vapour pressure and flash point shall be known for all potentially flammable fluids. Special precautions shall be in place.

23.13 Remaining coil tubing fatigue life shall be known and monitored prior to and during each job. A coil replacement philosophy should be in place commensurate with operating conditions. The position of all welds and the fluid exposure history shall be documented for each reel of tubing.

23.14 For coil tubing operations the maximum operating tension loads of 80% of minimum yield strength shall not be exceeded.

24 Barriers and Plugging

24.1 These policy statements define the minimum barrier requirements before undertaking the removal of any surface well control equipment such as the xmas tree or drilling BOP.

24.2 Minimum barrier requirements are:

- There shall be two mechanical barriers in each flow path
- The lower mechanical barrier shall be tested – if kill weight fluid is in the wellbore then the test shall be from above; if fluid in the wellbore is below kill weight, then test shall be an integrity test from below
- If the fluid in the wellbore is below kill weight then the upper mechanical barrier shall be tested from above to confirm independence
- If wellbore conditions or design preclude two mechanical barriers, kill fluid sufficient to control the well in the event of failure of a single barrier is required, as well as a dispensation to policy
- In an offshore environment, each flow path shall be isolated with at least one of the barriers installed below seabed

24.3 These policy statements apply equally to xmas tree valve repairs where the principle of double valve isolation shall be adhered to.

24.4 A downhole safety valve that has been satisfactorily pressure tested for 30 minutes without leakage, and that has been isolated, may be considered as a barrier.

25 Suspension and Abandonment

25.1 The decision to permanently abandon or temporarily suspend a well shall be approved by the relevant Business Unit Leader or their delegate and by the regulatory authorities.

25.2 All wells, whether onshore or offshore, permanently abandoned or temporarily suspended, shall be left in such a condition that:

- Potential leakage of formation fluid to surface has been adequately prevented
- Communication between permeable and/or hydrocarbon-bearing zones is isolated by cement
- Fresh water zones are isolated

25.3 For permanent abandonment a minimum of one cement plug above any permeable hydrocarbon-bearing zone or overpressured water-bearing zone shall be positively tested, to a pressure greater than leak-off, or by application of weight.

25.4 Cement plugs shall be a minimum of 30m in length and, where set in casing, be across good annular cement. The potential for casing corrosion shall be accounted for in the plugging plan.

25.5 The drilling site shall be left in a condition which conforms to a standard formally recognised by the appropriate Business Unit in conformance with the expectations of Getting HSE Right.

25.6 Prior to leaving an offshore location, a seabed survey shall be performed and any debris that cannot be reasonably recovered shall be documented.

26 Reporting

26.1 The following reports shall be a minimum for all drilling and well operations and shall be retained within the BU:

- IADC Drilling Report Form or equivalent where a rig is used
- BP daily report. For drilling and completions activities DIMS is the required format
- Casing and cementing reports
- Well data acquisition records
- Seabed clearance certificate at start and end of well operations