Supplemental Manual

The information contained in this supplemental manual is intended to meet the requirements of the new IADC curriculum, and must be used with the existing Boots & Coots Pressure Control for Drilling and Workover Operations Manual.

Topics:

Well Work Objectives

Kick prevention and formation fluid containment depend on maintaining pressure in the wellbore within the drilling window of all exposed formations. The drilling window depends on the pore and fracture pressure gradient. Therefore, knowing accurate pore and fracture data helps design the drilling program.

Other parameters that contribute to well control prevention events are related to the drilling fluid and operation program. The density of the drilling fluid should be within the limits of the drilling window, including a safety factor. The rheological properties of the drilling fluid should minimize the pressure drop and surge/swab to an acceptable level to mitigate any kick or loss in the wellbore.

The well design and drilling program may prevent kicks by controlling the well geometry, casing seat selection maintaining the wellbore full of proper drilling fluid, and following proper drilling guidelines.

- Formation parameters:
    - Formation pressure profile in the wellbore
    - Fracture pressure profile in the wellbore
    - Wellbore stability pressure profile in the wellbore
- Drilling fluid properties:
    - Density
    - Rheology (PV, YP)
    - Gel strength
- Drilling operation:
    - Keep the well full of mud
    - Monitor gas %
    - Look for changes in the trends of drilling parameters
    - Keeping the hole clean before tripping to reduce drilling related problems and reduce surge and swab
    - Tripping procedure
- Tubular design:
    - Avoiding tight geometry in the wellbore
    - Set casings to the appropriate depth
    - BHA design

Rules and Regulations

The petroleum industry is regulated by a number of entities and governing bodies across the world. Some of the more common regulatory bodies include:

- The Bureau of Safety and Environmental Enforcement (BSEE)
- The Bureau of Ocean Energy Management (BOEM)
- Bureau of Land Management (BML)
- API- The American Petroleum Institute. API has developed and implemented a vast majority of globally recognized Standards and Recommended Practices for processes and procedures for the oil and gas industry. The most notable API regulations regarding Well Control are:
    - API Std 53
    - API RP 16 E
    - API RP 16 A
    - API SPEC 16 D
    - API STD 65-2
    - API RP 64 (diverter systems)

Fracture Gradient, Kick Tolerance and Pore Pressure

The drilling fluid should provide hydrostatic pressure in the range of pore pressure to fracture pressure, which is usually called the drilling window. If the hydrostatic pressure of the drilling fluid is less than pore pressure, a kick could occur. Wellbore pressure that exceeds the fracture pressure may result in fluid loss to the formation.

Fracture Pressure, Formation Pressure and Kick Tolerance are concepts important to the planning of drilling, completing, or performing a workover. Based on pore pressure and fracture pressure, the minimal and maximal useable mud weights are determined. Usually a safety factor of 0.5 ppg or other pre-determined value is used to consider the effect of a surge or swab while tripping. Therefore, the safety factor may be referred to as “trip margin”.

Fracture pressure and formation pressure are the two (2) parameters used to start a drilling design; they will give the designer the starting point to select the casing setting points, the mud plan, MAASP, etc.

Kick tolerance is defined as the maximum volume of kick for a given kick intensity that could be circulated out of the well bore safely. Kick tolerance is calculated using the available FIT and mud weight data. The kick is considered to be gas, which is the worst-case scenario.

The formula below can be used to Calculate Kick Tolerance when the kick is at the bottom:

$$\text{Kick Tolerance(ppg)} = \frac{TVD_{Shoe}}{TVD_{Bit}} \times (LOT_{Shoe} - MW) - \frac{H_{influx}}{TVD_{Bit}} \times (MW - P_i)$$

Where

H_{influx} = Height of the influx at shut-in, ft

P_i = Density of the influx, ppg

LOT = Mud weight equivalent of leak-off test, ppg

MW = Mud weight in the well, ppg

Usually a safety factor or a safe margin for choke handling and other operational parameters like annular pressure drop, are considered in the analysis and calculations.

The highest pressure at the shoe is expected when the gas is either at the bottom or gas at the shoe. Therefore, kick tolerance is performed at both instances and the lowest kick volume is considered to be the limit of kick tolerance.

The kick volume for several kick intensities are calculated and plotted to present the limit of the kick tolerance for the well. Any kick situation below the line is considered to be the safe, and any condition above the line is considered to fracture the shoe and cause underground flow (underground blowout).

Kick intensity is the additional density that should be added to the mud for balancing the formation pressure. If an induced kick is taken, the kick intensity would be zero.

Casing and Cementing Programs

Casing Design

To start casing design you must verify:

- Final purpose of the well (Production, injection, relief, etc)

- Availability of casings, completion tools, drilling tools
- Formation profiles, pressures and temperatures
- Type of formation fluid (stratigraphic column)
- Rig capabilities and performance
- Fresh water level
- Country agency regulations

The main functions of casing are to:

- Isolate a fresh water zone to prevent contamination by wellbore fluids, drilling fluid, oil, gas, etc.
- Prevent caving in and forming caverns or sticking of the drill string in unconsolidated shallow formations.
- Provide a strong starting point to use a higher density fluid to control higher formation pressure.
- Isolate zones with different formation pressure gradients.

Cement is used to hold casing in place and to prevent fluid migration between subsurface formations. Cementing operations can be divided into two broad categories: primary cementing and remedial cementing.

Primary Cementing

The objective of primary cementing is to provide zonal isolation. Cementing is the process of mixing cement slurry, cement additives and water, and pumping it down through casing to critical points in the annulus around the casing or in the open hole below the casing string.

Remedial Cementing

Remedial cementing is usually done to correct problems associated with the primary cement job. The most successful and economical approach to remedial cementing is to avoid it by thoroughly planning, designing, and executing all drilling, primary cementing, and completion operations. Remedial cementing operations consist of two broad categories:

- Squeeze cementing
- Plug cementing

Reasons for Workover Operations

The majority of workovers are done because the well is not performing up to expectations.

Workover may be required for one or more of the following reasons:

- Production or injection rates are not satisfactory or changed abruptly.
- Mechanical problems such as packers, tubulars, sub surface safety valves, artificial lift components, cement, etc.
- Supplemental recovery project requirements
- Regulatory requirements
- Competitive drainage
- Reservoir data gathering
- Lease requirements
- Abandonments
- Change in well purpose (e.g. production to injector)
- Regulatory requirements, GORs out of agreement or regulations, new safety equipment regulations.

Initiation of supplemental recovery projects cause workovers because many wells must be converted to injector wells, observation wells, or disposal wells. Also, all wells need to be completed in correlative zones, thus a significant number of wells need perforating and stimulation and/or zones shut off via squeeze cementing or plugs (cement or mechanical).

Workovers done for the reasons just noted are generally completed to yield a profit in a reasonable length of time.

Completion Program

The main difference between well control operations related to drilling and completions is the open hole section. During drilling there is normally a section of open hole with some different formations exposed to the wellbore.

During drilling you do not know the real formations characteristics. Once the well is drilled, better information about the formations is collected. During completion all reservoirs characteristics are known.

Most of the completion jobs are conducted using clear fluids and in cased hole.

If the well is completed, kicks enter the wellbore quicker and the severity of the situation escalates faster. Gas migrates faster in clear fluids than in drilling fluids because clear fluids do not have gel strength or a yield point.

In old wells, the integrity of the casing may be very questionable and reverse circulation may be the choice for circulating the well.

Fluids Program

Drilling/completion fluid is the first line of pressure control. Therefore, it is very important to design the properties of the fluid carefully to prevent any issues. The drilling fluid should provide sufficient hydrostatic pressure to manage the wellbore pressure within the drilling window.

Also, the fluid should be carefully designed to avoid excessive surge and swab pressure, especially when operating in a narrow drilling window environment. Maintenance and contaminations are the next issues. Contaminated fluid results in more sophisticated well control operation and increases the time for regaining control of the well safely.

When you design a fluid plan you must take the following parameters into consideration:

- Formation pressure
- Fracture pressure
- Fluids compatibility to a minimum or no damage to pay zone
- Job objective
- Environmental regulations
- Personal safety

Barriers

With regard to well control (blowout prevention), a philosophy of *barriers* is employed to ensure maximum safety for workers as well as protection from environmental damage. This philosophy is instrumental in every phase of the total planned operation, from beginning to drill (spud), to final production throughout the life of the well including plugging and abandonment. A barrier, in the context of the industry, may be thought of as a shield or envelope that prevents formation fluids from flowing to the surface, resulting in a blowout.

- Primary Barrier – An element used to provide constant well control throughout normal operations. In drilling operations the mud or fluid used is considered the primary barrier. If a liquid is used as the primary barrier one must be able to both control and monitor the fluid. In a snubbing or coil tubing operation the stripper or annular BOP is considered the “primary” barrier.
- Secondary barrier- A barrier that is available during normal operations but is only activated after the primary barrier has failed.

- Tertiary Barrier- A last resort barrier or a barrier used if both the primary and secondary barriers fail. E.g. Blind / Shears or Master Valve.
- All barriers must be tested according to the standards and legal regulations for that area before operations can begin or continue.

There are two classes of barriers: fluid and mechanical. Drilling mud is considered the only independent fluid barrier. The hydrostatic pressure exerted by the mud plus the wall cake-building characteristic of the mud constitute an effective barrier providing that the mud weight (density) results in hydrostatic pressure greater than the formation pressure. There have been industry discussions concerning brine fluids but the consensus is that brine does not act as an effective barrier due to the fact that it does not build wall cake and therefore may seep into permeable formations thus reducing the hydrostatic pressure. Also, the density of brine is susceptible to change due to temperature and other factors. It is considered impractical to constantly monitor a column of brine in an open well.

Mechanical barriers include blowout preventers and other downhole equipment such as positive valves, Packers, plugs, etc. Casing and properly set cement can be considered effective barriers if successfully tested. Industry policy requires *at least* two barriers be in place at all times for safe operation. For example, during drilling operations the drilling mud is the primary barrier. Secondary barriers exist in the BOP stack. In underbalance operations, for example coiled tubing operations tertiary barriers are usually necessary.

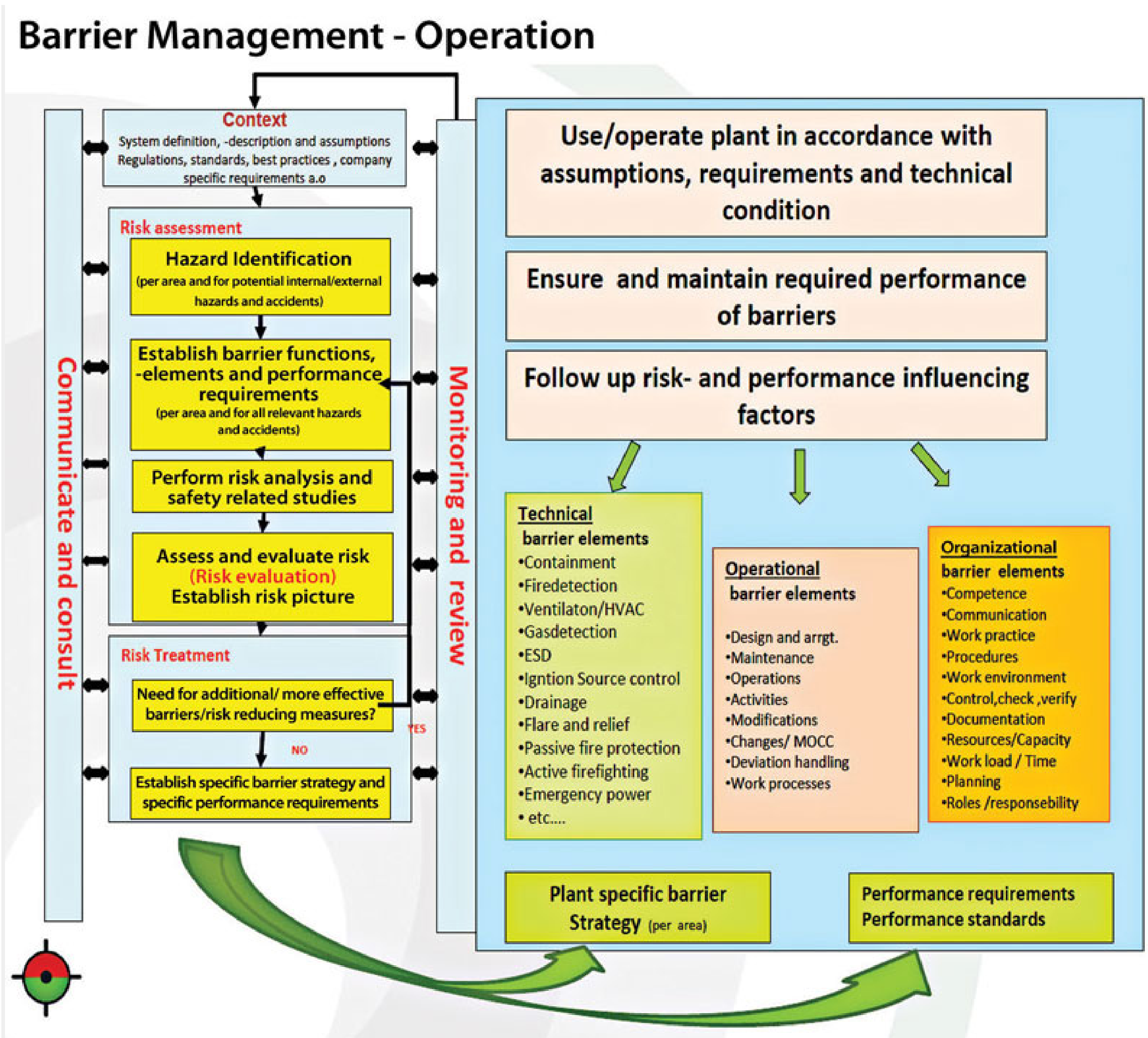
Personnel shall be aware of which barriers are not functioning or have been impaired." This is the sentence wherein the Petroleum Safety Authority (PSA) Norway has defined, in regulations, the challenge to companies operating on the Norwegian Continental Shelf (NCS) to reduce risk of major accidents.

The following is taken from PSA's Management Regulation Section 5: Barriers shall be established that:
a) Reduce the probability of failures and hazard and accident situations developing; and
b) Limit possible harm and disadvantages.

Where more than one barrier is necessary, there shall be sufficient independence between barriers. The operator or the party responsible for operation of an offshore or onshore facility shall stipulate the strategies and principles that form the basis for design, use and maintenance of barriers so that the barriers' function is safeguarded throughout the offshore or onshore facility's life.

Personnel shall be aware of what barriers have been established and which function they are intended to fulfill, as well as what performance requirements have been defined in respect of the technical, operational or organizational elements necessary for the individual barrier to be effective. Personnel shall be aware of which barriers are not functioning or have been impaired. The responsible party shall implement the necessary measures to remedy or compensate for missing or impaired barriers.

PSA's Management Regulation Section 10 states: The responsible party shall establish measurement parameters to monitor factors of significance to health, safety and the environment, including the degree of achievement. The operator or the party responsible for operation of an offshore or onshore facility shall establish indicators to monitor changes and trends in the major accident risk and environmental risk.


Barrier Management - Operation
Context
System definition, -description and assumptions
Regulations, standards, best practices , company specific requirements a.o
Risk assessment
Hazard Identification
(per area and for potential internal/external hazards and accidents)
Establish barrier functions, -elements and performance requirements
(per area and for all relevant hazards and accidents)
Perform risk analysis and safety related studies
Assess and evaluate risk
(Risk evaluation)
Establish risk picture
Risk Treatment
Need for additional/ more effective barriers/risk reducing measures?
YES
NO
Establish specific barrier strategy and specific performance requirements
Communicate and consult
Monitoring and review
Use/operate plant in accordance with assumptions, requirements and technical condition
Ensure and maintain required performance of barriers
Follow up risk- and performance influencing factors
Technical
barrier elements
•Containment
•Firedetection
•Ventilaton/HVAC
•Gasdetection
•ESD
•Igntion Source control
•Drainage
•Flare and relief
•Passive fire protection
•Active firefighting
•Emergency power
• etc....
Operational
barrier elements
•Design and arrgt.
•Maintenance
•Operations
•Activities
•Modifications
•Changes/ MOCC
•Deviation handling
•Work processes
Organizational
barrier elements
•Competence
•Communication
•Work practice
•Procedures
•Work environment
•Control,check ,verify
•Documentation
•Resources/Capacity
•Work load / Time
•Planning
•Roles /responsebility
Plant specific barrier Strategy (per area)
Performance requirements
Performance standards

Well Control Equipment Selection

Selecting the proper BOP stack configuration is a very important factor while planning for drilling a well or a workover on an existing well. BOP selection should consider the following parameters:

- Maximum wellbore pressure
- Drilling or completion fluid type
- Formation fluid
- Presence of H_2S or CO_2
- Geometry of the well at the surface
- Geometry and size of tubular and tool that will pass through the BOP
- Government regulations
- Environmental regulations
- Operator regulations

In addition to the BOP stack, surface safety valve and choke manifold configurations must be selected.

Non-Shearables

When running non-shearables thru the BOP stack pre-planning is crucial. The rig crew must have a clear understanding of all situations that may require the well to being shut in while non shearables are across the BOP stack. As well as the secondary procedure, should the primary barrier be unavailable or fail. A decision must be made as to when and how to drop the pipe and secure the well using the blind rams.

Prior to running a non-shearable thru the BOP stack, the bridge must be notified in advance. An announcement must then be made so that all concerned parties are aware of the current operation. Should an event of dynamic positioning or thruster failure occur the bridge must notify the driller, and the driller will act accordingly. Prior to pulling non shearables across the stack, a flow check should be performed to verify there is no flow from the well with the pumps off. An appropriate safety valve that can stabbed into the non shearable should be made available at all times. This may require the use of a drill pipe joint with the crossover to connect to the non shearable and then secure the well on the drill pipe and check for flow as needed. If at all possible a Full Opening Safety Valve (FOSV) should be used to allow for subsequent operations e.g. wireline or coil tubing.

In subsea operations, emergency disconnect procedures include general identification of color designation for traffic lights on dynamically positioned (DP) rigs.

- Green- all good

- White - caution or warning,
- Yellow - hang off
- Red - disconnect.

As the situation changes the bridge will change the color of the light that is located on the driller's panel to communicate what is required. The driller must confirm a shear/red light signal with the bridge before shearing pipe.

Tapered Strings

When running a tapered string proper calculations must be made before running the string. Always reference accurate pipe data in the planning phases of any operation to ensure proper procedure are employed. Whether the string is run wet or dry makes a big difference in all calculations. Proper calculations for each string are required. Each string will have its own specific displacement and capacity value to use for calculations.

When running a tapered string accurate monitoring on trips is important. The best method for monitoring a well during tripping operations is by using a calibrated trip tank. If there is a discrepancy between theoretical and actual trip tank readings, a flow check should be performed immediately and volume/stroke calculations should be re-checked in order ensure proper hole fill is maintained.

Once a kick is taken the well control procedure will be incorrect if inaccurate calculations are continued. Each string of pipe will have its own specific capacity and displacements. If a well control incident is encountered while using improper capacity calculations, the Wait and Weight Method pressure chart will be inaccurate. This is especially true in a highly deviated well because the hydrostatic pressure added per barrel or stroke would be different than what is actually being added to the drill string. For this reason the Drillers method is preferred when running a tapered string. It is important to always have a current kill rate pressure (KRP), sometimes called a slow circulating pressure, available at all times as part of kick awareness and preparation. The KRP is simply the circulating pressure at a selected slow pump rate, commonly 20, 30 or 40 SPM. Any activity that causes a significant change in drillstring friction will affect the KRP value. Common changes include, changes to the BHA, changes in mud weight, adding special tools to the string, or simply drilling ahead for more than 300 to 500 ft. These changes will call for a new KRP to be established and documented. A current, accurate KRP is crucial in establishing the initial circulating pressure (ICP) when a kick is circulated using a constant bottomhole pressure kill method. If no current KRP is available it can be established using the following technique:

- Pump at the selected kill rate.
- Adjust the casing pressure to its shut-in value with the adjustable choke
- When the pump rate is correct and the casing pressure is at the shut-in value, note and document the circulating pressure.

If the Wait and Weight Method is selected the following formula can be used to calculate the pressure step down.

Since there are different internal diameters for each section of the tapered drill string, the pump pressure must be calculated for each section.

$$\mathrm{ICP_{PSI}} - \left(\left(\frac{\text{Length}_{\text{ pipe section}}}{\text{Length}_{\text{ drill string}}}\right) \times \left(\mathrm{ICP_{psi}} - \mathrm{FCP_{psi}}\right)\right)$$

Where:

ICP_{PSI} = Initial Circulating Pressure

FCP_{PSI} = Final Circulating Pressure

Operators must ensure that it is possible to secure the well on any string being used. This can be achieved by; using Variable Bore Rams (VBR's), multiple ram style BOP's fitted with each appropriate size ram block. In most situations the primary BOP for securing the well is an annular preventer.

Special activities like displacing cement, spotting pills or balancing a plug require careful planning when considering fluid displacement through tapered sections.

Casing Operations

Running casing poses an increased risk for a well control incident if proper precautions are not taken. When running casing, special casing design with a narrow clearance must take extra considerations about torque and drag. Mud conditions like high viscosity or a contaminated mud could represent a major problem when running casing. Circulating bottoms up to ensure the hole is clean prior to tripping out with the drill string is an important step in ensuring the hole is free of debris prior to running casing into or out of a well. More than one bottoms up may be necessary to ensure proper hole cleaning and mud conditions.

One important factor, if not the most important factor that relates to running casing, is the speed at which a casing is run into or out of the well. Swabbing and Surging factors are increased due to the large diameter of casing being run which results in a narrow annular space. Casing centralizers can also increase the chance of swabbing or surging. When running casing during subsea operations the heave of the ship can increase the chance or risk of swabbing or surging. Precautions must be taken to prevent such an occurrence. Constant vigilance, supervision and hole monitoring are paramount. Monitoring the well using a calibrated trip tank and good communication of the returns is a very important factor in maintaining well control during casing operations. A trip sheet should be accurately filled out for wet and dry tripping. A pre job meeting that covers; Running speed, trip calculations, shut in procedures, should be had prior to running any casing.

When running casing it is common to use a self-filling shoe. One should always check with the manufacturer for possible causes of failure. One common reason for failure is debris or solids obstructing the shoe. This is why cleaning the hole prior to running in with such tools is important. Should a self-filling shoe fail in the closed position, the hole should be filled at pre-determined intervals. If the float fails in the open position it may be necessary to set a cement retainer and squeeze the shoe. It is recommended to pump through the shoe to make sure everything is in proper working order before starting cementing operations. If the shoe does fail in the open position, flow will be observed from the casing string due to the u-tube effect and can allow formation fluids to enter the wellbore or allow cement to backflow up inside the casing. It may be possible to re-connect and pump on it to try and free the shoe from any obstructions and allow the shoe to close or seal properly. Operators should always monitor the string weight during the operation for signs of shoe failure. Changes in the string weight can give a good indication of float status.

If a well control incident arises, the operator needs to be able and ready to shut in the well appropriately. Using the annular preventer is the primary BOP to use at appropriate closing pressures. If the proper closing pressures are not used the annular could damage the casing or otherwise fail. Casing rams should always be used when at all possible as a secondary barrier at surface. A circulating head must be ready to use during casing and cementing operations should it be needed. Also a landing joint with a crossover to the casing thread should be made available so that the well can be secured in case of emergency. If all of the above mentioned fails, contingency to drop the pipe should be made aware at the onset of a well control incident. If possible it is considered better to drop the pipe and secure the well than it is to have a blowout at surface.

Cementing Operations

During the cement setting to solidify or harden and develop compressive strength, the hydrostatic pressure decreases at the bottom of the hole due to a fluid gradient transition. The loss of hydrostatic pressure may result in channeling and flow of formation fluids or gas through the cement resulting in a kick. If a kick is identified the well must be shut in according to proper shut in procedures. E.g. Space out properly, shut down cement pump, close the annular BOP, Monitor shut in conditions. It is imperative to follow the recommended wait time that the cementing company proposes as a minimum wait time (WOC). Failure to wait an appropriate amount of time may result in catastrophic loss of the well. WOC time is dependent on many factors such as temperature, pressure, slurry rheology, and the use of accelerators and or retarders used in the slurry. Casing movement and pressure testing while the cement is setting can disturb the cement which may induce channeling through the cement and damage the cement bond between the casing and the borehole. Do not slack off weight or change the pressure the cement is under during the WOC time frame. When completing the cement operation it is recommended to run analysis of the cement before continuing with drilling operations. Cement Bond Log (CBL's) are used to analyze the cement job. If the CBL identifies locations where the cement is spotty or insufficient a cement squeeze can be used to repair the cement job.

Negative Testing

A negative test is pressure test in which the hydrostatic pressure is reduced such that the net pressure differential is in the direction of the formation to the surface. It is used to ensure that a plug or packer of some kind is holding properly from the bottom. It is the way to properly verify the integrity of a cement job.

Procedures for negative testing may vary slightly but essentially the same outcome is achieved. One way of achieving the proper hydrostatic underbalance is by circulating a lighter fluid through a circulation device e.g. SSD, ported sub, or circulation sub etc. Swabbing the string may achieve the required underbalance. Or using a coiled tubing unit to perform a nitrogen lift or circulating a lighter fluid. Once the desired underbalance or drawdown is achieved, conduct the inflow or negative test for 15 minutes or for the time detailed in the drilling program while monitoring the surface gauges for any possible pressure build-up. Once a successful test is accomplished unseat the plug or packer and circulate the light fluid while monitoring the well for flow or pressure.

If a failure is encountered during the negative test the following steps can be used to secure the well and prevent any further influx of formation fluids into the wellbore.

- Open the bypass
- Circulate bottoms up through the drill sting and through the choke to remove any formation fluids from the annulus
- Pump and squeeze cement through the packer
- Rerun test

Emergency Procedures

An operator must not only prepare and fully understand adopted emergency procedures but also know when to fully enact such procedures. Emergency procedures should be activated whenever there is a risk of; loss of life, Injury to personnel, environmental damage or loss of property. Recognizing when an operation is at risk and taking immediate action often requires extensive field knowledge. Supervisors and leaders should be thoroughly trained in emergency response procedures and *all* onsight personnel encouraged to report any unexpected event to their supervisor. Stop Work Authority is a common part of most emergency plans. Anyone at any time can stop the operation and notify supervisors if they are aware of an anomaly during an on-going operation. This is especially crucial regarding potential physical injury to personnel

An emergency response plan would include any situation:

- When a loss of well integrity or well control is imminent.
- If uncontrolled flow from the well is observed or suspected.
- Broaching of gas or other hazardous materials to the surface.
- Presence of hazardous gas is above a safe level.
- Severe weather conditions on or offshore.
- Risk of vehicle or vessel collision.
- When there is a risk of sabotage, kidnapping or any other form or means of terrorism.
- Return fluids indicate that something strange is happening down hole (black oil, high chloride water/mud, temperatures are extremely high.
- Inability to maintain pressures with choke due to rate or choke size. Also known as keeping up with the choke.
- Blow-by is encountered on the mud gas separator. In such event an operator must be able to line up on a panic line to divert safely until fluid returns are established.

Monitoring Pits During a Kick

If a well is killed using a constant bottomhole pressure method the volume of mud on the surface can be expected to increase. This is due to two factors: 1) adding barite to increase the mud weight. 2), There is some gas present in most kicks. As the gas is circulated to the surface maintaining constant bottomhole pressure by means of choke adjustments, the gas will expand, forcing mud out of the well. During the early stages of circulation, before the gas has moved far up the well, expansion may not be evident. However, the rate of expansion increases rapidly as the kick nears the surface causing the returning mud volume to likewise increase rapidly, sometimes to an alarming rate until the gas is removed, at which time the total pit volume will diminish proportionally. These effects can make it difficult to accurately monitor changes in pit level. The mud engineer can calculate the volume increase due to adding barite to the system but not the rate or volume of the expanding gas. The only thing that can be done is to carefully monitor the changing annular pressure, taking into account the calculated MAASP, kick tolerance, and the fracture gradient in order to avoid if possible, lost circulation. Close teamwork between the mud engineer and the mud pit personnel are crucial when circulating out a kick.

Stripping and Drills

Stripping is the process of moving pipe into or out of a well under pressure in a pipe heavy situation. Pipe heavy is when the force acting down from the pipe is greater than the force acting up on the pipe form the well bore pressure. As pipe is lowered into a closed-in well, pressure is trapped in the well which increases pressures in the wellbore. To control increases in pressure the Volumetric Method of Well Control is used to maintain constant BHP while stripping.

Typically, stripping operations occur when a well flows during a trip with the string off bottom. The amount of pipe to be stripped is small and the surface pressure is usually low.

To strip pipe into a well the rig must meet the following requirements:

- Is the rigs trip tank accurate enough to measure small amounts of fluid being bled from the choke?
- Can the closing pressure on the annular BOP be independently regulated and controlled
- In high pressure situations, will the BOP stack configuration allow double preventer closure around all sizes of pipe in the string? (combination of two rams, or a ram and annular) Note: Never use the lower most ram for stripping
- Is the BOP configured to allow proper space out between the rams?

If your rig is not equipped to properly and accurately strip into a well, it is recommended that the pipe not be moved and that the well is controlled at the depth that the kick is detected.

Volumetric Stripping

We learned in the volumetric method that a fluid volume equal to the pressure increase must be bled off in order to maintain BHP constant

Pressure increase $_{psi}$ ÷ fluid gradient $_{psi/ft}$ = feet of fluid

Feet of fluid $_{ft}$ x Capacity $_{bbl/ft}$ = barrels to bleed

When stripping, as pipe is run into the well, the volume equal to the pipe displacement must also be bled off..

Additional Volume to Bleed = Pipe displacement $_{bbls/ft}$ x Length of stand $_{ft.}$

Procedure

1. Begin stripping pipe with the choke closed.

2. Allow the CP to increase by pre-determined safety factor

3. Continue stripping pipe with the choke closed.

4. Allow the CP to increase by pre-determined working pressure

5. Continue stripping pipe while bleeding fluid to the trip tank, holding CP constant

6. Record barrels bled for each stand.

7. Once the fluid bled is equal to the pressure increase + the displacement volume, shut in the choke.

8. Allow the CP to increase by the pre-determined working margin.

9. Repeat steps 7 & 8 until the desired depth is reached.

10. When the BHA enters the influx, the CP will increase rapidly.

11. Once the bit is near bottom or you believe the bit is below the influx, stop stripping and begin the Drillers Method.

12. If the well kicks while the drill string is out of the hole and there is a need for extended stripping or the CP is greater than 500 psi you should not consider stripping without surge bottles installed in the hydraulic closing lines.

Stand	Casing PSI	Calc. Disp.	Actual Dip.	Difference	Total Diff.
1	300	N/A	N/A	N/A	N/A
2	350				
3	395				
4	450				
5	450	2.3	3.0	.7	.7
6	450	2.3	3.0	.7	1.4
7	450	2.3	3.4	1.1	2.5
8	450	2.3	3.7	1.4	3.9
9	450	2.3	3.7	1.4	5.3
10	450	2.3	3.9	1.6	6.9
11	450	2.3	4.0	1.7	8.6
12	450	2.3	4.0	1.7	10.3
13	475				Empty
14	510				
15	550				
16	550	2.3	3.5	1.2	1.2

Monitoring Equipment Failure/Erroneous Readings

Gauges used to monitor pump pressure, pump rate, shut in pressures etc. are prone to malfunctioning and failure. Gauges usually have minor inaccuracies but when they completely fail, a backup gauge must be available for use.

It's important to remember that the backup gauge may not read the same as the old gauge so errors can occur. The differences must be noted and taken into account during a process where pressure readings are critical.

Rough handling of the gauges on drilling rigs during rigging up or down, failure of the sensors or transducers which are located remotely from the gauges or damage to pneumatic, electronic or hydraulic transmitting devices can affect gauge readings. Many contractors and operators require the crew to test all gauges used in well control operations and keep track of any observed discrepancy, malfunctioning and/or failure. Gauges that are properly certified and calibrated should only be used. Any failures or discrepancies in gauge readings should be immediately reported to the supervisor. When installing pressure sensors or transducers they should be rigged up in such a way that in the event of failure it can be isolated and bled off so that new equipment can be installed. This is commonly known as block and bleed.

Hang Off and Drills

If a well control incident is encountered, some operators and contractors prefer to hang off the drill string on the ram preventers to prevent accumulation of gas below the subsea annular preventers and to prevent damage to the rams seals caused by the movement of the pipe. During severe weather conditions hanging off the drill string is necessary to release the drilling riser from the BOP stack to allow the rig to drive off. One example of a hang of procedure is:

- Conduct a space out to ensure that the rams will not close on a tool joint and that the lowest drill string safety valve is accessible.
- Close the hang off rams
- Slowly lower the drill string until a tool joint contacts the ram. Observe the weight indicator for a decrease in string weight for verification.
- If using a ram BOP that is not equipped with automatic locking devices, actuate the ram locking device.

This procedure should be practiced to ensure the crews are proficient at the operation prior to a live event.

Positive Test

If an underground blowout is suspected, no attempts should be made to control the well using conventional methods. If the annulus is opened formation fluids will enter the wellbore and increase surface pressures.

Upon shutting in a well that is suspected of underground flow, a positive test should be made. This test used to determine the condition and stability of the open hole.

Line up a low displacement pump and pump a small amount of fluid. If both the drill pipe and casing pressures increase, the hole is considered stable. If the drill pipe or casing pressure does not increase, a fracture in the open hole is assumed and loss circulation or underground flow procedures should be implemented.