9.4.4 Coring Fluids

Any special requirements for coring fluids shall be included in the Drilling Program. The general requirements for coring fluids are:

- The mud gradient should not exert an overbalance over the formation pressure of more than 200 psi.
- The static fluid loss should be less than 8 ml/30 min.
- The viscosity and yield point should be as low as possible to reduce core erosion.
- The solids content should be as low as possible to prevent core contamination.
- The mud filtrate salinity and composition should be as close as possible to that of the formation water.
- Water-based mud should be properly deoxygenated with an oxygen scavenger.
- No surfactants shall be used in the mud.

The mud shall be conditioned by the Drilling Fluids Engineer before pulling out for coring.

Any mud losses should be controlled before starting coring. LCM must not be pumped through a core barrel unless necessary.

9.4.5 Core Recovery and Packing

- A pre-job safety meeting must be held before pulling the core barrel through the rotary table to ensure that all personnel understand the job and potential hazards (e.g.trapped pressures and catcher failure, dropping core onto hand/feet).
- If there is any possibility of the core containing H2S, only the DSV, Driller, Coring Contractor, WGL and the minimum necessary number of crew shall be present when pulling the core barrel through the rotary table. If H2S is suspected, all personnel must wear breathing apparatus until it is confirmed that H2S is absent.
- The inner core barrel shall be retrieved/laid down only in single sections (10m).
- Every precaution shall be taken to ensure that inner barrel is protected during retrieval to avoid damaging the core.

9.4.5.1 Barrel Inspection on Core Recovery

- Ensure that the core barrel connections do not come apart when recovering the core or handling the barrels.
- When raising the inner barrel from the outer barrel, a water hose shall be used to flush drilling fluid from the barrel. Visually examine each inner barrel connection to ensure that it is firmly shouldered.
- If connection is not tight or appears suspect, the inner barrel clamp shall be installed and the connection tightened before continuing to recover the inner barrel.
- When core barrels are laid down, all connections shall be cleaned and doped and proper thread protectors shall be installed on all connections.

9.4.5.2 Core Handling

Any special requirements for packing shall be given in the **Drilling Program**. There must be sufficient materials at the wellsite for packing the cores.

In general, cores shall be sent as soon as possible to the assigned Laboratory for analysis. If it is necessary to store cores temporarily at the well site, they must be stored in a cooled place. This is the responsibility of the WSG.

9.5 MUD LOGGING

9.5.1 Responsibilities

The general range of mud logging parameters shall be specified in the Mud Logging Contract. The requirement for and scope of mud logging services is specified in the Drilling Program

9.5.2 Mud Logging Preparation

The following equipment checks must be made by the Mud Logging Contractor prior to commencing mud logging operations:

- The unit must meet the contract specifications. Deficiencies should be reported by the WGL and/or DSV to the DM who shall inform the Contractor's Representative.
- A full calibration of each sensor must be performed at the start of each well. Critical sensors may require more frequent calibration. Results of the calibration shall be reported on a standard calibration form for each specified sensor in the contract. Sensor calibration shall be verified at random by the WGL or DSV.

9.5.3 Monitoring

All the parameters specified in the contract scope of services shall be recorded against time and depth and continuously monitored.

The mud logging unit personnel shall immediately inform the Driller or DSV of any of the following:

- Potential well control problems or drilling hazards.
- Any H2S detected.
- All unexplainable pit alarms and trend changes in the trip tank.
- Any significant increase in background gas or connection gas.
- Any significant divergence in mud density of the drilling fluid entering and leaving the well (when monitored).
- Any increase or decrease from the torque baseline (when monitored).
- An increasing or decreasing trend in standpipe pressure (when monitored).

9.5.4 Geological Service

The full scope of geological services to be provided by the Mud Logging Contractor is contained in the scope of work in the contract. The following general practices should be followed:

- Cutting samples shall be taken so as to be representative of the interval drilled.
- Lithological analysis of the cuttings shall be performed on the washed samples with the aid of a binocular type microscope. Fluoroscopic analysis shall be carried out on all samples. Any samples indicating fluorescence shall be treated with solvents to detect hydrocarbons and establish the nature of the cut.
- Washed samples shall be dried and packed in envelopes marked with the date, well number and depth. Wet unwashed samples shall be put into sample bags lined with a

plastic bag at the time of collection at the shakers. Samples for geochemical analysis, if required, shall be packed in tins topped up with potable water. Bacteriacide shall be added before sealing the tin.

- Cutting lag time must be known at all times. A carbide lag time test should be performed every 12 hours or every 150 m whilst drilling or as requested by the WGL or DSV. The Driller must be informed before performing a lag test.

9.6 DRILL STEM TESTING

The Drill Stem Test (DST) is carried out to gather well/reservoir data and hydrocarbon/fluid properties, which may be essential for prospect/area evaluation and analysis. In general, tests are performed in open hole, and may use inflatable or conventional weight-set packers.

9.6.1 Responsibilities

All responsibilities for Drill Stem Testing are given in Section 9.2.

9.6.2 Standards

The following standards shall be adhered to during Drill Stem Testing:

- The surface pressure rating of the wellhead shall be at least 10% higher than the maximum of the following conditions:

  Condition 1: SITHP for a gas filled tubing for the highest reservoir pressure to be tested.

  Condition 2: The maximum surface pressure that is required to squeeze kill the test zone with the highest reservoir pressure to be tested.
- A Gamma Ray correlation will normally be performed on all inflate straddle tests
- DST intervals and packer setting depths and amount of water cushion shall be confirmed in writing prior to commencing the test. The DSV should refer to the DM in case of any queries.
- The type of separator required (if any) will be specified in the drilling program and confirmed by the WGL prior to the test.

9.6.3 Test Procedures and Guidelines

The following procedures and guidelines shall be adhered to during DST operations.

9.6.3.1 General Guidelines

The following guidelines shall be implemented for all Drill Stem Tests conducted within GSLM operations:

- **<u>DST tools shall not be opened during the hours of darkness.</u>**
- All test string calculations and pipe additions shall be checked by the DSV for accuracy. A detailed DST schematic shall be sent to the DM for each test.
- After setting the packer element, check that the annulus is filled with drilling fluid before opening the test tool.
- Annulus fluid level shall be continuously monitored at all times while the packers are set.
- During unseating operations and during the first ten stands pulled, the hole shall be continuously monitored for swabbing.
- The DSV shall be on the rig floor during setting, valve opening, unseating, fluid recovery and initial POOH operations.
- The DST technician shall supervise the make up and tally of ALL the DST string components.
- Prior to commencing the DST, the following tests/checks shall be conducted:

Pre DST Checklist

ITEM		CHECKED
Test interval(s) Packer depth(s) confirmed		
Jar Placement confirmed with testing engineer, DSV, DS and DE		
Water cushion confirmed with testing engineer, DSV, OGL		
Check if a Total Fire Ban is in place.		
Tasmanian Fire Service notified (if Total Fire Ban day) DSV/WGL		
JSA conducted		
Pre DST meeting held		
BOP tested within 14 days of DST		
DST equipment pressure tested and recorded		
Separator metering devices zeroed and calibrated		
Gauges and thermometers pre calibrated and checked against each other		
Detailed schematic of "as run" DST string completed		
Gamma correlation log available		
Flare line/pit visually checked		
Gas detector checked and functional		
Area around manifold/lines/separator cordoned off		
Mud pit volume totalisers functional/checked/calibrated for current pit volume		
Flow line sensor checked and functional		
Rig pumps lined up to fill annulus		
Signed by Toolpusher	Verified by Drilling Supervisor	

Table 60. Pre test checklist.

- DST equipment shall be pressure tested as follows:
  1. Flow head to choke manifold - 3000psi witnessed by DST contractor, verified by DSV.
  2. Choke manifold to separator - 1250psi witnessed by separator contractor, verified by DSV.
  3. Separator – 80% of pressure rating of separator - witnessed by separator contractor, verified by DSV
- For DST's occurring on a Total Fire Ban day the Tasmanian Fire Service shall be notified. A fire truck may be required on location if requested by the TFS.
- A PTW shall be completed for the pressure test.
- A JSA shall be conducted.
- A pre well test meeting shall be conducted between the DSV, Contractor Toolpusher, Driller, WGL, testing and separator contractor.
- A detailed schematic of the DST components shall be forwarded to DM.
- Drilling jars will not normally be used in an open hole DST, however this should be assessed on a test by test basis. Consideration should be given to running the drilling contractor oil jars one stand from the top of the collars. This is to be discussed with the testing engineer, DM prior to implementation.
- Run only enough drill collars to operate the test tools plus a maximum of 25% in vertical wells. Use spiral drill collars and HWDP where possible.
- Assess risks of differential sticking and consider modifying DC placement (e.g. alternating stands of drill collars and HWDP).

9.6.3.2 DST Scheduling

- Drill Stem test Tools must not be opened during the hours of darkness.
- The test string must be reverse circulated prior to pulling out of the hole on ALL drill stem tests.

9.6.3.3 Running Guidelines

- The DSV shall ensure that DST tools are RIH at a controlled rate. DST tools shall be run slowly into the hole (approximately 1 1/2 mins per 27 m stand, 1 min per 18 m stand).
- The string shall not be rotated while running in or pulling out of the hole.
- If ANY tight hole is experienced DO NOT leave weight on the test string as the down hole valve will open and mud will enter the test string, lowering the level of the annulus.
- DO NOT rotate the drill string while running in. Rotation will inflate the packer Elements.
- Check the drill pipe periodically for surface air blow that will indicate fluid entering the drill pipe.
- Ensure that no bent pipe is run above the DST tools. Crooked joints will cause pipe whip while rotating to inflate the packers.
- Ensure that there is at least 3 m (10ft) above the rotary table when the slips are set prior to setting the packers.
- Lock swivel and establish drill string neutral, up and down weight prior to installing If low head etc and setting the packer (s).
- Testing contractor to calculate amount of water cushion. This must be confirmed by the DSV/WGL.
- Pressure test surface equipment.

9.6.3.4 Reverse Circulation / Pulling Procedures

2. Unseat the packer.
3. If safe to do so POOH until tools above any coals.
4. Rig up lines on top of drill string to test lines and DST test choke manifold
5. Rig up both mud pumps on to the annulus.
6. Make sure all choke valves are closed.
7. Close annular
8. Drop bar
9. Reverse out with choke closed until the FIRST sign of a pressure increase is seen (the mud catching up the annulus). Make sure someone is at the DST test
10. choke and the valve is opened before pressure exceeds formation breakdown.
11. Reverse circulate through the choke to the tank / flare. Reciprocate pipe slowly while Reversing

Note:
When reverse circulating without filling the pipe ensure that the U tube effect cannot

create an annulus pressure control problem from reservoirs higher up the hole. Reverse circulating will be subject to a separate permit to work..

While POOH after a DST, the following procedures will be followed:

- Ensure the annulus is full prior to commencing the trip
- During unseating operations and during the first ten stands pulled, the hole shall be continuously monitored for swabbing.
- Do not rotate the drill string as this will re-inflate the packers.
- POOH slowly as packers come to any known or suspected tight spots. Make sure that the test tools are not swabbing.

9.6.4 DST Numbering Guidelines

For the purpose of identifying drill stem tests, the following shall apply:

- Consecutive numbers shall be given to each tool run in the hole that is a successful test, or has reached bottom and an attempt has been made to open the tool.
- Tool runs that are held up on way in hole, i.e. unable to get through bridges, tools stuck etc., are not to be given a number. Identify the test as "Test Misrun, (specify intended interval)".
- Test numbering to be alpha numeric where more than one interval tested in a single run in the hole (e.g. 1A 1B etc.).
- DST data sheets shall be made up on numbered tests only. For tool runs not reaching bottom, the pressure charts and field data sheet are to be sent to the GSLM office. No distribution is required.
- The DSV/WGL shall check and verify the charts and data sheets. The DSV/WGL shall ensure all relevant data is intact and is sent to GSLM (as required).

CHAPTER 10
WELL CONTROL

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Continued over

10.1 OBJECTIVES

The purpose of this Chapter is to detail GSLM's requirements with regard to well control standards, procedures and practices. It outlines the minimum standards to be complied with, and describes and specifies the general procedures and practices to enable operations and engineering personnel to perform the following tasks:

Ensure all regulatory requirements are met.

- Ensure that well control equipment complies with the minimum standards shown in Appendix 3.
- Ensure that personnel are fully qualified, trained and prepared to shut-in and kill the well if a kick is taken
- Recognise and react to the warning signs of potential well kicks.
- Plan and conduct effective well killing operations.

Note that well design is based on the following kick tolerance criteria:
12 ¼" intermediate hole, 30 bbl maximum influx (gas)
8 1/2" hole 30bbl maximum influx (gas)
6 1/8" hole 30bbl maximum influx (gas)
These volumes are easily detected with the current rig monitoring equipment.

Primary Well Control must be maintained at all times (except when air or under-balanced drilling). Primary Well Control is defined as the use of drilling fluids of sufficient density to overbalance formation pore pressure and prevent entry of foreign fluids into the wellbore.

Secondary control is defined as the proper use of blowout prevention equipment to control the well in the event that primary well control cannot be properly maintained.

For each well control operation, all personnel must have a pre-assigned task appropriate to their function. All personnel also must be familiar with GSLM's well control standards and procedures.

The preferred method of secondary well control is the hard shut in. The preferred method of killing the well is to use the Wait and Weight method. Consideration should also be given to using the drillers method, particularly if surface volume may be a problem.

10.2 RESPONSIBILITIES

The well control responsibilities of each crew member during well killing operations are tabulated below.

Task	Performed by	Verified by
Ensure all preparations, personnel certification and drills meet GSLM's requirements	Drilling Contractor Toolpusher	DSV
Ensure emergency barite stocks are available	Drilling Fluids Engineer	DSV
Well control equipment tested and fully functional	Drilling Contractor Toolpusher	DSV
All personnel informed of their pre-assigned tasks	Drilling Contractor Toolpusher	DSV
Identify and shut in well flow: inform relevant supervisor	Drilling Contractor Driller	Toolpusher
Monitor shut-in and record kick data	Drilling Contractor Toolpusher	DSV
Callout well control specialist and specialised equipment if requited	DM	CEO
Perform calculations and plan kill procedure	DSV / Toolpusher	DM
Preparation of kill mud (if not already available)	Drilling Fluids Engineer	DSV
Ensure well is secure, kill data collected and kill calculations are properly performed	DSV	DM
Liase with DM: provide information and request further assistance as required throughout operation	DSV	DM
Hold a pre-kill meeting with key personnel	Drilling Contractor Toolpusher	DSV
Supervise rig crew during kill	Drilling Contractor Toolpusher	DSV
Ensure adequate level of supervision on the rig floor at all times during kill procedures	Drilling Contractor Toolpusher	DSV
Co-ordinate activities of Driller and third party contractor personnel throughout operation	Drilling Contractor Toolpusher	DSV
Ensure well is secure: notify DM	DSV	DM

Table 61. Responsibilities for Well Control

10.3 GENERAL STANDARDS

The well control must be in accordance with the relevant Government regulations.

Company and Drilling Contractor personnel from Assistant Driller upward shall be in possession of a valid and recognised well control training certificate. All personnel shall be conversant with the GSLM standards and procedures as detailed in this chapter

The Drilling Contractor shall be responsible for performing pressure and function testing of all blow out prevention equipment and associated well control equipment that is provided within the terms of the contract between GSLM and the Drilling Contractor.

Prior to acceptance of a rig at the commencement of a drilling contract, GSLM shall review the documented BOP test standards, procedures and practices submitted by the Contractor, in order to establish whether these are in compliance with GSLM' s required standards. A joint operating standard shall then be developed and approved by both parties.

An accumulator test shall be run prior to drilling the surface casing on the first well of a new program. This test shall confirm sufficient volume in the accumulator bottles to meet requirements in 10.4.4 below.

10.3.1 BOP Pressure Testing

Pressure testing shall be performed using water and a plug type tester (where possible) on the entire BOP system as detailed in the text and table below. A cup type tester shall be used to pressure test the wellhead connection. If a test stump is available the BOP's should be tested on this while drilling surface hole.

Test	Frequency	Equipment
Regular Tests	Daily	The degasser shall be checked daily once the BOP's are installed. All preventers and manual closing controls shall be function tested. The blind rams shall be operated on each trip out of the hole
	14 days	Throughout all drilling, completion and workover phases, pressure testing shall be carried out once every 14 days from the day of the previous test.
Casing	New casing	BOP's shall be tested after prior to drilling out a new string of casing.
Operations Tests	Parts Changes	Pressure testing shall be undertaken whenever rams are changed or parts of the system have been replaced that may affect the pressure integrity.
	Major Repairs	After major repairs, and the first time the well control equipment is used for GSLM operations, the well control equipment shall be tested to its full rated working pressure.
	Drilling Program	All subsequent pressure tests shall be carried out in accordance with the Drilling Program.

Table 62. Frequency of BOP Pressure Testing

All pressure tests should be recorded on a pressure recorder. A test form must be completed after pressure testing the BOP's.

When testing the BOP stack, the casing side-outlets shall be open.

10.3.2 Diverter and BOP Equipment

The following equipment tests and preparations must be adhered to at all times:

- Prior to commencement of operations, well control equipment shall be in full compliance with specifications as per the relevant contracts. BOP equipment will be fully operational at all times while drilling below the surface casing shoe. The BOP's shall be function tested daily and pressure tested every 14 days.
- For all drilling activities, full blow out prevention equipment shall be installed and tested before the surface casing shoe is drilled out.
- With BOP's in use, all line outlets, on the BOP's, exposed to well pressure shall have a double isolation arrangement.
- A diverter system shall be installed and tested on the conductor when drilling the surface hole.
- The working pressure of well control equipment shall exceed the maximum anticipated surface pressure to which it may be subjected.
- Only genuine spare and replacement parts shall be used on BOP and associated equipment.

10.4 EQUIPMENT STANDARDS

All BOP equipment used in GSLM activities shall comply with the standards described below.

10.4.1 General BOP Arrangement

All pressure contained components of the BOP stack and related equipment shall be constructed of material that meets the standards of NACE MR-01-75 and API RP-53.

The BOP stack should comprise of at least:

- One annular type preventer.
- Two ram type preventers.

The ram preventers shall have the following, sized for the Drilling Contractor's drill string.

One set of pipe rams, normally top rams (dressed w/- appropriate drill pipe or casing rams)
One set of blind rams, normally bottom rams.

Stack configuration should ensure that the following objectives can be met.

- It must be capable of closing in on open hole and all tubulars programmed to be run through the BOP.
- It must allow for circulating out a kick with the drillpipe hung-off.
- It must allow for drillpipe to be hung-off and well secured.
- On re-entry, it must allow the well to be monitored for pressure and circulated, if required,prior to the rams being opened and the drill string recovered.
- It must allow for stripping operations to be conducted.

NACE MR-01-75
API RP-53

Annular Preventers

Annular preventers shall have the capability of sealing around smooth surface objects of all sizes, including drill collars, Kelly's, drillpipe, casing, wireline and open hole. They shall also allow drillpipe and tool joints to be stripped through the preventer under pressure.

Ram Preventers

The ram preventer shall seal only around a pre-designated shape, e.g. round objects (pipe and casing rams) or open hole (blind rams).

Connections

Only welded, flanged or hub connections shall be used on any equipment or line rated above 2000 psi. Threaded connections must not be used.

10.4.2 Choke and Kill System

The choke and kill system shall provide the valves and piping required to allow controlled circulation of the well under pressure. The choke and kill system shall include:

- A double valve arrangement on every line/outlet of the BOP.
- A hydraulically operated HCR valve included in the double valve arrangement on the (dedicated) choke line.
- Lines connecting the BOP stack to the choke manifold.
- A choke manifold.
- A flare line connected to the choke manifold.
- Hydraulically operated Choke Valve (preventor outlet)
- Each choke outlet on the BOP stack shall have one hydraulically operated, HCR type (High Closing Ratio), gate valve included in the double valve arrangement. This gate valve shall be set in the open position. Where dual-purpose kill/choke lines are used, each line shall have a hydraulically operated HCR valve included.

The following recommended practices for the installation of a choke (and kill) manifold shall be adhered to, as specified in API RP53 "API Recommended Practices for Blowout Prevention Systems":

a) The assembly, connections, full opening valves, fittings, piping, etc., subject to well or pump pressure should be flanged, clamped or welded and have a rated working pressure at least equal to the rated working pressure of the BOP.

b) All components should be selected in accordance with applicable API Specifications, taking into consideration pressures, volumes, temperatures and conditions under which they may be operated (i.e. gas, oil, drilling fluid, hydrogen sulphide, the environment, etc.).

c) The choke manifold assembly and all choke lines shall be 3" nominal diameter or larger, have a minimum number of turns and be securely anchored. The dedicated kill lines shall be 2" nominal diameter or larger, and should be fitted with two valves and a non-return valve.

d) The choke control station, whether at the manifold or remote from the rig floor, should be as convenient as possible and should include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, pump strokes etc., greatly increases well control efficiency.

e) Rig air systems should be checked to assure their adequacy to provide the necessary pressure and volume requirements for control of pneumatically or hydraulically operated chokes and valves. A redundant automatic choke control system, which may be manually operated, should be provided in the event that rig air becomes unavailable.

f) Initial testing of the entire choke manifold assembly to the same test pressure as the preventers should be performed when the blowout preventer stack is nippled up to the wellhead, and thereafter whenever the blowout preventers are tested.

g) Lines downstream of the choke manifold are normally not required to contain rated manifold working pressure, but should be tested during the initial installation.

Lines downstream of the choke manifold should be securely anchored, be of sufficient size to minimise friction and permit flow direction either to a mud/gas separator, ventlines, or to production facilities or emergency storage.

10.4.3 Degasser

The purpose of the gas separation equipment is to remove the gas from circulated out drilling mud so that the mud pumps operate effectively and the gas does not create a potentially explosive situation in the mud pits.

The mud gas separator shall be installed with a minimum 8" vent line, a minimum 4" choke manifold discharge line, and a mud seal of at least 6ft.

A small amount of gas in the mud will not significantly reduce the bottomhole pressure, but it may gas-lock the pumps and make the calculation of circulating pressures difficult or impossible.

10.4.4 BOP Control Systems

The accumulator must have sufficient volume to meet the following minimum volume criteria:

- Close the blind rams.
- Open the blind rams.
- Close the pipe rams.
- Open the pipe rams.
- Close the annular preventer.
- Open the annular preventer.
- Close one HCR valve.
- Open one HCR valve.

The BOP closing systems shall be capable of closing

- Each ram type preventer within 30 seconds.
- Annular preventers smaller than 20" within 30 seconds.

The accumulator volume must be checked to establish that the above criteria are met.

The following equation shall be used to calculate the total usable fluid volume for bottles.

$$USV = [PP]\,x\,[NS]\,x[VI]\left\{\frac{1.02}{PP+200} - \frac{1.06}{AP}\right\}$$

Where
USV = Usable volume
PP = Precharge pressure (usually 1215psia)
VI = Bladder internal volume at precharge pressure
NS = Number of bottles
AP = Maximum operating pressure (usually 2815psia)

Note: Usable fluid volume is defined as the recoverable volume of fluid between accumulator operating pressure and 200psi above the pre-charge pressure.

10.4.5 Drillstring BOP Valves

Components for shutting in the drill pipe internally are a basic part of well control equipment. All drill string BOP valves must have a pressure rating equal to, or greater than, the BOP stack.

The following drillstring BOP valves shall be available on the drill floor and ready for immediate use at all times:

- A full bore Kelly Cock shall be installed at the base of the kelly or top drive.
- A ball type stabbing valve (lower kelly cock), with connections or a cross-over to suit the workstring together with an operating handle for the valve, and removable handles for easy stabbing. This valve to be kept open and ready for installation.
- A circulating head with connections to suit the drill string
- Inside BOP (Gray type or equivalent).

10.4.6 Kick Detection and Well Monitoring Equipment

A brief summary of the main kick detection and well monitoring equipment that should be available and fully operational is given in the text and table below.

Equipment	
Kick Detection Equipment	The following minimum kick detection equipment shall be available and fully operational: • Flowline monitor • Active pit volume monitors • Gas detection at header box (mud logger responsibility) • ROP recorder • Trip tank with a system for accurately monitoring returns during tripping
Mud Monitoring Equipment	All mud monitoring equipment (flo-show and PVT) shall be checked at various rates/volumes prior to drilling out casing and twice daily thereafter to ensure measurements indicated are correct and alarms are functioning.
Trip Tank	A trip tank shall be available and shall be complete with a mechanically operated indicator of the trip tank level visible from the Driller's position.
Gas Detection Equipment and Alarms	All gas detection equipment and alarms shall be functioning properly.

Table 63. Kick Detection and Well Monitoring Equipment

Continuous monitoring and recording of the following parameters shall be available on the drilling site for all wells:

- Active pit volume.
- Weight on bit and hook load.
- Standpipe pressure and choke pressure.
- Rate of penetration.
- Mud pump SPM.

Warning Signs - Possible Kick

One or more of the following warning signs may be associated with the initiation of a kick, all can be caused by other factors. All require an immediate flow check.

a. Increase in Pit Volume

An unexplained change in pit volume is the definitive indicator of a kick.

b. Increase in Relative Flow

This is an increase in return flowrate while the pumps are still running at a constant output. This is often the first positive indicator that a kick is occurring, however an influx from a low permeability formation may be difficult to identify.

c. Incorrect Hole Fill

If the volume of drilling mud required to fill the hole while pulling pipe is less than the calculated pipe displacement, formation fluids may be entering the wellbore.

d. Gas Cut Mud

An increase in mud gas level may signify that formation gas has flowed into the well. It may simply be as a result of drilling a formation with a high gas content, however this could lead to an undesirable reduction in mud weight.

e. Reduced Mud Weight

Mud weight reduction (or any significant change in other mud properties) may indicate a dilution of the mud by formation fluids - gas, oil or water.

f. Drilling Break

A drilling break (ROP change) is due to a change in formation drilling characteristics, and may indicate increases in formation porosity, permeability and pore pressure. Breaks may be positive or negative.

g. Decrease in Pump Pressure

A large influx of formation fluids, reduces the hydrostatic pressure in the annulus.The mud in the drill string can then U-tube into the annulus and the result is a reduction in pump load and pressure. The pressure reduction can cause the pumps to speed up. Normally if this indicator is seen, a serious kick has occurred and other indicators should be associated with it.

h. Increase in Hookload

When an influx displaces the drilling fluid in the wellbore there should be a reduction in the buoyancy of the drill string which should be seen on surface as an increase in the hookload. An increase in hookload is not a reliable method of detecting a kick because it requires a large influx of low density fluid to produce a measurable hookload increase.

Pore Pressure & Underbalance Indicators

a. Background Gas

Background gas (BG) is the mud gas content that enters the system when the formation in which it was formerly contained is removed as cuttings. It is unrelated to pore pressure and will occur even in overbalanced drilling conditions. High BG levels which do not decrease with circulation may indicate a steady flow of gas from an underbalanced, low permeability formation.