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Theme

Controlling a gas kick during drilling (case study of MDZ729)

Discussed publicly

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DEDICATION

Mr BETTAOUI Abdessalam.

I dedicate this work to my parents who raised me to become the man I am today, my father who did everything he could for me, my mother who didn't forget me in her prayers. My success is dedicated to you .

To my brother Zoheir who has been always there for me.

To my dear sisters for being supportive all the time.

To all of my friends everyone by his name and every person that pushed me to continue my studies .

Mr BOUZEKRI Kheir-eddine.

I dedicate this work to my beloved family who help me over-coming many obstacles throughout different situations.

To my father who push me towards the top and help with all his efforts.

To my mother the only person who support me whatever the situation is and never forget me in her prayers.
To my siblings my brother Mohammed yacin and my dear sisters .

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First things first I thank ALLAH
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Mr. BETTAOUI Abdessalam, Mr. BELKACEM Yassine & Mr. BOUZEKRI Kheir-eddine.

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NOMENCLATURE

BOP	Blow out preventer	
API	American petroleum Institute.	
PH	Hydrostatic pressure	psi
MW	Mud weight	ppg
BHA	Bottom hole assembly	
HWDP	Heavy weight drill pipe	
DP	Drill pipe	
DC	Drill collar	
OD	Outside diameter	In
VBRs	Variable BOP rams	
ID	In side diameter	In
PVT	Pit volume totalizing	bbl
HCR	Hydraulic valve	
ROP	rate of penetration	
MWD	measurement while drilling	
SIDPP	Shut in drill pipe pressure	psi
SICP	Shut in casing pressure	psi
ICP	Initial circulating pressure	psi
FCP	Final circulating pressure	psi
BHP	Bottom hole pressure	psi
ΔP	working pressure	psi
Vb	mud volume to bleed	bbl
CAP	capacity	Bbl/ft
Rm	gas migration rate	ft/h

ΔP	chosen working pressure level	psi
V	mud volume to pump through the annular space	bbl
MD	measured depth	ft
NPT	time of non-production	h
LOT	Leak of test	
Pf	formation pressure	psi
MKW	Mud kill weight	ppg
MAASP	Maximum allowable surface pressure	psi
Px	Pressure at depth X,	psi
Pb	Bottom hole pressure,	psi
ρ_m	Mud gradient,	psi/ft
Z	Compressibility factor	
T	Temperature,	°Rankine
X	Distance from surface to top of influx,	ft
A	annular area,	in2
D	Well depth,	ft
$\boldsymbol{P_f}$	Pressure exerted by the influx at depth X,	psi
SICP	shut in casing pressure,	psi
$\boldsymbol{H_x}$	Height of the influx,	ft
$\boldsymbol{Cdcoh}$	Annulus capacity between open hole and drill collar,	Bbl/ft
$\boldsymbol{G_f}$	influx gradient	Psi/ft
TVD	True vertical depth.	ft
MDZ 729	Vertical well number 729.	
BHA	Bottom Hole assembly	
OH	Open hole	
ENAFOR	Enterprise national de forage (enafor).	

Introduction

Introduction

Drilling for oil and gas is a complex and challenging process that requires the use of advanced technology, specialized equipment, and highly skilled personnel. One of the most critical aspects of drilling is well control, which refers to the ability to maintain pressure and prevent the uncontrolled flow of formation fluids, such as gas or oil, into the wellbore. Failure to properly control a well can result in a blowout, which can have disastrous consequences for the environment, personnel, and equipment.

This thesis focuses on the topic of well control in the context of gas kicks, which occur when gas enters the wellbore and displaces drilling fluid, creating a potentially hazardous situation.

The first chapter provides an overview of drilling generalities, including the types of drilling rigs, drilling fluids, and drilling operations.

The second chapter examines the equipment used for well control, including blowout preventers, choke manifolds, and kill lines.

The third chapter explores various methods of well control, such as the driller's method and the wait and weight method, which are designed to quickly and effectively manage gas kicks.

The fourth and final chapter of this thesis presents a case study of a well with a gas kick and compares the effectiveness of the driller's method and the wait and weight method for controlling the well. The chapter includes calculations of the required mud weight and volume of kill mud for each method, a fill-out of the kill sheet, and a comparison of the results. The chapter concludes with a discussion of the advantages and disadvantages of each method and recommendations for future drilling operations.

Overall, this thesis aims to provide a comprehensive understanding of well control in the context of gas kicks and to demonstrate the importance of proper well control procedures for safe and successful drilling operations.

Chapter I

Basic concepts

I.1. Introduction

Drilling is a process of digging a hole in the ground and to make that possible we need to provide engineering support for optimum drilling operations including rig selection and design of the mud program, casing and cementing programs, the hydraulic program, the drill bit program, the drill string program, and the well control program.

Drilling operation helps to gather information such as ground strength, ground formations, composition and information about resources and also provides access to those resources.

I.2. Oil and gas rock accumulation

Four common types of trap in which oil and gas may be found are shown; See Figure 1 and 2. These are: Fault Trap, Salt Dome, Unconformity Trap and Anticlinal Trap. [1]

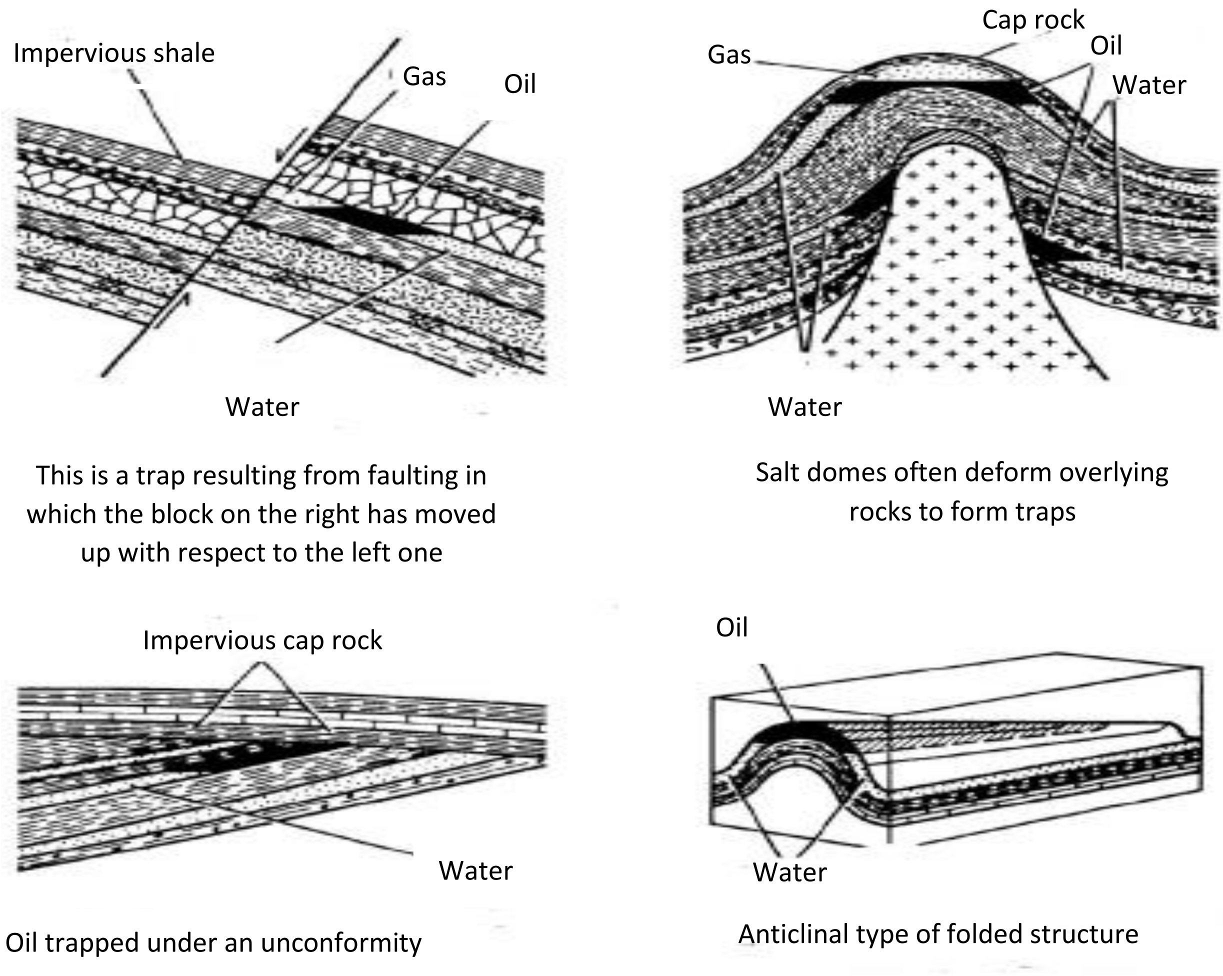

Figure I.1 - Typical Oil and Gas Rock Formations[1]

I.3. Well planning

When choosing a well plan that will minimize the drilling hazards without compromising the objective, a thorough analysis of all available information on the area to be drilled is essential.

I.3.1. Pressure Estimation

A variety of techniques are used to determine pore pressure (formation fluid pressure). These techniques depend on determining the "Normal Trend" of measured shale properties with depth and then spotting any deviations that might point to "Overpressure Zones." Several sources, including drilling records, well logs, sparker surveys, and seismic surveys, can provide information that is useful for well planning.

I.3.2. Drilling records

It is possible to identify hole issues, abnormal pressures, lost circulation zones, required mud weights and properties, and casing setting depths using drilling records, such as daily tour sheets, mud reports, bit records, casing and pipes, and geologic graph records.

I.3.3. Well logs

Well logs can provide useful geologic information such as lithology, formation tops and bed thicknesses, dips, faults, wash outs, lost circulation zones, formation fluid content and formation fluid pressure (pore pressure).

I.3.4. Sparker surveys

If accessible, shallow seismic data from "Sparker Surveys" can be used to find tiny shallow gas accumulations. These "bright spots" are typically low pressure and low volume, but they can occasionally be high pressure gas.

I.3.5. Seismic surveys

Seismic surveys may be crucial in wildcat regions where there is barely any data on offset wells. Pore pressures, formation strengths, and lost circulation zones that are determined solely from these may only be "guesstimates" that should be handled carefully, particularly beneath significant lime stone or dolomite thicknesses.

I .4. Casing seat selection

The most important pre-planning choice is frequently the depth at which to install each casing string in a well, particularly in areas where abnormal pressures and lost circulation zones will be expected.

Making the right decision for the casing placement requires careful consideration of the pore pressures (formation fluid pressures) and fracture pressures present throughout the well. As the pore pressure in a formation being drilled approaches the fracture pressure at the previous casing seat, it is obvious that a longer string of casing is needed, Figure 2 illustrates this, with an idealized casing seat selection shown.

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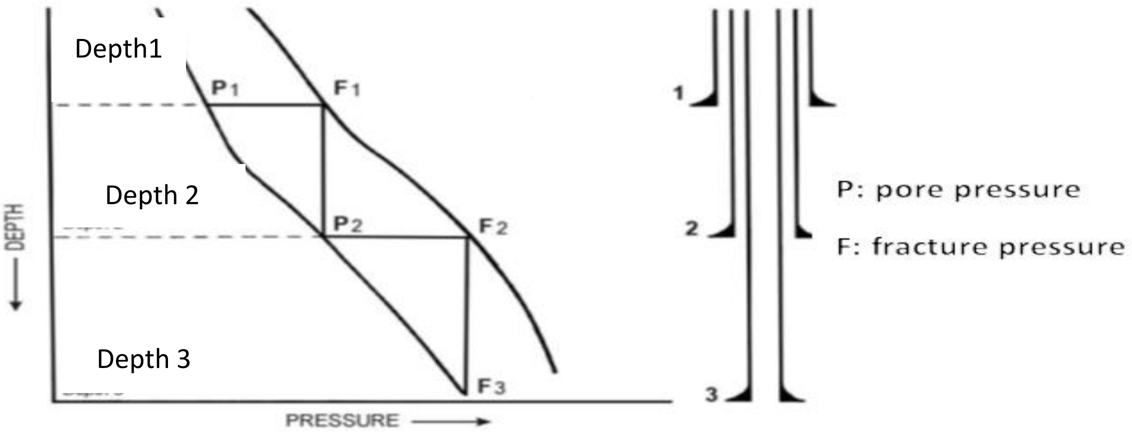


I.2 - Casing Seat Selection [1]

I.5. Casing selection

The maximum loads to which the casing may be exposed will determine the size, weight, and grade of casing needed for any well.

Well depth and the kind of completion required determine the casing size. The casing's weight and grade can subsequently be decided, taking necessary safety considerations into account. In order to maintain effective well control, this is done to ensure that the casing strength is adequate. Collapse pressure, burst pressure, and tension are the three main loads that need to be taken into account. There is a limit to the amount of kick, especially gas kick, that can be safely handled by a given casing due to limitations in casing strength, especially when wear safety allowances are taken into account. Drill teams need to be mindful of this potential significant constraint while working on deeper wells [2].

I.6. Rig selection

the lowest possible well cost. The two types of rotary drilling rigs are onshore (land) and offshore (marine). Mobility, flexibility, and maximum depth of operation are their primary design features.

The basic goal of rig selection is to pick the rig that will most nearly satisfy the requirement for drilling a practical hole at the planned well's lowest total cost from among those that are now available. The evaluation of each of the rig systems listed below is directly related to the selection process:

- Power generation system
- Hoisting system
- Fluid circulation system
- Rotary system
- Well control system
- Drilling data acquisition and monitoring system [3]

I.7. Drill string

A drilling rig is a column, or string, of drill pipe that transmits drilling fluid (via the mud pumps) and torque via the Kelly drive or top drive to the drill bit. The term is loosely applied to the assembled collection of the smuggler pool, drill collars, tools and drill bit. The drill string is hollow so that drilling fluid can be pumped down through it and circulated back up the annulus (the void between the drill string and the casing/open hole). The drill string is typically made up of three sections:

- Bottom hole assembly (BHA): drill bit, drill collars, downhole motor and rotary steerable system (RSS), measurement while drilling (MWD), and logging while drilling (LWD) tools. Short "subs" are used to connect items with dissimilar threads.
- Heavy weight drill pipe (HWDP)
- Drill pipe

I.8. Drilling fluid

Drilling fluids are fluids that are used during the drilling of wells. They provide primary well control of subsurface pressures by a combination of density and any additional pressure acting on the fluid column (annular or surface imposed).

I.8.1. Drilling fluid function and performance

The principal functions of drilling fluid are to:

- Control subsurface pressures, maintaining well control;
- Remove drill cuttings from beneath the bit and circulate them to the surface;

• Maintain wellbore stability, mechanically and chemically;

• Transmit hydraulic energy to the drill bit and downhole tools;

• Cool and lubricate the drill string and bit;

• Allow adequate formation evaluation;

• Provide a completed wellbore that will produce hydrocarbons;

• Form a low permeability, thin and tough filter cake across permeable formations.

I.8.2. Types of fluids

Drilling fluids include three main types: water-based muds, oil-based muds, Air drilling fluids, ,foams, are used in only very specific, limited applications. The most critical properties of these fluids are density, viscosity, fluid loss control, and chemical composition. The measurement of these properties gives the mud engineer a “status report” of the fluid and how it is reacting with the formation and the subsurface environment.

I.8.2.1. Water-based muds

Water-based drilling fluids are the most commonly used of the mud systems. They are generally less expensive and less difficult to maintain than oil muds, and in some special types of systems, they are almost as shale inhibitive. However, inevitably the action of drilling the hole in a consolidated formation relieves stress. If a water-based fluid is used, the water will tend to enter the formation and change the mechanical properties of the rock. These changes may be enough to cause formation damage and borehole instability. These damaging effects can be minimized by using an inhibited water-based fluid. The inhibited water-based systems cannot totally prevent water wetting of the rock pores, but they can minimize it.

I.8.2.2. Oil-based muds

Oil-based muds were developed to prevent water from entering the pore spaces and causing formation damage.

I.8.2.3. Air drilling

Under a restricted set of conditions, air can be used as the drilling fluid when drilling through formations having little or no permeability to water. Although classified as “air” drilling, several types of gasses are actually used.

I.8.2.4. Foam

Foam drilling follows the same format as mist drilling, but with a foaming agent introduced into the mist stream. Foam is preferred when drilling stable formations that may have a moderate influx of water.

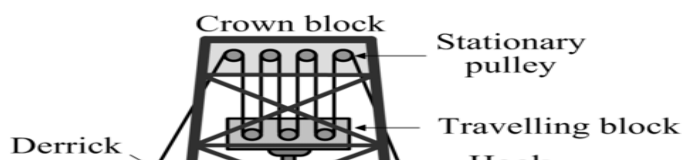


Figure 4- Schematic layout of petroleum drilling rig with fluid circulation

I.9. Well Control

Recently, "Well Control" has come into sharper focus because of how important it has become to everyone who is interested in it. Although relatively outdated, pressure control techniques are nevertheless employed in a number of locations around the world. Well control is a term and technical term that means controlling the pressure of the bottom hole formation that the well is penetrating.

Many losses of the vital resources came as results from the well control events, as well as running up the costs of drilling, environmental contaminant, increasingly the process of regulating, and the personnel liable to get injured and that comes to death. The large amount of an uncontrolled flow of gas, oil, or other well fluids from the well is owing to the people are involved committing technical mistakes, that may have been refrained in case of having genuine well control procedures. Well control is considered kind of an art which is performed many times on daily basis on rigs. It needs the right mud density, the mass or weight of a substance per unit volume, reasonable hole cleaning, speeds to be slow for moving, abundant checking and maintaining of blowout preventer (BOP), the crew needs training too. The pressure obstacles and the main and second flow, which means the mud column and BOP, have to be available permanently in order to keep the unexpected or the worst conditions of the blowout away. [8][18]

I.10. The importance of well control

The most critical situation is most likely to be gas kick which may happen on drilling a well because it may be come to a blowout unless it is to be controlled right away. The question brings up here “In case of blowout, who do expect to give you a hand?" It is the operator's duty to find the answer. Any mistakes can be eliminated by well trained personnel, well planned well programs in a harmony way. Making the initial drilling may cause a blowout. The people who are entitled to start putting to the well under control are drilling engineers while the process of planning going on to select the satisfactory quality of drilling equipment and decide the right size of a hole and frame or casing points. Both the BOP equipment and the rating of the pressure for the well head must be selected well to stand the well pressure. The crew must be well-trained enough to be able to understand the principles of how to control a well, as well as their fast response and being analytical to any situation. Circulating out the kick is as much as important; they must be supplied with good understanding of the causes and the reasons of the history of the actions. In spite of this, the people who are included in both of the executing of the programs and its planning are liable to make errors. To solve this problem is to train the personnel well and select the right equipment for that . [19][20]

I.11. PRESSURES

I.11.1. Mud hydrostatic pressure.

The hydrostatic pressure is defined as the pressure due to the unit weight and vertical height of a column of fluid and it is given by:

Hydrostatic pressure psi = density in ppg × 0,052× true vertical depth

Pressure gradient psi/ft = fluid density in ppg × 0,052 [2]

I.11.2. Formation pressure

Formation pressure or pore pressure is said to be normal when it is caused solely by the hydrostatic head of the subsurface water contained in the formations and there is pore to pore pressure communication with the atmosphere.

I.11.3. Normal formation pressure

Normal Formation Pressure is equal to the hydrostatic pressure of water extending from the surface to the subsurface formation. Thus, the normal formation pressure gradient in any area will be equal to the hydrostatic pressure gradient of the water occupying the pore spaces of the subspace formations in that area.

In absence of adequate data a value of 1.07 kg/L is used as the density of formation in normal pressure, (Gradient = 0,105 bar/m). [2]

I.11.4. Abnormal pressure

Every pressure which does not conform with the definition given for normal pressure is abnormal. The principal causes of abnormal pressures are:

Under-compaction in shales, Salt Beds, Mineralization, Tectonic Causes, Diapirism, Reservoir Structure.

I.11.5. Formation fracture pressure

In order to plan to drill a well safely it is necessary to have some knowledge of the fracture pressures of the formation to be encountered. The maximum volume of any uncontrolled influx to the wellbore depends on the fracture pressure of the exposed formations.

If wellbore pressures were to equal or exceed this fracture pressure, the formation would break down as fracture was initiated, followed by loss of mud, loss of hydrostatic pressure and loss of primary control.

I.11.6. Leak of tests

The leak-off test establishes a practical value for the input into fracture pressure predictions and indicates the limit of the amount of pressure that can be applied to the wellbore over the next section of hole drilled. It provides the basic data needed for further fracture calculations and it also tests the effectiveness of the cement job.

I.11.7. Maximum allowable annular surface pressure MAASP

The leak-off test was used to determine the strength of the formations below the casing shoe.

The applied surface pressure at which leak-off occurred is the maximum allowable annular surface pressure with the mud weight in use at that time. MAASP is the maximum surface pressure that can be tolerated before the formation at the shoe fractures.

MAASP (psi) = (Fracture gradient(psi/ft) – Mud gradient (psi/ft)) x True Vertical Shoe Depth (ft)

Chapter II

Well control equipment

II.1. Introduction :

There are many types of equipment that must be included in the drilling site. Equipment such as BOP's, chokes, accumulators, pit-volume indicators, gas detectors, and flow detectors to make it possible to detect and handle kicks with confidence. When modern equipment is coupled with good well design and thorough training, rig personnel are more able than ever before to control any well.

II.2. Equipment utility for well control

The first safety barrier on a well is mud, which provides primary control. In cases that the first barrier fails, we need a second barrier, so the BOP will provides a secondary control. Also, we need to be able to close on the various pipes down the well, which requires the use of multiple kinds of BOP (annular, Ram with various types, internal...).

In some cases of shallow gas we need to be able to evacuate effluent away from the rig using diverters, The number of stacking elements depends on the expected pressure in the well, A hydraulic unit is needed to operate BOP called koomey,

When the annular space is closed, it is necessary to be able to circulate through the well, control the pressures and separate the effluent from the mud, several equipment used such as choke manifold and the mud gas separator, The different elements are assembled by flanges that make it possible to seal,

The BOP, choke manifold must always be in functional condition to hold the pressure to confirm that pressure tests will be performed.

II.3. Auxiliary well control equipment

II.3.1. Gray Inside BOP

The Gray inside BOP is a valve Installed in the drill string, it protects the rotary swivel, rotary hose, standpipe, and mud pumps from drill pipe kicks. In order to keep well control by preventing high-pressure backflow, it may be used in conjunction with high-pressure pumps. The valve can be kept open via the use of a specialized release tool, allowing stabbing into place to stop fluid backflow. When drill pipe is pulled from the well, this optional release tool can be installed on the float valve and the entire assembly kept ready on the rig floor for quick installation at the first indications of serious backflow.

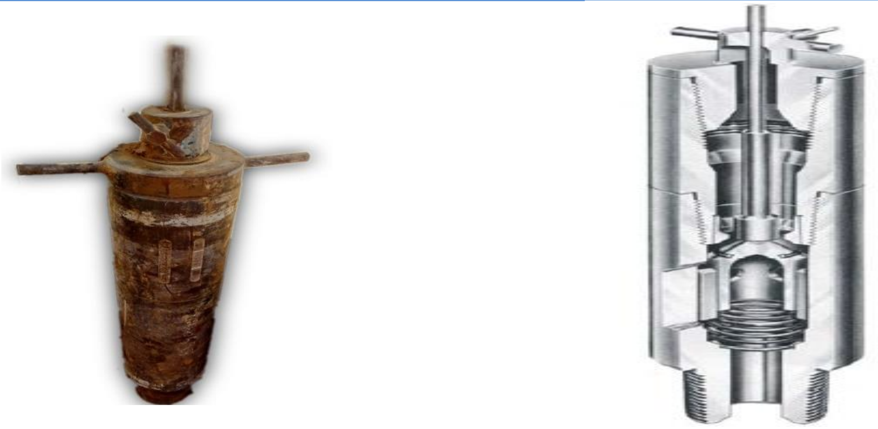


Figure II.1. gray valve [2]

II.3.2. Kelly Guard Valves

Hydril's Kelly guard is a mechanically operated ball valve that blocks the passage of the drill string. Kelly guards simplify control and prevent mud from spreading. They are attached above and below the Kelly in order to stop any upward flow from the wellbore or downward flow during a connection. Kelly Guard has a one-piece, compact body for easy handling and provides security up to 15,000 psi. Kelly guard is a 'Kelly cock' valve as defined by API Specification 7 for Rotary Drilling Equipment.

Figure II.2. Kelly guard

II.3.3. Top Drive Drill/Drill Pipe Safety Valves

Top drives incorporate an upper and lower Kelly guard as pictured. Because of their design, the upper splined valve can be operated remotely as well as manually when an actuator is present. Lower Kelly guard valves with connections to mate with the drill Pipe tool joint are used as safety valves for drill pipes.

Figure II.3. Cutaway View of Upper Splined Kelly Guard.

II.3.4. Drop-Down Check-Guard Valve

Check guard is a drop-in check valve for the drill string. The check valve remains at surface until needed and is retrievable by wire line. It provides the driller with a means to control the drill pipe pressure when required. The check valve allows fluid to be pumped downward to maintain well circulation while preventing fluid from flowing upward through the drill pipe. The valve can be recovered by removing the pipe from the hole or by utilizing a wire line.

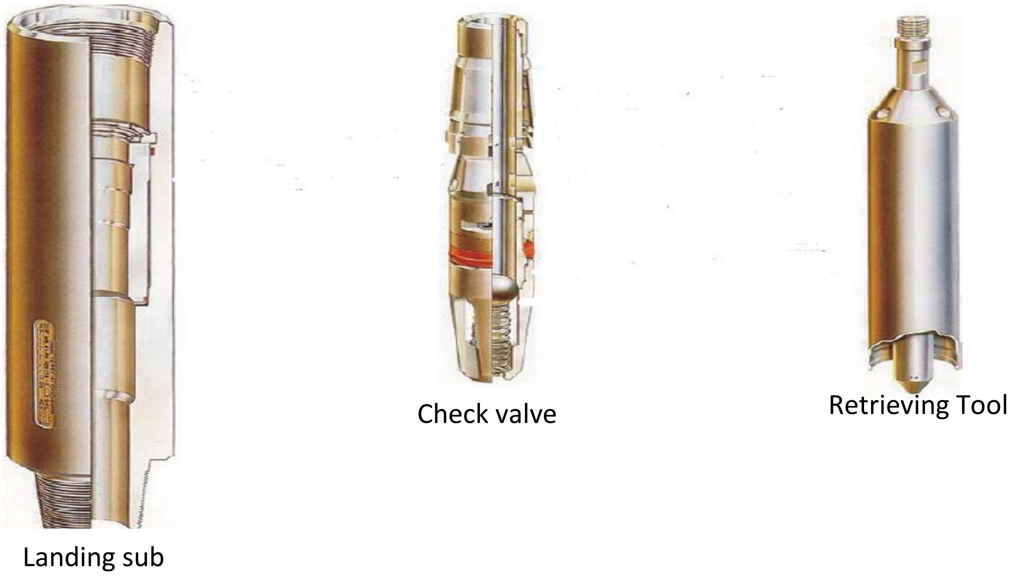


Figure II.4. Drop-Down Check-Guard Sub Valve and Retrieving Tool [2]

II.3.5. Drill Pipe Float Valves

Drill pipe float valves are normally installed above the drill bit. Simply they are NRVs (non-return valves). They enable circulation down the drill string only and Provide instantaneous shut-off from the annulus whenever the pumps are turned off. Their primary goal when drilling is to stop backflow while making links. Additionally, they provide hydraulic flow management when the drill string is tripping or shut-in at the set. Two common types are the spring loaded float valves and the flapper type float valve.

The flapper type valve has an included lock that enables the drill string to be placed into the hole while the valve is open, ignoring the need to fill the pipe.

As mentioned before, the spring loaded Baker float valve has similar functions In some variants, the center of the valve has a 5 mm hole drilled through it to enable the measurement of drill pipe pressure under shut-in circumstances.

Higher surge pressures, the inability to read drill pipe pressure or reverse circulate, and having to pause to fill the pipe are the primary negative aspects of using float valves.

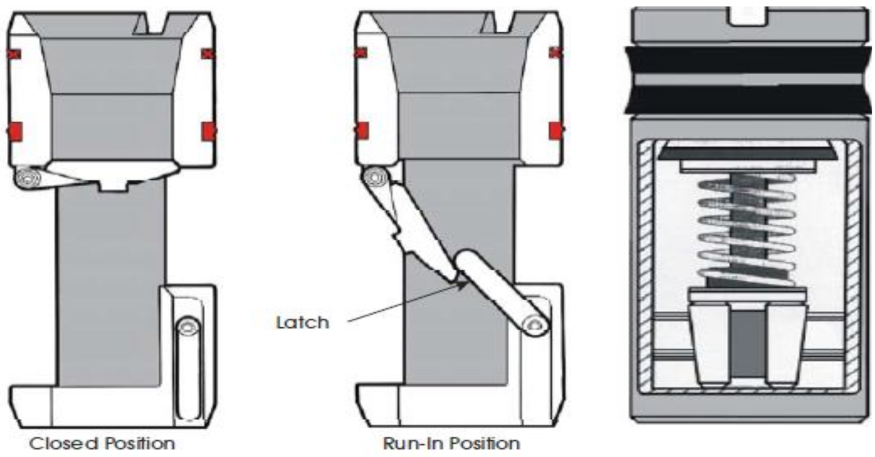


Figure II.5. Spring loaded type [2]

II.4. Well heads

Well head provides a means of landing and sealing around casing strings and supporting the BOP stack. Their pressure integrity is vital to well control, the rated working pressure exceeding the maximum expected surface pressure. They must also have sufficient strength to support subsequently installed casing and tubing strings as well as the BOP stack. [4].

II.5. Ram BOP

The most common type of Blow out preventers nowadays is ram type BOPs there is three common types of BOPs: Shaffer 'SL', Cameron 'U' and Hydril 'V'.

API RP53 requirements state that surface rams must close within 30 seconds and close within 45 seconds for the Subsea rams.

Ram BOPs Allows closure of the annular space, Depending on the equipment in the well:

- Closure on a given diameter (pipe rams, casing rams),
- Total closure (blind rams) when there is no drill string in the hole,
- Total shearing and closure (blind shear rams: BSR) to cut the drill string and make a seal after cutting,
- Variable closure (variable rams) for several tubular diameters,
- Closure on two tubes (dual rams) for double completions.

Operating principle:

An opening and shutting chamber are separated by a piston and a sleeve. Ram BOPs fixed to the piston rod's extremity moves along with the piston. The piston can move by applying pressure (1,500 psi) to an incompressible hydraulic fluid. The hydraulic connection enables the piston's sides to receive fluid. One of the compartments is purged when the other is under pressure. [5]

II.5.1 CAMERON 'U' BOP

The Cameron 'U' BOP is a ram type preventer designed for both land and subsea operations.

Features:

- U BOP rams are pressure energizing. Wellbore pressure acts on the ram to increase the sealing force and to maintain the seal in the event of hydraulic pressure loss.
- The Ram bonnets are opened and closed using hydraulic pressure.
- Large bore shear bonnets are available for U type BOPs. These effectively increase the closing area by 35%.
- A large manual locking screw facilitates locking and closing of the BOP if required.
- Wedgelock system available for subsea operations. Theses require a separate function to be deployed in order to lock the rams.

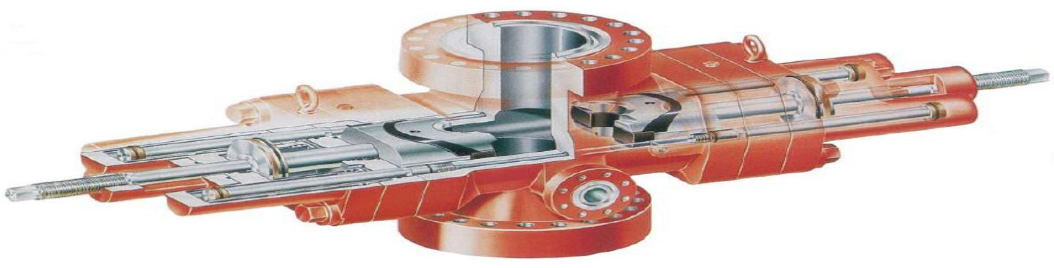


Figure II.6. U blowout preventer

II.5.2 U II BOP

The U II BOP is designed primarily for subsea use. It features a short stroke bonnet which reduces the opening stroke by 30%, reducing the overall length of the preventer and thus reducing the weight supported by the ram change pistons. The U II preventer wedgelocks act directly on the operating piston tailrod. The operating system can be interlocked using sequence caps to ensure the wedgelock is opened before pressure is applied to open the preventer. Like the U BOP the bonnets of the U II BOP are opened and closed using hydraulic pressure. Wedgelocks require a separate control system.

When combined with the CAMRAM packer the U II BOP provides a blowout preventer system that meets the API 6A rating of 250OF service. Packers and top seals are available for high pressure and H2S service.

Figure II.7. U II blowout preventer

II.5.3 'U' BOP – Pipe rams

For use in Cameron ram-type BOPs, Cameron pipe rams are available to suit all frequently used tubing, drill pipe, drill collar, and casing sizes. Sealing components have a sizable pool of feedable rubber and are pressure-energized and self-feeding.

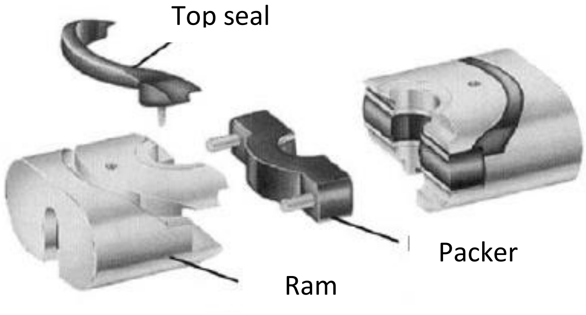


Figure II.8. U BOP pipe

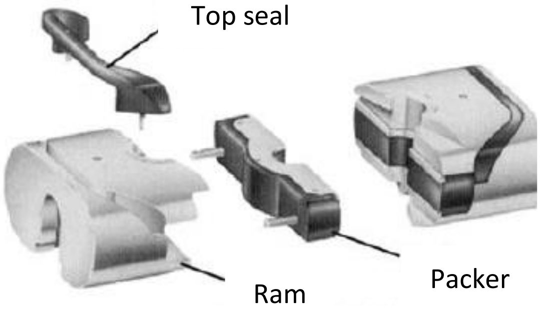


Figure II.9. U II BOP

II.5.4 Shear blind rams

Shearing blind rams shear the pipe in the hole, then bend the lower section of sheared pipe, allowing the rams to close and seal. They can be used as blind rams during normal operations.

The operating pressure required to shear pipe is 3,000 psi and the maximum size of pipe that can be sheared is 5 ½" OD. Shearing blind rams will shear pipe numerous times without damage to the cutting edge. The ram incorporates a single piece body with an integrated cutting edge.

Figure II.10. U and U II BOP shearing blind ram

II.5.5 Variable rams

VBRs can alter their diameter or bore size, making them more adaptable to various wellbore sizes and shapes than standard BOP rams, which have a fixed diameter. This is important in deep water drilling operations because the wellbore's diameter may vary as it descends deeper or runs into various geological formations.

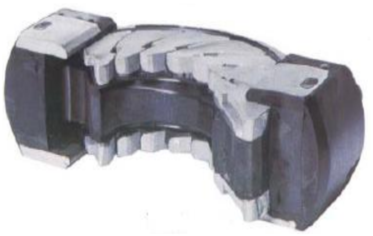


Figure II.11. VBR II

II.5.6 Shear blind rams

The wedgelock is a hydraulic mechanism which allows the BOP to be locked in the closed position remotely. The wedgelock assembly is attached to the BOP in place of the normal lock screw housing. (See figure below). The Green circle attachment is replaced by the orange circle attachment.

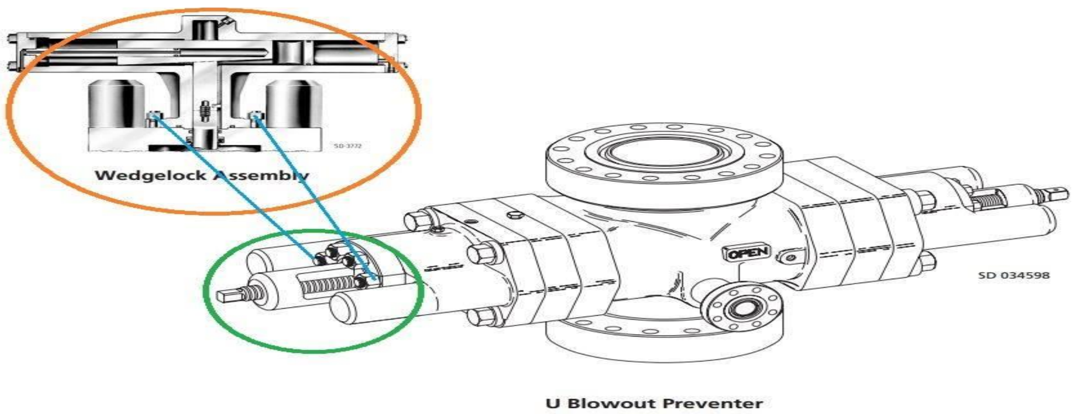


Figure II.12. U BOP wedgelock assembly

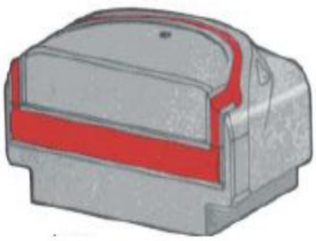
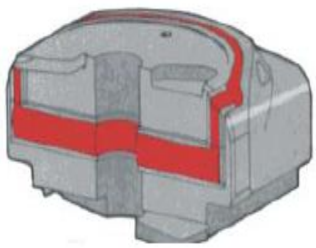
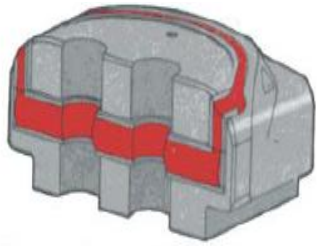
II.5.7 HYDRIL ram preventers

The Hydril ram type preventer is similar in operation and performance to the other ram preventers Hydraulic fluid is required to operate Hydril Ram BOPs. Hydraulic passages and fluid connectors are contained within the BOP body. Normal operating pressure is 1500 psi.

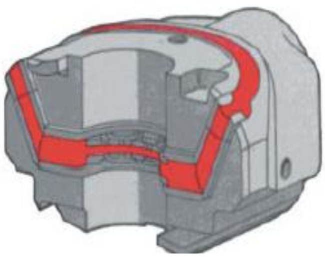
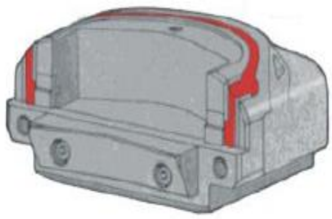
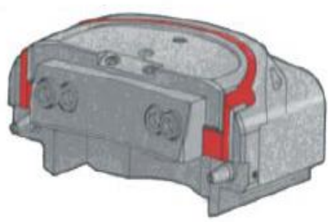
Features:

- Manual locking BOPs incorporate a heavy duty acme-thread to lock the rams in the closed position or to manually close the ram if the hydraulic system is inoperative.
- Multiple-position locking uses a hydraulically actuated mechanical clutch mechanism to automatically lock the rams in the closed position.
- A Field replaceable seal seat provides smooth sealing surfaces for the ram upper seal.
- Guide rods align the ram with the bonnet compartment, preventing damage to the ram, piston rod or bonnets while retracting the rams.

Figure II.13. Hydril 13 5/8” 10,000 psi Ram BOP with Manual Lock

Blind ram pipe ram dual offset ram

Hydril variable ram lower shear ram upper shear ram

Figure II.14. Hydril ram types

II.5.8 SHAFFER ‘SL’ RAM

The Shaffer ‘SL’ range is designed for large bore and high pressure subsea and deep land drilling, handling pressures from 15,000 psi down to 3,000 psi, with bore sizes 18¾” to 71/16”. The ‘SL’ BOP incorporates a mechanical locking system for use on surface stacks and has two types of automated locking systems for use subsea.

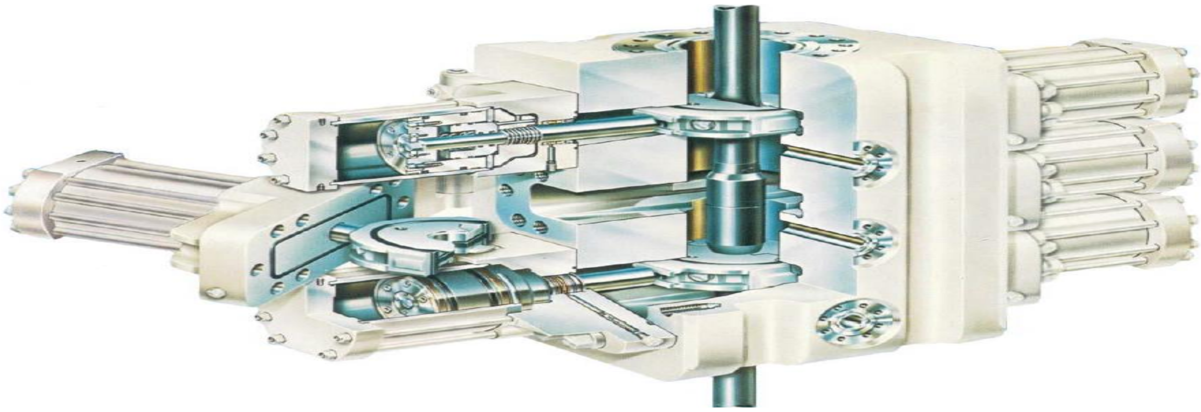


Figure II.15. SHAFFER 'SL' (Triple) RAM

'SL' ram features:

- Ram bodies are available in single, double and treble models.
- Rams can be changed out easily without breaking or remaking connections, even with pipe in the hole.
- Single piston hydraulic operators have a minimum number of working parts, assuring reliability and low maintenance.
- Available in flanged or studded connections.
- Full environmental H2S trim, conforming to API and NACE requirements.

Rams are available which will support a 600,000 pound drill string when a tool joint is lowered onto the closed rams.

II.6. Annular preventers

API RP53 state that surface annular preventers closing times should not exceed 30 seconds for smaller than 18 3/4" and 45 seconds for 18 3/4" or larger and it should not exceed 60 seconds for subsea annular preventers.

Utility:

Permit the closure of the annular space on various diameters (casing, pipes, cables,..) and seal as long as the surface is "regular" (sealing on a Kelly, on spiral DCs, but not on stabilizers), The BOP tend to be shut first (with a ram BOPs, positioning the seal well in advance is essential to prevent damage to the BOP and the tubular); it is possible to use them in complete closure, but not advised by the manufacturer; they also Allow stripping

Operating principle:

The BOP's piston and body define an opening and shutting chamber. The sealing element is in contact with the piston, which has a conical shape. The piston is moved by a hydraulic fluid under pressure, when one of the chambers is pressurized, the other is purged. The conical

piston compresses the sealing element as the compressed hydraulic fluid is sent to the sealing chamber. It closes and seals around the pipes in the well when being blocked upward. [5]

II.6.1 Shaffer Spherical BOP

Shaffer annular BOPs are rugged, compact and will seal on almost any shape or size-Kelly's, drill pipes, tool joints, drill collars, casing or wireline. They also provide positive pressure control for stripping drill pipe into and out of the hole. The annular BOP is one of the first lines of defense in controlling a kicking well.

Figure II.16. Shaffer spherical BOP

II.6.2 Annulars CAMERON 'DL'

Cameron annular blowout preventers are available in bore sizes from 7 1/16" to 21 ¼" and in pressure ratings to 20,000 psi.

- The packer is able to contain full rated working pressure even after long periods of use.
- Packer replacement is simple and fast. The quick release top, with its one-piece split lock ring, permits quick packer change out with no loose parts involved.
- The annular is designed to simplify field maintenance. Components subject to wear are replaceable in the field. The entire operating system may be removed in the field for immediate change out with a spare system, while the BOP remains in place on the stack.

Figure II.17. 'DL' Annular Blowout Preventer [6]

II.6.3 Annulars - HYDRIL 'GK'

The 'GK' annular preventer is designed for surface installations and is also used on offshore platforms and subsea. Standard operation requires both opening and closing pressure. Seal off is affected by hydraulic pressure applied to the closing chamber, which raises the piston, forcing the packing unit into a sealing engagement. Main features include:

- **Only two moving parts** (piston and packing unit) mean few areas are subjected to wear. The BOP is thus safer and more efficient requiring less maintenance and less downtime.
- **Piston is designed to be well pressure assisted**. This ensures a more positive seal off under kick conditions for a higher margin of safety.
- **Field replaceable wear plate in the BOP head** serves as an upper non-sealing wear surface for the movement of the packing unit, making field repair fast and economical.
- **Piston stroke measurement** provides indication of packing unit life without disassembly.
- **Three choices of packing unit rubber compounds**

Figure II.18. Type 'GK' Annular Blowout Preventer

II.6.4 Annulars - HYDRIL 'GL' preventer

The HYDRIL "GL" preventer is a type of BOP that applies a lot of power to the rams using a geared lock mechanism to ensure a tight seal and stop any further fluid flow from the well. It is controlled by a hydraulic control system and built to endure high pressure and high temperature conditions.

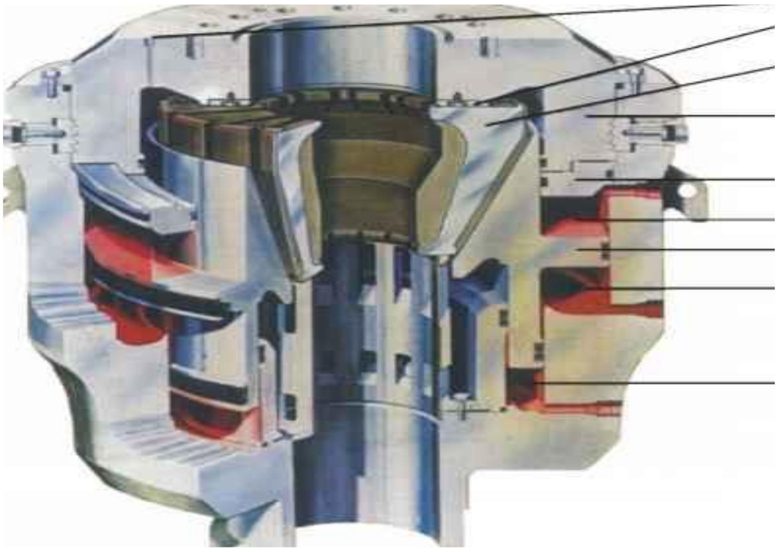


Figure II.19. Hydril 'GL' Annular Preventer

II.7. Diverters

Diverters are primarily used during the beginning of hole sections in shallow gas risk zones when the use of BOPs are forbidden due to low fracture margins. Their primary function is to ‘divert’ wellbore fluids a safe distance away from the rig floor during shallow well kicks. Diverters commonly have 12 inch ID ‘overboard lines’ and incorporate a large diameter low pressure annular type preventer.

Under the BOP, there are one or two side openings. To reduce erosion during gas kick, these lines should have the largest possible diameter. Before closing the BOP when using a diverter, the outlet underneath it must be opened, Thus systems (BOP, valves) where it is impossible to close the well.

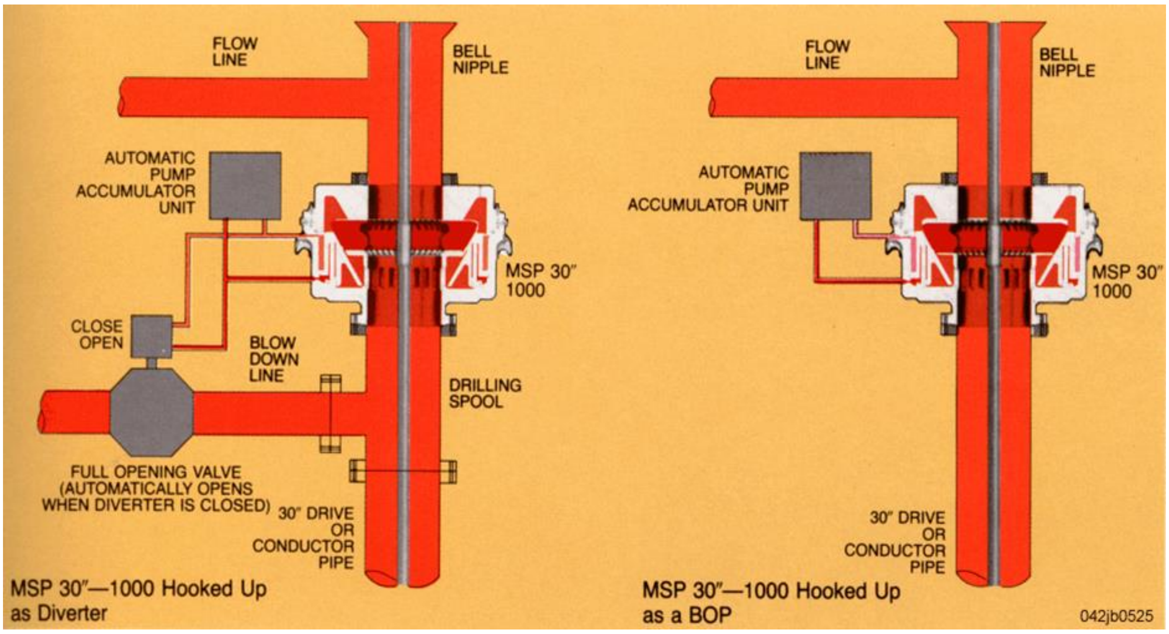


Figure II.20. Use of annular BOP in diverter and blowout preventer [5]

II.8. BOP control system

It provides the storage of a hydraulic fluid under pressure and the use of that fluid to run the BOP and kill and choke line (HCR) valves. The amount of oil stored under pressure in the unit will typically be available to put the well in safety if required during operation if there is a loss of energy sources on site.[5]

Figure II.21. real picture of BOP control system (Koomey)

II.9. Mud control and monitoring equipment

Correct installation and operation of this equipment is fundamental to effective primary and secondary well control. The following are the most important aspects:

II.10. Pit volume measurement

A pit volume totalizing (PVT) should be provided. A calibrated read-out and audio alarm should be installed at the Driller’s station.

II.11. Flow line Measurement

A device should be provided for measurement of flow line and mud return rate. This (Flo Show) device should have a read-out and alarm at the Driller’s station.

II.12. Trip Tank

Trip tanks are used to fill the hole on trips, measure mud or water into the annulus when circulation has been lost, monitor the hole when tripping, logging or other similar type operations.

II.13. Mud Gas Separator

The separator is installed downstream of the choke manifold to separate gas from the drilling fluid. This provides a means of safely venting the gas and returning usable liquid mud to the active system. There are two types of mud gas separators: Atmospheric and Pressurized.

- The atmospheric type separator is standard equipment on nearly all rigs and is referred to in the field as a ‘gas buster’ or ‘poorboy' separator. The main advantage of this type of separator is its operational simplicity which does not require control valves on either the gas or mud discharge lines.
- A pressurized mud gas separators are used to overcome line pressure losses when an excessive length of vent line is required to safely flare and burn the hazardous gas an

extended distance from the rig, this type is also used on rigs with high risk of H2S areas.

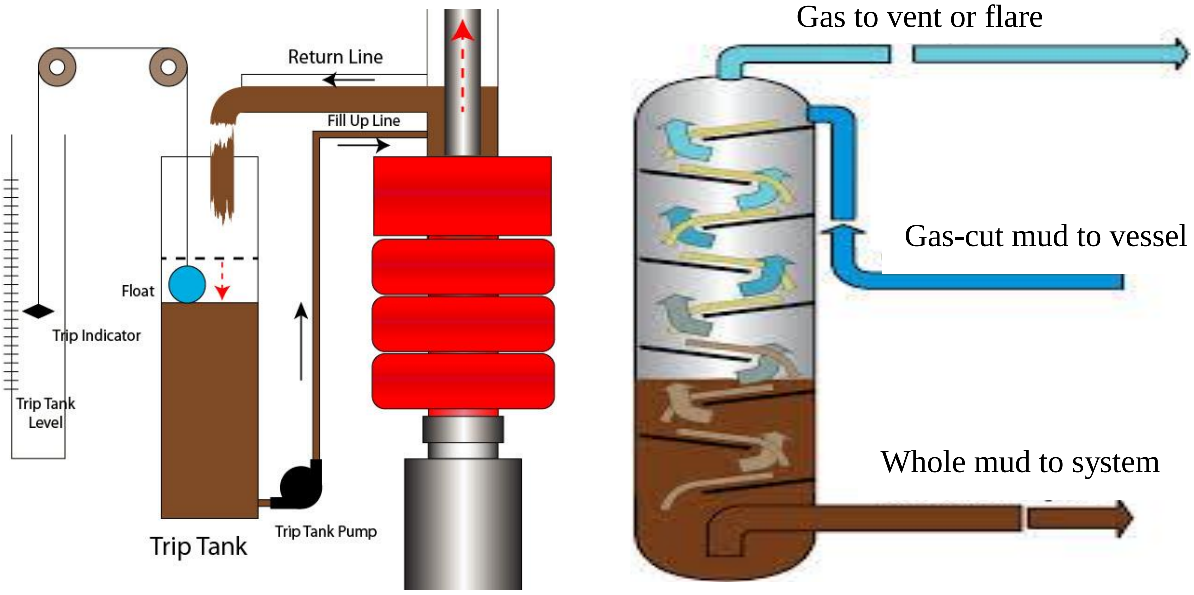


Figure II.22. example of trip tank and mud gas separator [2]

II.14. Choke manifold

The choke manifold allows to circulate in the well when the annular space is closed and to evacuate the fluids of the well towards various points (separator, "torch", boorbey). The pipeline between the BOP and choke manifold includes:

- A manual valve at the exit of the BOP which serves as back up, it is in the open position during drilling,
- The remote controlled valve (HCR) placed after the manual valve is in closed position.
- The choke line connects the BOP stack to the choke manifold. It is recommended to have at least two valves on the manifold (usually one is remote controlled, the other is manual),
- Gate valves to direct the fluids. [5]

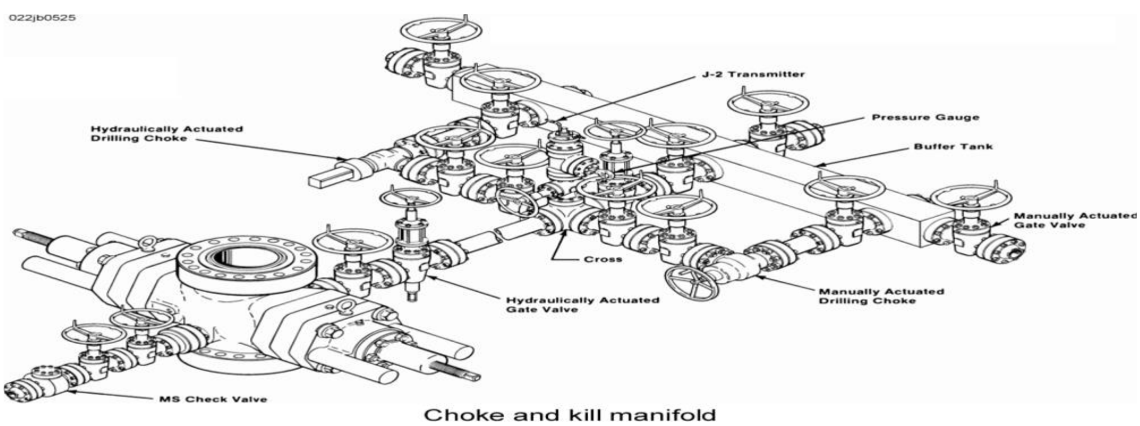


Figure II.23. Choke and kill manifold

Chapter III

Kicks and well control methods

III.1. Introduction :

When drilling for oil or gas, it is crucial to maintain control of the well to prevent blowouts or other dangerous situations. Well control refers to the techniques and procedures used to maintain pressure within a well and prevent the uncontrolled release of hydrocarbons. There are several well control methods, including primary and secondary barriers, drilling fluid systems, and blowout preventers. These methods are designed to prevent the flow of oil or gas from the reservoir into the wellbore and ultimately to the surface. The importance of well control cannot be overstated, as a loss of control can lead to catastrophic consequences, both in terms of human safety and environmental impact.

III.2. Kicks

A kick is the sudden influx of formation fluids into the wellbore during drilling operations when the formation pressure exceeds the pressure exerted by the drilling fluid. This can be a hazardous situation that requires prompt detection and effective control measures to prevent a blowout. Well control techniques are critical for maintaining a safe and efficient drilling environment.

III.2.1. Factors affecting kick severity

Several factors affect the severity of a kick. One factor, for example, is the “permeability” of rock, which is its ability to allow fluid to move through the rock. Another factor affecting kick severity is “porosity.” Porosity measures the amount of space in the rock containing fluids. A rock with high permeability and high porosity has greater potential for a severe kick than a rock with low permeability and low porosity. For example, sandstone is considered to have greater kick potential than shale, because sandstone has greater permeability and greater porosity than shale.

Yet another factor affecting kick severity is the “pressure differential” involved. Pressure differential is the difference between the formation fluid pressure and the mud hydrostatic pressure. If the formation pressure is much greater than the hydrostatic pressure, a large negative differential pressure exists. If this negative differential pressure is coupled with high permeability and high porosity, a severe kick may occur.

III.2.2. Causes of kicks

The main causes of kicks are:

A. Falling to fill the hole properly when tripping
B. Swabbing in a kick while tripping out
C. Insufficient mud weight

D. Abnormal formation pressure
E. Lost circulation
F. Shallow gas sands
G. Excessive drilling rate in a gas bearing sands

Currently almost 50% of all blowouts are attributed to a combination of causes (A) and (B). Each of the possible causes are described in the following paragraphs.

A.Falling to fill the hole properly when tripping

This is one of the common causes of kicks. If the fluid level in the hole falls, than a reduction of bottom hole pressure must occur since the length of the fluid column has shortened.

As drill pipe and collars are pulled out of the hole, a volume of mud equal to the volume of steel which has been removed, must be added to the hole to keep it full. If this is not done the length of the mud column is reduced, thereby lowering the bottom hole pressure. Once this pressure drops below formation pressure, at any point in the open hole, a kick may occur. The holes should be filled, either on a continuous basis with a re-circulating trip tank, or on a regular fill-up schedule. If the volume required to fill the hole is significantly less than the volume of steel known to have been removed, then either:

a) Fluid must have entered the hole from the formation, or

b) Gas already present in the well bore is expanding.

The two acceptable methods most commonly used to maintain hole fill-up are the pump-stroke measurements method and the continuous circulating trip tank method.

B.The pump stroke measurements

The method of keeping a full hole—the pump-stroke measurement method—is to periodically fill up the hole with a positive-displacement pump. A flowline device can be installed with the positive-displacement pump to measure the pump strokes required to fill the hole. This device will automatically shut off the pump when the hole is full.

C.Continuous Circulating Trip Tank

The trip tank, as shown in Figure 1 can be set to continuous gravity feed, or it can use pump feeding. The advantage of this system is that the hole remains full at all times, and the volumes used can be continuously and accurately maintained. The main drawback to this system is that the trip tank does not contain enough mud to permit a full trip without refilling. The drill crew should develop a routine of checking the trip tank level frequently and therefore be aware when refilling is required. It is relatively easy for other problems to distract attention from this need, especially when drill collars are being pulled and extra demands placed upon the drill crew.

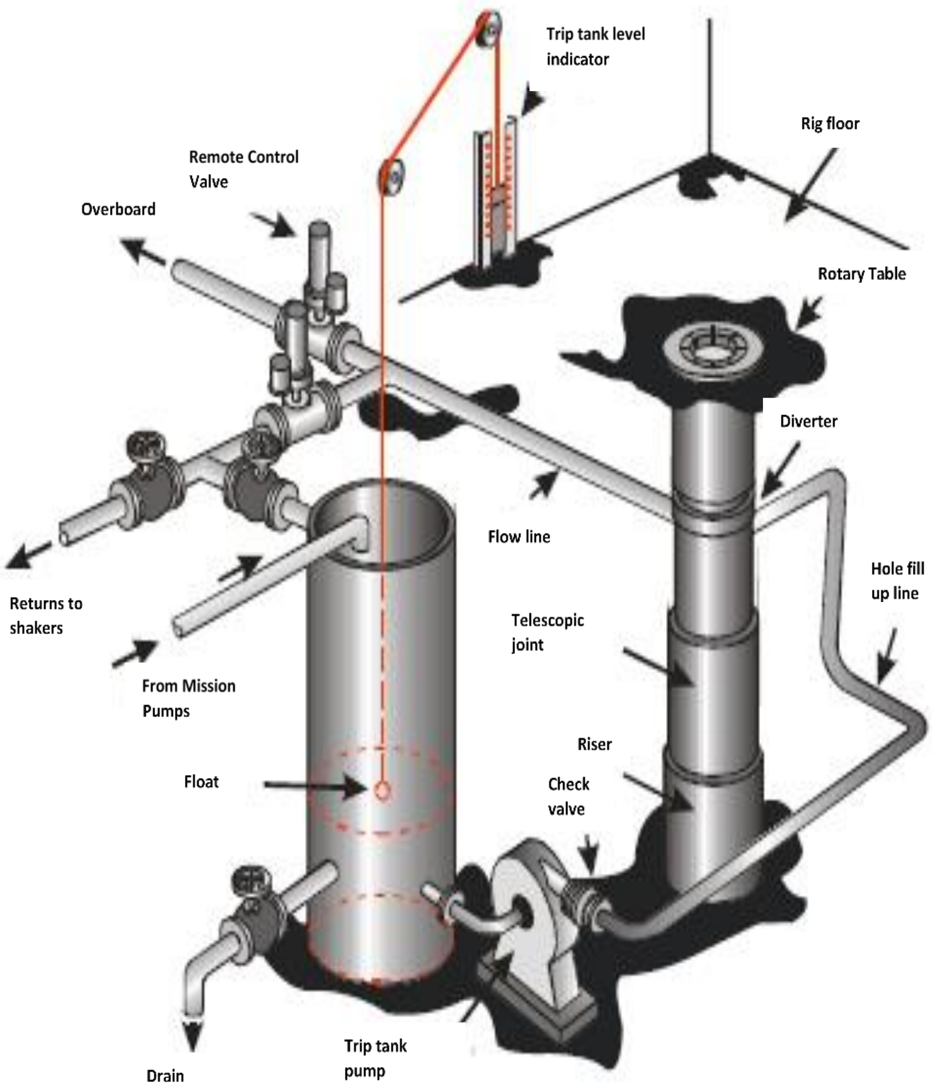


Figure III.1. Continuous Circulating Trip Tank

D.Swabbing in a kick

Pulling the drill string from the borehole creates swab pressures. Swab pressures are negative, and reduce the effective hydrostatic pressure throughout the hole and below the bit. If this pressure reduction lowers the effective hydrostatic pressure below the formation pressure, a potential kick has developed. Variables controlling swab pressures are:

a. Pipe Pulling Speed: It takes more energy to move mud quickly, so the faster the string is moved, the greater the pressure drop.

b. Small Hole Clearance, or Slim Hole Geometry: It takes more energy to move the same volume of mud through a smaller space, so the less the annular space available, the greater the pressure drop.

c. High Mud Viscosity, or Gel Strength: Evidently, it takes more energy to move a thick mud than thin one, hence the more viscous the mud, the greater the pressure drop.

The likelihood of swabbing in a kick can be reduced by good drilling practices, including use of an adequate trip margin. These include:

a. Circulating the hole clean before starting a trip.

b. Noting the pressure and position of ‘tight-spots’ from previous trips.

c. Conditioning mud to as thin a condition as well circumstances permit.

d. Careful observation of pipe pulling speed. [1]

E.Insufficient mud weight

The hydrostatic pressure exerted by the column of mud in the hole is the primary means of preventing kicks. Insufficient mud weight can result from penetration of an unexpected, abnormally high-pressure zone, or be due to deliberate underbalance drilling methods in field development wells. Accidental dilution of the mud with make-up water, in the surface tanks, is a relatively common occurrence, and must be guarded against. With water base muds and fast drilling, it is common to add considerable quantities of water. If the drilling rate slows, and other problems distract attention from the routine checking of active mud weight, the slow reduction in mud weight may escape notice until it is too late [1].

F.Abnormal pressures

Abnormal formation fluid pressures, or ‘sur-pressures’ can arise for a number of reasons. They can be categorized as:

a. Differential Fluid Pressure

b. Surcharged Shallow Formations

c. Sediment Compression

d. Salt Beds

e. Mineralization.

Generally, if a permeable zone containing fluids pressured above the normal gradient for the area is to be penetrated, then appropriate mud weights must be run. Where possible, prediction of likely abnormal pressures should be carried out, both during well planning and during drilling. A number of trends will signal changes in formation pressure.

G.Loss of circulation

Another cause for a kick to occur is the reduction of hydrostatic pressure through loss of drilling fluid to the formation during lost circulation. When this happens, the height of the mud column is shortened, thus decreasing the pressure on the bottom and at all other depths in the hole. The amount the mud column can be shortened before taking a kick from a permeable zone can be calculated by dividing the mud gradient into the overbalance at the top of the permeable kick zone. [2]

$$H\ (ft) = \frac{\text{Overbalance (psi)}}{\text{mud gradient(psi/ft)}} \qquad [2]$$

H.Shallow gas sands

Kicks from shallow sands (gas and water) whilst drilling in the top hole section with short casing strings can be very hazardous, as documented by many case histories. Some of the kicks from shallow sands are caused by charged formations:

poor cement jobs, casing leaks, injection operations, improper abandonments, and previous underground blowouts can produce charged formations. [7]

III.2.3. Kick indication

Well control warning signals can be classified in three major general categories as follows: [2]

III.2.3.1. Previous Field History and Drilling Experiences

1. Depth of zones capable of flowing.
2. Formation gradients.
3. Fracture gradients.
4. Formation content.
5. Formation permeability.
6. Intervals of lost circulation.

III.2.3.2. Physical Response From the Well

1. Pit gain or loss.
2. Increase in drilling fluid return rate.
3. Changes in flowline temperature.
4. Drilling breaks.
5. Variations in pump speed and/or standpipe pressure.
6. Swabbing.
7. Drilling fluid density reduction.
8. Hole problems indicating underbalance (i.e., tight hole, packing-off, sloughing).

9. Excessive pressure or pressure changes between casing strings

III.2.3.3. Chemical and other technical responses from the well

1. Chloride changes in the drilling fluid.
2. Oil show.
3. Gas show (chromatograph).
4. Formation water.
5. Shale density.
6. Electric logs.
7. Drilling equation exponents. [2]

But the most common signs of a kick are:

a. The increase in the rate of penetration (ROP)

In general, the sudden increasing in the rate of penetration (ROP) is a warning sign of either a well kick or a drilling break, which show that the pores in formation could have been broken into. In the interval of the potential pay, the crews shouldn't be forgotten but must be alerted that the normal minimum interval ranges from 2 to 5 feet regarding to whatever drilling break could be penetrated. This is one of the most important aspects of pressure control. Many multimillion-dollar blowouts could have been avoided by limiting the open interval. By doing a limit for the open interval, this may be reducing a large amount of money which comes to millions as a kind of the pressure control [8].

b. Increased flow from annulus

The constant volume of fluid break into the hole while the constant volume come out equally in the two cases when mud pumps run at constant speed. The process of formation fluid which replace the mud from the ring-shaped, the annulus, while it moves constantly and continuously in a current from the formation into the wellbore takes place when the mud returns start rising without any increase in the speed of pumping. Here another sign of a possible kick that is to say any increase in influx rate. The first sign of taking place a kick is the rising influx at the flow-line. A positive kick indicator is the indication of the rate of increasing the returns of mud flow, which doesn't need flow check, but it needs to shut the well right away to minimize the volume of the flow. [9.10]

c. Gain in pit volume

An unaccounted volume gain in the drilling fluid pit(s) is an indication that a kick may be occurring. As the formation fluid feeds into the wellbore, it causes more drilling fluid to

flow
from the annulus than is pumped down the drill string, thus the volume of fluid in the pit(s) increases. [2]

d. Change in pump speed or pressure

The initial surface indication that a well kick has occurred could be a momentary increase in pump pressure. The pump pressure increase is seldom recognized because of its short duration, but it has been noted on some pump pressure recording charts after a kick was detected. The pressure increase is followed by a gradual decrease in pump pressure, and may be accompanied by an increase in pump speed. As the lighter formation fluid flows into the wellbore, the hydrostatic pressure exerted by the annular column of fluid decreases, and the drilling fluid in the drill pipe tends to U-tube into the annulus. When this occurs, the pump pressure will drop and the pump speed will increase. The lower pump pressure and increase in pump speed symptoms are also indicative of a hole in the drill string, commonly referred to as a washout. Until a confirmation can be made whether a washout or a well kick has occurred, a kick should be assumed. [2]

e. The increasing of both number and size of cutting

On penetrating a high pressure zone, the size of the cuttings may be changed. They can be long and come into splinters. Naturally the shale pressured create little cuttings with circular tips flat, whereas the over pressured shale cuttings form long and splintery with angular edges. Since the decrease of hydrostatic differs the pressure of the pores from bottom-hole pressure then it occurs, and the hole cuttings are going to greatly tend to come off bottom. A cracking may also occur because of a shale expansion, and a collapse into a hole could be underway. The changes in the shapes of cuttings and the shakers loaded by these cuttings need proper directing to the surface [2]

f. Drilling fluid against gas ‘gas-cut’

When observing water-cut mud, oil, or gas, the effective actions and precaution must be taken into effect. Usually, this sign is coming together with the other signs when the well is suffering from an influx. Any increase in chloride or water cut mud or even calcium which has been circulated from the bottom; it always shows the fluid of the formation has broken into the wellbore. This may show that a well influx in progress or it could be made by swabbing. Any increase in calcium or Small chloride may show that some zone which have high pressure cannot allow the fluid out or to pass though. In case of a bit breaks into a zone of high pore pressure, a background gas could be rising suddenly. This background gas is the gas which collected between the wellbore cuttings. This gas would run up to the surface and may form fifty percent of the volume of the drilling fluid volume in case of this gas has got high pore pressure which allow to it to expand and force its way up. If this situation is prepared well in advance, the trouble can be saved the day [2.11].

III.2.4. Flow check procedure

This confirms that a kick is in progress. If any of the previously mentioned signs occur, either singly or together, a flow check will be carried out to confirm the situation. Pick up the Kelly to clear the bushings, with the pumps on, then shut the pumps off and check for flow.

Normally the well flows for a few seconds before stopping, if it continues to flow, it is likely a kick has occurred.

III.2.4.1. Kick detection and monitoring with MWD tools

During circulation and drilling operations, measurement while drilling (MWD) systems monitor:

- Mud properties
- Formation parameters
- Drill string parameters

The system is widely used for drilling, but it also has applications for well control, including the following:

- Drilling-efficiency data, such as downhole weight on bit and torque, can be used to differentiate between rate of penetration changes caused by drag and those caused by formation strength. Monitoring bottomhole pressure, temperature, and flow with the MWD tool is not only useful for early kick detection, but can also be valuable during a well-control kill operation. Formation evaluation capabilities, such as gamma ray and resistivity measurements, can be used to detect influxes into the wellbore, identify rock lithology, and predict pore pressure trends.
- The MWD tool enables monitoring of the acoustic properties of the annulus for early gas-influx detection. Pressure pulses generated by the MWD pulser are recorded and compared at the standpipe and the top of the annulus. Full-scale testing has shown that the presence of free gas in the annulus is detected by amplitude attenuation and phase delay between the two signals. For water-based mud systems, this technique has demonstrated the capacity to consistently detect gas influxes within minutes before significant expansion occurs. Further development is currently under way to improve

the system's capability to detect gas influxes in oil-based mud.

- Some MWD tools feature kick detection through ultrasonic sensors. In these systems, an ultrasonic transducer emits a signal that is reflected off the formation and back to the sensor. Small quantities of free gas significantly alter the acoustic impedance of the mud. Automatic monitoring of these signals permits detection of gas in the annulus. It should be noted that these devices only detect the presence of gas at or below the MWD tool.

The MWD tool offers kick-detection benefits, if the response time is less than the time it takes to observe the surface indicators. The tool can provide early detection of kicks and potential influxes, as well as monitor the kick-killing process. Tool response time is a function of the complexity of the MWD tool and the mode of operation. The sequence of data transmission determines the update times of each type of measurement. Many MWD tools allow for reprogramming of the update sequence while the tool is in the hole. This feature can enable the operator to increase the update frequency of critical information to meet the expected needs of the section being drilled. If the tool response time is longer than required for surface indicators to be observed, the MWD only serves as a confirmation source.

III.2.5. Kick identification

When a kick occurs , note the type of influx (gas, oil, or salt water) entering the wellbore. Remember that well-control procedures developed here are designed to kill all types of kicks safely.

The influx gradient can be evaluated using the guidelines in Table III.1.

Table III.1. Influx gradient evolution

Table - Influx Gradient Evaluation Guidelines	
GRADIENT (PSI/FT)	**INFLUX**
0.05___0.2	**GAS**
0.2___0.4	**Probable combination Gas oil/salt water**
0.4___0.5	**Probable oil or salt water**

III.3. Categories of well control

a. Primary well control

While drilling, the hydrostatic pressure provided by the drilling fluid is greater than the formation pressure but less than the fracture gradient. When hydrostatic pressure falls below reservoir pressure, reservoir fluid may enter the wellbore. "Loss of Primary Well Control" is the term for this situation.

Not only is hydrostatic pressure greater than formation pressure, but it must also not exceed fracture gradient. If the mud in the hole is sufficiently heavy, it will break the wellbore, resulting in a loss of circulation (partially or completely). When fluid is lost into the formation, the mud level in the well bore decreases, resulting in a decrease in hydrostatic pressure. The principal well control and wellbore influx or kick will be lost in the worst-case situation. [12]

b. Secondary well control

According to the previous section, primary well control is a hydrostatic pressure bore that inhibits reservoir influx while drilling operations (drilling, tripping, running casing/completion, and so forth) are being performed. When primary well control fails, it results in kick (wellbore influx) into a wellbore. As a result, this circumstance necessitates the use of specialized equipment known as a BOP to manage kick.

That is known as a BOP, which stands for Secondary Well Control. Please keep in mind that BOP must be utilized in conjunction with particular kick control measures such as the driller method, wait and weight, lubricate and bleed, and bull heading. Without well management methods for using BOPs, the rig will be nothing but heavy equipment. There are several types of BOP available. [12]

c. Tertiary well control

Tertiary Well Control is special methods used to control the well if primary and secondary well control are failed. These Following examples are tertiary well control:

- Drill relief wells to hit adjacent well that is flowing and kill the well with heavy mud.
- Dynamic kill by rapidly pumping of heavy mud to control well with Equivalent Circulating Density (ECD).
- Pump barite or gunk to plug wellbore to stop flowing.
- Pump cement to plug well bore. [12]

III.4. shut in procedures

III.4.1. Soft shut-in procedure

III.4.1.1. Circuit alignment during operations

During operations the circuit has to be aligned as follows:

- Manuel valve on choke line is opened
- Hydraulic valve on choke line has to be closed
- The choke on choke manifold has to be opened
- All the valves leading to the separator passing by the choke (downstream valves) have

to be in open positions.

- Beside these valves, all the valves have to be in closed position. [13]

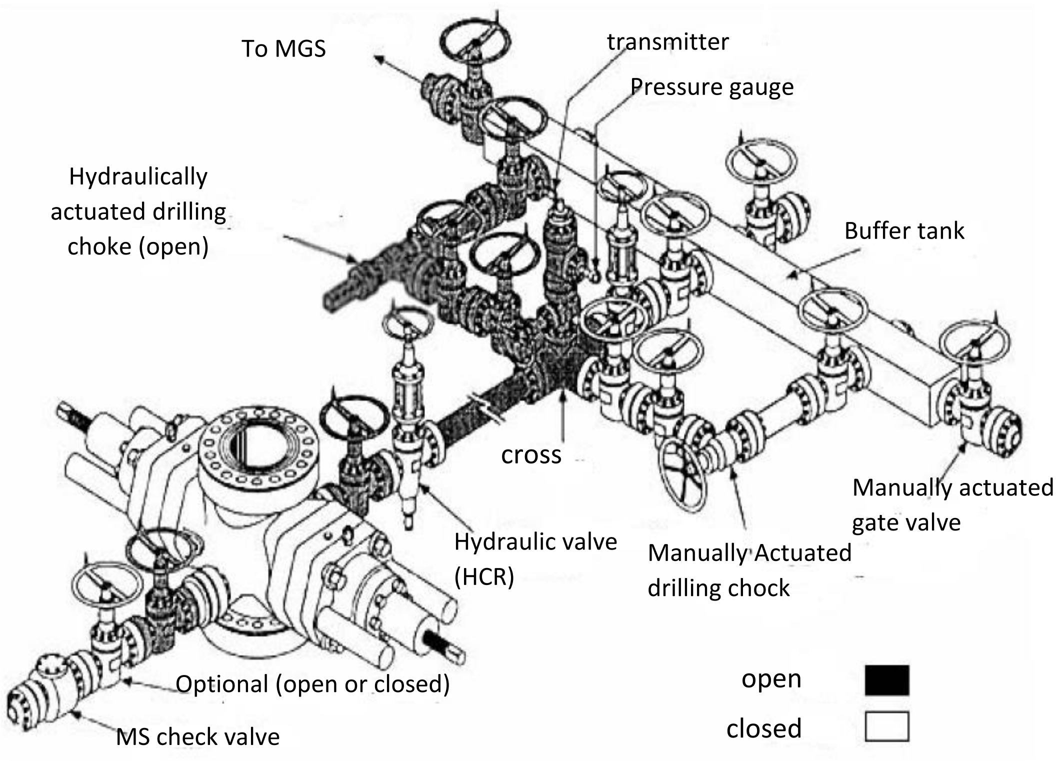


Figure III.2. Circuit Alignment in soft Shut in Procedure[13]

III.4.1.2. soft Shut in procedure while drilling

The procedure is performed as follows:

- if there is any kick indication, stop rotary, pick up off bottom and space out (Tool joint one meter above rotary table to avoid getting the next tool joint on the pipe rams)
- Stop pumps, perform flow check. If the well is flowing then:
- Open choke line valve at the BOP stack (Called HCR)
- Close annular BOP
- Close Choke
- Read and Record pressures and times. Check pit volume gain in order to prepare the kill sheet
- If the gas is migrating , control the wellbore pressures during the shut in [13]

III.4.1.3. Soft Shut in procedure while tripping

If there is any kick indication, stop tripping immediately. Here, two different situations can be identified:

a) The well is flowing, then the shut in is proceeded as follows:

- Set the string on the slips
- Install a fully opening safety valve in open position. Close the valve once is installed
- Open choke line valve at BOP stack (HCR valve)
- Close annular BOP
- Close choke.
- Read and record pressures and times, check pit volumes

It depends on the situation to weather to start killing procedures or to strip back to the bottom.

- If the stripping is faced, then, Stab IBOP (Grey valve)
- Open the fully opening safety valve
- Reduce the annular pressure and start stripping the string to the bottom

b) The well is not flowing:

- Set the string on the slips
- Install IBOP (grey valve or non-return valve)
- Run back in the hole with controlling the volumes, if any anomalies are noticed then proceed to the stripping. Once on bottom, circulate annular volume and evaluate the situation. [13]

III.4.2. Hard shut-in procedure

III.4.2.1. Circuit Alignment in Hard Shut in Procedure

During operations the circuit has to be aligned as follows:

- Manuel valve on choke line is opened
- Hydraulic valve on choke line has to be closed
- The choke on choke manifold has to be closed
- All the valves leading to the separator passing by the choke (downstream valves) have to be in open positions.
- Beside these valves, all the valves have to be in closed position. [13]

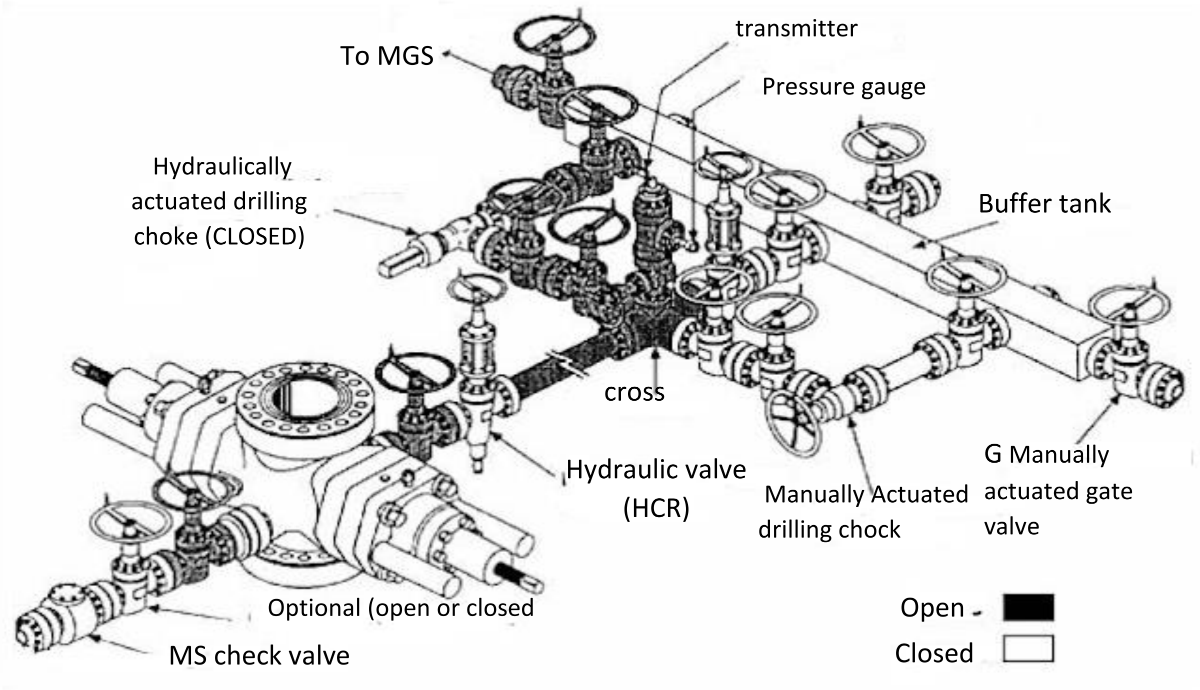


Figure III.3. Circuit Alignment in Hard Shut in Procedure[13]

III.4.2.2. Hard shut in procedure while drilling

- if there is any kick indication, stop rotary, pick up off bottom and space out (Tool joint one meter above rotary table to avoid getting the next tool joint on the pipe rams)
- Stop pumps, perform flow check. If the well is flowing then:
- Close annular or pipe rams
- Open choke line HCR valve
- Start plotting the trend of pressures, drill pipe pressure and casing pressure, note also the gain. [13]

III.4.2.3. Hard shut in procedure while tripping

If any kick indication is noticed, the tripping has to be ceased immediately and the next steps have to be performed. Two situations can be faced:

a) The well is flowing:

- Set the drilling string on the slips
- Install the fully opening safety valve in opened position
- Close the safety valve
- Close the annular BOP
- Open the HCR valve on the choke line
- Record the pressures with the time and the gain volume[13]

b) If the well is not flowing

- Set the drilling string on the slips
- Install the IBOP (grey valve or the non-return valve)
- Trip back in the hole with controlling the volumes, if any anomalies are detected shut the well in following the hard procedure then continue the running in the hole with stripping. Once on bottom, circulate a bottom up volume and evaluate the situation. [13]

III.5. Well control methods

The following is a list of the main well kill methods used in oil well control:

- Wait and Weight.
- Driller method.
- Concurrent Method.
- Dynamic Kill procedure.
- Volumetric Method.
- Lubricating Technique

III.5.1. Wait and Weight

The Wait and Weight is sometimes referred to as the Engineer's Method or the One Circulation Method. It does, at least in theory, kill the well in one circulation.

Once the well is Shut In (hard shut-in well procedure – Soft shut-in procedure) and pressures stabilized, the Shut-In Drill Pipe pressure is used to calculate the kill mud weight. When ready, Kill mud is pumped down the Drill Pipe. At commencement, enough Drill Pipe pressure must be held to circulate the mud, plus a reserve equivalent to the original Shut In Drill Pipe pressure. This total steadily decreases as the mud goes down to the drilling bit, until with Kill mud at the Drilling Bit, the required pressure is simply that needed to pump Kill mud around the well.[190]

The choke in the choke manifold is adjusted to reduce Drill Pipe pressure while Kill mud is pumped down the Drill String. With kill mud at the bit, the static head of mud in the Drill Pipe balances formation pressure. For the remainder of the circulation, as the influx is pumped to the surface, followed by Drill Pipe contents and the kill mud, the Drill Pipe pressure is held at the final circulating pressure by choke adjustment.

Advantages

- The Main Advantages of Wait & Weight Killing Method are:
- Lowest wellbore pressures, and lowest surface pressures – this means less

equipment stress.

- Minimum choke circulating time – less chance of washing out the choke. [190]

Disadvantages

- Considerable waiting time (while weighting up) – gas kick migration.
- If large increases in mud weight required, this is difficult to do uniformly in one stage. [190]

How To Kill The Well By Wait & Weight Method (Procedure)

1- Calculate Kill mud weight:

Kill mud weight(ppg) = original mud weight(ppg) + $\frac{SIDPP(PSI)}{TVD(ft)} + 0.052$ [2]

2- Initial Circulating Pressure:

Initial circulating pressure = slow circulation rate + SIDPP [2]

3- Once the pipe capacity of the Drill String is calculated, it is possible to draw a graph showing how Drill Pipe pressure varies as Kill mud is pumped down to the Drilling Bit.

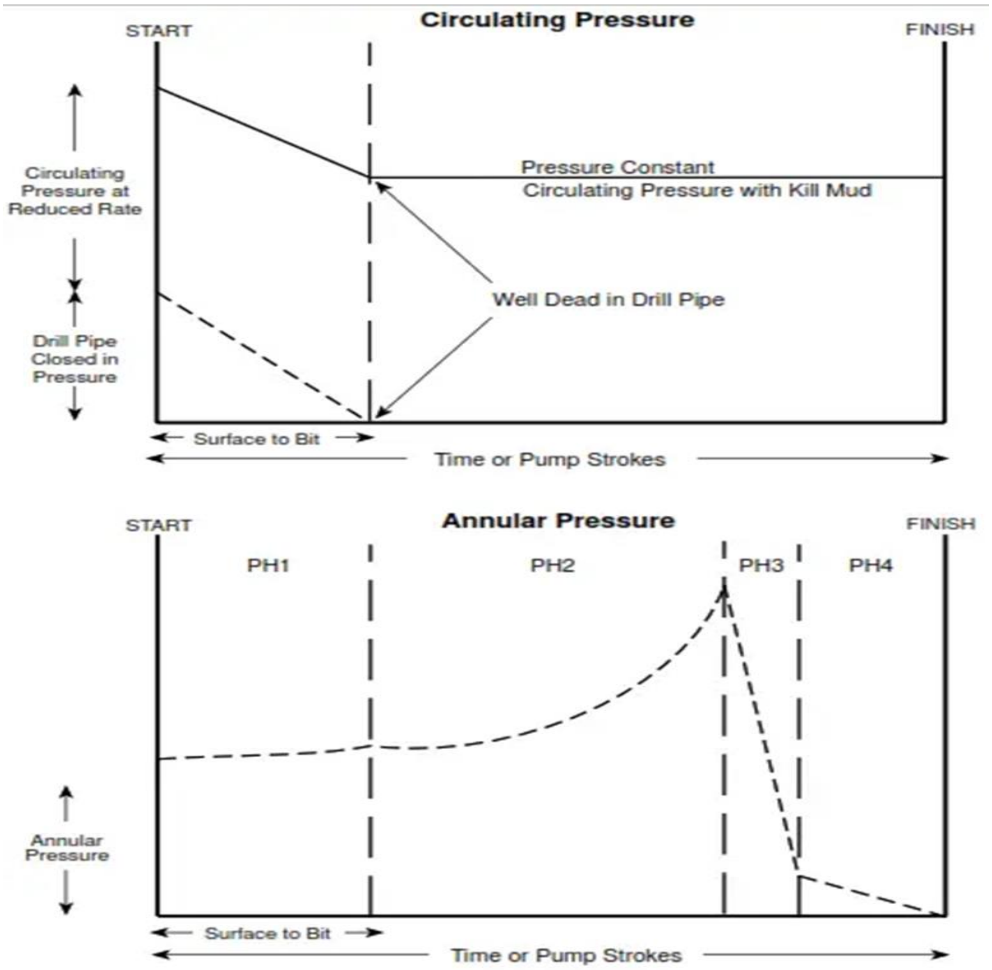


Figure III.4. Circulating and Annular Pressure Killing profile by Wait&Weight Method

4- The choke is cracked open, the pump started to break circulation, and then brought up slowly to the Kill Rate, While that keep the casing pressure as near as possible to the SICP reading.

5- When the pump is up to the Kill Rate, the choke operator transfers to the Drill Pipe pressure gauge.

6- As the Kill mud proceeds down the Drill Pipe, the Drill Pipe pressure is allowed to drop steadily from the Initial Circulating Pressure to the Final Circulating Pressure, by choke adjustment. (through the table you have already done)

- Where the Kick is a small one, at or near the bottom of the hole, the Drill Pipe pressure tends to drop of its own accord as the kill mud moves down. Little or no choke adjustment is required.
- Only in cases of diffused gas Kicks with gas far up the annulus will significant choke adjustments be needed during this period.

7- In Wait & Weight Kill Method, and after kill mud has reached the Drilling Bit, the Drill Pipe pressure is maintained at the Final Circulating Pressure until the kill mud returns to the surface.

Changing Pump Rate: While the pump rate is adjusted, the casing pressure is held steady by adjusting the choke. Once the pump is stabilized at its new speed, the revised circulating pressure is ready from the Drill Pipe gauge. If a gas influx is very near to the surface, adjusting pump rate by holding a steady casing pressure may significantly increase the bottom hole pressure. This is due to the rapid expansion of gas near the surface. Alterations in pump rate are to be made early on. [14]

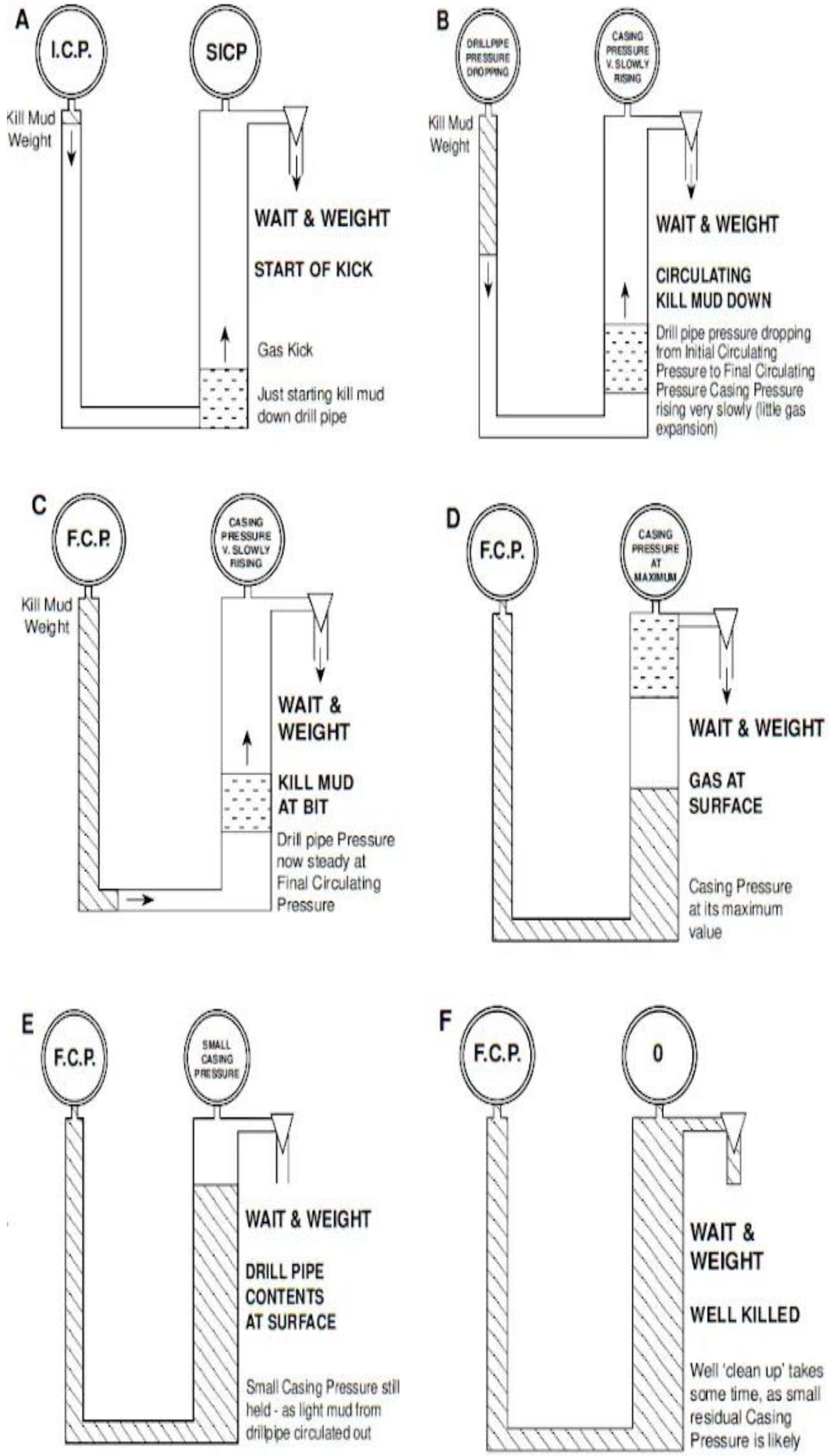


Figure III.5. Wait & Weight Method Diagrams

III.5.2. Driller's method

The mud weight circulates the kick in the Driller method, achieving the required level as a minimum for this method. When it comes to removing the kick and adding kill weight mud, it results in the most control way ever. As a result of this, the well is being circulated under pressure are the longest of the three methods which has more or less choke problems. During the first circulation, the annular pressures already are finished as the high annular pressure may arise when killing a gas kick with this method. This annual pressure will reach the maximum point before the arrival of gas .This method is most used on small land rigs where the driller has just simple equipment, also used on deviated and horizontal wells. The Driller's method has a lot of benefits in case of availability of the limited information about the well conditions. There are many procedures for Driller's method are shown in figure (III.5), considers the following:

1. The information is extremely recorded and the well is highly closed.
2. The Initial Circulation Pressure is well organized through the calculation of the pressure required on the drill pipe for the first circulation of the well.
3. The choke is opened through one quarter by starting the break circulation and the pump which is reaching the kill rate.
4. During the matching between the pump and the kill rate processing, the choke operator should operate the choke to avoid the farness between the casing pressure and the casing pressure reading.
5. As soon as the pump is up to the kill rate, the choke operator has to notice drill pipe pressure gauge and adjust the choke to retain the initial circulating pressure on the drill pipe pressure gauge.
6. The initial circulating pressure should be in progressive holding on the drill pipe pressure gauge through moderating the choke depending on the first circulation till the circulating of all the kick fluid of the well.
7. Right after going out the kick, the well shut and the kill mud weight required is combined.
8. No sooner than readiness of the kill mud, the choke opens one quarter, beginning of the pump, the circulation is already broke.
9. During the deliverance of the pump to the kill rate, the choke operator must turn the choke on with the aim of maintaining the casing pressure steady at the same level of the pressure.

10. The moment that the drill pipe contained a heavy mud there are two options for keeping B.H.P. constant, it should maintain the casing pressure also constant or let the graph going from ICP to FCP, if the influx was gas and all the gas was not removed in first circulation. after reaching the bit , the pressure held on the drill pipe which is hoped for the circulating of the kill mud around the well, This is the final circulating pressure which growing for the extra mud weight. Thereafter, the drill pipe pressure is held at the final circulating pressure by controlled opening of the choke, as the kill mud moves up the annulus [10.15].

Advantages

- Minimum Arithmetic
- Minimum Waiting Around Time - can start kill at once
- Minimum Information Required

Disadvantages

- Highest Annular Pressure Produced
- Maximum Well Under Pressure Time
- Longest 'On-choke' Time

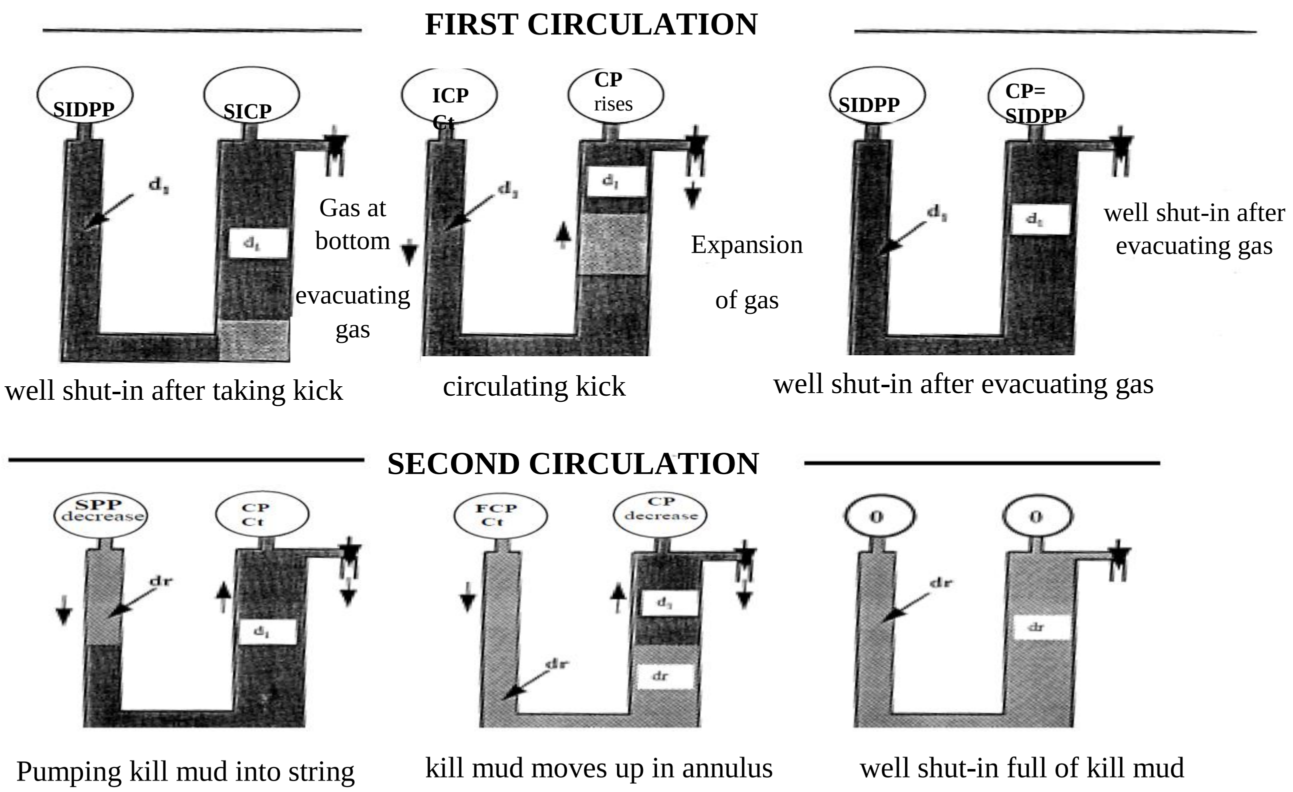


Figure III.6. Driller's method circulations

III.5.3 Concurrent method

The Concurrent Method is considered a group of the Driller's method and the Wait and Weight method. The crew starts rotating the kick out of the well right away, by using the earliest mud weigh. The fashion of gradually in increasing the weight of the mud whereas rotating out the kick is called concurrent method. The increasing rate counts on mixing the feature of many services which are available with the equipment on the rig. The circumstances that are complicated are when the drill pipe is filled with several varieties of the densities of the fluids, calculating the hydrostatic pressure of the bottom of the wellbore to find out its condition in case of being difficult. The most powerful way to kill a kick is through supplying sufficient supervision to be found on the rig. The following steps of Concurrent method are: On recording all the information and data about the kick, slowly open the pump at the time of altering the chock till the initial circulating pressure to be reached at the point of reduced rotating rate. At the maximum rate the drilling fluid will be weighted up with the available rig equipment, since the fluid of drilling varies in the suction tank as the choke operator supposed to be informed. The operator goes to check the series of repeated actions of the pump if gone during the weight of the fluid of the new drilling shown on his chart, likewise with every change of the fluid of the new drilling to adjust and fix the choke pressure until this match the conditions of the new drill pipe as has been recorded before on the surface for the purpose of bitting the graph. To keep the operation in progress, the pressure should be stayed steady and that come by arriving the final kill drilling fluid at the bit, so the final circulating pressure will be highly possible to be reached. Then operation will be well done [10.15.16].

III.5.4. Dynamic Kill procedure.

Dynamic Kill Principle

When a blowout occurs, the well unloads a stream that can include hydrocarbon liquid, gas or water flowing at a high rate, driven by a drawdown that can be thousands of psi below reservoir pressure. Dynamic kill is a process to kill a blowout by pumping heavy mud into the wellbore at high rates to suppress the flow. The process introduces kill mud into the blowout well to raise the density of the blow stream, as well as to generate considerable friction pressure in its wellbore.

The combination of these two effects eventually kills the blowout by restoring bottom hole pressure above that of the formation.

In a typical kill operation, the planned weight and volume of kill mud is prepared, and all pumps and fluid systems are kept running before drilling out of the liner shoe. Upon intersection, fluid from the relief well typically U-tubes into the target well, and all pumps are used to keep the annulus full in the relief well, followed by pumping at the appropriate kill rates until the blowout is dead.

III.5.5. Volumetric Method

The volumetric method is a conventional control method which consists to let a gas bubble to migrate up to surface without circulation but allowing it to expand under control.

This method is used in some particular situations where the circulation of the intruded fluid becomes impossible such as :

- Drill string out off hole
- Drill string stuck
- Drill string plugged
- Power failure
- Drill string washed out or twisted off

Two possible situations could appear when performing the volumetric method:

1st case : No possibility to circulate but annulus and internal string are Communicating

Every time that reading of stand pipe pressure is possible, the bleed off method controlled by DP pressures will be selected.

This consists to bleed appropriate quantity of mud at intervals while gas migrates up in the annulus by holding stand pipe pressure steady and equal to shut-in drill pipe pressure (SIDPP) until gas reaches the BOP's. This procedure insures the control of the BHP.

In practice, a safety margin is taken in consideration of pressures fluctuations while operating the choke.

2nd case : No possibility to circulate and no pressure communication between annulus and internal string

When the pressure reading at DP is not possible, the BHP control must be done by the annular manometer.

a) Selections and calculus

1. Select working pressure (ΔP)

The working pressure (ΔP) is defined as being the predetermined increase of annular pressure before bleeding off a certain volume of mud to keep the bottom hole pressure constant. Working pressure is selected generally between 5 and 10 bars.

The casing pressure increase is induced by the gas migration in the well let closed-in.

2. **Select safety margin (S)**

A safety margin of 10 to 15 bars is taken to palliate to pressures variations due to the choke handling.

3. **Calculus of the volume to bleed off (Vb)**

The volume Vb is the mud volume to bleed off in the trip tank giving a hydrostatic pressure in the annulus equal to the selected working pressure (ΔP). The calculus of this volume is obtained by the following formula:

$$\boldsymbol{V_b = \frac{10.2 \times \Delta P \times Ca}{MW}}$$

Where

Vb : mud volume to bleed (BBL)

ΔP : working pressure (PSI)

d1 : mud density (PPG)

Ca: annular capacity at gas position (bbl/ft)

4. **Calculus of the gas migration rate (Rm)**

If a kick is taken while drilling and the well is shut-in, the intruded fluid will be located at bottom of the annulus. After a certain time, the migration of the gas will take place inducing higher and higher pressures along the well.

The gas migration rate is estimated from the pressure increase recorded after a certain elapsed time. To determine the gas position at any moment in the annulus, the following formula can be used:

$$\boldsymbol{R_m = \frac{10.2 \times \Delta P}{MW}}$$

Where

Rm : gas migration rate (ft/h)

ΔP : pressure increase per hour (psi/h)

MW: mud density (ppg)

b) Volumetric Method application procedure

1) Note the stabilized shut-in casing pressure **SICP**
2) Let the casing pressure to increase up to : **Pa2 = SICP + S +ΔP**
3) Bleed off in the trip tank at **constant casing pressure** equal to **Pa2** the calculated mud volume **Vb** corresponding to the gas position in the annulus by using the manual choke preferently.
4) Let the **annular pressure to increase** with a quantity equal to the selected working pressure. The casing pressure will have a new value **Pa3 = Pa2 + ΔP**
5) Repeat the sequences **3** and **4** until the gas reaches the surface, then it will

be evacuated using the lubricating method.

III.5.6. Lubrication Method

It is a method of evacuating a gas volume beneath the preventers by replacing it with mud. The concept of the approach is to maintain a consistent bottom hole pressure by pumping in a specified volume of mud through the kill line and bleed an amount of gas to lower the casing pressure to the hydrostatic pressure of the pumped volume.

Lubricating Method application procedure

1) Note the casing pressure Pa
2) Select a working pressure level ΔP which is generally between 5 and 10 bars
3) Calculate the mud volume V giving a hydrostatic pressure in the annulus equal to the selected working pressure level ΔP

$$\boldsymbol{V = \frac{10.2 \times \Delta P \times Ca}{MW}}$$

where

V : mud volume to pump through the annular space (bbl)

ΔP : chosen working pressure level (psi)

MW : mud density (ppg)

Ca : annular capacity casing-DP (bbl/ft)

4) pump into annulus (kill line) the calculated mud volume V
5) let the mud settle down through the gas
6) bleed the gas using manual choke to reduce casing pressure with a value equal to the selected working pressure ΔP plus the overpressure due to the mud injection.
7) repeat the sequences 4, 5 and 6 until the complete evacuation of the gas.

NOTE : *In case of a swabbed gas while tripping ,the casing pressure must be null at the end of the lubricating operation and increasing the density would lead to a circulation loss .*

Chapter IV

A real case study

IV.1. Well description

The horizontal development oil producing well MDZ729 was drilled in the MD subdivision of the Hassi Messaoud field (1B Bock). The MDZ729 well was drilled to a total depth of 10807.6 Ft (TVD). A gas kick appeqr 15/05/2019

IV.2. Operation objectives

- Reduce time of non-production (NPT)
- Achieve a required penetration rate (ROP performance).
- Collect geological information and production data during drilling, logging and production

IV.3. Introduction

A gas kick is a well control problem that occurs when the pressure found within the drilled rock is higher than the mud hydrostatic pressure acting on the borehole or rock face the greater formation pressure has a tendency to force formation fluids into the wellbore.

The case study of "MDZ729" in the MD subdivision of the Hassi Messaoud field is an important one. The gas kick that appeared in this well was studied to determine the best method for controlling it. The two methods that were compared were the driller's method and wait and weight method. The kill sheet was filled out and calculations were done to compare the two methods. This chapter will provide a detailed analysis of the case study.

IV.4. Signs and causes of the kick

From the warning signs: Increase in the percentage of gas in the mud at the outlet by 50% ,Small change in rate of penetration

From the positive signs: Increase in the level of active mud back by 10 bbl.

The causes in this situation are:

- Insufficient mud weight
- Formation at high abnormal pressure
- Contamination of mud by gas

IV.5. Calculation and preparation of Kill sheet

IV.5.1. Well data

LOT pressure: 1562.2 psi, MW of LOT: 9.0797 ppg, Fracture MW: 11,97 ppg

MW: 7.7469 ppg, Mud gradient: 0.403 psi/feet, TVD of shoe: 10387.6 feet, TVD :

10807.6 feet.

Pump stroke: 0.094 bbl/stroke, Pump speed: 25 stroke/minute, Pc1= 470 psi

Shut in casing pressure 321 psi, shut in drill pipe pressure 204 psi, volume of gas kick(pit gain) 10 bbl, kill mud weight 8,1 ppg, well temperature 60° F.

IWCF Surface BOP	KILL SHEET	1 of 2

WELLNAME: MDZ 729 UNITS: enafor #13 FT DATE: 15-mai-23

DEPT: #####

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM FORMATION STRENGTH TEST (A) 1562,2 psi

DRILLING FLUID DENS. AT TEST (B) 9,0797 ppg

MAX. ALLOWABLE DRILLING FLUID DENSITY =

(A) psi	/	0,052	/	Shoe TVD	+	(B) ppg	=	(C) ppg
1562,2	/	0,052	/	10387,6	+	9,0797	=	(C) 12,0

INITIAL MAASP	=	[(C) ppg	-	Curr Dens]		x	Shoe TVD	x	0,052	
	=[	12,0	-	7,7469	]	x	10387,6	x	0,052	
						=	2282			psi

CURRENT WELL DATA:

DRILLING FLUID DATA

DENSITY 7,7469 ppg

GRADIENT 0,403 psi/ft

CASING & SHOE DATA

SIZE 9,625 in

M. DEPTH 10387,6 ft

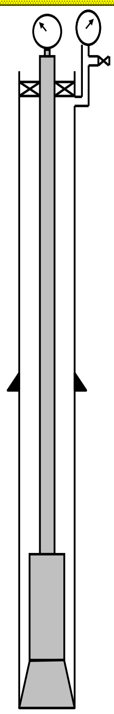
T.V. DEPTH 10387,6 ft

HOLE DATA

SIZE 8,5 in

M. DEPTH 10807,6 ft

T.V. DEPTH 10807,6 ft



PUMP No. 1 DISPLACEMENT	PUMP No. 2 DISPLACEMENT
0,094 bbl / stk	0,094 bbl / stk

SLOW PUMP RATE DATA		DYNAMIC PRESSURE LOSS PUMP No. 1		PUMP No. 2	
25	SPM	470	psi	450	psi
20	SPM	410	psi	350	psi

PRE-RECORDED VOLUME DATA:	LENGTH ft		CAPACITY bbl/ft		VOLUME bbl	
DRILL PIPE 5"	9724,88	x	0,01735	=	168,727	
HWDP 5"	367,47	x	0,0088	=	3,23374	+
DRILL COLLAR 6.5"	715,25	x	0,00837	=	5,98664	+
DRILL STRING VOLUME			(D)		177,947	bbl
DC x OPEN HOLE		x		=		
DP/HWDP x OPEN HOLE	0	x	0	=	0	+
DC x OPEN HOLE	420	x	0,029	=	12,18	
OPEN HOLE VOLUME			(F)		12,18	bbl
DC x CASING	295,3	x	0,03216	=	(G') +	9,5
HWDP x CASING	367,5	x	0,04642	=	(G") +	17,06
DP x CASING	9724,88	x	0,0479	=	(G) +	465,82
TOTAL ANNULUS VOLUME	(F+G'+G"+G)=(H)		505			bbl
TOTAL WELL SYSTEM VOLUME	(D+H)=(I)		683			bbl
ACTIVE SURFACE VOLUME	(J)		314,46			bbl
TOTAL ACTIVE FLUID SYSTEM	(I+J)		998			bbl

PUMP STROKES strokes		TIME minutes	
		25	
VOLUME		PUMP STROKES	
PUMP DISPLACEMENT		SLOW PUMP RATE	
(E) stks 1893		76	min
		75,7221	
130	stks	5	min
4956	stks	198	min
5368	stks	215	min
7261	stks	290	min
3345	stks		
10606	stks		

Figure IV.2. kill sheet

Table IV.1. Kill sheet results

Mud kill weight **MKW (ppg)**	**MKW= SIDPP /TVD/ 0,052+current mud weight** **MKW=204/10807.6/0.052+7.7469=8.1**
Initial circulating pressure **(psi)**	**ICP= Dynamic pressure loss + SIDPP** **ICP=470 + 204 = 674**
Final circulating pressure **(psi)**	**FCP= Dynamic pressure loss* MKW/ Current mud weight** **FCP= 470*8.1/7.7469= 491**
Maximum allowable surface pressure **(psi)**	**MAASP=(Fracture mud weight- current mud weight)*0.052*shoe TVD** **MAASP=(11,97-7.7469)*0.052*10387.6=2282**

IV.5.2. Driller's method

1. **The pressure at the casing shoe at 10387.6 feet when the well is first shut in**

   Px = SICP + ρ_m X [17]

   $P_{10387.6} = 0.403 * (10387.6) + 321$

   $P_{10387.6} = 4507.2\ psi$

2. **The pressure at the casing seat at 10387.6 feet when the top of the influx reaches that point**

   $$Px = \frac{B}{2} + \sqrt{\frac{B^2}{4} + \frac{P_b \rho_m z_x T_x h_b A_b}{z_b T_b A_x}} \qquad [17]$$

   $$B = \boldsymbol{P_b} - \boldsymbol{\rho_m}(\boldsymbol{D} - \boldsymbol{X}) - \boldsymbol{P_f}\frac{\boldsymbol{A_b}}{\boldsymbol{A_x}} \qquad [17]$$

$_b$ = Conditions at the bottom of the well

$_x$= Conditions at X

Px = Pressure at depth X, psi

P_b = Bottomhole pressure, psi

ρ_m = Mud gradient, psi/ft

Z = Compressibility factor

T = Temperature, °Rankine

X = Distance from surface to top of influx, feet

A = annular area, *in2*

D =Well depth, feet

P_f = Pressure exerted by the influx at depth X, psi

SICP = shut in casing pressure, psi

Calculating the height and the pressure of the influx

$$P_f = G_f(H_x)$$

The height of the influx

$H_x = \frac{gain\ volume}{Cdcoh}$. where :

H_x = Height of the influx, feet

$Cdcoh$= Annulus capacity between open hole and drill collar, bbl/ft

G_f = influx gradient

$H_x = \frac{\mathbf{10}\ \boldsymbol{bbls}}{\mathbf{0,029}}$.

Hx= 344 feet

Calculating the influx gradient Gf:

Pb = Gf Hx + ρm(D – X) + SICP And Pb = ρm(D) + SIDPP

So : Gf Hx + ρm(D – X) + SICP = ρm(D) + SIDPP

Where

$$G_f = \frac{\rho m(D) - \rho m(D - X) + SIDPP - SICP}{H_x}.$$

$$G_f = \frac{0{,}403(10807{,}6) - 0{,}403(10807{,}6 - 344) + 204 - 321}{344}.$$

Gf = 0,062 psi/feet

So Pf = 344×0,062 = 21,6 psi

Calculating B :

B = 4586 – 0,403(10807,6 – 10387,6) – 21,6 * 37,75/37,75 / B = 4395,1

Calculating the temperature :

Geothermal gradient 1°/100feet

1°R = 1°F + 459,67 [17]

If x = 10807,6 feet T °R = 60 + 10807,6/100 + 459,69 = 628°R

x = 10387,6 feet T10387,6 = 624°R

x = 0 T0 = 520°R

$$P_{10387,6} = \frac{4395,1}{2} + \sqrt{\frac{4395,1^2}{4} + \frac{4586(0,403)(624)(344)(37,75)}{628(37,75)}}$$

$P_{10387,6}$= 4534, psi

3. The annulus pressure when the gas bubble first reaches the surface

$$Px = \frac{B}{2} + \sqrt{\frac{B^2}{4} + \frac{P_b \rho_m \, z_x T_x h_b A_b}{z_b T_b A_x}}$$

B = $\boldsymbol{P_b} - \rho_m(\boldsymbol{D} - \boldsymbol{X}) - \boldsymbol{P_f}\frac{A_b}{A_x}.$ / A0 = 38,75 in^2

At surface x = 0

So B = 209,5

P0 = 828,5 psi.

<u>The influx height at surface</u>

$$H_0 = \frac{Pf\ Z0\ T0\ Af}{P0\ Zf\ Tf\ A0}.$$

$$H_0 = \frac{4586(520)(37,75)(344)}{828,5(628)(38,75)}.$$

H0 = 1536 feet

Table IV.2. Evolution of annular pressure in function of pumped volume and variation of influx height, temperature and pressure in each point driller’s method

Tx (°R)	B	Px (psi)	H influx (ft)	X (ft)	pumped volume (bbls)	Pa D (psi)
520	209,5	828,5	1536	0	0	321
530	612,5	1091,4	1188	1000	50	321
540	1015,5	1396,8	946	2000	100	326
550	1418,5	1731,7	777	3000	150	331
560	1821,5	2086,2	657	4000	178	343
570	2224,5	2453,6	569	5000	225	391
580	2627,5	2829,6	502	6000	300	447
590	3030,5	3211,7	450	7000	350	518
600	3433,5	3598,0	408	8000	400	594
610	3836,5	3987,4	374	9000	450	675
620	4239,5	4379,1	346	10000	504,64	828,5
623,876	4395,7	4531,5	337	10387,6	514	204
628,076	4565,0	4696,8	327	10807,6	550	204
					600	204
					650	204
					682,6	204

4. Graph analysis driller’s method

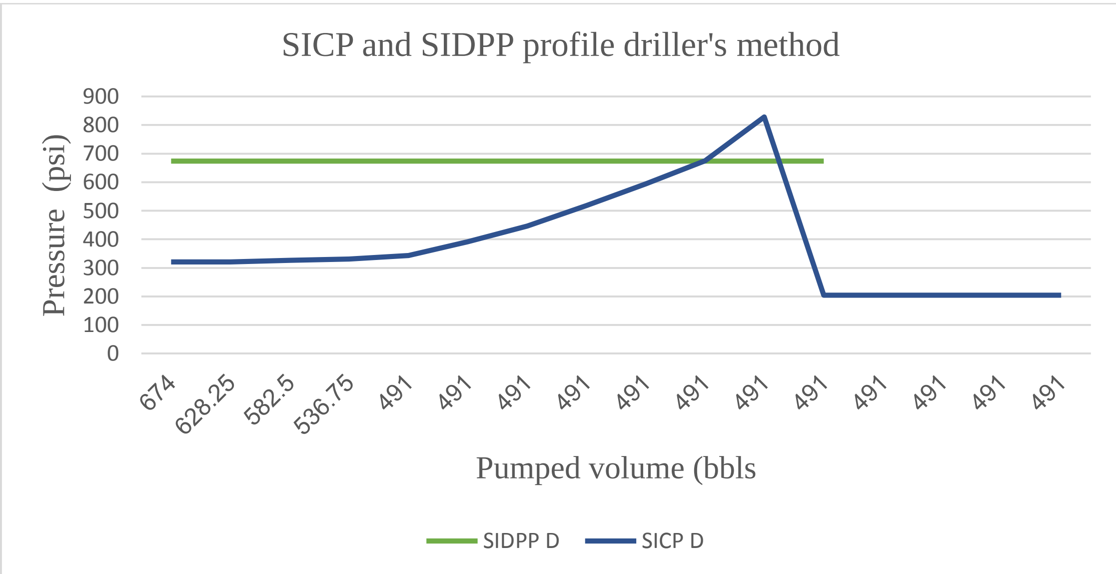


Figure IV.3. SICP and SIDPP profile driller's method

Interpretation

After the influx enter the wellbore the fast detection of this intruder and the immediate closing of well are the keys for a successful operation when closing the well. We wait for stabilization of manometers. after that, we read 321 psi shut in casing pressure and 204 psi shut in drill pipe pressure at 0 bbl pumped volume, the cause why SICP>SIDPP is because we have homogeneous mud inside drill pipe and non-homogeneous mud in annulus mixed with cuttings in addition to two different densities of gas and mud proofed by the next equation: Pb (psi) = SICP (psi) + Hydrostatic pressure (psi) | annulus| = SIDPP (psi) + Hydrostatic pressure (psi) |inside drill pipe|

SICP (psi) = SIDPP (psi) + Height of influx (ft)* 0.052(density of current mud(ppg)- density of influx (ppg))

Driller's method has two cycle we evacuate the influx in first cycle with current mud density once we start the operation we notice SIDPP equal to the initial circulating pressure ICP 674 psi and still constant during the first cycle because we use the same first current mud weight, shlumberger recommend to rise the pumps in stages with 5 to 10 stroke per minute, a dangerous phase when top of gas bubble at shoe the pressure at that point is quietly big because moving from bigger to smaller area , the annulus pressure keep rising until maximum value of 828,5 psi while the pumped volume is 504,64 the gas bubble here is under the BOP, by continuing pumping the mud and once we evacuate the influx completely the annulus pressure drop down to be equal to first SIDPP at 204 psi we wait for stabilization we close the well then we continue the second cycle using kill mud weight.

IV.5.3. Wait and weight method

1. **The pressure at the casing shoe at 10387,6 feet when the well is first shut in**

Px = SICP +ρ_m X

$$P_{10387.6} = 0.403 * (10387.6) + 321$$

$$P_{10387.6} = 4507.2\, psi$$

2. **The pressure at the casing seat at 10387.6 feet when the top of the influx reaches that point**

$$Px = \frac{B}{2} + \sqrt{\frac{B^2}{4} + \frac{P_b \rho_{mr} z_x T_x h_b A_b}{z_b T_b A_x}},$$

$$B_1 = P_b - \rho_{mr}(D - X) - P_f \frac{A_b}{A_x} + Lvds(\rho_{mr} - \rho_m) \qquad [17]$$

$Lvds =$ Length of drill string volume in annulus, feet

ρ_{mr} = kill mud gradient, psi/ft

Calculating B1 :

B1 = 4586 – 0,42(10807,6 – 10387,6) – 21,6 * 37,75/37,75+3976(0,42 – 0,403)

B1 = 4455,6

Calculating $P_{10387,6}$:

$$P_{10387,6} = \frac{4455,6}{2} + \sqrt{\frac{4455,6\ ^2}{4} + \frac{4586(0,42)(624)(344)(37,75)}{628(37,75)}}$$

$P_{10387,6} = 4599$ psi

3. **The annulus pressure when the gas bubble first reaches the surface**

$Px = \frac{B}{2} + \sqrt{\frac{B^2}{4} + \frac{P_b \rho_{mr}\, z_x T_x h_b A_b}{z_b T_b A_x}},$

$B_1 = P_b - \rho_{mr}(D - X) - P_f \frac{A_b}{A_x} + Lvds(\rho_{mr} - \rho_m)$

B1 = 4586 – 0,42(10807,6 – 0) – 21,6 * 37,75/38,75+3976(0,42 – 0,403) / B1 = 93

Calculating $P_{10807,6}$:

$$P_{10807,6} = \frac{93}{2} + \sqrt{\frac{93\ ^2}{4} + \frac{4586(0,42)(520)(344)(37,75)}{628(38,75)}}$$

$P_{10387,6} = 779$ psi

<u>The influx height at surface</u>

$H_0 = \frac{Pf\ Z0\ T0\ Af}{P0\ Zf\ Tf\ A0}.$

$H_0 = \frac{4586(520)(37,75)(344)}{779(628)(38,75)}$ / H0 = 1634 feet

Table IV.3. Evolution of annular pressure in function of pumped volume and variation of influx height, temperature and pressure in each point wait and weight method

T	B	Px	HX	X	pumped volume	Pa w&w
520	93,5	779	1632,86	0	0	321
530	513,5	1038	1249,27	1000	50	321
540	933,5	1346	981,86	2000	100	321
550	1353,5	1688	797,21	3000	150	326
560	1773,5	2054	667,28	4000	178	330
570	2193,5	2434	573,05	5000	225	363
580	2613,5	2825	502,51	6000	300	408
590	3033,5	3222	448,16	7000	350	469
600	3453,5	3624	405,20	8000	400	538
610	3873,5	4029	370,50	9000	450	620
620	4293,5	4437	341,95	10000	504,64	779
623,876	4455,8	4599	340,78	10387,6	514	204
628,076	4632,2	4771	330,70	10807,6	550	158
					600	105
					650	54
					682,6	0

4. Graph analysis wait and weight method

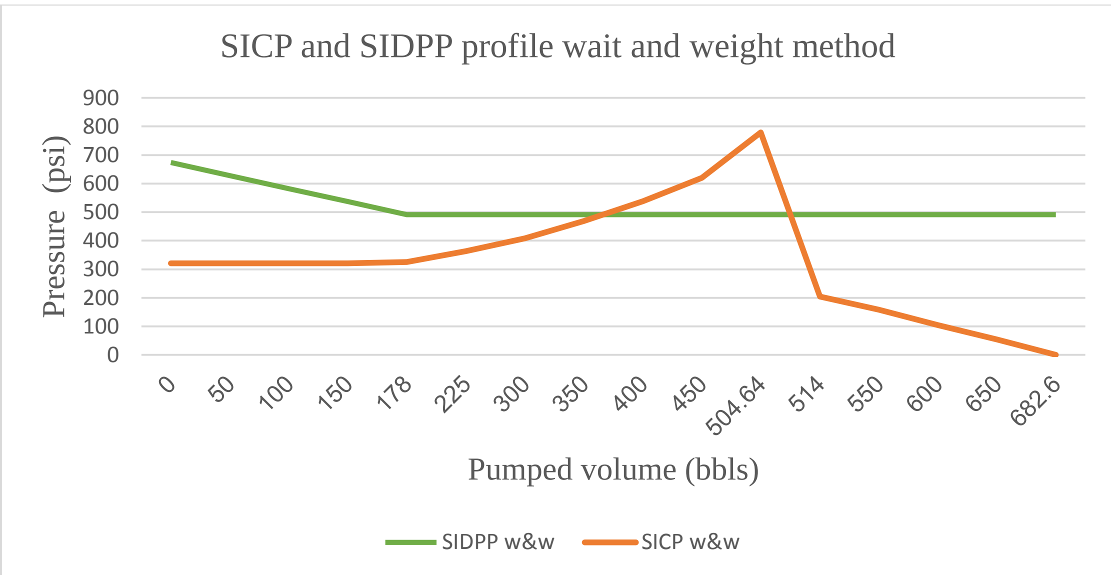


Figure IV.4. SICP and SIDPP profile wait and weight method

Interpretation

Wait and weight method has one cycle of circulation, we read SIDPP=204psi and SICP=321psi after closing the well and waiting stabilization., we start circulation after preparing kill mud weight.

Open the well, once starting the circulation SIDPP increase to be equal to ICP=674 psi, when the mud enter drill string SIDPP starting decrease regularly and SICP still constant until the kill mud weight reach the drill bit, the SICP start to increase and we read SIDPP= FCP=491psi and still constant till the end of operation because the interior of drill string is homogeneous with the new kill mud/ SICP=325 psi.

The max value of SICP reached when the influx beneath BOP SICP=779psi after that the annular pressure drop down to be equal to the first SIDPP ,SICP=204psi, so the influx is completely evacuated and remain internal volume of drill string with first mud weight under BOP while evacuation of this volume (first mud weight) the annular pressure decrease regularly until the wellbore is full of kill mud we read annular pressure SICP=0psi at 682.59 bbl.

5. Graph analysis driller's and wait and weight method

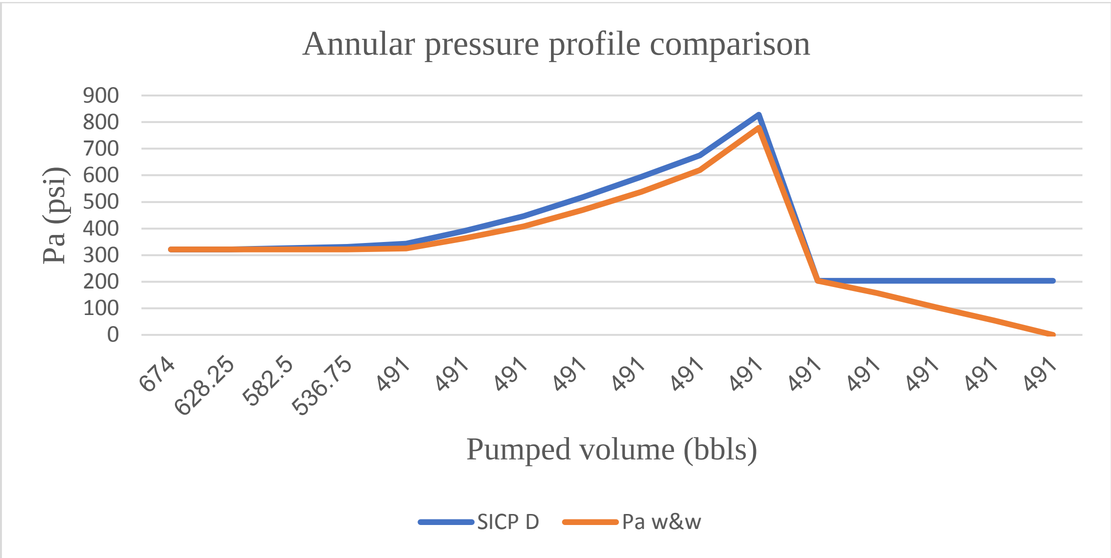


Figure IV.5. Annular pressure SICP profile comparison

Interpretation

According to Figure IV.4. we can say that the two profiles of the annular pressures for the two methods (Driller's and Wait & Weight) are the same until the moment we reach the bit. When the killing mud reach the bit in the wait&weight method it gives lower annular pressures than the Driller's method which gives a margin of safety to the choke operator to avoid fracturing when the effluent does not reach the shoe, the small difference between the two methods when reaching the maximum pressure 828,5 psi using driller’s method and 779 psi using wait&weight method due to small height of open hole and the small difference between the first mud weight and kill mud weight, for this reason the Wait&Weight method is preferred in reality by the Driller's.

IV.6. Comparison of driller’s and wait and weight method

Both the driller's method and the wait and weight method are widely used techniques for well control in the event of a gas kick. While they share the common objective of preventing a blowout and maintaining wellbore integrity, there are notable differences in their approach and effectiveness.

1. Response Time and Implementation:

- Driller's Method: Rapid response, allows for quick actions to increase mud weight and close the well, limiting gas influx.
- Wait and Weight Method: Gradual approach, requires well shut-in and time for equilibrium before adjusting mud weight. Suitable for situations where a slower and controlled response is preferred.

2. Accuracy of Calculations:

- Driller's Method: Relies on simpler calculations based on predetermined kill ratios, providing a quick but potentially less precise estimation of required mud weight and volume.
- Wait and Weight Method: Employs detailed calculations considering influx characteristics and mud properties, resulting in a more accurate estimation for better well control.

3. Sensitivity to Formation Properties:

- Driller's Method: Assumes constant influx conditions and does not account for variations in formation properties.
- Wait and Weight Method: Considers dynamic behavior, including influx composition and formation pressures, adapting to changing downhole conditions and providing a better understanding of the reservoir.

4. Equipment and Personnel Requirements:

- Driller's Method: Relies on experienced personnel with quick decision-making, effective communication, and well control expertise.
- Wait and Weight Method: Emphasizes comprehensive monitoring systems,

sophisticated data analysis, and specialized personnel with expertise in well control and influx management.

By considering these factors, operators can select the most appropriate method based on response time requirements, calculation accuracy, sensitivity to formation properties, and available equipment and personnel resources.

IV.7. Recommendations:

1. The selection of the appropriate well control method should be based on a thorough evaluation of the specific well characteristics, influx properties, and operational requirements.
2. Consider implementing a hybrid approach, utilizing the strengths of both methods. For example, initiating well control using the driller's method for rapid response and subsequently transitioning to the wait and weight method for more precise control.
3. Emphasize the importance of continuous monitoring and real-time data analysis to identify any deviations, adjust the well control strategy, and optimize the drilling operation.
4. Provide comprehensive training and continuous professional development programs for personnel involved in well control, ensuring they have the necessary skills and knowledge to effectively manage gas kicks and implement the chosen method.

By considering these recommendations and tailoring the well control strategy to the specific well conditions, operators can enhance safety, minimize risks, and optimize well control operations in the presence of gas kicks.

Conclusion:

In conclusion, both the driller's method and the wait and weight method have their advantages and limitations in the context of well control during gas kicks. The driller's method offers a rapid response and simplicity in calculations, making it suitable for immediate actions and straightforward situations. On the other hand, the wait and weight method provides a more precise and adaptable approach, considering various downhole factors and aiming for equilibrium.

Based on the case study analysis, it is evident that the wait and weight method demonstrated better accuracy in controlling the well, as it accounts for changing influx characteristics and formation properties. However, it is important to recognize that the effectiveness of each method may vary depending on the specific circumstances of the well, including reservoir conditions and drilling operation constraints.

General Conclusion

In conclusion, this thesis has provided a comprehensive overview of well control in the context of gas kicks, which are a significant risk factor in drilling operations. We have explored the various methods and equipment used for well control, with a particular focus on the driller's method and the wait and weight method. Our analysis of a case study involving a gas kick has demonstrated the importance of effective well control in preventing blowouts and ensuring the safety of personnel and equipment.

Our comparison of the two methods showed that while both methods can be effective, the wait and weight method was generally more accurate and reliable in our case study. However, it is important to note that the effectiveness of each method will depend on the specific circumstances of each well, and that the driller's method may be more appropriate in certain situations.

Overall, our analysis underscores the importance of proper well control procedures and the need for constant vigilance during drilling operations. We hope that this thesis has contributed to a deeper understanding of well control in the context of gas kicks and will serve as a valuable resource for future drilling operations. By following the best practices and guidelines outlined in this thesis, we can help to ensure the safety and success of drilling operations around the world.

Abstract

This thesis investigates the crucial aspect of well control during drilling operations in the presence of gas kicks. It comprises four chapters covering drilling generalities, well control equipment, kicks and well control methods, and a practical case study of well MDZ729 That provides an overview of drilling operations and discusses the importance of well control equipment in maintaining wellbore integrity. It explores gas kicks, their causes, and associated risks, focusing on the driller's method and the wait and weight method as primary well control techniques. In the case study of well MDZ729, both methods are employed to control a gas kick. Detailed calculations and the completion of a kill sheet are performed, followed by a comprehensive comparison of the two methods.

Keywords: well control, kicks, gas, driller’s, wait and weight, methods, losses

Resumé:

Cette thèse étudie l'aspect crucial du contrôle de puits lors des opérations de forage en présence de venue de gaz. Elle comprend quatre chapitres couvrant les généralités du forage, l'équipement de contrôle de puits, les venues de gaz et les méthodes de contrôle de puits, ainsi qu'une étude de cas pratique du puits MDZ729. Elle donne un aperçu des opérations de forage et discute de l'importance de l'équipement de contrôle de puits pour maintenir l'intégrité du puits. Elle explore les venues de gaz, leurs causes et les risques associés, en mettant l'accent sur la méthode du Driller's et la méthode de wait and weight en tant que techniques principales de contrôle de puits. Dans l'étude de cas du puits MDZ729, les deux méthodes sont utilisées pour contrôler une venue de gaz. Des calculs détaillés et la réalisation d'une feuille de killsheet sont effectués, suivis d'une comparaison complète des deux méthodes.

Mots clés : contrôle de venue, venue, gaz, driller’s, wait and weight, méthodes, pertes

ملخص:

تتناول هذه الرسالة الجانب الحاسم للتحكم في الآبار أثناء عمليات الحفر في حالة حدوث اندفاعات الغاز. تتألف الرسالة من أربعة فصول تتناول المبادئ العامة للحفر ومعدات التحكم في الآبار واندفاعات الغاز وأساليب التحكم في الآبار، وتتضمن دراسة حالة عملية للبئر .MDZ729 توفر الرسالة نظرة عامة على عمليات الحفر وتناقش أهمية معدات التحكم في الآبار في الحفاظ على سلامة الآبار. كما تستكشف اندفاعات الغاز وأسبابها والمخاطر المرتبطة بها، مع التركيز على طريقةDriller's وطريقة wait and weight كأساليب رئيسية للتحكم في الآبار.

في دراسة حالة البئرMDZ729 ، يتم استخدام كلا الطريقتين للتحكم في اندفاع الغاز. يتم إجراء حسابات مفصلة وملء ورقة 'kill sheet'، تليها مقارنة شاملة بين الطريقتين.

الكلمات المفتاحية: التحكم في الآبار, واندفاعات الغاز, أساليب, الحفار, الانتظار والوزن خسائر,

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