b. Connection Gas

Connection gas (CG) is caused by the temporary reduction in bottomhole pressure during a connection, due to the combined effects of ECD loss and the swabbing effect of moving the pipe. CG is characterised as a peak above background gas, which is recorded one lag time after the connection.

The presence of CG indicates pore pressure is less than drilling ECD, and greater than mud hydrostatic during swabbing. Increase in CG magnitude on successive connections is an indicator of increasing pore pressure.

c. Trip Gas

Trip gas (TG) is gas which entered the hole during tripping. Trip gas will be detected in the mud on circulating bottoms up after a round trip. An increasing trend in the magnitude of trip gasses may indicate that pore pressure is increasing. Significantly high Trip gas may indicate a close to balance situation exists in the hole.

d. Shale Cavings

Any cuttings that have not been created by bit action are termed 'cavings'. Pressure cavings are long, splintered and angular, and occur when overpressure causes the shale borehole wall to crack and burst into the well.

e. Decrease in Shale Density

Shale density normally increases with depth but this trend is reversed in abnormally pressured zones. The density of the cuttings is measured and plotted versus depth. Any deviation from the normal trend line may be interpreted as a pore pressure change.

f. Temperature Measurements

A change in temperature gradient is often associated with an abnormally pressured formation. The limitation of this method is that the mud temperature can usually only be measured on surface and is subject to external influences.

10.5 BOP SYSTEM TESTING AND INSPECTION

The BOP system shall be pressure tested according to the priciples below. Individual well programmes may require variations to test pressures.

- All BOP tests shall be tested to a low and high pressure. The actual pressure required will be given in the drilling programme. The criteria for the minimum pressure required for the high pressure test will be the greater of:
    a) Maximum surface pressure assuming gas from TD to surface.
    b) Surface pressure assuming gas from last casing shoe to surface with a 16 ppg fracture gradient at the shoe.
- All BOP system components shall be tested to a low pressure test of 200 psi prior to the required final high pressure test value.
- All BOP system components should be subjected to differential test pressures in the direction of pressure that will occur in service.
- The annular preventers should be pressure tested first, in order to allow them additional time to relax prior to pulling the test tool.
- Ensure valves are open downstream of the component being pressure tested.
- Maximise the number of components being tested on each test in order to minimise the number of tests.
- Ensure the downstream side of all preventer choke and kill valves are pressure tested.
- The criteria for a satisfactory test shall be a minimum of five minutes with a decline of less than 5% of test pressure.
- Test fluid volumes pumped and bled back must be carefully monitored and recorded. This is particularly important when testing against the casing pack-off to avoid pressuring the casing annulus and risking casing collapse.The control panels used should be alternated on each function and pressure test.
- All pressure tests shall be witnessed and signed by the DSV. Pressure tests shall be recorded on a chart recorder, reported on the Daily Drilling Report (Form F-301), the IADC Tour Sheet and the BOP Test Sheet (Form F-201).

10.5.1 Accumulator Function Test Requirements

- All Systems shall be cycled from the normal operating position and times recorded.
- Remote systems shall be checked, cycled, timed and recorded every day.
- Accumulator charging pump output will charge the accumulator system from precharge pressure to operating pressure in 15 minutes or less.
- Accumulator pump systems shall be functioned every tour while drilling by the driller.
- Rig air pressure systems shall be bled off every day to function test fail safe systems.
- Should any of the above tests indicate faulty equipment, the equipment must be repaired immediately and re-tested before drilling operations resume.

10.5.2 Maintenance and Inspection

The following general requirements for maintenance, inspection and testing of BOP and associated equipment shall be implemented as follows:

a) A BOP body pressure test shall be carried out once a year on the test stump, in accordance with the manufacturer's specification for such a test.

b) BOP's shall undergo a regular major overhaul and inspection, depending on the type of work and period in use. Periods between checks shall not exceed 5 years.

c) BOP hydraulic operating lines shall be tested to the maximum accumulator manifold pressure when newly installed and during every regular BOP stack test, by opening the Koomey KR bypass valve. The control lines to the annular preventer shall be tested once per well to the maximum operating pressure. The control lines are to be disconnected from the annular preventer in order to avoid damaging the annular preventer rubber.

d) Ensure the manufacturer's BOP operating manual is followed and no alterations are made to the BOP equipment without written consent from the manufacturer. Re-certification may be required after making equipment alterations.

e) Only genuine spares/replacement parts shall be used on BOP and associated equipment.

f) A maintenance schedule and checking procedures for BOP's shall be available on the drilling location and workshop.

g) Records of maintenance both scheduled and unscheduled shall be kept in a BOP history file at the Contractor's office. A copy of this file should also be kept at the rig.

10.6.0 WELL CONTROL DRILLS

Well control drills shall be initiated by the DSV and performed to ensure that the crews are adequately trained and prepared to implement well control procedures correctly. They shall only be conducted when they do not complicate ongoing operations. A kick should be simulated by manipulation of a primary kick indicator such as the tank level indicator or the flowline indicator.

The drills described below include the full sequence of shutting in a well, however the critical reaction time shall be recorded up to the point when the designated person is about to begin the closing sequence of the annular preventer(s).

It shall be necessary to repeat the drills each tour until the DSV is satisfied that the crews are adequately trained and responsive.

10.6.1 Well Control Drill Reporting

The following shall be recorded in the IADC tour report and the Daily Drilling Report:

- The types of drill conducted and the reaction time from the moment the kick is simulated until the crew is ready to start the closing procedure. The operation shall be recorded as "Well Control Drill".
- The total time taken to complete the drill.

10.6.2 Well Control Drills

The following sections describe the tasks required to perform four types of well control drills. These four drills are also displayed schematically in the Appendices at the end of this Chapter.

Note that the shut-in drill listed below assumes a hard shut-in technique for on-bottom drilling.

Kick Drill Condition 1 (On Bottom Drilling

1. Stop rotary.Raise kelly and slow down pump (Stop pump when lower kelly cock and first tool joint are above table)
2. Close annular preventer.
3. Open choke line (HCR valve).
4. Record drill pipe and casing pressures.
5. Record time to complete drill.

Kick Drill Condition 2 (While Tripping the Drill String)

1. Position upper tool joint above rotary table and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Install kelly and open inside BOP.
6. Record drill pipe and casing pressures.
7. Record time to complete drill.

Kick Drill Condition 3 (While Out of Hole)

1. Close blind rams.
2. Open choke line (HCR valve).
3. Record casing pressure.
4. Record time to complete drill.

Kick Drill Condition 4 (While Drill Collars are Adjacent to Preventers)

1. Position upper drill collar box at rotary and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Record drill pipe and casing pressure.
6. Record time to complete drill.

Note: If only 1 stand of drill collars remains to be recovered, the stand should be removed and the well treated as in Condition 3.

10.6.3 Routine Daily Precautions

Mud engineer to ensure adequate chemical supplies to control the well are available.

Slow Circulating rates (SCRs) for each pump must be taken (as a minimum) as shown below:

- Once per tour or at 150 m intervals during the tour.
- At bit and/or BHA changes.
- After significant changes in the drilling fluid density or rheology.
- Prior to drilling the casing shoe or transition zones.

Reporting shall be on the IADC and Daily Drilling Report and must include:

- A minimum of two pump rates.
- The SCRs chosen should not be less than 0.5 bbl/min and not greater than 4 bbl/min.
- The pressures must be recorded using the gauge to be used during well kill operations.
- SCRs shall be taken on all pumps and at the same rates.

10.6.4 Well Control Data Reporting

Basic well data must be recorded accurately at regular intervals and be easily available. This must include the following:

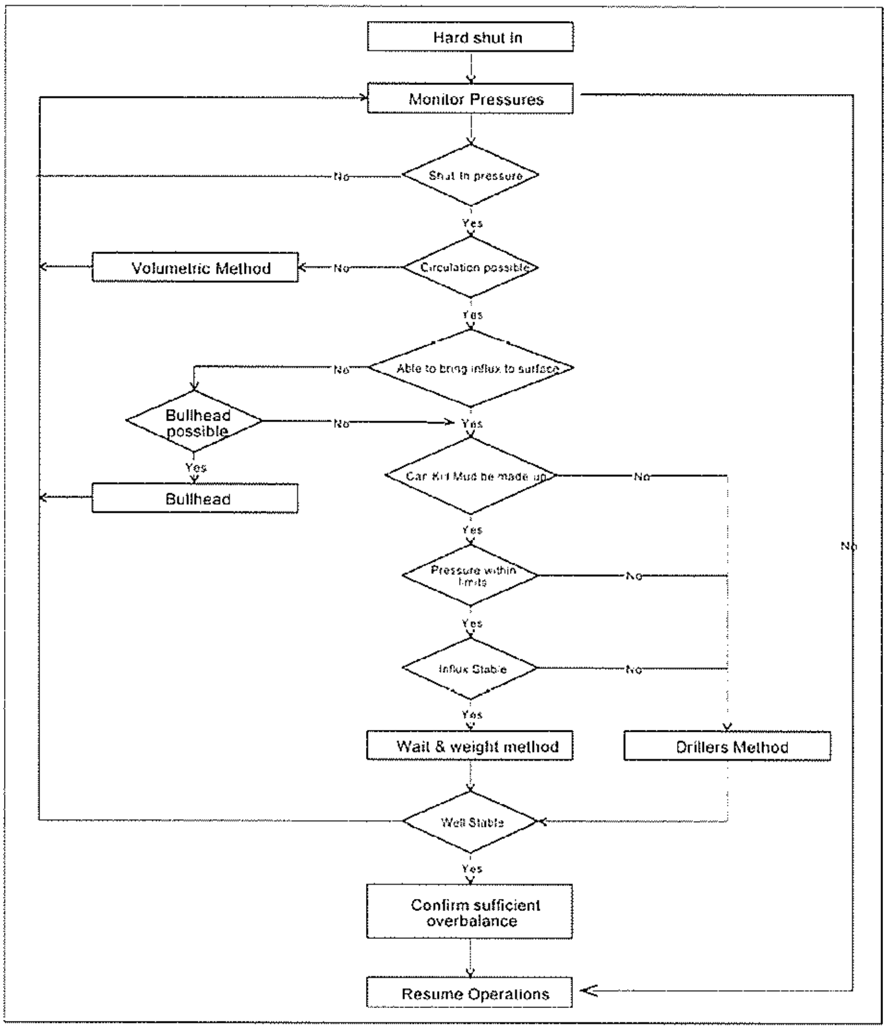
- SCR Pressure/Rate Data (see above).
- Leak Off Test as given in Chapter 10.9 of this Manual.
- Maximum Allowable Annular Surface Pressure , and see Appendix I, this Chapter.
- Completion of Killsheet by the DSV, Driller and Toolpusher.

10.7.0 WELL CONTOL PROCEDURES

- The preferred GSLM shut-in method of well control is 'hard' shut-in.
- The preferred method of Secondary Well Control is the Wait and Weight Method (Refer 10.7.3). Consideration should be given to using the drillers method (Refer 10.7.5) in situations where mud mixing and handling may be a problem.
- Other approved methods such as Bullheading and Volumetric Methods (see following text) shall only be utilised in special cases.

The appropriate method to be used is decided after consultation with the DSV and DM. The following flowchart shall be used as a guide.

Well Control Method Selection - Decision Analysis



Figur 10. Well Control Method Selection – Decision Analysis

10.7.1 Well Shut-in Procedures

The following sections describe the tasks required to perform three different shut-in procedures. These three procedures are also displayed schematically in the Appendices at the end of this Chapter.

Note: that the shut-in procedures listed below assume a hard shut-in technique.

Shut-in Procedure (While Drilling or Making Connection)

If well is flowing:

1. Stop rotary.
2. Raise kelly and slow down pump.(Stop pump when lower kelly cock and first tooljoint are above table).
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Read and record:
    a) Shut-in Drill Pipe Pressure (SIDPP)
    b) .Shut-in Casing Pressure (SICP).
    c) Pit volume increase.
6. After recording shut-in pressures proceed to kill well as per Section 10.7.3.

Shut-in Procedure (Tripping with Drill Pipe) - Flow Chart

1. Position upper tool joint above rotary table and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Read off the SICP. If this value is less than 1000psi (or the MAASP, whichever is the lower pressure), reduce pressure on annular preventer, lubricate element and strip back in (if possible).
6. When the string is stripped in to maximum allowable SICP, stab in kelly and establish SIDPP, record new SICP.
7. After recording shut-in pressures proceed with well kill procedures.

Note: If it is not possible or feasible to strip drillstring back to bottom, the well may require to be killed using other techniques, the preceding may help in deciding which method to use (eg Bullheading: See Section 10.7.7).

Shut-in Procedure (Tripping with Drill Collars)

1. Position upper drill collar box at rotary and set slips.
2. Open choke line (HCR valve).
3. Close annular preventer if installed (if not installed, then add 1 joint or 1 stand of drill pipe to collars, and run back in hole; close pipe rams)
4. Install an inside BOP to the drill collar or drill pipe box.
5. Secure string at derrick floor.
6. Close inside BOP valve.
7. Shut in at choke.
8. Close manual valve upstream of choke.
9. After recording shut-in pressures proceed with well kill procedures.

Note:

a) If only 1 stand of drill collars remains to be recovered, the stand should be removed and the well shut in.

b) Drill collars could be dropped into the hole depending on potential severity of blowout.

10.7.2 Well Control Data and Calculations

The following data shall be monitored and recorded on the Well Control Operations log at the drill floor throughout a well kill operation.

- Times.
- The shut-in casing pressure (SICP).
- Shut-in Drill pipe pressure (SIDPP).
- Active pit volume.
- Description of events, including all pressures at one minute intervals until they have stabilised.

Well Calculations shall be made on the Killsheet and submitted to the DSV for approval. The DSV, Toolpusher, and Driller shall independently prepare a kill sheet for verification. These shall be used by the DSV to ensure accuracy of the well control calculations.

10.7.3 Wait and Weight Method (Well Kill Procedure)

The following well kill procedure is also given schematically in the Appendices at the end of this Chapter.

1. Zero stroke counter. Start the pump slowly while simultaneously opening the remote adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant.
3. When the pump is up to speed, read and record the Initial Circulating Pressure (Pic). In all cases use the actual Pic rather than the calculated value.
4. Maintain the drill pipe pressure as per the drill pipe pressure schedule on the Kill sheet. Maintain constant pump speed throughout circulation.
5. When the kill mud reaches the bit, maintain the drill pipe pressure constant at the Final Circulating Pressure (Pfc) by choke adjustment until kill mud reaches surface.
6. When kill mud reaches surface, shut down the pump and close the choke. Read and record SIDPP and SICP.
7. If drill pipe and casing pressures are recorded, bleed-off pressures to check for trapped pressure. If the well is not dead, resume circulation to ensure uniform kill mud throughout wellbore.If drill pipe and casing pressures equal zero, flow check through the choke line.
8. Circulate wellbore conventionally and add a suitable overbalance to the mud weight.

Note: If it is necessary to stop pumping at any time during the well circulation, immediately shut-in the well. To resume pumping, maintain kill line (wellhead) pressure constant while bringing the pump up to speed to account for choke line pressure drop. Pic shall be re-checked as per Step 3, and the drill pipe schedule adjusted if necessary.

10.7.4 Concurrent Method

The Concurrent Method is a variation of Wait and Weight Method. It is used when it is not possible to weight up the mud system to kill weight at once, but when the Driller's Method will result in an unacceptably high well bore pressure.

The mud weight is increased in stages until the well is full of kill weight mud, with each new weight being circulated all the way to surface. A new drill pipe schedule is constructed for each circulation as per the Wait and Weight Method.

10.7.5 The Driller's Method (Well Kill Procedure)

The Drillers Method is described below. The procedure has been subdivided into the procedure during the first circulation and the procedure for the second circulation.
The Driller's Method Well Control Schematic Procedures.

First Circulation

The procedure for the first circulation is as follows:

1. Zero stroke counter. Start the pump slowly while simultaneously opening the remote adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant to account for choke line pressure drop.
3. When the pump is up to speed read and record the Pic. The actual Pic should be used rather the calculated Pic.
4. When the influx has been circulated out of the well stop the pump and shut the well in at the choke. Read and record SICP and SIDPP. If the influx has been totally removed SICP should equal SIDPP.

Note: A kill graph is not required for the first circulation, since drill pipe pressure will be maintained constant at Pic after bringing the pump up to speed. Pic should be estimated prior to commencing circulation:

Pic = PSCR + SIDPP (psi)

Second Circulation

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

Note: The standpipe pressure at the start of the second circulation (Pic) may be taken as the actual circulating pressure at the end of the first circulation.

1. Prepare Kill Graph. The circulating pressure when the kill mud reaches the bit shall be calculated as follows:

$$P_{fc} = P_{ACTUAL} \; x \; \frac{\text{Kill Mud Weight}}{\text{Original Mud Weight}} \; (psi)$$

The standpipe pressure versus volume pumped or time should be plotted. Standpipe pressures should include a safety margin (use 150psi) to allow for choke operator reaction time.

The graph shall be prepared as follows:

- i. Plot the initial standpipe pressure (Pic) at the start of the second circulation.
- ii. Plot the standpipe pressure when kill mud has reached the bit (Pfc)
- iii. Connect the two points with a straight line. This line represents the standpipe pressure whilst pumping the kill mud from the surface to the bit.

1. Start well killing procedure by zeroing the stroke counter.
   Start the pump slowly while simultaneously opening the adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant to account for choke line pressure losses.
3. After the pump is up to speed, read and record the Pic . The actual Pic should be compared to the calculated value, and if required, adjustment made to the drill pipe pressure schedule to account for any differences between the two values.
   In all cases, use the actual Pic rather than the calculated value.
4. Maintain the drill pipe pressure as per the drill pipe pressure schedule.
   Maintain constant pump speed throughout circulation.
5. When the kill mud reaches the bit, maintain the drill pipe pressure constant at the Pfc by choke adjustment until kill mud reaches surface.
6. When kill mud reaches surface, shut down the pump and close the choke. Check drill pipe and casing for pressure.If drill pipe and casing pressures are recorded, bleed off pressures to check for trapped pressure.If the well is not dead, resume circulation to ensure uniform kill weight mud throughout wellbore.
7. If drill pipe and casing pressures equal zero, flow check through the choke line.
8. Circulate wellbore conventionally and add a suitable overbalance to the mud weight.

Note: If it is necessary to stop pumping at any time during the well circulation, immediately shut-in the well. To resume pumping, maintain kill line (wellhead) pressure constant while bringing the pump up to speed to account for choke line pressure drop. Pic shall be re-checked as per Step 3, and the drill pipe schedule adjusted if necessary.

10.7.6 Static Volumetric Method (Well Kill Procedure)

The Static Volumetric Method is used to control rising well pressures due to a migrating influx. It is a constant bottomhole pressure method. It can only be used if the influx is migrating. It is an alternative to a circulation kill method which may be used in the following circumstances:

- Drill string out of hole.
- Drill string cannot be stripped to bottom.
- Washed out or parted drill string.
- Plugged bit.

Static Volumetric Control Procedure (Casing Pressure Method)

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Prepare the Volumetric Control Worksheet for the kill operation. The influx migration and hydrostatic pressure equivalent shall be determined as shown in the table below.

Calculation	Equation	Abbreviations
Influx Migration Rate	$MR = \dfrac{(P2 - P1) \times 19.25}{MW \times T}$	MR = Migration Rate up constant cross Section annulus (ft/hr) P1 = Surface pressure at start of time Interval T (psi) P2 = Surface Pressure at end of time Interval T (psi) MW = Mud weight (ppg) T = Time interval between Pressure Readings (hours) HPE = Hydrostatic Pressure Equivalent of 1 barrel of mud in the annulus (psi) dh = Hole or Casing ID (in) do = Drill String OD (in)
Hydrostatic Pressure Equivalent	$HPE = \dfrac{53.44 * MW}{(dh^2 - do^2)}$	

Table 64. Influx Migration Rate and Hydrostatic Pressure Equivalent Calculations

2. Allow casing pressure to increase by an overbalance margin plus an operating margin. The suggested value for each of these margins is 100psi.
3. Bleed off a volume of mud from the annulus which is equivalent to the operating pressure margin. Maintain the casing pressure constant as the mud is bled from the well. This will be a very slow process because the rate of expansion is governed by the migration rate calculated in Step 1. This will result in the formation remaining over- balanced by the overbalance margin. Use a manual choke to ensure adequate control.
   Record all volumes and pressures on the Volumetric Control Worksheet.
4. Repeat steps 2 and 3 above. Do not vent gas when the influx reaches surface as the bottomhole pressure may decrease and a further influx may be taken.
5. Prepare high density mud to pump into the well. Calculate the hydrostatic pressure equivalent for one barrel of lubricating mud in the annulus using the same equation outlined in Step 1.
6. Line up to pump lubricating mud down the kill line.

7. Pump lubricating mud into the well until pump pressure reaches a predetermined limit based on MAASP (Maximum Allowable Annulus Surface Pressure).
   Record volume pumped.
8. Allow the lubricating mud to fall through the influx as the well is left static.
9. Bleed gas from the well to reduce the casing pressure by an amount equivalent to the hydrostatic pressure of the lubricating mud pumped into the well. Ensure returns are lined up through the poor boy degasser and the volume of any mud bled back is recorded. Shut-in immediately when mud returns are noted when bleeding off.
10. Repeat Steps 5 and 6 until all gas has been vented from the well.

Static Volumetric Control procedure (Drill Pipe Pressure Method)

This procedure shall only be used in the following circumstances:

- Pipe on bottom.
- No drill string float (ported or un-ported) installed.

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Determine the migration rate as shown in the table above.
2. Allow the drill pipe pressure to build up by an operating margin of c. 100-200psi overbalance margin. This will depend on the MAASP.
3. Bleed mud from the choke manifold until the drill pipe pressure has reduced to the original stabilised shut-in value plus the overbalance margin.
4. The mud must be bled very slowly; the delay time may be considerable before drill pipe response is seen.
5. It is essential that the bottomhole pressure is not allowed to fall below formation pressure.
6. Continue Steps 2, 3, 4 and 5 until the influx has migrated to surface. Do not bleed off gas.

10.7.7 Bullheading

Bullheading can be considered when:

- Large gas influx that will result in an excessive volume of gas or excessive pressure at the surface if circulated out.
- Pipe is off bottom and cannot be stripped in.
- No pipe in the hole.

Factors which may affect the feasibility or success of bullheading:

- Discrete or strung out influx. An influx sustained while drilling may be contained in a large mud volume that will be difficult to squeeze away.
- MAASP due to formation fracture pressure and equipment rating.
- Formation permeability.

Bullheading Procedure

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Assess the migration rate as described in Section 10.8.6
2. Calculate MAASP for the current mud weight.
3. Establish injection pressure by pumping down the annulus at a slow rate.
   Keep pump rates constant and plot the injection pressure versus the volume.
4. Do not exceed MAASP.
5. If injection pressure continues to increase, stop pumping and observe.
   A decrease in pressure indicates successful bullheading.
6. Continue pumping to over-displace the top of the influx to TD by 50%.
7. Shut down and observe the well.
8. Raise mud weight (if necessary), if possible circulate using Wait and Weight Method until annulus is clear of influx.

10.7.8 Stripping

The procedure described in this section is the Combined Stripping and Volumetric Technique that maintains constant bottomhole pressure while the pipe is stripped through the annular. The principle used to accomplish this is a volume balance of the wellbore; for every barrel of pipe stripped in the hole a barrel of mud is bled off.

The following text summarises the calculations performed prior to stripping in. This procedure is also shown schematically in the Appendices at the end of this Chapter.

Maintaining Constant Bottom Hole Pressure

The pipe volume added to the well will increase the bottomhole pressure if mud volume is not bled off. Bottomhole pressure will also increase due to influx migration during the time period that stripping operations are being conducted. As the BHA enters the influx, an additional increase in bottomhole pressure can occur. These effects must be accounted for in order to maintain constant bottomhole pressure.

Determine Pipe Volume Effect

1. Calculate the pipe volume (per stand of pipe stripped in) as follows:

$$V = LS\ (Ddp + Cdp)$$

Where		
	V	= Volume per stand (bbls).
	LS	= Average stand length (ft).
	Ddp	= Drill pipe displacement(bbls/ft).
	Cdp	= Drill pipe capacity (bbls/ft).

2. When each stand has been stripped in, bleed off the calculated required volume of mud from the annulus (i.e. during connection). This method can provide a clearer indication of when the BHA enters the influx.

   Note: A float must be used and the pipe filled when RIH.

   Alternatively, it may be preferred to bleed off volume as the pipe is being run, to maintain a more constant pressure regulation process, or if the pressure increase resulting from adding one stand approaches or exceeds MAASP.

3. If pipe is being stripped out of the hole, the required volume of mud should be added continuously as the pipe is being pulled to ensure the bottomhole pressure does not drop and thereby allow additional influx to enter the wellbore.

Determine Influx Migration Effect

When stripping operations take a significant time to complete, influx migration effects must be considered. Usually, the volume of mud to be bled for influx migration is small relative to the volume bled off to compensate for the addition of pipe into the hole.

Influx migration can be detected by:

- A gradual increase in surface pressure even though the correct volume of mud is being bled from the well.
- Surface pressures increasing when the pipe is stationary.

The volume of mud to be bled-off for influx migration can be calculated using the Hydrostatic Pressure Equivalent formula given in Section 10.7.6

Determine Effect of BHA Entering Influx

When the BHA is run into the influx, the surface pressure will increase at a higher rate than prior to entering the influx. This is due to the displacement of the influx around the BHA extending the influx height and hence lowering the total hydrostatic pressure in the annulus.

Whilst balancing formation pressure, the surface pressure therefore increases.
It is very important to recognise this effect and to ensure that the casing pressure is not bled off to compensate for the increase in pressure.

The maximum possible pressure increase due to the BHA entering the influx shall be calculated as follows:

$$PMI = \frac{(53.44)(MW - IFG)}{dh^2} V \left\{ \frac{dh^2}{dh^2 - do^2} - 1 \right\}$$

Where		
	PMI	= Maximum Pressure increase (psi).
	MW	= Mud weight equivalent (ppg)
	IFG	= Assumed influx fluid density (ppg)
	V	= volume per stand of pipe (Bbls) as calculated above
	dh	= Hole size (in)
	do	= BHA OD (in)

Stripping Procedure

This procedure is also shown schematically in the Appendices at the end of this Chapter.

1. Install inside BOP valve above drill pipe stab-in valve. Open stab-in valve.
2. Reduce annular closing pressure to the recommended pressure for stripping pipe at the actual casing pressures. Allow a slight leakage through the preventer while stripping.
3. The pipe should be slowly lowered through the annular while the annular surface pressure is accurately monitored. Reduce running speed when passing tool joints through the annular.
4. Bleed the required volume of mud from the well during each connection unless MAASP pressure limitations dictate that it be bled more frequently. Complete the Stripping Worksheet for each stand run and each time volume is bled.

   Note: Maintain an overbalance of 50 to 200psi at all times while stripping, unless formation integrity will not be able to take such an overbalance.
5. Fill the pipe every five stands with original weight mud.
6. Strip to bottom or desired depth to kill well.

Changing Rams etc. while stripping

The combination wear bushing/test tool designed for the compact wellhead system is capable of being hung off on the wear bushing. In the event of a serious leak in the annular preventer or pipe rams therefore, it is possible to:

1. Strip in the combination tool using the annular and pipe preventer.
2. Land out on the wear bushing.
3. Back out the running string above the combination tool (this connection must be made up “soft”).
4. Close the blind rams above the tool.
5. Effect necessary repairs while monitoring/control pressures.
6. Retrieve the combination tool and strip out of hole.
7. Resume operations.

10.8 WELL CONTROL PROBLEMS

Conventional well control procedures are based upon the assumption that all of the well control equipment operates as designed and the wellbore is able to withstand the imposed pressures. Mechanical problems and formation fracturing, however, occurs occasionally during well killing operations causing complications with conventional procedures.

Careful consideration must be given to the available well data before selecting an alternative procedure. The figure below outlines the possible cause of problems for several unexpected changes in surface measurements.

	DRILL PIPE PRESSURE	CASING PRESSURE	DRILL STRING WEIGHT	PIT LEVEL	PUMP S.P.M.
LOSS OF CIRCULATION	⬇	⇩	⬆	⬇	⇧
CHOKE PLUGS	⬆	⬆	NO CHANGE	⇩	⇩
BIT NOZZLE PLUGS	⬆	NO CHANGE	NO CHANGE	NO CHANGE	⇩
BIT NOZZLE WASHES OUT	⬇	NO CHANGE	NO CHANGE	NO CHANGE	⇧
PUMP VOLUME DROPS	⇩	⇩	NO CHANGE	NO CHANGE	NO CHANGE
HOLE IN DRILL STRING	⬇	NO CHANGE	NO CHANGE	NO CHANGE	⇧
GAS FEEDING IN	NO CHANGE	⇧	⇧	⬆	⇧
CHOKE WASHES OUT	⇩	⬇	NO CHANGE	⬆	⇧
GAS REACHES SURFACE	NO CHANGE	⬆ THEN ⬇	⇩	⬇	NO CHANGE
SYMBOLS:	⇧ INCREASE	⇩ DECREASE	■ MAJOR	□ MINOR	

Figure 11. Well Control Problem Indicators

10.8.1 Well Control in Horizontal Wells

Although the kill calculations are identical for straight, deviated and horizontal wells (true vertical depths used in all cases) and the well control procedures are based on the same principles, these considerations should be implemented during both the planning and operational phases of a horizontal drilling programme.

1. <u>Tripping</u>

In general, the bottom hole assemblies used to drill horizontal wells are not as likely to cause swabbing as those run in vertical wells. However, substantial reservoir intervals may be exposed, increasing the potential for swabbing and making induced kicks greater than in a vertical well.

Extreme caution shall be exercised when returning to bottom following a trip. The horizontal section of the wellbore could be partially or completely filled with reservoir fluids despite the well being static (i.e. not flowing). It is therefore recommended that bottoms up be circulated through the choke manifold and degasser prior to drilling ahead.

2. Influx Volume and Nature

In the event of a kick in a horizontal well it is virtually impossible to determine the nature of the influx (i.e. oil, gas, water) due to equivalent shut in drill pipe and casing pressures. It may be difficult to validate data obtained during a kick and hence it is recommended to assume a gas influx at all times.

3. Productivity

The economic rationale responsible for the implementation of a horizontal drilling programme should be kept in mind when considering well control issues. The enhanced productivity and amount of reservoir section exposed tend to increase the rate of influx. Rig personnel should be particularly cognisant of well control procedures while drilling through the pay zone, especially if drilling at the balance point with non-damaging brines. Well control should never be ignored due to directional control problems.

10.8.2 Gas Hydrates

Gas hydrates can present serious problems during well control operations. Gas hydrates are complex crystalline structures of hydrocarbons and water having the appearance of hard snow. They can form at temperatures above the normal freezing point of water under certain pressure conditions. This formation process is accelerated where there are high gas velocities, pressure pulsations or other agitation's which cause mixing of the hydrate components.

The conditions for hydrate formation can be predicted. These pressure and temperature conditions can exist in a well control operation where low geothermal gradients exist, or downstream of a pressure drop in the system, i.e. choke. This can result in plugging of surface lines downstream of the choke.

Prevention of gas hydrates can be accomplished by maintaining pressures and temperatures outside the hydrate range, or by suppressing the hydrate formation temperature by injecting glycol into the gas stream. In well control operations pressure or temperature control methods for gas hydrate prevention are usually not possible, therefore use of glycol injection is recommended.

A gas hydrate contingency plan should be formulated for all wells where the potential exists for gas hydrate formation. The plan should provide a method of injecting glycol at the BOP stack.

A suggested method of accomplishing this is to pump glycol down the kill line with the cement unit and slowly injecting it into the well as the gas approaches surface and enters the choke line.

10.8.2 Cement Plug

If the well can not be controlled by conventional means it may be necessary to cement off the over-pressured zone.The cement slurry design should take account of the following factors:

- Spacer type and volume must prevent contamination during displacement.
- Surface lines must be free of potential contaminants.
- Gas channelling must be minimised by application of appropriate cement recipe technology.
- Slurry volume must be sufficient to allow for displacement into the formation.
- Slurry density must be sufficient to provide overbalance during displacement

The use of cement offers little chance of recovering the drillstring once cement is displaced up the annulus, particularly around stabilisers in the BHA. It must also be considered that there is a poor chance of achieving adequate cement isolation in the annulus between the BHA and hole. In addition, cementing will often result in the bit nozzles becoming plugged preventing further cementing attempts without resorting to
perforating the drill pipe. Consequently cement plugs should be considered a last resort.

10.8.4 Barite Plug

This is a mixture of barite and water or diesel. The objective is to utilise the rapid settling effect of the barite in water, in the absence of any viscosifier, to rapidly form an impermeable barrier to flow.

The following is a guide to the typical recipes for 1 barrel of barite plug. The mud engineer should perform pilot testing prior to pumping:

Required Density (ppg)	Volume of Freshwater Required (bbl)	Amount of Barite Required (lbs)
17.9	0.642	530
20.0	0.560	643
21.0	0.528	695
21.93	0.490	740

Table 65. Barite Plugs, Barite-Water Mix for Water Based Muds

Lignosulphonate thinner at 0.4ppb and caustic should be added to keep the barite particles separate.

Displacement Procedure

1. The barite slurry should be mixed by adding the barite to previously prepared water and thinners.
2. The slurry must then be pumped immediately unless continuous agitation is possible.
3. The slurry should be pumped at a higher rate than the kick rate and no less than 10 bbl/min with both the cement unit and rig pump tied into it.
4. After the plug has been displaced, it should be verified that flow has been stemmed by shutting in the well and observing pressures.
5. If the flow has stopped and a second plug is not required then the pipe will be pulled above the plug and circulated clean.