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Analysis of Kick Detection Methods in the Light of Actual Blowout Disasters.

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Submission date: August 2017
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MASTER'S THESIS

Study program	**Petroleum Engineering**
THESIS TITLE	Analysis of Kick Detection Methods in the Light of Actual Blowout Disasters.
Closed/Open	Open thesis
Student name	Oltingey Lindi
Supervisor name	Sigve Hovda
Credits	30 units
Department	Department of Geoscience and Petroleum
Date of Submission	**August 2017**

Abstract

Kicks or formation fluid influxes pose persistent challenges and operational costs during drilling, workover, completion and sometimes after temporary abandonment operations. Despite of presence of variety of kick detection methods, oil and gas wells still experience undetected kicks and detected kicks which sometimes becomes uncontrolled and results into blowout. Kicks that evolved into blowout stage cost billions of dollars, human lives and damage to the environment. For instance Macondo well incident that occurred in 2010 cost about $40 billion and 11 fatalities, Piper alpha in north sea that occurred in 1988 cost about $3.4 billion and 167 fatalities, and Petrobras 36, Brazil, that occurred in 2001 cost about $350 million and 11 fatalities (Tabibzadeh & Meshkati, 2014a). So it's better to incur cost to detect and control kicks rather than healing its consequences. The available methods for kick detection has its strength and weaknesses. These weaknesses give a loop for kicks to flow to surface undetected and hence it might bring about blowout disasters. Therefore the main goal of this thesis will be to analyse kick detection methods to recognise the loop holes for the occurrence of blowout disasters and suggest the means of improvement. The critical evaluation will be based on blowout cases selected which occurred due to late or failed kick detection. Therefore earlier kick identification and controlling is crucial for the development of petroleum industry in general but in particular avoidance of blowouts. The mains causes of blowouts has been categorized into human errors, technological deficiencies, cost cutting and kick detection techniques problems.

Conclusion from this thesis suggests the extension of kick detection method beyond drilling operations to the completion, workover or completion operations and establishment of advisory program that could automatically be advising the crew working in the rig is paramount. This will enable quick decision making. Also advisory program will reduce the probability of human errors occurrence that leads to blowout. Apart from advisory program also change in mud returning volume method could be developed into sensors that can be used beyond drilling operations.

Acknowledgement

I would like to express my sincere gratitude to my thesis supervisor, Associate Professor Sigve Hovda for his efforts in helping me from the beginning to the accomplishment of this thesis. His inputs, patience, motivation, enthusiasm, advices and immense knowledge were very importance and helpful to me in accomplishment of my thesis.

Also, I would like to thank EnPe-NORAD, and Statoil under Angolan Norwegian Tanzanian Higher Education Initiative (ANTHEI) project for financial support throughout my studies. I also appreciate the support from the University of Dar es Salaam (UDSM), especially Department of Chemical and Mining Engineering (CME) for allowing me to use facilities at the department.

Lastly I would like to thank my family for the support and courage in the course of doing this thesis.

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NOMENCLATURE

BHA-Bottom Hole Assembly

BHP -Bottom Hole Pressure

BOP- Blowout Preventer

BP- British petroleum

CBHP- Constant Bottom Hole Pressure

BSEE -Bureau of Safety and environmental Enforcement

DG-Dual Gradient

DHSG -Deepwater Horizon Study Group

DHSV-Downhole Safety Valve

ECD -Equivalent Circulating Densities

EDS -Emergency Disconnect System

ERD -Extended Reach Drilling

ESD -Emergency Shutdown

IADC - International association of Drilling contractors

ICP- Initial Circulating Pressure

KB- Kelly Bushing

LMRP -Lower Marine Riser Package

MAASP -Maximum Allowable Annular Surface Pressure

MPD- Managed Pressure Drilling

MW- Mud Weight

NCS -Norwegian Continental Shelf

NPT -Non-Productive Time

PCCC -Pressure Containing anti-Corrosion Caps

PVT -Pit Volume Totalizer or Pressure/Volume/Temperature

RCD -Rotating Control Device

ROV -Remotely Operated Vehicles

RTTS-Retrievable Pressure Testing, Chemical Treating and Cement Squeezing

TVD- Total Vertical Depth

USA- United States of America

PMCD -Pressurized Mud Cap drilling.

1.INTRODUCTION.

Kick is defined as an influx of fluid (gas, oil or water, combination of them or diffusion of gas into a drilling fluid) into the wellbore. (Azar, 2007; Velmurugan, Bansal, & Sharma, 2015). An influx flows into the wellbore when the formation pressure exceeds hydrostatic pressure that includes hydrostatic friction components. When uncontrolled, a kick may develop into a blowout that may lead to loss of operation, rig, human lives and damage to the environment. The most dangerous kick occurs due to gas influx. This is because gas has the capability of expanding at lower pressure i.e. close to surface or on the surface. This influx may cause explosion when ignited on platform once it reaches surface without being controlled. This explosion is known as blowout. (Azar, 2007; Schubert & Wright, 1998). For example according to (Jacobs, 2015), Macondo well blowout in USA caused death of 11 people due to explosion that occurred. Apart from deaths, also it recorded the worst oil spill in US history. Oil spill affects directly all living organisms in the sea. Due to loss of lives and destruction of environment, the kick detection technology become evident that it has to be investigated, enhanced and improved so that kicks impacts or damages can be reduced or prevented from similar incidents

Kicks consequences may lead to stoppage of operations or blowout thus early kick detection became among the top priorities in drilling industry in order to avoid loss of well control. (Fraser, Lindley, Moore, & Vander Staak, 2014). Loss of well control has been defined by Bureau of Safety and Environmental Enforcement (BSEE) as uncontrolled flow of formation or other fluids to an exposed formation or at the surface through a diverter. The uncontrolled flow is a result of failure of surface equipment or procedures which are supposed to control any unwanted flow.(Fraser et al., 2014). Kick detection is complicated, involving a mixture of sensor readings that must be correctly interpreted. Because of this, many of the present kick detection technologies suffer from a high rate of incorrect alarms and only works under certain drilling conditions. These false alarms are among technological deficiencies which might influence the tendency of not taking alarms very seriously. (Jacobs, 2015). When an influx is identified within a short period of time after its flow to the wellbore, the easier it becomes for countermeasures to be taken and reduces the magnitude of the effects that could have occurred and thereafter could enable the crew to shut in the well before hydrocarbons entered the riser and thereby prevent the kick.

To minimize the consequences of undetected kicks, it is desirable to analyse the available kick detection methods so as to identify their weaknesses and propose a suitable detection technique. To reach that objective the following activities needs to be incorporated; To identify kick detections methods, to audit through chosen blowout cases and identify their causes, to assess strengths and weaknesses of each method, equipment and technology applied, to suggest suitable methods to avoid or prevent blowouts.

1.1 BLOWOUT

A blowout is an accident that occurs when uncontrolled loss of oil and/or gas under pressure from the reservoir and/or the production line enters the wellbore, rise to the surface and explode when ignited. (Ahluwalia & Ruochen, 2016) Norwegian Petroleum Directorate(NPD) defined blowout as "A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed." Taking Norway as an example, during 41 years (from the day they started drilling until 2007) of offshore operation on the Norwegian Continental Shelf (NCS) there have been three major blow-out accidents. Three major blow-out accidents that occurred in the offshore oil/gas operations on the NCS are;

- The Bravo accident of 22nd April 1977,
- The West Vanguard accident of 6th October 1985 and
- The Snorre A blow-out incident 28th November 2004 (Sætren, 2007)

These blowouts in Norwegian continental shelf happened in different blocks and there are variety of causes for each incident as discussed in the following subchapters. As seen in Figure 1, the platforms were in fire and they were totally destroyed when fire stopped. The combined pictures in Figure 1 presents the reality when the blowout disaster occurs.

Figure 1:Pictures of the platforms during and after the accident, (Sætren, 2007)

According to (P. Skalle, Jinjun, & Podio, 1999), drilling engineers and fire-fighting specialists will never stop investigating and analysing blowouts cases because of the cost of blowouts, the loss of life and pollution suffered from blowouts. For example blowout pollution rate has been divided in four levels according to the amount of spills as: Enormous (>10000 bbls), Large (£10000 bbls), medium (£1000 bbls) and Small (£100 bbls). The main logic is to investigate and analyse available data and information to be able to determine where was the problem or error, reveal weak points, and attack them through finding appropriate solutions to avoid the same situation. The best way to learn is through mistakes that has been conducted in the past.

Blowouts can be controlled by the following techniques; Collapse of open hole wellbore (also known as Bridging), Closing the blowout preventer (BOP), Pumping Cement slurry (Cement), Capping, Depletion of small reservoirs, Install equipment, Pumping Mud, and

Drilling Relief wells (Dynamic killing) etc. See some other examples of blowout occurrences around the world in the **Table 2**

See **Table 3** for amount of spilled oil which costs millions of dollars and operation that was taking place. **Table 3** displays the date of each blowout from 1980-2010. From the **Table 3** it is obvious that many blowouts occurred on production drilling wells especially during workover (WO), drilling and Production (PR) operations . It is evident from the **Table 3** that influx flows into a well while drilling is no longer in progress and some of kick detection methods becomes inapplicable in detecting unwanted influxes.

1.2 WELL BARRIERS

(Aggelen, 2016; Anders et al., 2015) Well barriers are supposed to support the wellbore during and after drilling operations. Barriers is a potential element in managing major hazards and safety process in oil and gas industry. Generally In basic terms the overbalanced drilling mud is the “primary” well barrier and the BOP is the “secondary” well barrier. Well barrier concepts were introduced to oil industry in Norway by 1992. The standards was developed for illustration where by a blue line was drawn to form an envelope across those components that would control the well pressure by direct contact, and the blue line was named as primary well barrier (envelope). Second was a red line which was drawn to illustrate an envelope outside the primary envelope, independent of primary barrier elements, representing components that would control pressure if an influx developed in a primary component. The red line was named as secondary well harrier as seen in Figure 2.

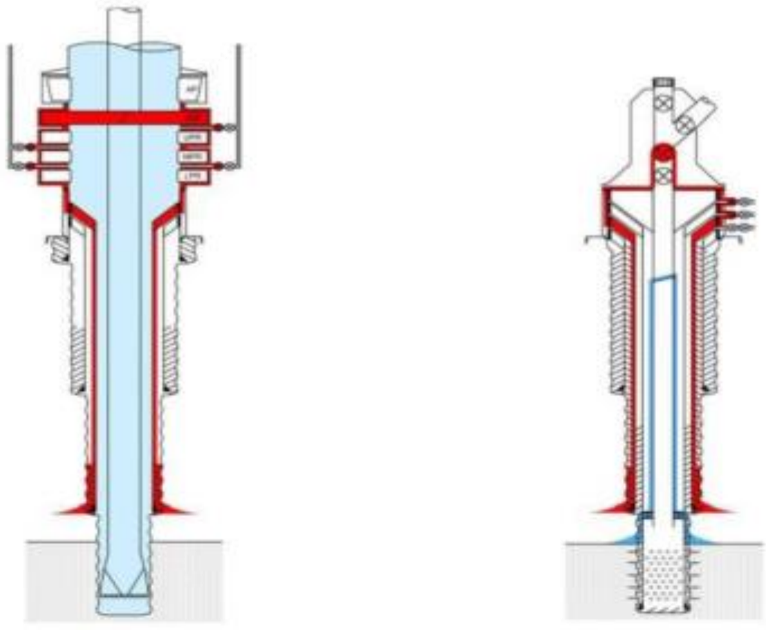

Figure 2: Two barrier envelopes where blue represents primary barrier and red represents secondary barrier(Anders et al., 2015)

Barrier analysis and barrier management had become key elements especially after Macondo and Montara incidents. The focus on barriers has increased to ensure that barriers are identified and installed in place and functions appropriately. The Norwegian Petroleum Safety Authority even states that “Effective barrier management is a fundamental condition for prudent operation” therefore the field of barrier management is developing very quickly.(Aggelen, 2016)

2. BACKGROUND

2.1 WELL PRESSURE.

Near the earth's surface during beginning of drilling process, pressure window seems to be wide but as it gets deeper the pressure window become narrow as seen in Figure 3. Pressure in the well depends on depth drilled, density of fluid and friction forces.

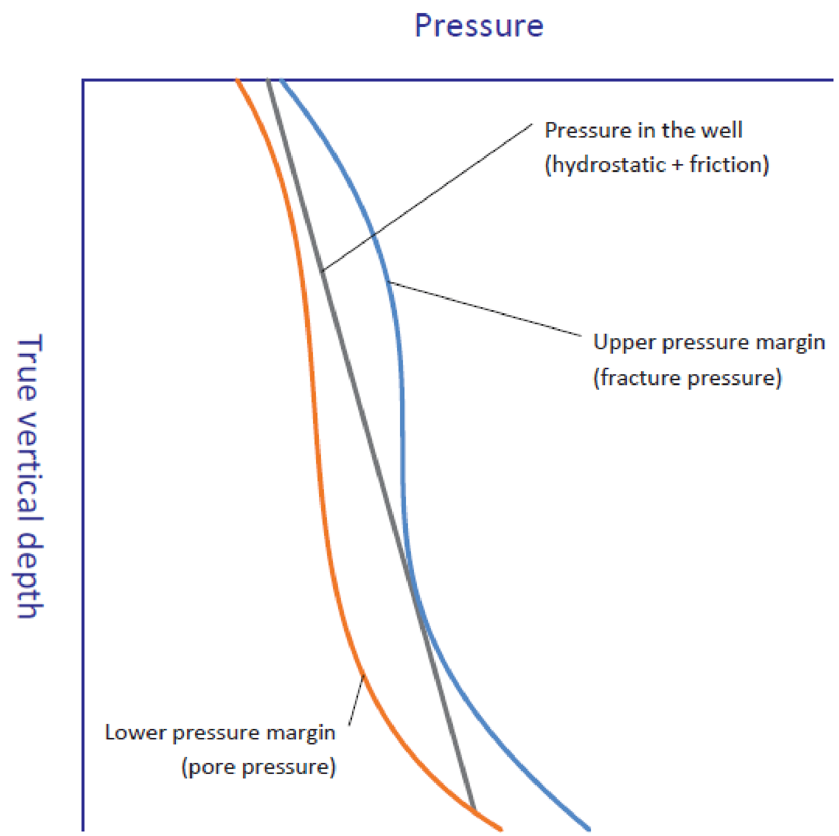

Figure 3: Pore pressure, Hydrostatic pressure and Fracture pressure(Hauge, 2013)

The hydrostatic pressure in the well can be calculated as shown in equation 1

$$P_{hydr} = \rho g h_{TVD} \tag{1}$$

P_{hydr} is hydrostatic pressure, ρ is the density of drilling fluid, g is gravity constant ($9.81\frac{m}{s^2}$) and h_{TVD} is total vertical height of a well.

Pore pressure, hydrostatic pressure and formation pressure appears like as shown in Figure 3. In conventional drilling, the main purpose it to keep hydrostatic pressure below fracture pressure (P_{frac}) and above formation pressure ($P_{formation}$). By ensuring that hydrostatic pressure is higher than formation pressure, any influx into the well can be controlled. Also when hydrostatic pressure is lower than fracture pressure, the controlling of circulation losses and damage to the formation can be achieved .(Hamarhaug, 2011)

In short $P_{hydr} < P_{frac}$ and $P_{hydr} > P_{formation}$, therefore $P_{frac} > P_{hydr} > P_{formation}$.

According to (Jacobs, 2015) the deeper the well and the slower the kick is moving, the longer it will take the system to provide a warning. Some kicks remain stationary and others migrate upward at rates that range between minutes and hours. Generally, kick occurs when hydraulic pressure becomes less that formation pressure. Hydraulic pressure is the pressure due to drilling fluid used. The fluid density determines the hydrostatic pressure, so it can be varied accordingly to raise or lower hydrostatic pressure. The hydrostatic pressure and frictions in the wellbore makes a total of well pressure. When formation pressure is larger than hydraulic pressure it allows influx of fluid from the formation into a well. As it is generally obvious that usually fluid flow from a region of high pressure to a region of low pressure. Even though hydraulic pressure can be varied, influx still flows into a wellbore since formation pressure is not always predictable. This enables influx to flow into a well before higher formation pressure is noticed and counter measure being established. The difference between hydrostatic pressure and formation pressure is called differential pressure.

$$\Delta P = P_{hydr} - P_{formation}$$

Depending on the value of ΔP, the following conditions may be experienced.

If $\Delta P > 0$, then there will be overbalance hence there will be no kick

If $\Delta P = 0$, then there will be balanced condition and there will be no kick

If $\Delta P < 0$, then there will be underbalanced condition, then there will be an influx and possibility of a kick.(Azar, 2007). Refer to Figure 4 below.

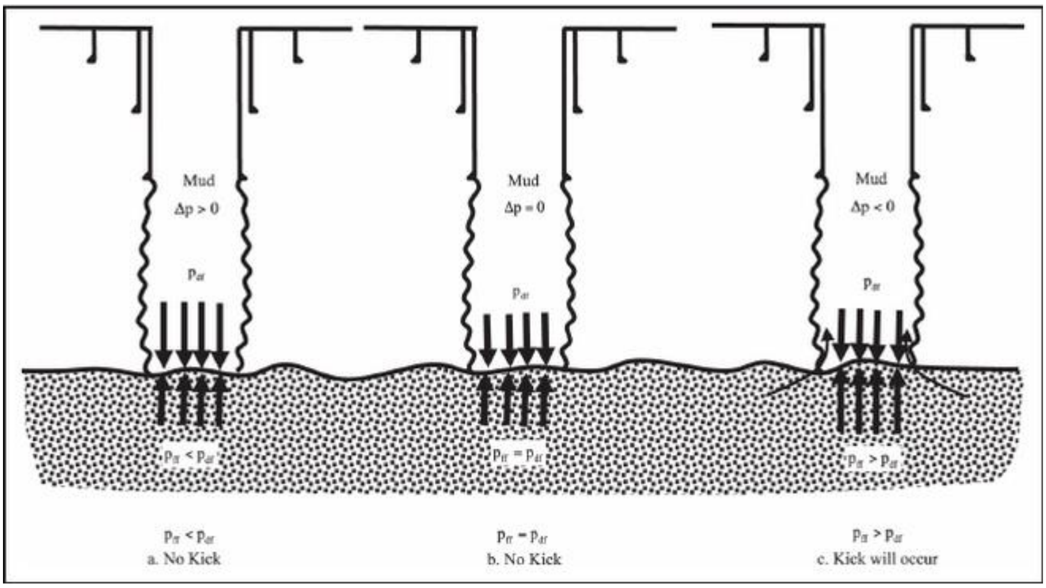

Figure 4: Drilling conditions, a. overbalanced, b. balanced and c. underbalanced.(Azar, 2007)

A small gas influx at the well bottom can be potentially dangerous because it expands while approaching the lower hydrostatic pressure near the surface. At low pressure gas expand and displace an equivalent amount of mud from the well, thus reducing the bottom hole pressure (BHP) which then allows more gas to flow in from the formation pores.(Azar, 2007) as seen in Figure 5.

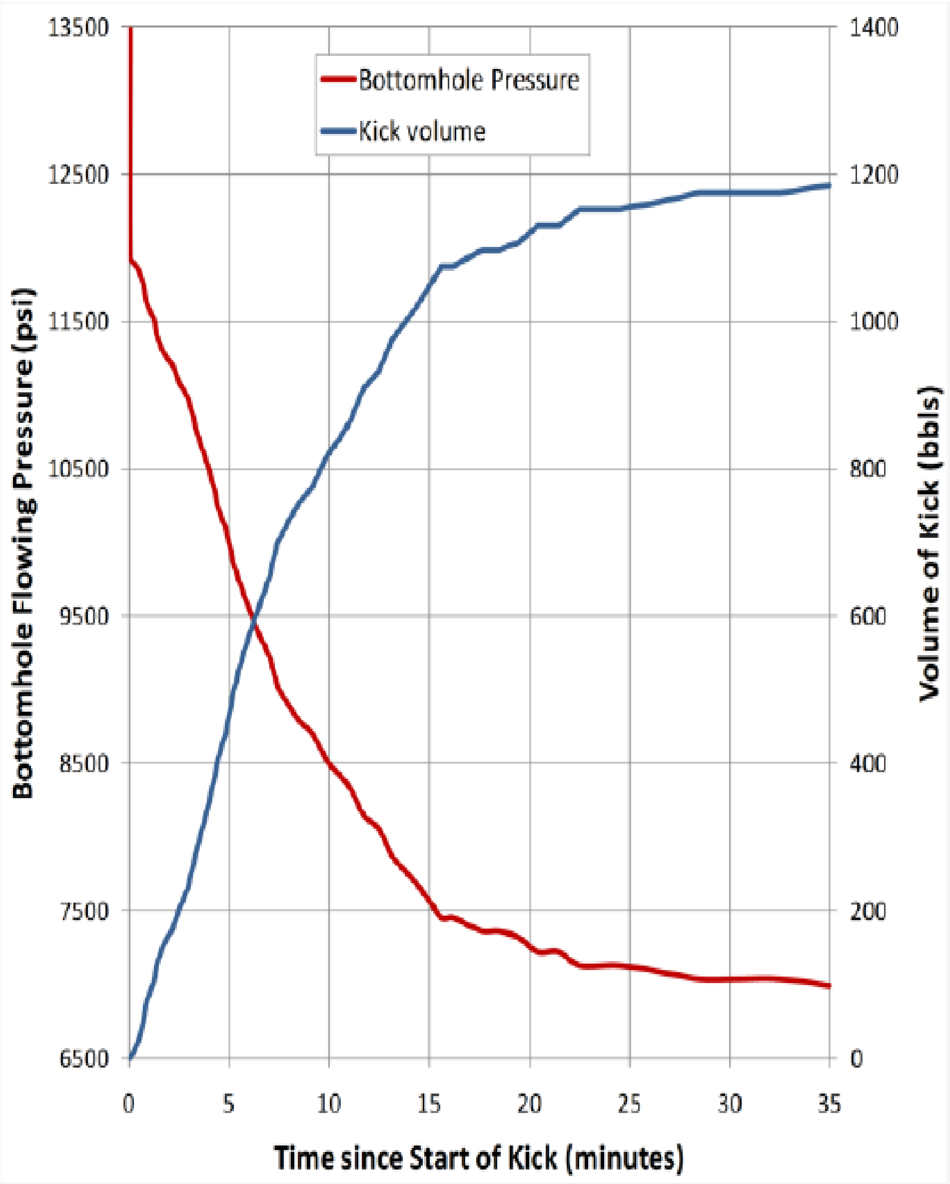

Figure 5: Relationship between bottom hole pressure and kick volume with time (Willson, 2012)

2.2 PRESSURE VARIATION IN SUBSURFACE

(Azar, 2007)The subsurface is not uniform. Though it is believed that pressure increases while moving towards the centre of the earth, unexpected high pressure zones can still be encountered while drilling. Also hydrostatic pressure can be less than formation pressure due to lost circulation and improper tripping out practices, inadequate drilling mud weight, and gas cut mud.

It is appropriate to know the formation and fracture pressure before selecting the mud weight. This is because mud weight brings about hydrostatic pressure which is not ought to be below formation pressure or above fracture pressure, so that kicks or lost circulation and formation damage can be avoided respectively.

Gas cut mud can be observed when drilling through a high pressure shale that contains gas, trip gas while tripping, drilling through gas reservoir. Gas cut mud is not considered as a major threat because the bottom pressure reduction is very small since gas expands upwards near surface.

2.3 KICK OCCURRENCE

The drill string is an assembly which comprises of connected hollow drill pipes of about 9m. Usually 3 drill pipes mounted on one another together make a single stand. These drill pipes are hollow and therefore they allow passage of drilling mud into the wellbore bottom. On bottom of drill pipes there is drill bit which crushes the rock while drilling. The drilling fluid cools the bit and transfer cuttings back to the surface through the annulus (between drill pipe and casing/open hole). This drilling fluid helps also to generate hydrostatic pressure inside the wellbore and creates overbalanced condition in the wellbore. (Hauge, 2013)

A kick may occur while drilling, tripping or after tripping.(Azar, 2007). Also a kick can occur in completion, workover ,and during or after abandonment stages.

After drilling every section, casing and cementing operations follows in order to support the wall of borehole but also ensuring no formation fluid that can flow into the wellbore as shown in Figure 6. Each section has the designed depth and drilling continues until the required depth is reached whilst using drilling mud as a primary barrier to support wellbore and restrict any flow of formation fluid into wellbore. Therefore the lower, uncased sections become prone to influxes in case of abrupt change in formation pressure, see open hole in Figure 6.

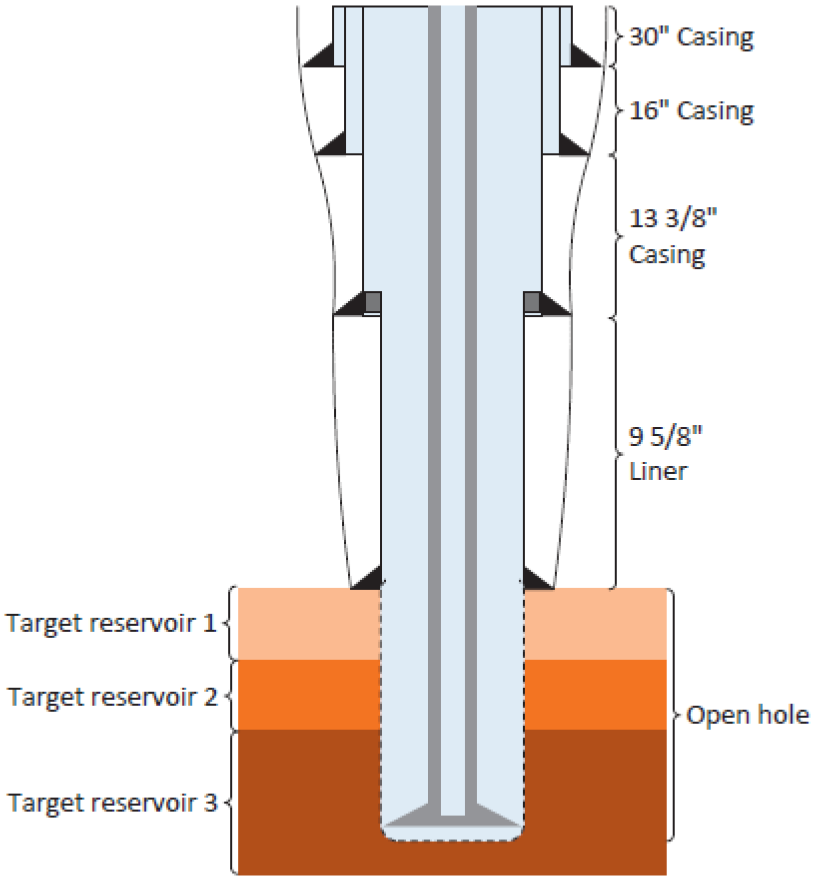

Figure 6: Example of casing program (Hauge, 2013)

2.4 FACTORS THAT IFLUENCE A KICK.

The kick is driven by a force developed by gradient in potential between geological formation and drilling mud used. Normally drilling mud is expected to exert the pressure higher than formation pore pressure that supports the wellbore (overbalanced). The density of drilling mud is designed while adhering to key boundaries which are formation pressure and fracture pressure (pressure window). Predicting the pore pressure accurately all the time is almost impossible. We try to predict the pore pressure so that we can deal with over-pressured zones. Over-pressured zones are zones where there is an abrupt increase in formation pressure which is higher that hydrostatic pressure. These over-balanced zones occurs because of unbalanced rate of compaction or under compaction. Under compaction is a situation where a sediment buried faster than how its pore fluid can drain which builds up high pore pressure, porosity reduction due to mineral transformation in pore void, change in volume of formation fluid due to aquathermal pressuring mechanisms and fluid diagnosis. All these variations makes it difficult for the operator to constantly predict pore pressure. (Rose, Tost, & Huerta, 2016).

While continuing drilling, the drilling mud can drop some of its weighing material, becomes light (reduced density) and lowers hydrostatic pressure which then make well pressure low. When hydrostatic pressure goes down in any means it allows the flow of formation fluid (influx) into the wellbore. Drilling mud is usually prepared is such a way that mud always have higher density than formation fluid but when an influx (especially gas) enters into the wellbore, it mixes with mud, dilutes the drilling mud and the drilling mud density goes down as well.(Rose et al., 2016)

Also kicks occurs while tripping because the removal of drill pipe leaves the large space to be covered by drilling mud and lowers the pressure at the bottom, this effect is known as swabbing. (Rose et al., 2016) The drilling mud height might not be able to cover the left column of annulus after tripping.

A small gas influx at the well bottom can be potentially dangerous because it expands while approaching the lower hydrostatic pressure near the surface. At low pressure gas expand and displace an equivalent amount of mud from the well, thus reducing the bottom hole pressure (BHP) which then allows more gas to flow into wellbore from the formation pores.

2.4.1 A list of main factors that influence kick

Mud weight being less than formation pressure. There has been an emphasize across drilling industry to drill with mud weight (which bring about hydrostatic pressure) close to formation pressure to increase rate of penetration. In some areas kick is allowed in order to assess the pore pressure and fluid contained in reservoir. Also to save cost in areas with historically less formation productivity, operators drills underbalanced. These acts may influence well control problems including a kick. (Grace, 2003)

Failure to keep the wellbore full filled with drilling mud, refer Figure 7. Kicks may occur when the drilling bit is off bottom i.e. while tripping back. Pressure in the wellbore gets reduced when the pumps are set off before tripping, and this reduction equals the annular pressure losses. When the equivalent circulating density becomes likely equal to formation pore pressure, the flow may continue while circulation has been stopped. Also when the drilling pipe is hoisted, the mud level in the wellbore falls because some amount will replace the space that was occupied by drill pipe, and hydrostatic pressure is reduced. The volume of hoisted pipe space needs to be converted into a pump strokes in order to know how much to fill into wellbore. As the drill pipe is hoisted and fluid level falls, hydrostatic pressure is reduced at the bottom, and if this reduction goes beyond the safety margin , the possibility of kick to occur increases. Therefore the wellbore has to be maintained full using a lined-up trip tank (as in Figure 7) to be able to monitor the mount of fluid taken by wellbore and that returning to trip tank, so that any changes can be detected.(Grace, 2003; Joseph, 16 May 2017, 09:11 UTC)

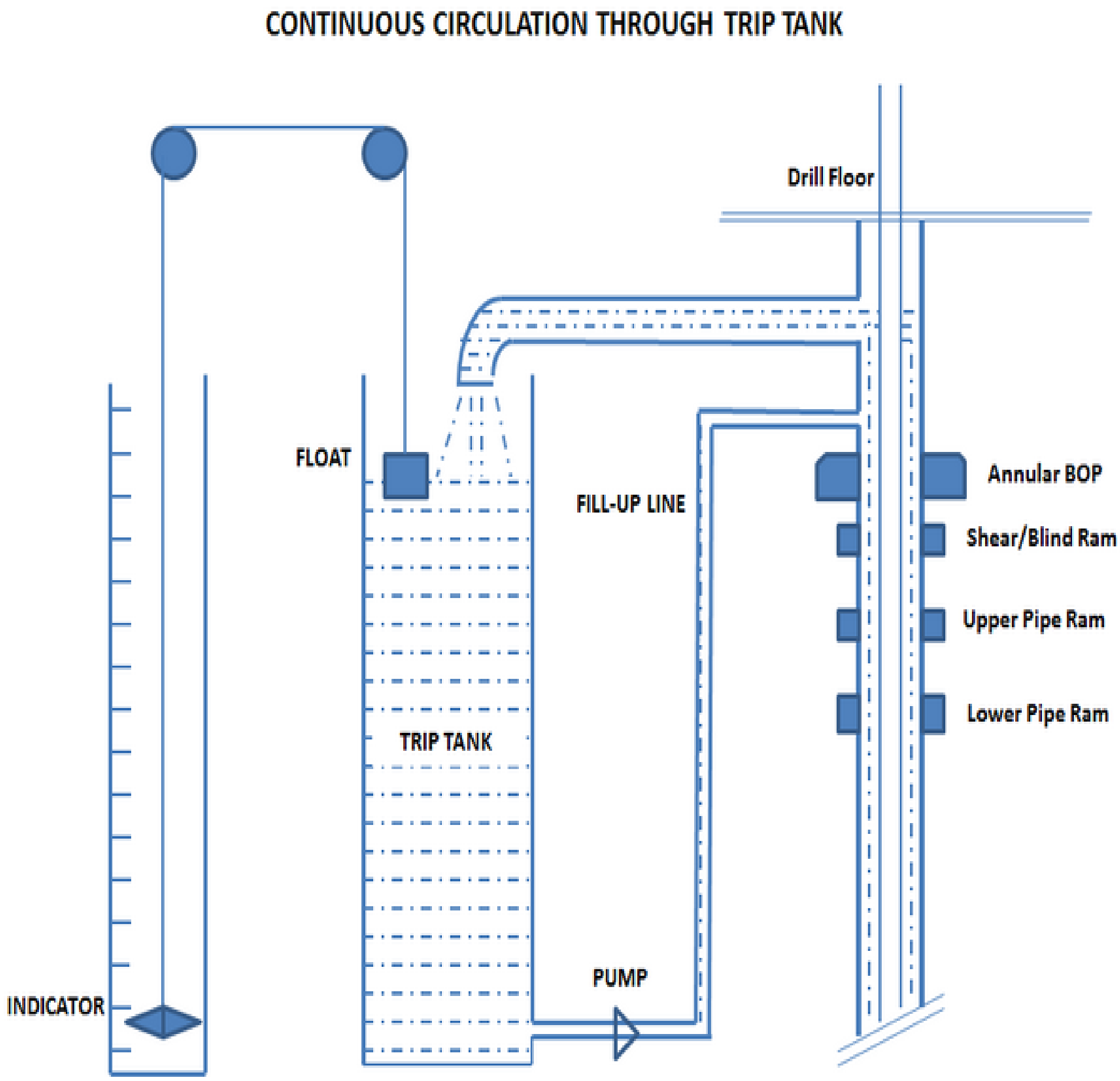

Figure 7: Lined up trip tank (Joseph, 16 May 2017, 09:11 UTC)

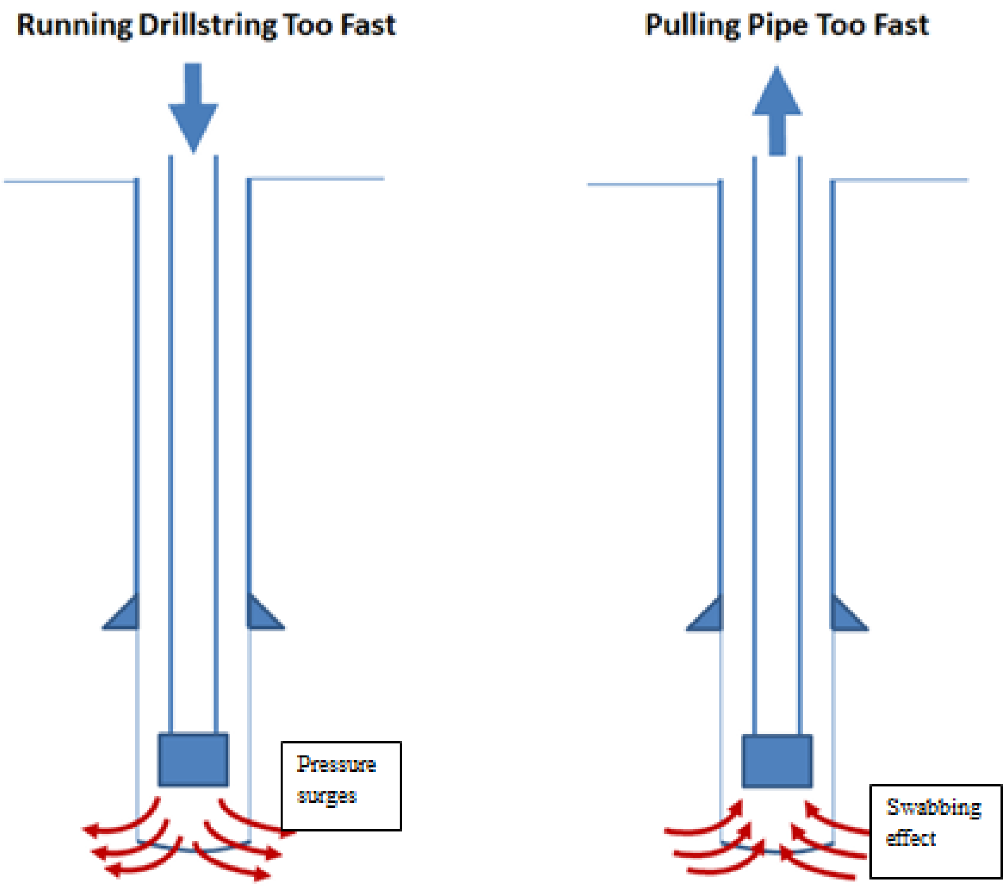

Figure 8: Surging and Swabbing effects (Joseph, 16 May 2017, 09:11 UTC)

Swabbing and surging. In the drilling process drill pipes can be pulled up to do connection or placed back for further drilling. When the pipe is hoisted quickly swabbing occurs and when run into the wellbore fast it causes surging. Swabbing increases when the mud cake is thick and reduces bit sharpness and blocks the nozzles. The speed of pulling the drill pipe has potential effect on swabbing because the faster the pipe is pulled, the pressure at bottom reduces dramatically and allowing influx. So to avoid this effect pipe has to be pulled slowly or placed back quickly and circulate out invaded fluid. Swabbing occurs when the drill pipe is run-in into wellbore fast and bottom pressure increases rapidly. This may influence mud losses if the formation is porous or fractured. Therefore proper monitoring of trip tank is very essential. Swabbing and surging can be affected by speed of pulling pipe, mud properties, viscosity and wellbore geometry, see Figure 7 and Figure 8 for illustration.(Grace, 2003; Joseph, 16 May 2017, 09:11 UTC)

Also rarely kick occurs as a result of low mud density. Mud density can be reduced due to penetration into a formation with high pressure before any indication of change in pressure or the well is crossing a fault or unconformity or the type of formation has changed. Also lost circulation may contribute to flow of influx. This is because the height of mud column is reduced so much to the extent that it becomes equal to pore pressure and thus bottom pressure gets reduced too and hence allowing an influx into wellbore and small perturbation can evolve into kicks. (Joseph, 16 May 2017, 09:11 UTC)

3. KICK DETECTION

Generally there are several kick performance indicators such as kick detection volume and kick response time. Kick detection volume can be defined as amount of influx that has been detected, and it indicates how much volume of influx flows into a wellbore before being identified as a kick and kick response time indicates the time it take from when the kick has been identified to the time the kick has been brought under control. These indicators need to be monitored so that the amount of the kick and duration it takes to circulate the influx out of the well is known. (Fraser et al., 2014)

In order to manage kicks which may cause blowouts, the improvement should be made on the instrumentation and displays used for well monitoring. There is a need for the development of automated alarms and algorithms to warn the operators when anomalies arise. An individual stays for around 12 hours in front of these displays trying to identify any anomalies. Due to possible consequences for anything that might go wrong, relying on the right person to check on the right data at right time while other operations runs simultaneously cannot be accepted.(Hauge, 2013)

3.1 KICK TOLERANCE.

(Mosti, Morrell, Anfinsen, Vielma, & Nergaard, 2017) defined Kick tolerance as "the maximum influx volume that is possible to shut in and circulate to surface without exceeding the formation fracture strength at the casing shoe''. Many of the underground blowouts occurs due to insufficient kick tolerance. Kick tolerance determines the intensity through which a well can be shut in without exceeding the fracture pressure of weak zones along the wellbore.

Any casing setting depth design begins with the tubing because the casing program has to be able to accommodate the maximum tubing size to avoid restriction during production. Therefore during any casing design, the designed program starts from the reservoir section and then progress to the upper sections. The quality and type of casing designed take into account fluids (kick), mud weight, and mechanical forces (such as cemented in during installation, bending forces, and temperature changes).

Kick tolerance is a necessary tool for casing design but its calculation approach varies. In order to be able to circulate the kick to surface, formation, casing and well control equipment should be able to withstand the pressure when shutting in the well. Kick tolerance is calculated based on well pressure and when the kick front is at the casing shoe where formation can be easily fractured. Also the pressure margin is added to the well pressure in the kick tolerance calculations as a safety factor and this safety pressure margin is pre-determined by company technical requirement as shown in equation (2). For instance in Norway, 70 bar pressure margin is always applied.(Mosti et al., 2017)

Kick tolerance calculations has got no standards that are commonly applied across the petroleum industry. The approach and standards for calculation may vary from company to company and this affects the act of assessing the risks while drilling. One of the disagreement is on where pore pressure estimated can be used in calculations. (Denney, 2012; Sonnemann & Santos, 2012)

The following factors are taken into consideration in the calculations of kick tolerance. Refer equation (2) to (7).

- Wellbore true vertical depth and inclination
- Casing shoe true vertical depth and inclination
- Estimated or measured fracture resistance at weak point
- Wellbore diameter in the open hole
- Estimated pore pressure at a specific depth potential source of influx
- Mud weight in wellbore at the time of influx
- Safety factors to compensate for possible inaccuracy of pore pressure estimates.
- Safety factors to compensate for possible inaccuracy of crew operations such as pressure margin for choke operator error, pressure margin for mishandling of choke line friction. etc.(Sonnemann & Santos, 2012)

The Table 1 below shows examples of input data required for kick tolerance calculations

Table 1: Input data for kick tolerance calculations(Denney, 2012)

Variable	Well A	Well B
Well depth in ft.	5000-12000	6000-11000
Casing depth in ft.	3000	7000
Casing size	16’’	9-5/8’’
Fracture grad. At csg shoe, ppg	15	17

Mud weight, ppg	12	13
Bit size	14-1/2’’	8-1/2’’
Drill pipe size	5.5’’	5’’
Drill collar size	8’’ x 3’’	6.5’’ x 3’’
Drill collar length, ft.	950	800

(Denney, 2012) For simple kick tolerance calculations, the following assumptions are made; no compressibility, constant temperature and constant density. The following procedures are followed in calculating kick tolerance.

First is calculating maximum vertical height of a gas influx (H_{max}) based on fracture gradient, mud weight, kick fluid density, predicted pore pressure and adjusted Maximum Allowable Annular Surface Pressure (MAASP). This MAASP is adjusted by subtracting safety margin pressure (e.g. 70 bar in Norway). P_f stands for the pressure in the formation (pore pressure). $P_{shoe,max}$ stands for the fracture gradient at shoe , H_{max} is the max height of kick acceptable, ρ_{mud} is the density of mud (mud weight), $G_{i,shoe}$ is the intensity of the influx when it is at the shoe (bar/m), h_{TD} is the total depth, h_{csg_shoe} is the depth of the casing shoe.

$$P_{shoe,max} = P_{LOT} - P_{safety} \quad (2)$$

Pressure at the casing shoe by using Driller’s method is expressed as

$$P_{shoe,max} = P_f - P_{FG} - g(h_{TD} - h_{csg\_shoe} - H_{max})\rho_{mud} \quad (3)$$

Using calculated maximum pressure at casing shoe, the maximum height of kick/ gas is expressed as

$$H_{max} = \frac{P_{shoe,max} - P_f + \rho_{mud}\left(h_{TD} - h_{csg\_shoe}\right)g}{g\ x\ \rho_{mud} - G_{i,shoe}} \quad (4)$$

Second, the influx volume at the casing shoe (V_{shoe}) is calculated by multiplying H_{max} with the Annular capacity factor around the drill pipe $Ca_{a,dp}$ as seen below

$$V_{shoe} = H_{max} x Ca_{a,dp} \tag{5}$$

Third step: Boyle's law is used to take influx volume at the casing shoe V_{shoe} to the bottom of the well and now considered as volume on bottom V_1. Also $P_{shoe}$is used as pressure at the casing shoe and P_p used as predicated pore pressure.

$$V_1 = V_{shoe} x \frac{P_{shoe}}{P_p} \tag{6}$$

The other volume of the kick V_2 is calculated around the bottom hole assembly (BHA). The procedures are just similar to the calculation of V_1 except the last step where instead of using drill pipe capacity $Ca_{a,dp}$, drill collar capacity $Ca_{a,dc}$ is used

$$V_2 = H_{max} x Ca_{a,dc} \tag{7}$$

After calculating both volumes V_1 and V_2, then kick tolerance is assumed to be the smallest volume between the two volumes. This is where the uncertainty raises. The two volumes are calculated as shown in the Figure 9 below.

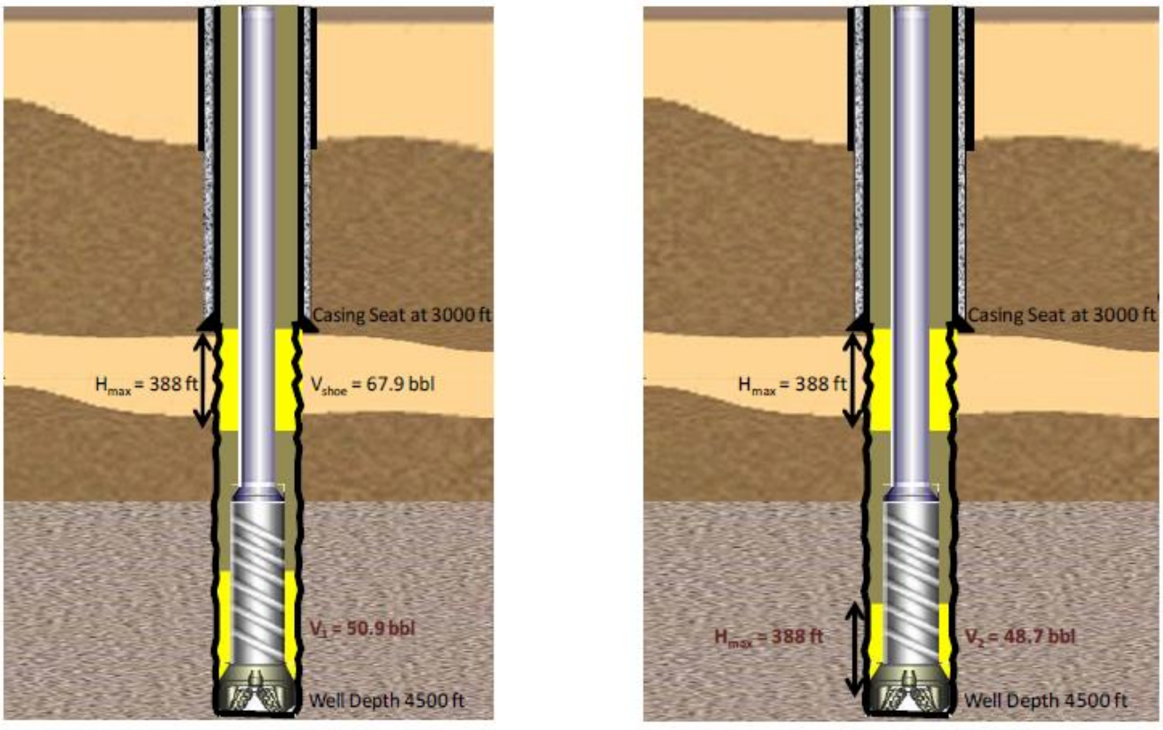

Figure 9:Illustration of V_1 calculation figure on the left, and Illustration of V_2 calculation on the right. (Denney, 2012)

Kick tolerance is believed to be a key component for well design but it has some confusion and inconsistency applications. Its lack of standards still rises debates among drilling contractors and operators. The assumptions made by the industry to ignore some effects leads to conservation of errors depending on well geometry and parameters applied. Therefore in order to produce reliable kick tolerance all possible effects should be taken into account during calculations.(Denney, 2012)

3.2 EXISTING KICK DETECTION METHODS.

3.2.1 An increases in the mud return flow rate.

The volume of mud circulating to and from the mud pit is expected to remain nearly constant during drilling operations provided that there is no change in pump speed. This flow in and out of mud tank can be monitored using differential flowmeter. When the mud returns to surface, it is constantly analysed to identify the type of formation we are drilling through and most importantly if the mud contains any sign of hydrocarbons or water. Formation influx flows into wellbore when natural formation pressure becomes greater than that exerted by the mud column in the wellbore. This act can be seen on the surface as an increase of the mud pump discharge pressure. An influx with lower density tends to decrease hydrostatic pressure further because of partial displacement of the mud column in the annulus by a formation fluid. Therefore, mud displacement by formation fluid increases the mud return flow rate as shown in Figure 10. This phenomenon can be monitored on surface hence used in the process of kick detection.(Grace, 2003; Ibarra et al., 2016; Joseph, 16 May 2017, 09:11 UTC)

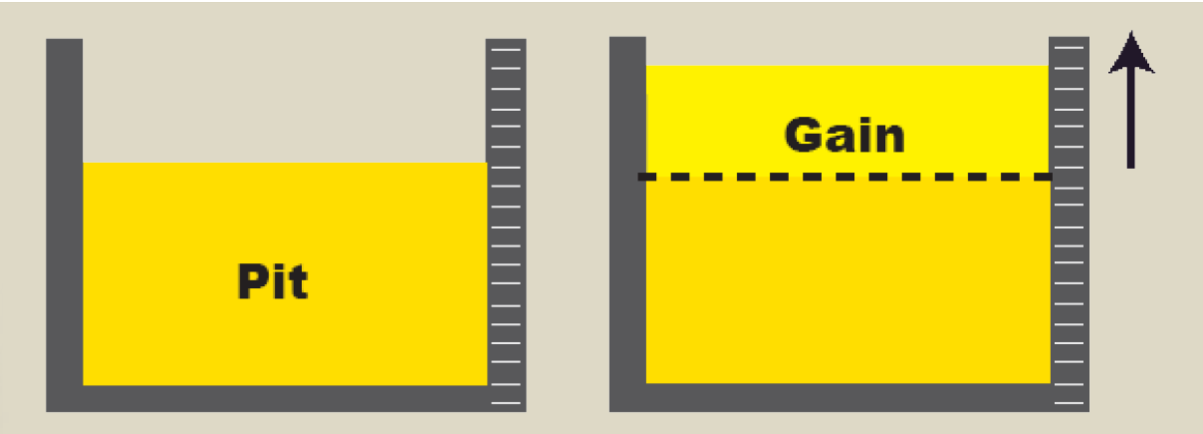

Figure 10: Pit before and after gain

Weaknesses of this method.

When drilling through deep wells the risk of having undetected kick increases because of bottoms-up circulations takes so long time to reach on the surface for analysis and recognition of an influx. An act of analysing this returning drilling mud is known as mud logging. So this may lead to a blowout due to late kick detection. While waiting for any indicator of an influx, if there is an influx in the returning mud, the influx volume and intensity grows in the wellbore. Since it takes long time for any kick indicator to be identified, the drillers ability to quickly control any potential impacts of kicks gets reduced. Furthermore the pit gain indicator varies according to influx fluid solubility. When the influx fluid is gas and is highly soluble, just small volume of influx may result into a large volume of influx since it expands.(Rose et al., 2016)

On the other hand increase of the mud return flow rate is not always clearly noticed. Furthermore, kicks can generate almost unnoticeable pressure rises and result in fluid entries into the annular space that reduces the protective barrier provided by the mud column in the wellbore. Also rock fragments that fall into wellbore can pack the annular space and shows a pressure increase similar to the one related to the kicks. Therefore kick detection using this method is ambiguous and cannot be relied as the only method for kick detection.(Ibarra et al., 2016)

3.2.2 Increased rate of penetration.

As the difference between hydrostatic and formation pressure decreases the drilling rate increases. When the rate of penetration increases there are two possibilities, first maybe soft formation is being penetrated and therefore no need to worry. Second is when higher pore pressure is encountered, and difference between hydrostatic and formation pressure goes down, then the influx might have entered the well.(Azar, 2007; Fraser et al., 2014)

While drilling ahead bit wears, become dull and its capacity of penetration rate decreases. When the difference between formation and hydrostatic pressure decreases, the drilling rate increases because of reduction in cuttings hold down effect. Abrupt increase in rate of penetration may also indicates that the new formation is being drilled and unbalanced condition has occurred. The drilling crew should be notified when reaching pay zones so that they can ensure that sudden increase in drilling rate(drilling break) does not exceed i.e. 2 to 5ft. (Grace, 2003; Joseph, 16 May 2017, 09:11 UTC).

(T. Eren & Ozbayoglu, 2011; Pål Skalle, 2016) Rate of Penetration (ROP) is a dependent parameter predictable as a function of independent drilling parameters. Rate of Penetration (ROP) can be defined as a function of formation strength, compaction, differential pressure, weight on bit (WOB), rotary speed, tooth wear, and bit hydraulics. Drilling rate is an important parameter for the detection of instantaneous changes in pore pressure, which may also influence detection of an influx. The rate of penetration can be affected by the following parameters:

- Lithology changes (between soft and hard formation)
- Bottom hole cleaning (to ensure cuttings are not accumulating)
- Bit weight
- Rotary speed
- Fluid properties (particularly concentration of fines)
- Bit type
- Bit dullness
- Differential pressure

The rate of penetration depends on the difference between hydrostatic pressure and pore pressure, provided other parameters remains constant. There are two situation that are caused by rate of penetration such as Dynamic Hold Down effect and Static Hold Down. The Dynamic Hold Down effect takes place when cuttings are detached from its original position. If drilling mud pumped in wellbore to remove cuttings won't circulate to remove cuttings, a vacuum pressure is created, holding the cuttings back. The Static Hold Down is related to the increased rock strength generated by the differential pressure. Rate of penetration can be expressed mathematically as seen in equation (8).

$$ROP = K \; x \; RPM \; x \; (\frac{WOB}{d_{bit}})^{d} \tag{8}$$

K stands for Drillability constant, d represent deviation of rate of penetration (ROP) caused by differential pressure, RPM is revolution per minute, WOB is the weight on bit and d_{bit} stands for bit diameter.

3.2.2.1 Drilling rate of penetration model

(Tuna Eren & Ozbayoglu, 2010) stated that the rate of penetration model below is one of the most accepted models in drilling projects. Referring to equation 9 below a_1 represents effect formation strength, which means the less the magnitude of this coefficient, the low the rate of penetration and vice versa is true. Simply means the high magnitude coefficient reflects soft formation and less magnitude reflects hard formation. Also f_1 represent formation drillability, x_1 is the dummy variable, which equates 1 for every observed rate of penetration.

$$\frac{dF}{dt} = exp\left(a_1 + \sum_{j=2}^{8} a_j x_j\right) \tag{9}$$

Then f_2 represent primary effect of rock strength due to normal compaction, f_3 represent rock secondary effect of normal compaction, it considers the effect of under-compaction, f_4 stands for the function of differential pressure at bottom, f_5 represents the function of bit diameter, f_6 represents the function for rotary speed, f_7 represents tooth tear function and f_8 stands for the hydraulic function that take into account the effect of bit hydraulics. All these functions in simple Figure 11

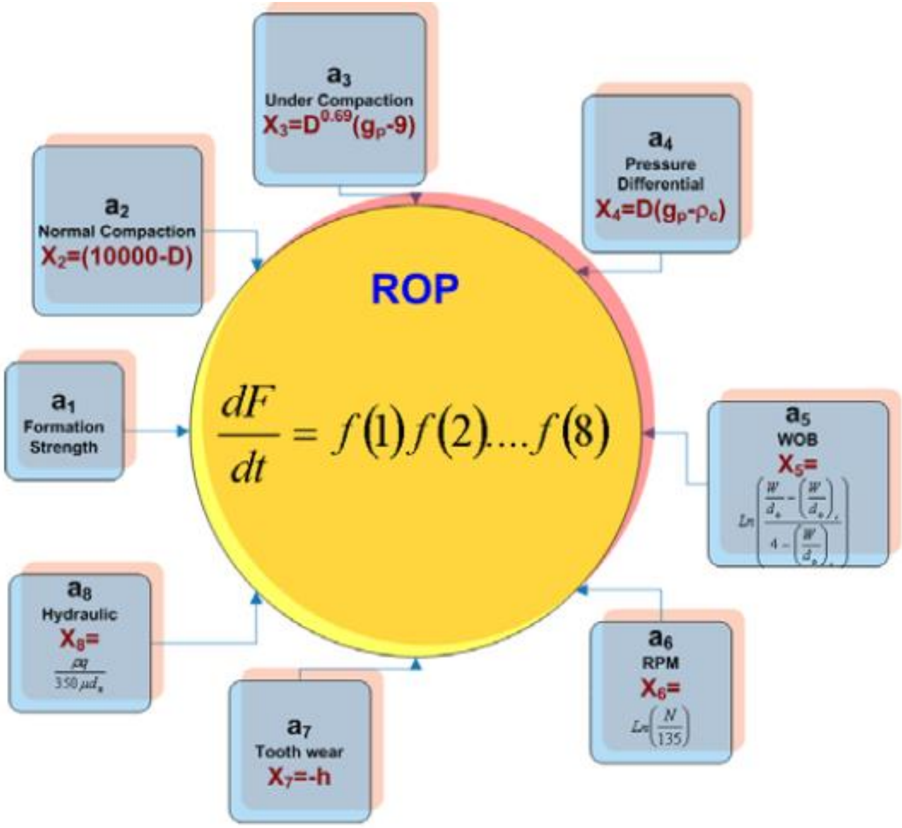

Figure 11: General rate of penetration equation (T. Eren & Ozbayoglu, 2011)

Key to Figure 11

a_1 stands for formation strength parameter

a_2 stands for exponent for the normal compaction trend

a_3 stands for under-compaction exponent

a_4 stands for pressure differential exponent

a_5 stands for bit weight exponent

a_6 stands for rotary speed exponent

a_7 stands for tooth wear exponent

a_8 stands for hydraulic exponent

3.2.3 Well flow with pumps off

Flow with pumps off refers to any flow from the well when there is no pumping.(Azar, 2007; Fraser et al., 2014). False alarms of kicks are sometime due to the effect of ballooning and breathing of naturally fractured reservoirs. These kind of reservoir can act like a buffertank which slowly allows seepage of drilling fluid while pressure is high (hydrostatic pressure) and empties (flows out) when the pressure is reduced such as when slowing down pumps.(Hauge, 2013)

The returning flow from the well is unexpected when the rig pumps has been turned off. When the flow continues while pumps has been shut down, then there is driving force that is pushing the fluid out of annulus. This driving force is a result of formation pressure exceeding hydraulic pressure, and thus allows influx. The flow with pumps off can be due to expansion of drilling mud because of heating caused by friction. The changes of mud volume because of expansion is very minimal and has no negative effect. The flow back (when pumps are off) can also be caused by pumping insufficient heavy mud into wellbore which can be displaced by a u-tubing effect.(Joseph, 16 May 2017, 09:11 UTC)

3.3 KICK DETECTION CATEGORIES

(Jacobs, 2015) wrote that, kick detection methods can be categorized into two groups.

1. **Traditional open to atmosphere drilling operations**
2. **A closed to atmosphere system (Managed Pressure Drilling).**

Early kick detection systems can measure kicks with volumes smaller than 1 bbl. This system rely on managed pressure drilling systems such as rotating control device that diverts all returning mud flow to the MPD manifold. Inside the manifold, the MPD chokes are used to force the mud system to control response to kicks automatically.

(Johnson, Leuchtenberg, Petrie, & Cunningham, 2014) categorized kick detection techniques into the following categories.

1. **Conventional kick detection**

   An influx of hydrocarbon from a permeable and hydrocarbon bearing formation occurs when underbalanced condition occurs. There multiple causes of underbalanced condition such as inadequate circulating density, unexpected higher formation pressure, swabbing etc. The mentioned factors enables the hydrocarbon flow from a formation into a borehole. Also overbalanced condition forces drilling mud into a permeable formation. Overbalanced condition is caused by depletion, excess circulating density, surging and formation pressure being lower than expected.

Pit volume totalizer (PVT) system is the tool used to account for total fluid volume. This system is reliable for monitoring kicks and losses.

Increase in volume of returning mud is termed as an influx while decrease in returning volume is termed as lost circulation.

2. **Enhanced kick detection (EKD).**

   Enhanced kick detection research has been conducted for a while longer now but it became prominent post Macondo well incident. When the kicks are noticed and recognized earlier, the process of managing them becomes simpler and the panic among crew member can be reduced and normal operations can resume quickly. (Fraser et al., 2014)

   According to the investigation conducted by Bureau of Safety and Environmental Enforcement (BSEE) on kick incidents , about 50% of loss of well control events could have been prevented or controlled. For instance inappropriate reading of kick indicator was considered as one of the key factor for Macondo incident. Therefore this phenomenon suggests that accurate, direct and unambiguous enhanced kick detection system could have warned the crew and the blowout could have been avoided.(Fraser et al., 2014).

   Managed pressure drilling has qualified to be used in drilling unconventional or difficult fields and this enabled the establishment of enhanced kick detection. Managed pressure drilling balance the equivalent circulating density and formation pressure to minimize influxes and stabilizes the wellbore.(Johnson et al., 2014)

3. **Deep water kick detection**

   Control of a kick depends on time of detection. When in subsea, the process of kick detection becomes more problematic since there is large amount of water between wellbore, surface and volume of mud in the riser which can cover a kick or delay its detection. The additional volume of mud in the riser can be up to twice the volume in the wellbore. In any case, control of a kick in a subsea well can be achieved if detection of the kick can be made sooner. Advanced digital instruments can be used to detect a kick. In this category smart meters are added to the conventional PVT system to help notifying any change in returning volume. (Toskey, 2015)

Besides adding smart meters to conventional pressure/volume/temperature (PVT) systems, the deep water detection system should take into account vessel movement, wellbore effects, and fluctuations in rheology and drilling parameters, and it should feed information directly to the MPD system. Eventually, deep water kick detection should be achieved in such a way as to improve and automate existing drilling-data measurements and enhance proven practice with the addition of accurate flow measurement. (Carpenter, 2016)

3.3.1 Procedures of circulating the kick out of well.

When the kick is detected and the operator decides to shut down the well, two procedures can be put into consideration which are soft and hard shut in. soft shut in involves closing the Blowout preventer while keeping choke line is open and hard shut in involves closing both the BOP and choke line. The softer method boosts the pressure inside the wellbore while hard shut in stops the influx quickly. Before shutting in the well, the drill pipe has to be lifted above the wellbore bottom to avoid obstruction of cuttings and weighing material in the bit nozzles. (Hauge, 2013)

To be able to prevent u-tubing effect while changing the mud weight to regulate pressure, sometimes the non-return is installed upstream the bit. The shut-in casing pressure (which is pressure in the annulus needs to be recorded before starting well control procedures. When the volume of in and outflow is accurately measured , then the volume of the kick can be estimated. Increase in pit gain gives indication of an influx. When shut in casing pressure, volume if influx, mud type and density, wellbore diameter, BHA and drill pipe diameter are known , then density of influx can be determined. If the formation fluid is oil o water then circulating out of well is much easier as compared to when the influx is gas. This is because gas tends to carry the formation pressure while percolating when not allowed to expand. Also gas is flammable, poisonous and it requires proper handling when reaching the rig. (Hauge, 2013)

3.3.2 Methods that can be used to prevent kick occurrence while drilling

As previously stated an influx flows into a wellbore when pore pressure exceeds pressure exerted by drilling mud. Also exceeding formation fracture pressure can cause loss of mud. An influx (kick) may cause a catastrophe when develops into a blowout. Before beginning well control operations shut in casing pressure has to be recorded, pressure at the casing shoe, and surface choke depth.

(Pål Skalle, 2016) pointed out three principles to be considered before killing a well

- Bottom pressure must exceed pore pressure
- Bottom pressure is regulated using drill string filled with a drilling mud of known density
- Once the pump has been turned on under constant and predetermined rate, bottom pressure can be controlled using back pressure valve at the surface.

(Azar, 2007)There are methods which are used to circulate out the kick. Driller’s and Engineers (Wait and weight method) methods assumes that:

- Kick is caused by mainly gas
- Kick does not blend in mud
- Ideal gas law applies
- Annulus cross section remains constant.
- Gas density is negligible
- Bottom hole pressure is maintained constant
- Friction pressure losses are negligible.

Driller’s method

Circulation rate that would be used to kill the well whenever any kill occurs is determined in advance. In the Driller's Method the influx from the formation is displaced before pumping or injecting in killing mud into wellbore. This method is simple to use but it induces higher pressure in the un-cased annulus and it requires much time because the kick has to be circulated out before injecting killing mud.(Pål Skalle, 2016).

Driller’s method is highly applicable while the bit is at bottom of wellbore. If the bit is off bottom, the drill pipe has to be lowered to ensure the bit has reached on bottom of wellbore.

Circulation out of the kick is conducted in two stages. First the kick is circulated using the original drilling mud. In the second round, the killing fluid is injected into the wellbore to restore primary well barrier. While circulating out the kick, the bottom pressure has to be equal or slightly above formation pressure in order to avoid continuous flow of an influx. at the same time pressure at the casing shoe should be lower than fracture pressure to avoid a possibility of underground blowout.(Litlehamar, 2011)

While kick is circulated out in the first round using original mud, the mud pump is slowly adjusted to a predetermined slow rate and this is achieved by adjusting choke valve . On subsea wells the kill line is kept constant to ensure constant bottom hole pressure and regulating the pump speed. When the pump reaches kill rate, pressure in the drill pipe is held constant at a pressure known as initial circulating pressure (ICP). As long as the drill string is assumed to contain the mud of known density with constant drill pipe pressure, bottom hole pressure will remain constant.

Engineers method

In this method, the killing fluid is prepared and injected immediately. When applying driller's method pressure in the annulus increases and choke nozzles may erode quickly. So if there is a risk of fracturing in the casing shoe , Engineer's method should be given priority.

Volumetric method

Volumetric method allows a particular amount of mud to be out of the well while the mud moves up the hole and expand simultaneously. It is assumed that gas is weightless, so the removal of heavy weight mud from wellbore annulus causes the loss of hydrostatic head. Pressure in the casing should be allowed to increase at the same amount while gas expanding in a closed well to maintain constant bottomhole pressure.

3.3.3 Dynamic killing

The dynamic method is a confirmed technique for killing a blowing well with a fluid such as water which is not dense to sufficiently kill the well thoroughly while it is not dynamic (static). The blowing well can be killed through injecting a fluid at a particular rate into a communication link and up to the wellbore bottom until the reservoir pressure is exceeded and make the influx stop coming into wellbore and the well ceases to produce. (Blotto, Tambini, Dellarole, & Bonuccelli, 2004)

Dynamic killing is comprised of complex multi-phase fluid dynamic system in a complex geometry which involves blowout well, relief well and reservoir. There exists dynamic killing techniques. The purpose of dynamic kill calculation techniques is to try and correlate the injection rate of fluid used to kill with killing time and required equipment such as injection pump head and power, relief well size. To achieve this main goal an advanced model capable of simulating the killing phenomenon during all its transients is essential for applicability screening and system design.(Blotto et al., 2004)

3.3.3.1 Dynamic model

(Blotto et al., 2004) The dynamic kill model contains both software structure and subroutine description. The software package main function is managing inputs and outputs and data flow while data processing is performed by subroutines. Refer Figure 12

The secondary subroutines are comprised of the following.

- Blowing Well Module. BW
- Minimum Killing Flow rate Module. QK
- Reservoir Module. RS
- Relief Well Module. RW.

Software inputs are;

- Blowing well and relief well geometries
- Type and properties of fluids
- Reservoir petrophysical parameters
- Thermo-fluid dynamic conditions of wells and reservoir

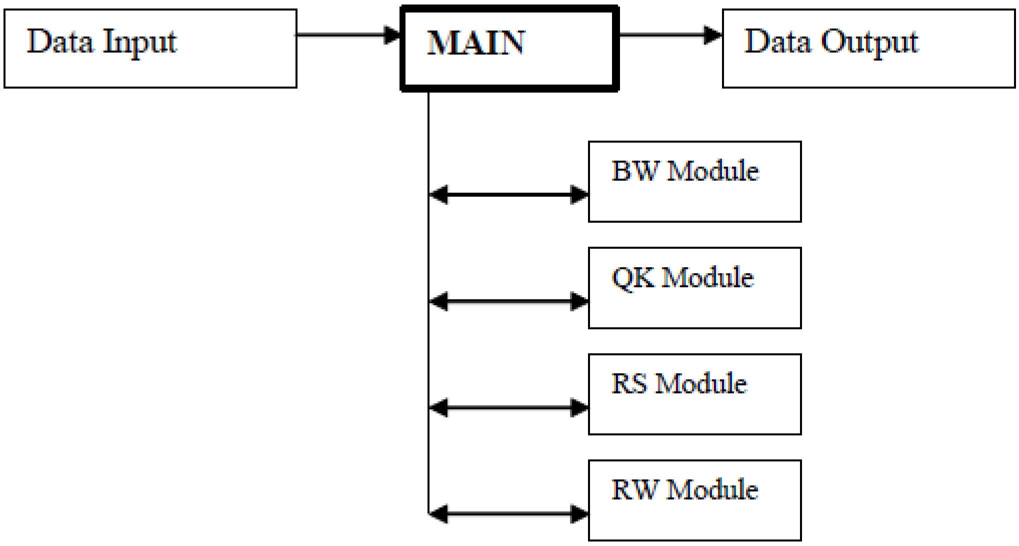

Figure 12: Software package(Blotto et al., 2004)

After processing input data using the software tool, the expected outputs becomes plots and tables that correlate killing flow rates with killing times, relief well pressures and injection pump requirements. The four main subroutines making up the software which are BW, QK, RS and RW as shown in Figure 12 are managed by a simple algorithm (as shown in Figure 13) that predicts three hidden loops to obtain converging results.

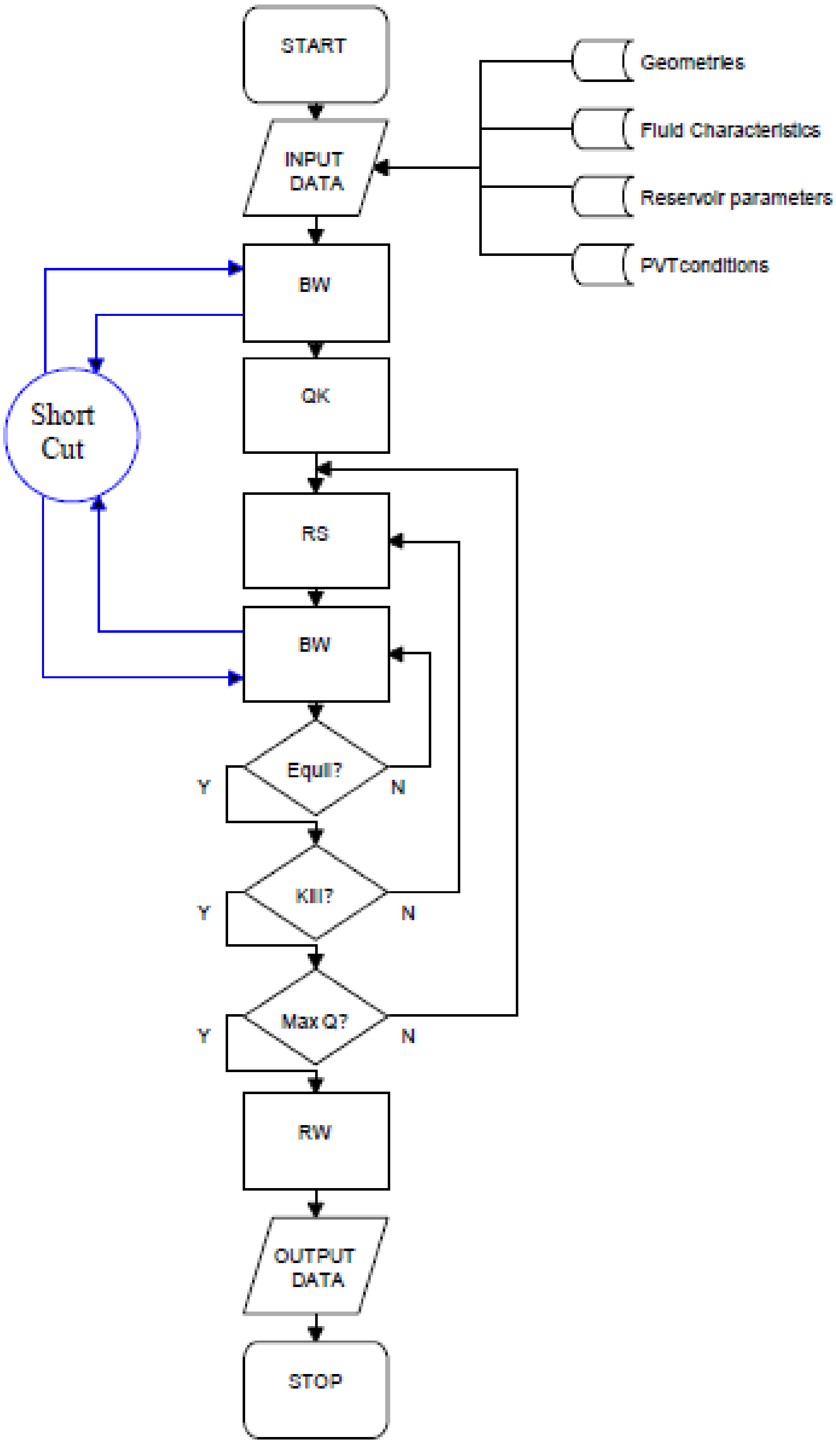

Figure 13: Software algorithm (Blotto et al., 2004)

The most inner loop consists of blowing well (BW) module which is responsible for balancing conditions between blowing well and upgraded injection rate coming from injection well. The balancing conditions reached reflects bottom hole pressure of blowing well and influx production.

The second (middle) loop shows the history of water injected quotas pumped into blowing well. In this case transitional conditions where the influx stops flowing into wellbore is reached when killing conditions are met. The killing conditions are met when blowing well pressure is equal to static pressure of reservoir and the influx coming into a wellbore becomes only injected fluid(water).The last(outer) loop, defines parameterization of the way which applies the injected flow rate.

The blowing well module multiphase that approximate pressure losses and bottom hole pressure in the blowing well provided geometry and fluid properties are known. This module is applied in two algorithm locations such as initial blowout conditions which calculates blowout flow rate and blowing well bottom flowing pressure and reservoir pressure profile during uncontrolled influx. Refer Figure 13

The output data provided by the software after processing input data as tables and plots are the following:

- Injection flow rate
- Breakthrough time
- Killing time
- Injection pressure
- Pinup pressure
- Pump power
- Injected volume
- Total energy

Blowouts can be killed by dynamic killing but there are a lot of problems that makes it difficult. The killing fluid is pumped through injection well, this kind of well might not always be available instantly. Therefore even if all necessary equipment and technique for dynamic killing area available, enough time to prepare is still required and the means which is injection well.

4. MANAGED PRESSURE DRILLING

It is difficult to discuss kick detection in isolation without discussing about managed pressure drilling. Kick detection and managed pressure drilling are intertwined because it is difficult to effectively account for all properties without discussing the effect of Managed pressure drilling (MPD) on drilling technology. Therefore kick detection and managed drilling pressure are integrated. (Johnson et al., 2014).

According to (Hannegan, 2006), IADC (International association of Drilling contractors) defined managed pressure drilling as 'An adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore.' The main objectives is to determine the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. Managed pressure techniques (MPD) techniques are used to avoid an influx which may result into a kick. If there will be accidental influx, it can be dealt with appropriate surface and downhole tools and that can be successful with fewer interruptions to the drilling program.

Managed pressure drilling is mostly applied to wells where primary well control cannot meet the needs of pore pressures due to weak fracture gradients in the well profile (Hilts, 2013). Extended reach drilling tends to have narrow pressure window. Narrow pressure window refers to the gap between formation pressure and fracture pressure. Neither do we require formation pressure to be greater than hydrostatic pressure nor hydrostatic pressure being higher than fracture pressure because of already mentioned side effects. So MPD is mostly applied to ensure that the fracture pressure is not exceeded.

Managed Pressure Drilling (MPD) has so many necessities, one of them is its capability to use surface back pressure to enable pipe joint connection without stopping drilling ahead or during shut in of the well which sometime causes non-productive time (NPT). So this non-productive time (NPT) can be avoided in large extent and thereafter reduces drilling operation cost, save working days and increases income profit to the company .(Hannegan & Fisher, 2005). Also (Hilts, 2013) stated that "Managed pressure drilling (MPD) is a drilling technology applied to unconventional prospects where conventional, hydrostatically over-balanced drilling methods encounter problems".

Managed Pressure Drilling (MPD) gives a room for quick corrective action to deal with observed pressure variations. The aim of MPD is to both establish the downhole pressure environment limits and regulate the annular hydraulic pressure profile to fit within that window. MPD as tool in association with conventional drilling manages annular hydraulic pressure profile using the already set system in order to mitigate the risks and costs connected with drilling wells within narrow, downhole environmental limits. (Coker, 2004)

There are two categories of methods to detect kicks, which are conventional methods where normal overbalance hydrostatic method is applied and unconventional methods where the pressure window is very narrow. Managed pressure drilling is highly applied in unconventional methods.

Conventional drilling predictions have adequate margin between pore pressure and fracture pressure. These conventional plays have the capability to maintain primary well control whether the wellbore is static or dynamic (Hilts, 2013). Unconventional drilling prospects exist where the drilling pressure window is very narrow. Narrowness in pressure window threatens the stability and integrity of wellbore.

Managed pressure drilling equipment connects with the mud circulating system of the drilling rig, and creates a closed atmosphere in the wellbore as shown in Figure 14. This closed atmosphere gives an extra surface backpressure value to the bottom-hole pressure calculation. A closed flow loop helps to identify changes in flow rate and pressure abnormalities. Surface backpressure can then be adjusted as required to control reservoir influx and loss of drilling fluid into the surrounding subsurface formation. This simply means that managed pressure drilling regulates surface backpressure so that a constant bottom-hole pressure within the drilling window can be maintained.(Hilts, 2013).

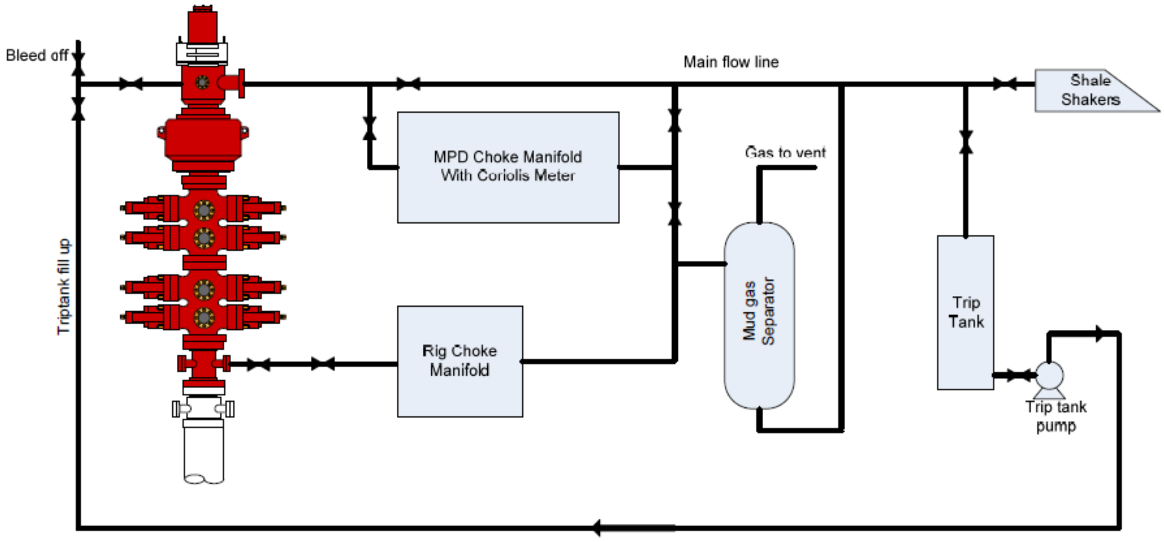

Figure 14: Managed pressure drilling setup in a closed wellbore(Nas, 2011)

The variation in bottom hole pressure as seen in Figure 15 is a result of mud pump operation, and this variation can be rectified managed pressure drilling. When pump are set on, MPD tend to reduce the applied surface backpressure in proportion to the addition of annular friction pressure. The vice versa occurs when the mud pumps are set off where Surface backpressure is added proportionately as annular friction pressure is decreased. Therefore constant bottom-hole pressure is retained and wellbore stability is attained.(Hilts, 2013)

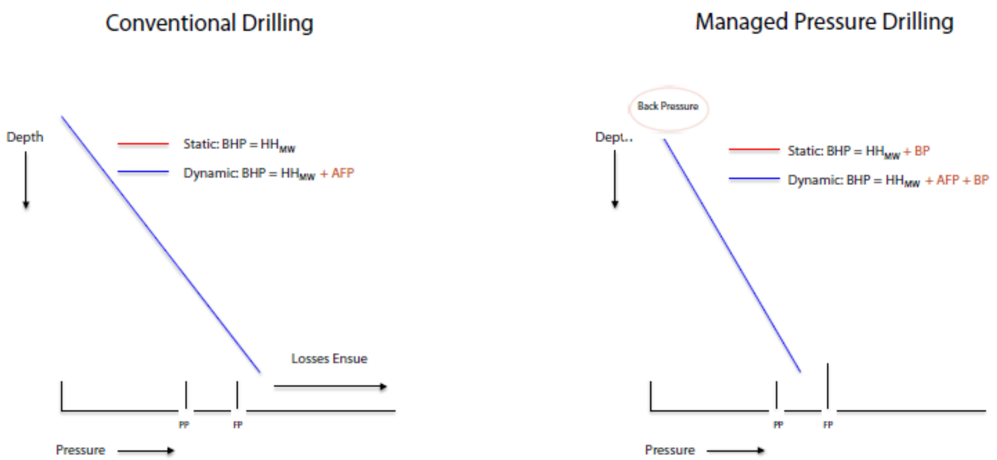

Figure 15: Differences between conventional and managed pressure drilling(Hilts, 2013).

Fluctuations tends to happen in the bottom hole pressure. Managed drilling pressure can be used to regulate the occurring fluctuations as follows:

Diversion Mode

When Managed pressure drilling regulates surface backpressure in the process of adding or removing annular friction pressure in the well profile, bottom-hole pressure fluctuations still occurs. These fluctuations occurs due to pipe connection at the rig floor. Managed pressure drilling helps to re-direct drilling mud flow away from the standpipe, which allows the maintenance of mud pumps during operation in all times. This practice was known as "diversion mode".

The flow path is routed to the alternative route called rig pump diverter. Then drilling fluid is conducted through the managed pressure drilling choke manifold where the essential surface backpressure is provided across the wellhead. The act of keeping mud pumps on during pipe connections ensures a constant bottom-hole pressure, which brings about wellbore integrity. Also pipe connection duration is served during drilling operations.(Hilts, 2013).

Extended Reach Drilling

Managed pressure drilling has been proved to be very applicable in extended reach drilling (ERD) operations. The difficulty with ERD wells is the risk of exceeding fracture pressure due to high equivalent circulating densities (ECD) provided. The risk of exceeding fracture pressure comes from the continual increase in annular friction pressure along the heel-to-toe section of the well.(Hilts, 2013).

Managed pressure drilling (MPD) system uses a collection of tools and techniques to manage annular hydraulic pressure profile. MPD may control back pressure, fluid density, fluid rheology, circulating friction and borehole geometry. Managed pressure drilling (MPD) allows faster corrective action on observed pressure variations. (Coker, 2004; Hannegan, 2006).

4.1 MANAGED PRESSURE DRILLING CATEGORIES.

Managed pressure drilling has been categorized into two major parts which are reactive and proactive managed pressure drilling.

Reactive managed pressure drilling involves a closed and pressurizable mud returns system at the rig floor and drilling is done with conventional and casing program. This system is applied to react with occurring downhole surprises. The occurring surprises are dealt with equipment installed in the rig. Those equipment are such as rotating control device (RCD), choke and drill string floats. In general these equipment tend to regulate hydrostatic pressure to accommodate lower or higher pore pressure or fracture pressure. (Hannegan & Fisher, 2005)

For **Proactive managed pressure drilling**, fluids and casing program are designed at the beginning. Pipes are connected with a backup of surface pressure. This system is more applicable in marine environment where hydrostatic pressure and formation pressure are very dynamic.(Hannegan & Fisher, 2005)

4.2 VARIATIONS OF MANAGED PRESSURE DRILLING (MPD).

(Hannegan, 2006; Hannegan & Fisher, 2005) identified four key variations of Managed drilling pressure as follows.

4.2.1 Constant bottom hole pressure.

This variation concentrates on offset wells that encounter kick-loss scenario and well control issues as a result of drilling into unknown or narrow downhole pressure environment limits. The Constant Bottomhole Pressure variation is exceptionally suitable to be applied in narrow pressure environments. The applied fluid is designed at a predetermined depth to be at or nearer balanced than conventional. Practically, The hydrostatic head as a result of mud when not circulating may result in a modest underbalance and then jointed pipe connections are made with a surface backpressure roughly equivalent to the circulating annulus friction pressure detected on the last stand of drill string.

Constant bottom hole pressure (CBHP) is the normally used to describe measures that are taken to correct or lessen the effect caused by circulating friction loss or equivalent circulating density (ECD) in the struggle to stick within the boundaries that are determined between pore pressure and fracture pressure.(Rehm, Schubert, Haghshenas, Paknejad, & Hughes, 2013)

4.2.2 Dual gradient variation

This is said to be popular in land (onshore) drilling programs. The wellbore is drilled with two fluid gradients in the annulus. This is accomplished depending on the operating environment. Techniques to practice Managed pressure drilling (MPD) variation involves injecting a lower-density, possibly nitrified fluid via a parasite casing string on land programs or into a deep water rigs booster pump line. This is done in order to further reduce the effective bottomhole pressure without the need of changing the density of the mud in the hole from time to time. A well designed application of this dual gradient may change the bottom hole equivalent circulating density significantly without a need to change mud density or pump rates (Hannegan & Fisher, 2005). Also Dual gradient (DG) generally uses various tactics to regulate the up-hole annular pressure by controlling equivalent circulating density in deep water marine drilling.(Rehm et al., 2013)

4.2.3 Returns flow control

HSE, this is also known as Returns Flow Control variation of Managed pressure drilling (MPD). Its primary objective is to obtain the benefits of a mud returns system on the rig floor that is closed to atmosphere for health, safety, and/or environmental reasons. This variations also helps in drilling on platforms where simultaneous production operation are on progress. The intention is to inhibit drilled cuttings gas from evading to atmosphere at the drilling nipple, bell nipple, or tipper marine riser and triggering atmospheric explosive vapor monitors and in some installations. Automatic shutting down production elsewhere on the platform needs approval of regulatory authorities before performing the operation.(Hannegan & Fisher, 2005)

4.2.4 Pressurized Mud cap drilling

Pressurized Mud Cap Drilling (PMCD) is famously applied particularly on offset wells where depleted zones was encountered and in areas where extreme mud loss has been experienced due to drilling horizontally into inclined fractures or into formations containing large hollow voids. Pressurized Mud cap drilling (PMCD) involves drilling with sacrificial fluid or sea water with necessary inhibitors. This is common when drilling in marine environment and where no returns to the surface. During killing of a well, a heavy mud called ‘mud cap’ is pumped to the annulus using a dedicated pump through rotating control device (RCD). The column height and density of this mud cap is predetermined by ensuring surface back pressure is at minimum requirements. The mud cap with cuttings is forced into an hazardous zone.

Pressurized mud cap drilling (PMCD) is a technique which allows to drill safely while intentionally allowing total lost returns. Pressurized mud cap drilling (PMCD) describes the process of drilling without returns at surface while ensuring constant full annular fluid column is maintained above the formation in which the injection fluid and drilled cuttings are pumped in it. The annulus filled with fluid column above formation that is being injected needs to have observable surface pressure in order to be able to balance down hole pressure (Rehm et al., 2013). One disadvantage of this method is excessive mud cost , but also it enables drilling with lighter fluid in which rate of penetration increases.(Hannegan & Fisher, 2005)

5. RETROSPECTIVE ON BLOWOUTS ACCIDENTS

(Tabibzadeh & Meshkati, 2014a, 2014b) Although the probability of blowouts to happen is slightly small but when it happens it causes a catastrophe. Various failures in offshore drilling industry which has been collected, analysed and documented found that 60% of accidents (Blowouts) are caused by human and organizational factors. This can be witnessed in the discussed blowouts (Macondo and Montara blowout incidents) and three blowouts from Norwegian petroleum industry. The remaining 40% is mainly due to technical and technological faults.

5.1 MONTARA WELL BLOWOUT

By 2010, the Montara well blowout was the third largest oil spill in and worst of offshore petroleum industry history in Australia. The blowout in Montara well happened through well named H1. The well was already drilled, cased and cemented before the occurrence of blowout. According to investigation that was conducted on the blowout incident, it was found that the cement was poor in 9⅝” casing. It was discovered hydrocarbons entered into the wellbore through 9⅝” casing shoe. The well was abandoned temporarily by march 2009 but the well control barriers didn’t comply with the regulations set by the authorities. The cementing on 9⅝” casing wasn’t pressure tested to assess its integrity even though there were complications during cementing process and one secondary well barrier wasn’t installed as programmed during designing. The cement was displaced by drilling fluid in the casing shoe (9⅝” section) and causes wet shoe and also the top and bottom plugs failed to work. And the 9⅝” casing shoe was left vulnerable to formation fluid (influx) trying to flow into wellbore. (ACT CANBERRA, 2010)

On 20th August 2009, the Montara well crew were about to tie back all wells and connect on a single platform in order to start production. On the same day the 20’’ trash was removed from well and it became clear to the working crew that the pressure containing anti-corrosion caps (PCCC) wasn’t installed on 13⅜” casing section, so the threads of 13⅜” casing had rusted and corroded. As a result of corroded 13⅜” PCCC, the crew decided to remove the 9⅝” PCCC in order to place a tool inside to clean 13⅜” threads. Then the 9⅝” wasn’t installed back. This was a big blunder because then 9⅝” casing section was not there anymore to support wellbore and act as a barrier, so the wellbore was left open and vulnerable to any influx. The crew believed that the inhibited sea water and cemented casing shoe barriers were enough to encounter formation pressure. The rig was then taken on another well for other operations. On 21st august the blowout was observed from well H1 and 40-60 barrels of oil flowed out. Nobody was injured or killed during blowout incident since the derrick and cantilever of the West Atlas were positioned over the H4 Well but the environmental damage and costs incurred were tremendous (ACT CANBERRA, 2010).

Therefore according to Montara Commission of Inquiry, investigation of the blowout event established that the cause of the blowout was largely recognized and was due to primary well control barrier failing. The investigation report further notified that initial cementing difficulties were caused by the fact that only one of the two secondary well control barriers pressure containing anti-corrosion caps was installed. (Ahluwalia & Ruochen, 2016)

5.1.1 Montara blowout chain of events

Disasters do not just happen, there are chain of events that contributes to its occurrence. According to (ACT CANBERRA, 2010) investigation team on Montara blowout, the following events contributed to the Montara blowout.

(a) The cemented 9⅝" casing was meant to become the primary barrier but the cement was poorly placed in place which caused leakage in the 9⅝" casing shoe.

(b) The float collar or valve failed during installation of casing shoe, in which the fluid that was pumped to displace cement inside the drilling pipe caused the over-displacement of cement in the annulus (outside casing). Then it left the casing shoe with poor cement.

(c) The pumping of displacement fluid didn't follow oil industry practices regulation and led to wet casing shoe, hence casing shoe integrity became poor as a barrier for any influx of fluids. These failures were against sensible oilfield practice, and were also against PTTEPAA's (operating contractor) own Well Construction Standards.

(d) The acts and errors of contractor (PTTEPAA) personnel (which was drilling contractor) from the on-rig and onshore contributed in creating the non-detection of substandard casing shoe.

(e) Atlas (Atlas Drilling (S) Pte Ltd – owner of the West Atlas and West Triton drilling rigs) personnel were not involved in cementing of casing shoe. PTTEPAA takes a larger degree of responsibility for failures occurred than Atlas because it was agreed between them that PTTEPAA should take on primary responsibility for well control.

Also in its daily operations PTTEPAA did not in fact depend on Atlas for expert supervisory on issues concerning well control operations.

(f) On the part of personnel from both PTTEPAA and Atlas contributed directly on the failures that occurred because they failed to ensure a test of the cemented casing shoe was carried out after waiting on cement to set.

(g) If a test on cement integrity could have been carried out, it would have confirmed the reliability of the cemented casing shoe as a barrier wasn't sufficient which would have enabled remedial action to be taken and hence the blowout would not have occurred.(ACT CANBERRA, 2010)

(h) The investigation team also pointed out that the use of an incorrect volume of 'tail' of cement by PTTEPAA in the process of cementing of the shoe in the H1 Well on 7 March 2009 may have directly and proximately contributed to the Blowout . This may have led to the creation of channels or 'wormholes' in the cement surrounding the 9⅝" casing string and casing shoe. Therefore further affecting the integrity of the cemented casing shoe as a barrier. (ACT CANBERRA, 2010)

(i) The other cause of Montara Blowout include the failure to install a Pressure Containing anti-Corrosion caps (PCCC) on the 13⅜" casing string of the H1 Well. This Pressure Containing anti-Corrosion caps (PCCC) was intended to operate as a secondary barrier against a blowout. If the 13⅜" PCCC could have been installed then it would have operated as a secondary barrier against a blowout. Additionally failure to install a 13⅜" PCCC caused the removal of the 9⅝" PCCC in August 2009, thus leaving the H1 Well without any secondary barriers against a blowout.

(j) The other factor contributed to Montara blowout was removal, and non-reinstallation of a PCCC on the 9⅝" casing string of the H1 Well around 20th August 2009. This PCCC was also intended to operate as a secondary barrier against a blowout. The Blowout occurred approximately 15 hours after removal of the 9⅝" PCCC. In this case it is said that if the 9⅝" PCCC hadn't been removed, or been re-installed, the Blowout wouldn't have occurred.(ACT CANBERRA, 2010)

(k) The PTTEPAA personnel on-rig and onshore, wrongly assumed that fluid in the wellbore could be trusted as an effective barrier against a kick which could lead to a blowout. This act was contrary to the regulations of well control and operating companies but it was done anyway. Also the casing fluid was not monitored after removal of the 9⅝" PCCC

During the blowout incident the crew came to assembly point, but luckily enough the kick stopped at well one and people were ordered to go back to their work locations. Few minutes later the decision were taken by PTTEPAA and Atlas personnel to take the rig to well H1 to start installing an RTTS packer (which is Retrievable Pressure Testing, Chemical Treating and Cement Squeezing Packer) in order to stop the blowout. RTTS packer was decided to be installed in the H1 Well so as to secure it and prevent more unexpected discharge of fluid and gas. Before even finishing uninstalling skid cantilever at well H4, well H1 kicked again. After second kick, the alarms sounded again, crew assembled at their muster locations and were evacuated by life boats and only people that were assigned to control further discharge remained on the rig. Later on all personnel were ordered to evacuate the rig and all engines were shut down. On 21^{st} of august 2009, the management formulated its emergency response group which consisted of 30 people to try to stop the blowout. (ACT CANBERRA, 2010)

5.2 MACONDO WELL BLOWOUT

In April 2009, BP was granted permission to drill on the Macondo well in Mississippi Canyon Block 252 using Transocean's dynamically positioned floating drill rig (Marianas) by Mineral Management Service (MMS). In the initial stages of issuing drilling permit, BP were asked to use the best available and safest technology by that time. Also BP attested their ability to deal with worse case spill scenario of 162000 barrels per day. BP plan showed that the blowout case scenario was unlikely and environment impact analysis concluded that there was no significant environmental impacts expected. By September 2009, BP using Transocean's dynamically positioned floating drilling unit (Deepwater Horizon) finalized the setting of Tiber well in the northern Gulf of Mexico as seen in Figure *16* .

Drilling of Macondo well started on 6^{th} October 2009. Macondo well was an offshore well with 500ft water depth and it was drilled to an actual depth of 18360ft as seen if Figure 17. It was estimated to cost about 96 million dollars in a duration of 51 days to its accomplishment.

Figure 16:Deepwater Horizon semisubmersible drilling rig (Deepwater Horizon Study Group, 2011)

On November 2009 the rig (known as Marians) that was used to drill Macondo well was damaged by Hurricane Ida that passed nearby the well and the rig was disconnected and taken onshore for repair. Then on January 2010 the damaged rig (Marians) was replaced by another rig called Deep water horizon which was owned and operated by Transocean, which was under contract to BP. Then later on February 2010, drilling of Macondo well resumed using the new rig that was already installed. While drilling continues it was discovered that the Blowout Preventer (BOP) couldn't be activated automatically when emergency occurs because of failures in pods (both yellow and blue). (Deepwater Horizon Study Group, 2011)

In the Macondo well incident which occurred on the evening of April 20, 2010, an uncontrolled flow of water, oil mud, oil, gas, and other materials came out of the drilling riser and possibly the drill pipe on the dynamically positioned drilling vessel Deepwater Horizon.(Deepwater Horizon Study Group, 2011).

Two or more consecutive explosions and an enormous fire followed shortly after the uncontrolled flow started. The fire continued unceasing for about two days with the support of hydrocarbons coming from the Macondo well. On the incident, apart from loss of lives of

11 out of 126 persons on the platform also 17 people were injured and 4.9 million barrels of oil was spilled into the gulf. The platform kept burning and came to sink about 36 hours later and the fire was stopped. The riser and drill pipe inside bent at the top of the subsea Blowout Preventer (BOP) and fell crumpled and broken on the seafloor, and allowing outflow of gas and oil. The outflow of oil and gas where controlled after 83 days using several attempts.(Deepwater Horizon Study Group, 2011). The attempts to stop the blowout were first the BOP and diverter packer which closes the drill pipe in the annular at the wellhead at subsea was activated and were shown to be on by the lights in the bridge BOP control panel. Diversion of high momentum fluids was unsuccessful which caused internal combustion. Also Emergency Shutdown (ESD) functions were not encoded to be automatically started on activation of rig combustible gas detectors, nor was the platform loud general alarm automated. Second the Emergency Disconnect System (EDS) was unsuccessfully switched on manually on the BOP control panel in the vessel bridge space just before the vessel was abandoned. Third, the BOP kept feeding the fire burning the vessel through riser which was still connected to it until when the vessel sunk. Fire-fighters failed to control the burning fire because they could not disconnect the fire from fuel. Fourth, Remotely Operated Vehicles (ROV) was used before and after sunk of vessel to try and close the blind shear (B/S) ram BOP and the variable pipe ram BOP elements, but none of the attempts was successful. (Deepwater Horizon Study Group, 2011)

Deepwater Horizon Study Group (DHSG) used the evidences from the area of incident and found that the blowout of Macondo well probably was initiated with a violation in the well structure at its bottom (around 18000ft below sea surface). The well progress was in the level of preparing it for production and temporary abandonment. A large quantity of hydrocarbons entered the well as it was prepared for abandonment. The tests performed couldn’t reveal these hydrocarbons in the well. Gas started coming out of oil when the drilling fluid was replaced by light sea water.

As the gases rose inside the well bore, they quickly expanded in volume as they entered the lower pressures near the surface. Seawater, drill mud, and other fluids in the well bore were pushed ahead of the rising and expanding gases. This stream of gases and fluids were followed by high-pressure oil, gases, and other fluids from the reservoir.

In the last minute the crew on the deck decided to divert the gases, oil, and other well fluids into an oil-gas separator instead of diverting the blowing out well directly overboard. The oil-gas separator was intentionally meant to control any contamination of the seawater because of the oil-based drilling mud ,thus why well fluids and gases were not diverted overboard at first place. The experience was gained from former incident where major kick encountered during drilling was controlled by directing kicks into oil-gas separator.(Deepwater Horizon Study Group, 2011)

The high volume and high pressure of the seawater, gases, drilling mud, and other fluids in the well bore overpowered the separator hence permitting gas and the other well fluids to escape onto the drill deck and surrounding facilities. Emergency alarms and shut-down equipment and processes couldn't work to stop the blowout. The gas ignited and two or more explosions occurred. The blowout reached the drill deck where eleven workers who were struggling to stop the blowout were killed on the spot.(Deepwater Horizon Study Group, 2011)

At a total depth (TD) of 13305ft (around 8000ft below see floor) a serious well control incident occurred in which unexpected formation fluid flowed into the wellbore and it existed for about 33 minutes before being detected. The incident resulted in stuck of drill pipe and well logging tools. This caused the drilling team to side-tract the well because they couldn't drill through or remove the drill pipe, and they reached 17000ft (TD) by end of March 2010. As a result of well control problem, BP redesigned casing to account for high formation pressure in the wellbore and it was approved by regulating authority (Minerals Management Service).(Deepwater Horizon Study Group, 2011)

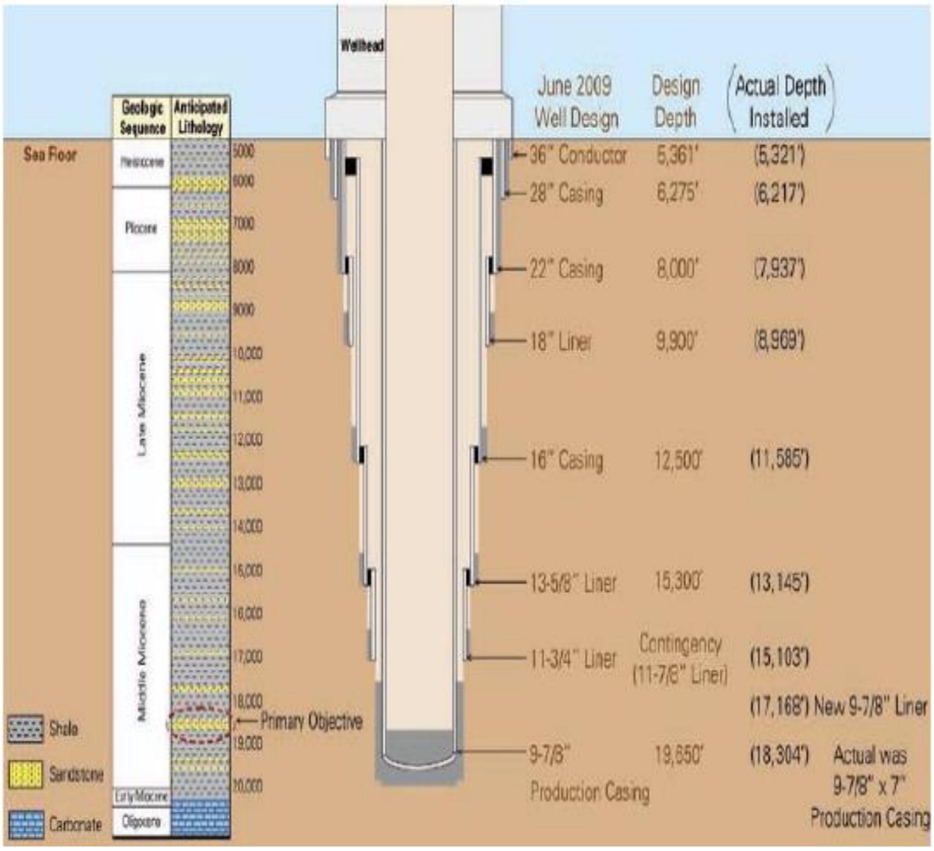

Figure 17: Geology and original design of Macondo well(Deepwater Horizon Study Group, 2011)

The zone which contained hydrocarbons with 124ft thickness was penetrated while drilling the well. A production-type casing was installed and cemented using nitrogen-foam cement slurry comprising numerous additives. The bottom of the 7 inch casing (Production casing) shoe was sitting at around 18,303ft below Kelly bushing (KB). The annulus between production casing and drilling casing was sealed with sealing assembly that was equipped in casing hanger of 9⅞ inch at subsea wellhead. The drill string whose size was narrowing was placed to 8,367ft (below KB) and then a spacer and seawater was pumped into the drill pipe and up through the annulus to the BOP. The annular BOP was shut around the drill pipe to isolate the riser and then pressure test was conducted by bleeding-off from of the drill pipe to check for the stability and integrity of the casing, seal assembly, and cement job at total well depth (TD). And the test showed that the BOP could handle about a 2,000 psi under-balance as referenced to the estimated production zone pore pressure of about 13,000 psi at TD.(Deepwater Horizon Study Group, 2011)

Surprisingly hydrocarbons from pay zone started entering into the well bore and migrated up the lower marine riser package (LMRP) to the rig floor. There was no clear and direct evidence that pinpointed how, why and where this is no definitive public information that describes exactly why, how, and where this influx of hydrocarbons occurred and flowed upward to the rig through the more-or-less stationery well fluids in the well below 8,367ft Kelly bushing (KB).(Deepwater Horizon Study Group, 2011)

Although there was no specific and direct cause of Macondo hydrocarbons influx but (Christou & Konstantinidou, 2012) pinpointed that the root technical cause of the blowout was that the cement that was pumped by BP and Halliburton to the bottom of the well did not seal off hydrocarbons in the formation. This means cement did not form a good barrier to protect wellbore against influxes. The following are the factors that made the pumped cement not to seal off hydrocarbons: First, due to drilling complications engineers were forced to design the cement that gave low overall volume. Second the cement mixture (slurry) was poorly designed and tested. Also abandonment operations was performed in the last minute causing the drilling crew to leave the well underbalanced because additional barrier to back cement job was not installed. The negative pressure test implemented and accepted without establishing well integrity. (Christou & Konstantinidou, 2012)

According to investigation of both incidents (Macondo and Montara well blowouts) it was found that serious systemic failures in relation to risk management were evident. Kicks can be controlled by correct installation of barriers. Barriers tend to degrade over time which increases the risk levels accordingly. So in order to ensure proper functioning of well barriers, constant correction strategies is required to maintain and enhance well barriers effectiveness and capability to control or detect formation influxes. Therefore barriers needs to be monitored on a more frequent basis so that proactive decisions can be taken to manage barriers.(Ahluwalia & Ruochen, 2016)

5.3 THE BRAVO BLOWOUT ACCIDENT (1977)

On the 22nd of April 1977 an oil and gas blowout occurred in well named B-14 on the Bravo production platform in the Ekofisk field. During the occurrence of blowout , the operation that was in progress was workover operation. This operation involved complex actions such as pulling around 1000 ft. of production tubing from wellbore. Before this operation is implemented, Christmas tree has to be removed first and the well was killed using heavy fluid (high density mud) and also downhole safety valve (DHSV) was installed at a depth of 50m.

The Blowout happened while installing Blowout Preventer (BOP). After blowout Downhole safety valve (DHSV) was blown out of tubing and was found on surface undamaged. The immediate cause of the blowout was that the DHSV were not tied and secured into the seating nipple in the tubing appropriately, so the blowout forced the DHSV out of well easily. During the time of installing BOP in the night between April 21st and 22nd Downhole safety valve (DHSV) failed to prevent flow of fluids when the well became unstable during the morning of April 22nd.

Before blowout occurrence, two warnings of abnormal conditions were received during the day of the 22nd and appropriate actions were not taken by the working crew. The first warning came before noon when mud was observed flowing out of the control line coming from the Downhole safety valve (DHSV). The second came when the Christmas tree had been removed, at approximately 16:30 in the evening , when mud also came up through the tubing. Each of these warnings should have awakened the working crew and immediate ceasing of the work and closing of the well should have been implemented. The Blowout persisted for 8 days, leaking an estimated 157500bbl (22500tons) of crude oil. The well was closed in by a US specialist crew and luckily enough there was no any lives lost, but it caused environmental damage and loss of millions of Norwegian kroners due to leaked crude oil. (Sætren, 2007; Wackers, 2006)

5.4 THE WEST VANGUARD BLOW-OUT (1985)

On Sunday 6th of October 1985 at 2030 an uncontrolled blowout occurred on the semi-submersible drilling rig West Vanguard during exploration drilling operation on block 6407/6 on the Haltenbanken. Shallow gas blowout occurred during a normal drilling operation before necessary development was made to mount a blowout safety valve. The gas diverter system of the rig could not withstand the forces of the blowing gas which contained sand and other solid particles flowing at high pressure and then gas flowed out onto the platform and were ignited.

The blowout caused the death of one person out of 80 people on the platform and the cost was hundreds of millions Norwegian Kroner. This is how blowout occurred, the drilling progressed normally until the sand formation which contained gas was drilled through at a depth of 2363 meters below sea floor around 2100 hours. According to geological data that were available by the time, the sand formation containing gas in that depth was not proven.

The pre drilling check, the sand formation which contained gas was to be encountered 60 meters below 2363 meters.

Drilling crew decided to circulate out the gas and continued with drilling operation but a new increase in gas coming out was observed and they continued circulating. Although gas was circulated, the gas amount flowing to surface increased and blowout happened.(Sætren, 2007; Wackers, 2006) Around approximately 2300 hours, the blowout developed totally and general evacuation alarm was declared. Few minutes later the crew attempted to divert gas using the diverter system under harsh conditions. They also released the riser connection at the sea floor and moved the platform away from the gas plume by freeing the anchors on one side of the platform. Two explosions occurred and the platform were greatly damaged see Figure 18. One person went missing until today while other people were rescued immediately. The well continued blowing for five to six days unstoppable and started calming gradually after six days. The rig was moved away and taken to a nearby site for maintenance. (Sætren, 2007)

Figure 18:West Vanguard when the blowout broke; the main deck was damaged

5.5 THE SNORRE A BLOW-OUT (2004)

Snorre A incident occurred on the 28th of November 2004. This is how the disaster unfolded, On the 28 November 2004, the crew on the rig at Snorre A facility were pulling pipes out of wellbore to prepare a well for side tracking. The uncontrolled gas flowed and developed into a blowout and gas was all over the seabed and under the platform. Due presence of gas under the facility, the possibility of vessel getting closer to facility bottom to unload the additional drilling mud became cumbersome.

The killing mud was prepared and pumped into wellbore on 29th of November and the well stabilized. This incident was the most serious incident on Norwegian continental shelf history of blowouts. The situation progressed when the production tubing was pulled through blowout preventer (BOP). While pulling production tubing, the suction effect developed and gas found its way into wellbore. Then gas flowed into production tubing through a hole and into casing through a damaged casing. Then gas leaked outside BOP and ended up leaking from the seafloor. Some alarms started going on and the crew were notified of the danger. The alarms were understood to be caused by leakage of process module and into cooling water. While the crew were struggling trying to identify the cause of alarms, other alarms in other areas also went on, and the crew couldn’t establish the source of leakage and started evacuating by helicopter.

Two hours after alarms, gas could be seen in bubbles at the platform bottom. The gas bubbles had managed to enter in the coolant circuits and fire begun and bad enough the pilot flame in the flame tower could not be shut down. The alternative power generators were switched on because main power generators went off but they couldn’t provide an adequate power to mix and prepare killing mud to counter the gas in the wellbore. Few crew members remained on the platform to figure out how they can stop the problem while others were flown to nearby platforms using helicopter. They succeeded to prepare heavy mud and it was pumped into wellbore and well stabilized and were closed. According to reports, It had taken the crew about 2 hours and 6 minute from the first gas alarm sounded until they were in a position to confirm that a blowout was about to happen.(Sætren, 2007)

5.6 FINDINGS FROM BLOWOUT REPORTS AND KICK TECHNIQUES

5.6.1 Human errors

Human errors played big role for both Macondo and Montara well incidents mainly but also in Norwegian continental shelf incidents. The act of forgetfulness to place back the removed casing after cleaning (In Montara well) was the major fault that needs rectification and improvement.

Poor team working also contributed indirectly to occurrence of these disasters. If the crews between service company (Contractors) and main owning company (Parent company) don't work cooperatively, it may lead to errors which brings about influxes and hence blowouts. For instance Atlas (Atlas Drilling(s) Pte Ltd which is owner of the West Atlas and West Triton drilling rigs) personnel were not involved in cementing of casing shoe which was the cause of Montara incident. Therefore to reduce the chances of blowouts working crews cooperation and team working between companies should always be emphasized.

Another human errors that was obvious was in the process of conducting negative pressure test. The negative pressure test in the Macondo well was mainly used to lower pressure in the wellbore to find out if casing and cement in place could withstand formation pressure without allowing any leaks., so it could help in revealing any leaks or poor cement and casing. The negative pressure test was first conducted in the drill pipe instead of conducting the test in the kill line as it was planned , this proved beyond doubt that there was planning violation. While in the process of conducting the second negative pressure test, it was discovered that the system added 15 barrels instead of 5 barrels as it was expected, showing the possibility of presence of influx into wellbore. This shows that the influx was already flowing to the surface before negative pressure test was complete. Also the procedure for conducting the test on the kill line was not followed and hence problems. The kill line was already filled with fluid. The crew recognized that and they decided to close kill line for further discussion. During this time of discussion the pressure in the system increased to 1400 psi, then the kill line was re-opened and bled to 0 psi while pressure in the drill pipe continued to be 1400 psi. Lack of quick decision making or advisory program that could help in finding out the alternative or what to do. And this indicator was enough to notify the crew of something bad happening, but instead the crew approved the test to be successful any way. Also crew lacked enough knowledge on how to interpret negative pressure test, thus why the investigation team advised the crew to be trained. It was suspected that the viscous spacer was still in the choke and in the kill line while conducting negative pressure test.

Trying to stop kicks by applying the experience of events that was successful in the past does not guarantee success in the current or future events. For example the act of allowing the kick material to pass through the separator instead of diverting it overboard should be re-considered even if it was conducted because of past experience of past events in the area of operations. This act was a complete failure which allowed oil and gas to leak on the platform and later on blowout.

5.6.2 Technology deficiencies

The tendency of alarms to sound falsely while there is no any kick is among technological deficiencies. This makes the crew members relaxed even when serious alarms sound because of experience and thinking it might be false alarm. Also the act of DHSV being blown out of well undetected is a technological problem. The barriers needs improvement from day to day, and also testing of BOP and other devices is always necessary, for example in the Macondo well blowouts the automated shutdown system failed to activate in time of incident. Also in Snorre A, a system to identify source of leakage is crucial to counter attack the signals of wellbore influxes immediately.

The plan on how and where the downhole safety valve (DHSV) can be installed was already designed and prepared prior to fitting process. There were deviations from the plan while installing the DHSV which made easier for the DHSV to be blown out of well. Also the mud weight was not in accordance to the mud weight specified in the workover program.

In the investigation conducted, Preliminary findings indicated that there was unexpected loss of fluid in the riser pipe, which notified that there was a leak in the blowout preventer annular. This is the reason the BOP could not be switched on automatically, because of a leak in the BOP at first place.

5.6.3 Cost cutting

Long working hours also influences blowouts incident since the capability of identifying anomalies decreases due to tiredness. An individual stays for around 12 hours in front of these displays trying to identify any anomalies. Due to possible consequences for anything that might go wrong, relying on the right person to check on the right data at right time while other operations runs simultaneously cannot be accepted. Since it takes long time for any kick indicator to be identified, the drillers ability to quickly control any potential impacts of kicks gets reduced. In this case operators needs help of sensors or advisory program to help reduce too much dependence on working crews. Over working and long shift hours places pressure on working crew because of feeling of tiredness after some time, this makes the operators probably poor in decision making or interpreting signals. Therefore the issue of cost cutting influence kicks and later blowout indirectly.

Time pressure to save operations costs. One of the biggest costs in drilling operations is hiring a rig. Rig costs are charged per day, so the service company tries to work effectively to reduce number of days of hiring a rig in order to reduce cost. For example the drilling engineer in Harstad did not look through all documentation handed over to him from the Bergen office due to time pressure. Necessary information and knowledge on potential hazards were not passed/provided to the crew doing the job to a sufficient and required degree.

5.6.4 Kick detection problems

Kick detection techniques as already mentioned provide a loop for kick to go undetected (refer to volume increase in returning mud method). Their improvement will help to reduce or eradicate the amount of kicks that reaches to the stage of causing blowouts. Furthermore the pit gain indicator varies according to influx fluid solubility. The weaknesses of kick detection methods are such as; When the influx fluid is gas and is highly soluble, just small volume of influx may result into a large volume of influx since it expands. Also rock fragments that fall into wellbore can pack the annular space and shows a pressure increase similar to the one related to the kicks. Therefore kick detection using this method is ambiguous and cannot be relied as the only method for kick detection. Most of the kick detection methods concentrated on drilling operations and there is no methods for detecting kicks during workover and completion operation, after abandonment stage and preparation for production stage. It was obvious that blowouts frequency increased in operations after drilling.

Rate of penetration influences kick detection only if there is drilling otherwise it’s totally inapplicable. Blowouts can be killed by dynamic killing but there are a lot of problems that makes it difficult. The killing fluid is pumped through injection well, this kind of well might not always be available instantly

6. SUGGESTED METHODS FOR PREVENTING BLOWOUTS

From section 5.6 we have seen that there are multiple problems that faces blowout prevention. In order to help mitigate this problem, the following measures can be taken.

6.1 VOLUME INCREASE IN THE MUD TANK

Volume of mud in the tank can be used as a good method to detect kicks during drilling and post drilling operations. Consider the increase in volume in the tank as the method of detecting a kick. Total volume of drilling mud (V_T) in the circulation includes volume of drilling mud in the wellbore $(V_{wellbore})$ and volume of mud remained in the tank $(V_{remained})$. Similarly the volume in the wellbore comprises of $(V_{wellbore})$ volume mud in the drill pipe (V_{pipe}), volume of mud in the annulus $(V_{annulus})$, volume of an influx (if there is any) (V_{influx}) and volume of mud in the riser (V_{riser}) (if there is riser). See illustration in Figure 19.

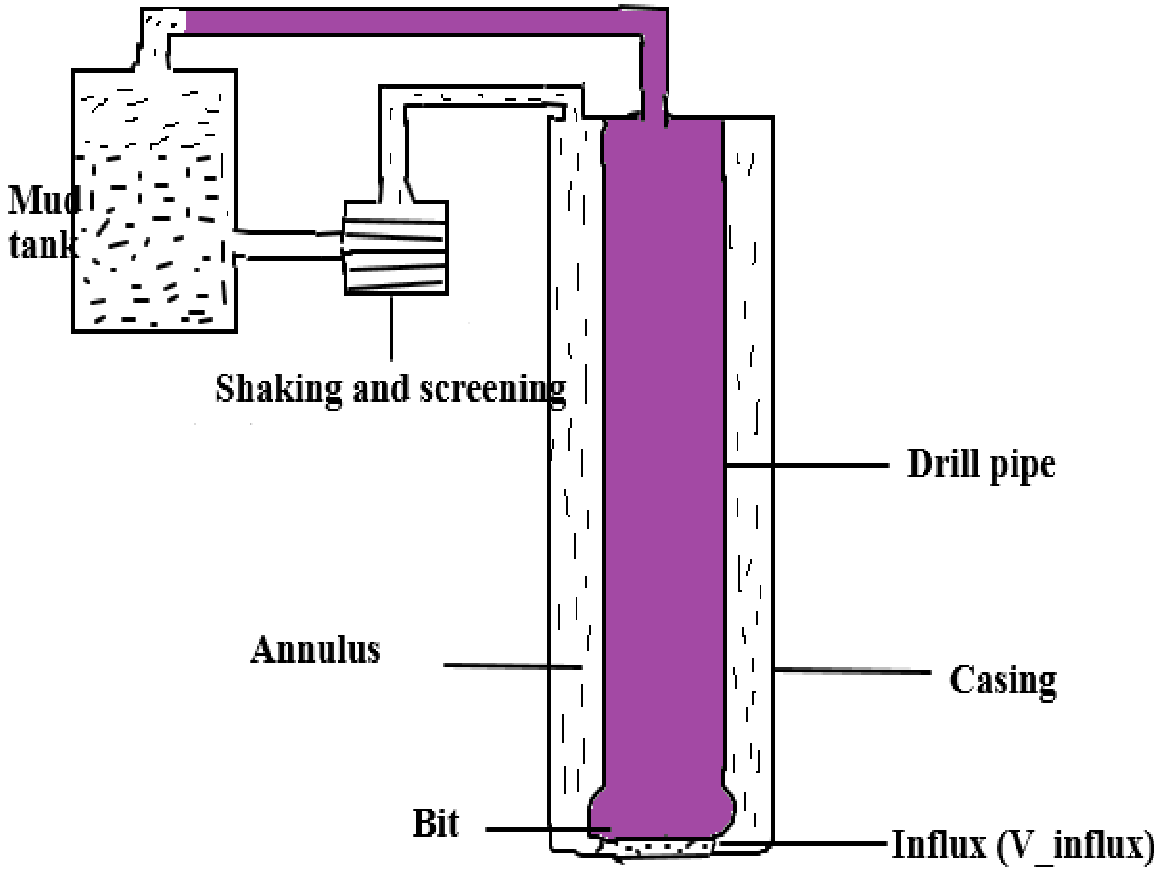

Figure 19: Illustration of increase in volume model

(Pål Skalle, 2016; P. Skalle et al., 1999) Assume the pumping rate from the pump is known $(Q_p)(\frac{m^3}{s})$, using the rate through which mud is pumped, with volume of mud, and the time then location of drilling mud can be determined. Frictional forces in the pipe, drill bit nozzles and annulus should be taken into consideration.

Assumption to consider in the process of calculating an increase in volume.

- Assume a vertical wellbore
- Constant temperature
- Constant density of drilling mud
- No compressibility
- Constant flow of circulating mud has been established.
- Lost mud in the circulation is negligible

Therefore

$$V_T = V_{remained} + V_{pipe} + V_{annulus} + V_{influx} + V_{riser} \tag{10}$$

Volume of mud in the drill pipe depends on geometry of drill pipe i.e. cross sectional area, and length of drill pipe column, the same applies to volume in the annulus which depends on wellbore radius, external radius of drill pipe and vertical distance of wellbore. This varies from section to section since cross sectional area narrows as the well gets deeper.

For drill pipe, the cross sectional area varies from section to section since size of drill pipe reduces downward (Assume A_{pipe} is the total area for drill pipe in all sections, use internal radius of drill pipe) and total length of pipe is TVD , then

$$V_{pipe=}A_{pipe}\ xTVD \tag{11}$$

Volume of mud in the annulus depends on drilled section diameter (nearly equal to bit diameter) A_{bit} , total vertical distance (TVD), and external radius of drill pipe in respective section (Assume a single section) $A_{pipe-outer}$ and area of borehole.

$$V_{annulus=}(A_{bit} - A_{pipe-outer})\ xTVD \tag{12}$$

Therefore volume of an influx could be

$$V_{influx} = V_T - (V_{remained} + V_{pipe} + V_{annulus} + V_{riser}) \tag{13}$$

$$V_{influx} = V_T - (V_{remained} + (A_{pipe} + A_{bit} - A_{pipe-outer})\ xTVD + V_{riser}) \tag{14}$$

If the sensors placed right at the wellhead, or below conductor casing, it would enable detection of increase in volume provided the assumptions applies and constant variables are placed into the algorithm. I have tried to use equation 12 to find out the relationship of volume of influx with depth, which actually reflects the probability of kick occurrence in relation to depth as can be observed in Figure 20. The more the drilling continues, the higher the probability of kick to occur increases.

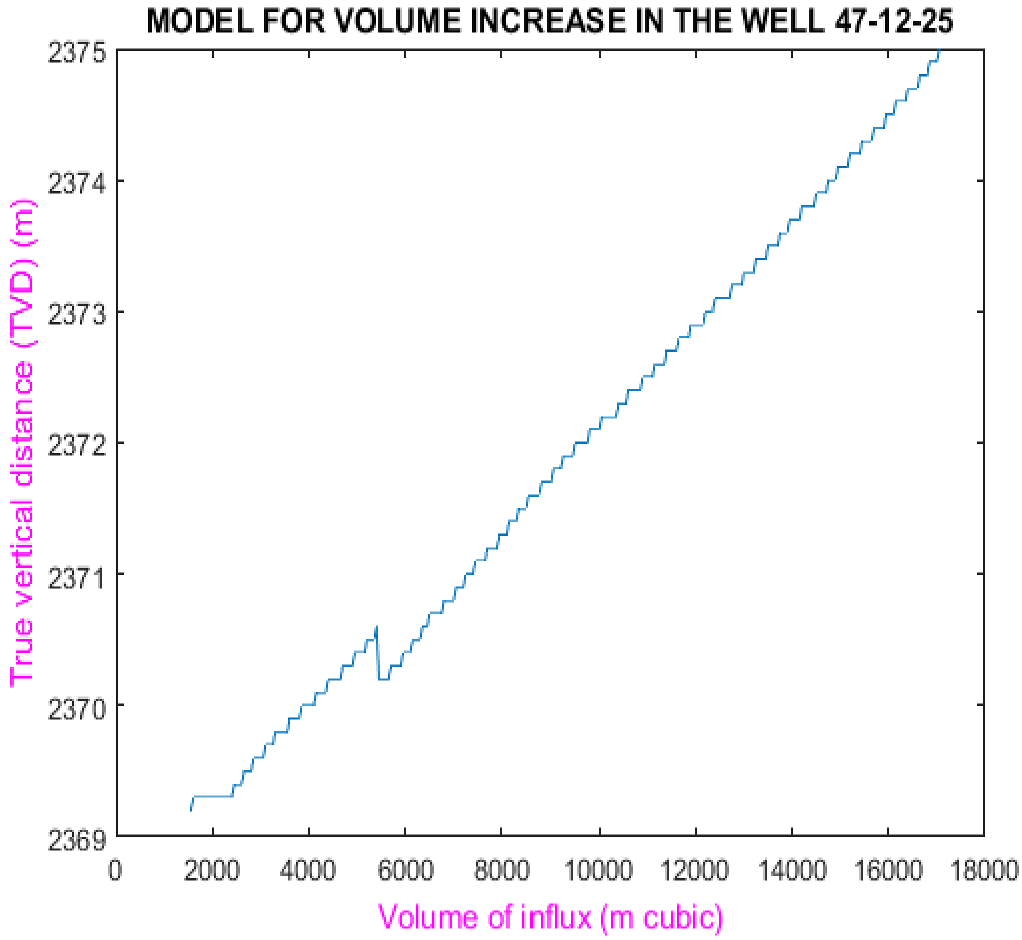

Figure 20: Model for probability of influx in the well

6.2 RATE OF PENETRATION INFLUENCE ON KICK DETECTION.

As can be observed in Figure 21, the rate of penetration can be seen varying from depth to depth. The big variation is observed on depths 2410m and 2300m, there was abrupt increase in rate of penetration. As explained before there are two possible causes such as penetration through soft formation, or low differential pressure (formation pressure increase in relation to hydrostatic pressure). Therefore if the sensors installed in the well head and just above the pit displays that kind of variation at the surface screen in the control room, the crew should concentrate on identifying what is happening downhole so that if there is any influx, the process of controlling it begins immediately.

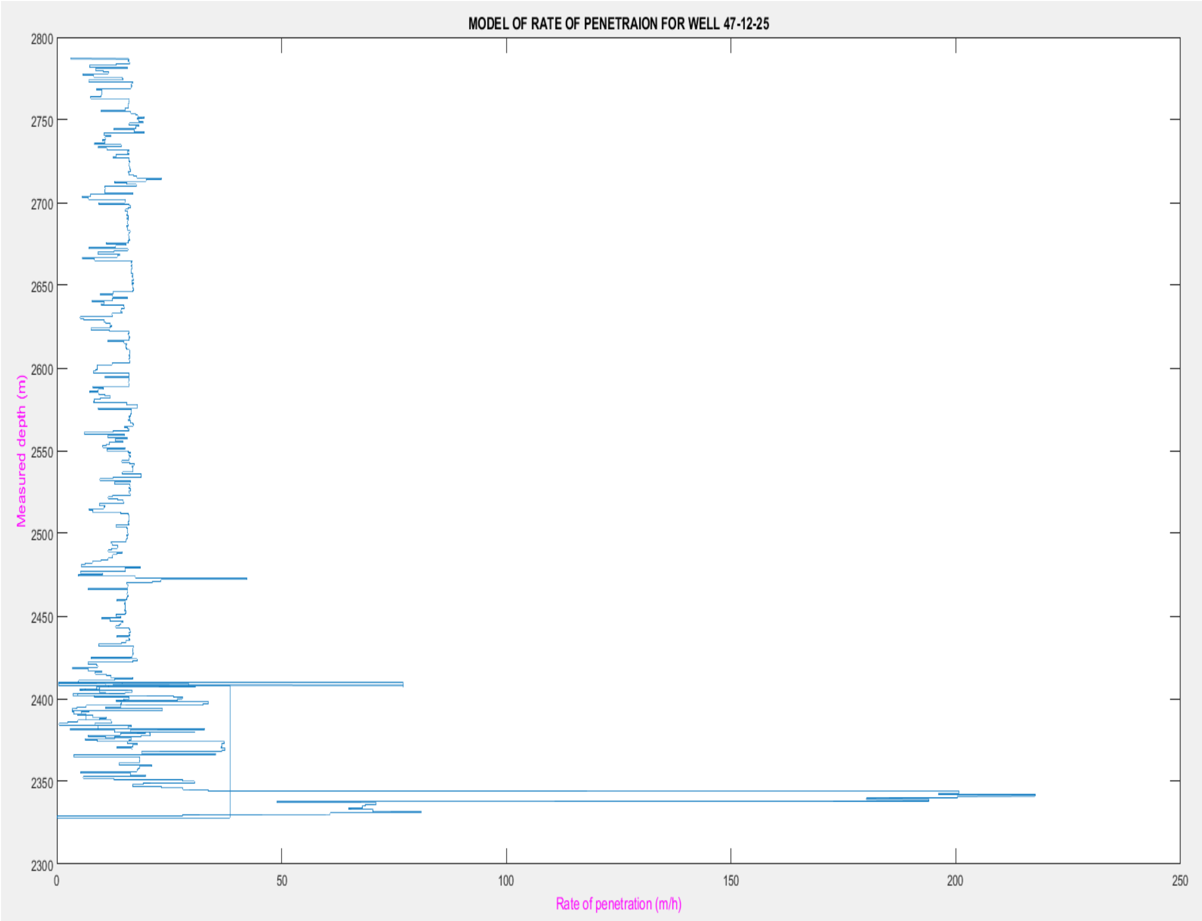

Figure 21: Rate of penetration variation with respect to measure depth

Rate of penetration is limited to drilling operation in the act of kick detection. There is no way it can be used if drilling won't be on progress. Therefore in other operations apart from drilling operation, this methods cannot be applied, so other methods of kick detection can be used.

6.4 CASING AND CEMENTING.

In all discussed blowout reports, casing and cementing was mentioned to be one of the problems. In order to completely stop the communication between formations and wellbore or zones within the formation appropriate casing and cementing operations are very essential. To make these operations successful, a cooperative team effort with comprises members from the operating company, the drilling staff, the drilling contractor, and the service companies is required.

To minimize problems that can occur during running casing an appropriate cementing floating equipment is necessary in order to maintain high efficiency, proper mud conditioning and better drilling capability. Also casing centralization assists in ensuring fewer problems such as pipe sticking, adequate standoff, and enhanced total displacement efficiency. Cementing operations comprises of; firstly is the fluid pumped (the fluid pumped can be slurry or spacers), second surface mixing and pumping equipment and third is downhole tools such as casing equipment. (Rogers & Heathman, 2005)

(Reddy, Xu, Ravi, Gray, & Pattillo, 2007) Cement settling down rate and shrinkage after being pumped into wellbore is of big concern because of their long term impact on zonal isolation. From cementing perspective, a path through which fluid can migrate from zone to zone or to the wellbore can be created based on the following factors.

- ❖ If the spacer pumped into wellbore to displace drilling mud failed to remove drilling mud effectively
- ❖ If the cement slurry placed into annulus wasn't enough to cover the intended region/area.
- ❖ If the cement protective covering fails because of either shrinkage or loss of structural integrity from its lack of ability to tolerate stresses from well operations.

When the cement sheath fails to offer perfect zonal isolation because of shrinkage problems, the following might be the causes; volumetric shrinkage which leads to poor bonding and micro annulus formation between cement sheath and casing or formation, increase permeability due to shrinkage stresses caused by tensile cracks, or both. If any case of the three mentioned above takes place, the formation fluid will have passes to allow it flow into unintended locations.(Reddy et al., 2007)

6.5 MANAGED PRESSURE DRILLING METHOD

If managed pressure drilling can control the annular pressure drilling, it can applied in making sensors installed in the casing shoes to monitor any flow of material into the annulus before the influxes rises up or makes its way inside casing. The equipment, and devices used in the detecting changes in annular pressure can be as modified and applied to regulate pressure during other drilling operations such as workover and completion.

6.6 NEGATIVE PRESSURE TEST.

Negative pressure test is the test conducted to see if there is any leaks through cement or casing by lowering the pressure exerted by drilling mud. According to the Macondo well investigation (Deepwater Horizon Study Group, 2011) negative pressure test couldn't reveal the presence of hydrocarbons in the wellbore. The deep water horizon at Macondo well misinterpreted negative pressure test results according to the formal investigation on the incident.

(Deepwater Horizon Study Group, 2011) Preliminary findings from investigation indicated that there was unexpected loss of fluid in the riser pipe, which notified that there was a leak in the blowout preventer annular. While in the process of conducting the second negative pressure test, it was discovered that the system added 15 barrels instead of 5 barrels as it was expected, showing the possibility of presence of influx into wellbore.

After receiving undesirable results from negative pressure test conducted in the drill pipe, the negative pressure test was shifted to kill line where a particular volume of fluid came out instantly after opening. This means the kill line was already filled with fluid. The crew recognized that and they decided to close kill line for further discussion. As this time of discussion the pressure in the system increased to 1400 psi, then the kill line was re-opened and bled to 0 psi while pressure in the drill pipe continued to be 1400 psi. This indicator was enough to notify the crew of something bad happening, but instead they crew approved the test to be successful.

The negative pressure test was first conducted in the drill pipe instead of conducting the test in the kill line as it was planned. The evidence in the investigation reports suggested that the spacer that was used to displace drilling fluid by sea water didn't rise above Blowout preventer (BOP) , this situation may have increased pressure in the drill pipe. The negative pressure test in the Macondo well was mainly used to lower pressure in the wellbore to find out if casing and cement in place could withstand formation pressure without allowing any leaks.

They had to believe the incomplete results of negative pressure test because of economic issues, that they couldn't manage to re-do the test again and again. Negative pressure test is applied in checking or inspecting the integrity of cement at the bottom of the wellbore.

In this thesis discussion we will narrow things into negative pressure test, cementing, casing to reflect on our case study reports on incidents and their relationship to automatic kick detection. As stated earlier, the flow of an influx into wellbore extends beyond drilling. I will try to investigate what made negative pressure test give false results on presence of hydrocarbons and maybe why there was misinterpretation by BP deep water horizon crew. The crew lacked enough knowledge on how to interpret negative pressure test, thus why the investigation team advised the crew to be trained. It was suspected that the viscous spacer was still in the choke and kill line while conducting negative pressure test. The spacer could have plugged the kill line and obstruct the installed gauge in the kill line to read the actual pressure in the wellbore.(Tabibzadeh & Meshkati, 2014b)

(Rahmani, Bourgoyne, & Smith, 2013)The success of negative pressure test can be verified using both flow and pressure checks. For the flow check, a trend between bleed off pressure and volume can be anticipated based on fluid compressibility, tubing expansion, and drainage from surface piping.

Deviations from that known trend will enable recognition of the commencement of a leak. Sensing a low rate leak is difficult if the duration for conducting the test is too short. So a 30 minute test duration was assessed for detection of low rate leaks.

6.6.1 Test calculations.

The volume of fluid expected to be bled off during the test is calculated as

$$\Delta V = V C_f \Delta P \qquad (15)$$

Where ΔV is the change in volume, $C_f$is fluid compressibility, ΔP is the change in fluid pressure. So that is the volume that will be allowed to flow out of wellbore. Therefore negative pressure test can be monitored and controlled using both flow (ΔV) and pressure (ΔP) checks in the wellbore.

6.7 SYSTEMATIC WAY TO AVOID HUMAIN ERRORS

In all mentioned blowouts, human errors has been one of the dominant cause for their occurrence, so to reduce the blowout frequency human errors should be reduced or eliminated. Human errors are caused by forgetfulness, ignorance and imperfection. To avoid or reduce human errors which influence occurrence of blowouts, an advisory program should be formulated. This advisory program will be showing step by step, procedures, and operations after operation to avoid skipping any step or procedure along the way. In petroleum industry the chain of orders sometimes delays quick response on sudden matters. If an advisory system can help to detect/prevent a kick or possibility of blowouts even after abandonment and advise on decision to be taken, then it would reduce or eliminate blowouts.

The decisions made by humans varies, depending on the situations, time and technology available. Furthermore, they can vary from operation to operation and within the same operational phase. In order to reduce the variations and provide increased progress and reliability. automated advisory systems should be set and used to manage the variations observed in several operations today and deliver repeatable and more decisive results. Automated advisory system will improve the general operational progress due to its expectedness in reasoning, thus reducing human judgment as a factor. The execution should be done quickly into the general automated reasoning system after enhancements areas are detected and output is verified through operational standards.(Saeverhagen, Thorsen, Dagestad, Svensson, & Grovik, 2012) No process is perfect; every system breaks down at some point.

(Brechan, Corina, Gjersvik, Sigbjørn, & Skalle, 2016) Cementing in wells is usually conducted to establish integrity between steel casing or liner and the adjacent formations over well life time. The objectives of pacing cement in the wells is; Support vertical and radial forces applied to casing, Separate permeable formations from one another , Obstruct unwanted fluids from the producing interval from below zones , Shield casing from corrosion, Resist chemical deterioration of cement, Confine abnormal formation pressures.

(Brechan et al., 2016) Before cementing, the following are general considerations for cementing casing based on the casing type:

- ❖ Conductor casing string is cemented to control the drilling mud from escaping and circulating outside the casing.

- Surface casing string should be cemented to safeguard fresh-water formations near the surface from contamination or flowing of fresh water into wells and provide a structural connection between the casing and the subsurface formations.
- Intermediate casing strings are cemented to seal off abnormal pressure formations and cover incompetent formations, which could cave or slough, and lost circulation formations.
- Production casing string is cemented to ensure that the produced fluids don't migrate to non-producing formations and to obstruct other fluids from the producing interval.

Secondary cementing is conducted often when primary cementing was poor or insufficient after primary cementing. There are five most important considerations concerning the cement slurry designed for a squeeze cementing operation as follows.

- Fluid loss control. The slurry is normally designed to match the strength of formation that needs to be squeezed. Slurry design considers between low permeability and high permeability. Low permeability formations should utilize slurries with 100–200 ml/30min water losses while high permeability formations should utilize slurries with 50–100 ml/30min water losses.
- Slurry volume. This is estimated after inspecting the confinement of primary cement and prior to the squeeze operation. Commonly, high-pressure squeeze operations of high-permeability formations that have relatively low fracture strengths will require high volumes of slurry. On the contrary, low-pressure squeeze operation through perforations will require low volumes.
- Thickening time. High-pressure squeeze operations that pump large volumes in a rather short time period usually require accelerator additives. While, low-pressure, low-pumping-rate squeeze operations usually require retarder additives.
- Dispersion. Thick slurries will not flow well in narrow channels. Squeeze cement slurries should be designed to be thin and have low yield points. Dispersive agents should be added to these slurries.
- Compressive strength. High compressive strength is not a necessary characteristic of squeeze cement slurries.

Main reasons of failure of cement to provide required isolation

- Lack of hardness (kick-off plug)

- ❖ Contaminated cement slurry
- ❖ Placed at wrong depth

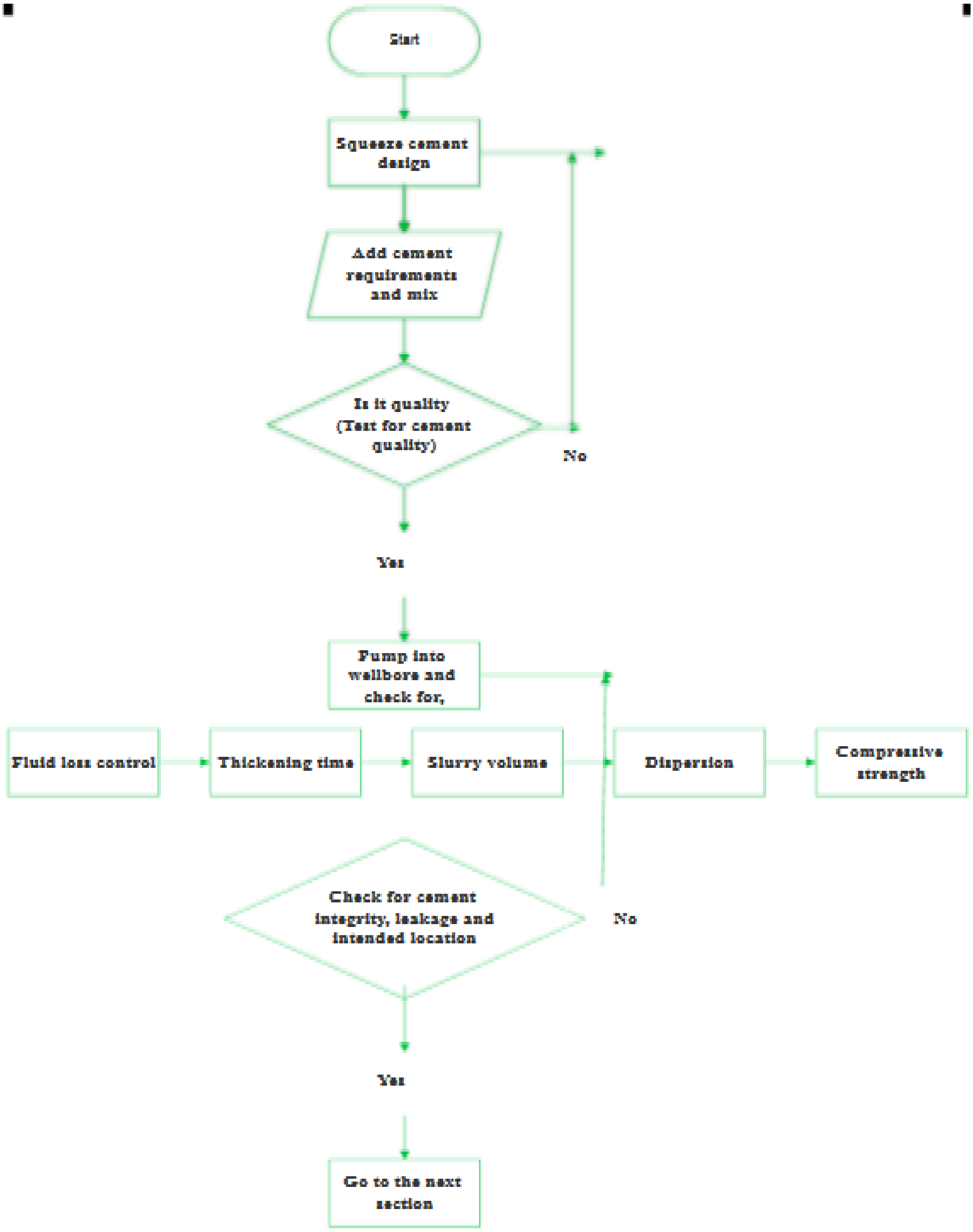

Figure 22: An example of steps or procedures for slurry design and pumping advisory program

I tried to establish procedures to be followed to avoid skipping any task, so that we can successfully reduce the effects of human errors. The cement case procedures in a simple form are shown in Figure 22, other tasks like casing that caused Montara well incident can also be developed and consider improvement on cementing procedures.

On Montara well incident the problem was much about human error and operating against set regulations. The regulation required the pressurized containing anti-corrosion caps (PCCC) to be installed in every casing section but it wasn't installed in 13 3/8'' casing section. This forced the crew to remove casings 9 5/8'' in order to clean the corroded 13 3/8'' and install the pressurized containing anti-corrosion caps, they forget to install the 9 5/8'' casing which is said to be the cause of blowout.

In relation to the both discussed blowout incidents (Macondo and Montara well incident) the big problem is human and technological error. Also the kick detection methods are very popular in the process of drilling, through in reality most of disastrous blowouts happen in the process of completion and temporary abandonment. Therefore kick detection methods should be extended beyond drilling operation. The sensors for detecting any change in volume or pressure inside the wellbore should be installed.

To rectify human error like forgetfulness in the operation, the sequence to follow should be set and supervised to ensure there is no any step to be skipped in the process of drilling , completion, and abandonment.

Not only human error but also too dependence or reliance on single technology or equipment to stop the kick when occurs should be reduced. For instance in Macondo well incident, the blowout preventer failed to shut down the well automatically and even after being established. So more than two equipment to shut down could help in case another fail. The switches designed to start the blockage of wellbore in case of blowout , should be more than two and set away from wellhead or region where the kick material will hit first to ensure that, the process of blocking the well even when kick has come is still possible. An example of advisory system has been illustrated in Figure 27 in the appendix.

The confirmation of operation accomplishment would more accurate if tested and confirmed by more than one operator to reduce human errors. Although this will take more time in the operations and hence increase in cost but it's better to avoid huge losses caused by blowouts.

6.8 GENERAL DISCUSSION OF BLOWOUTS

Blowouts cost millions of dollars every time they happen. These costs come from spillage of products being searched or produced, cleaning of environment after spillage or damage, burned rigs and other equipment and also payment to affected people during these disasters.

Figure 23 has been developed based on the frequency of blowouts from **Table 2**. As seen in Figure 23, the blowout from year to year is not constant. Although technology has been improving, still it does not guarantee prevention of blowouts to occur. Also the increase in complexity of environment where oil and gas is being produced still pause a great challenge to the industry. As already stated in the discussed blowout cases, technology deficiencies and human errors influences these disasters.

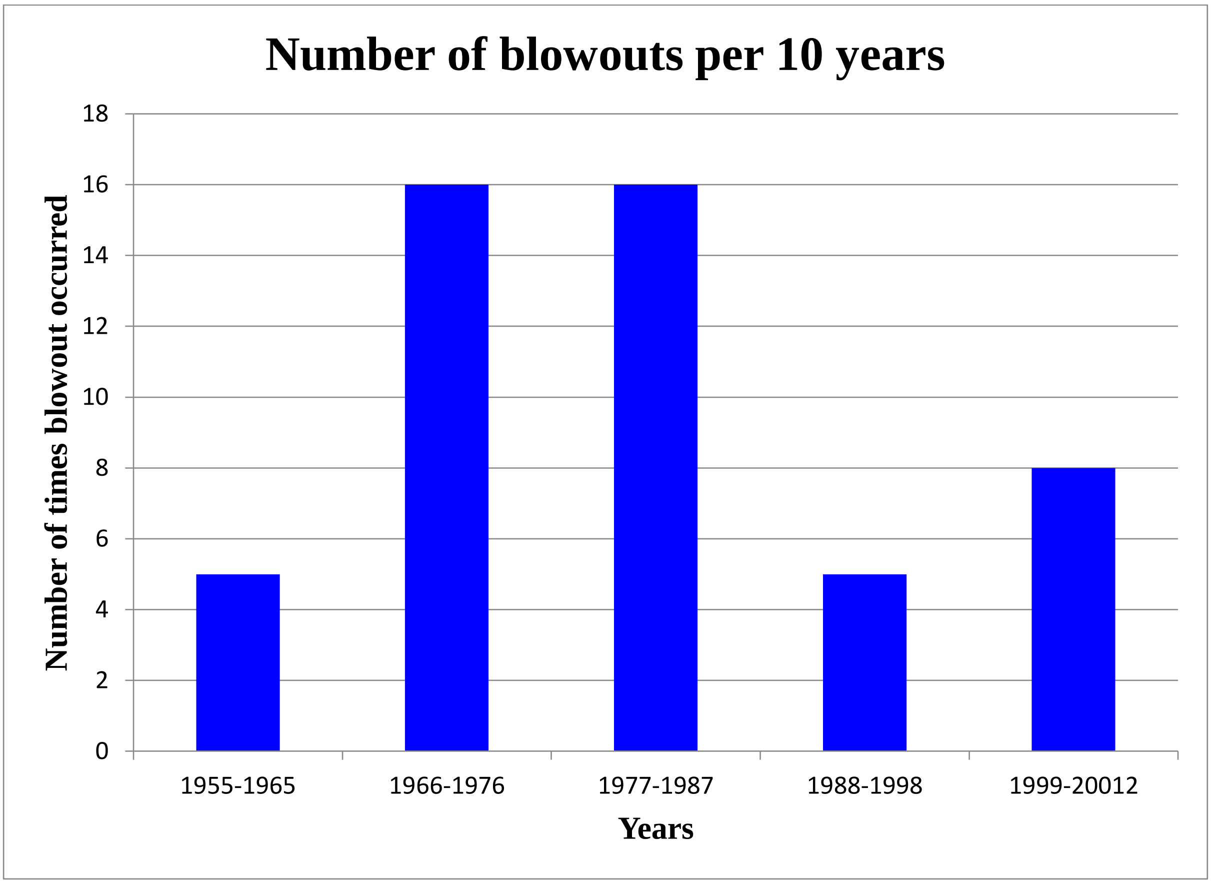

Figure 23: Frequency of blowout per 10 years period

Most of the researchers focused on kicks happening during actual drilling but as it can be seen in Figure 24, blowouts tend to occur even in other operations such as production, completion and workover. In the mentioned figure, it is obvious that most of blowouts occurs during workover operation. Workover involves wireline for logging operations, pulling of drill pipes ready for completion and coiled tubing. Sometime workover is applied to replace the corroded production tubing. For instance increase in the volume of mud cannot be applied to detect any influx while performing workover operations etc. Therefore these operations cost a lot of money because of equipment for safety that are installed but blowouts still occurs. The research on how to stop influxes/kicks during other operations rather than drilling should be established to try to reduce the possibility of blowout.

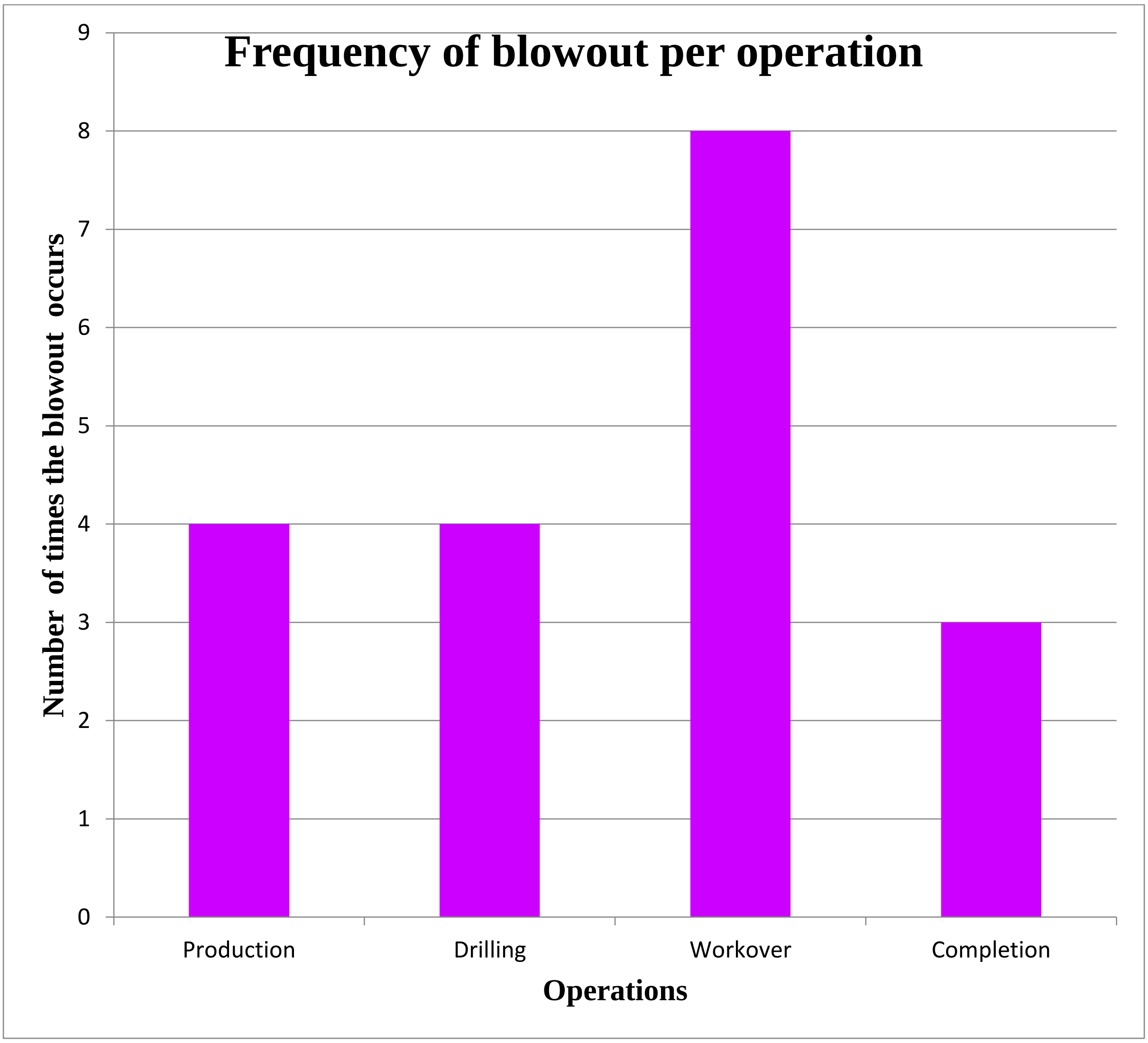

Figure 24: Frequency of blowout per each operation

Referring to Figure 25 and Figure 26 the amount of products being spilled is large. When a blowout occurs, the possibility of shutting down the wellbore gets reduced, therefore the products may come out uncontrollably. Large amount of barrels of oil or millions cubic feet of gas is lost due to these blowouts. So the company owning the reservoir losses millions of dollars. It is obvious from mentioned figure that oil has been spilled in large amount compared to condensate.

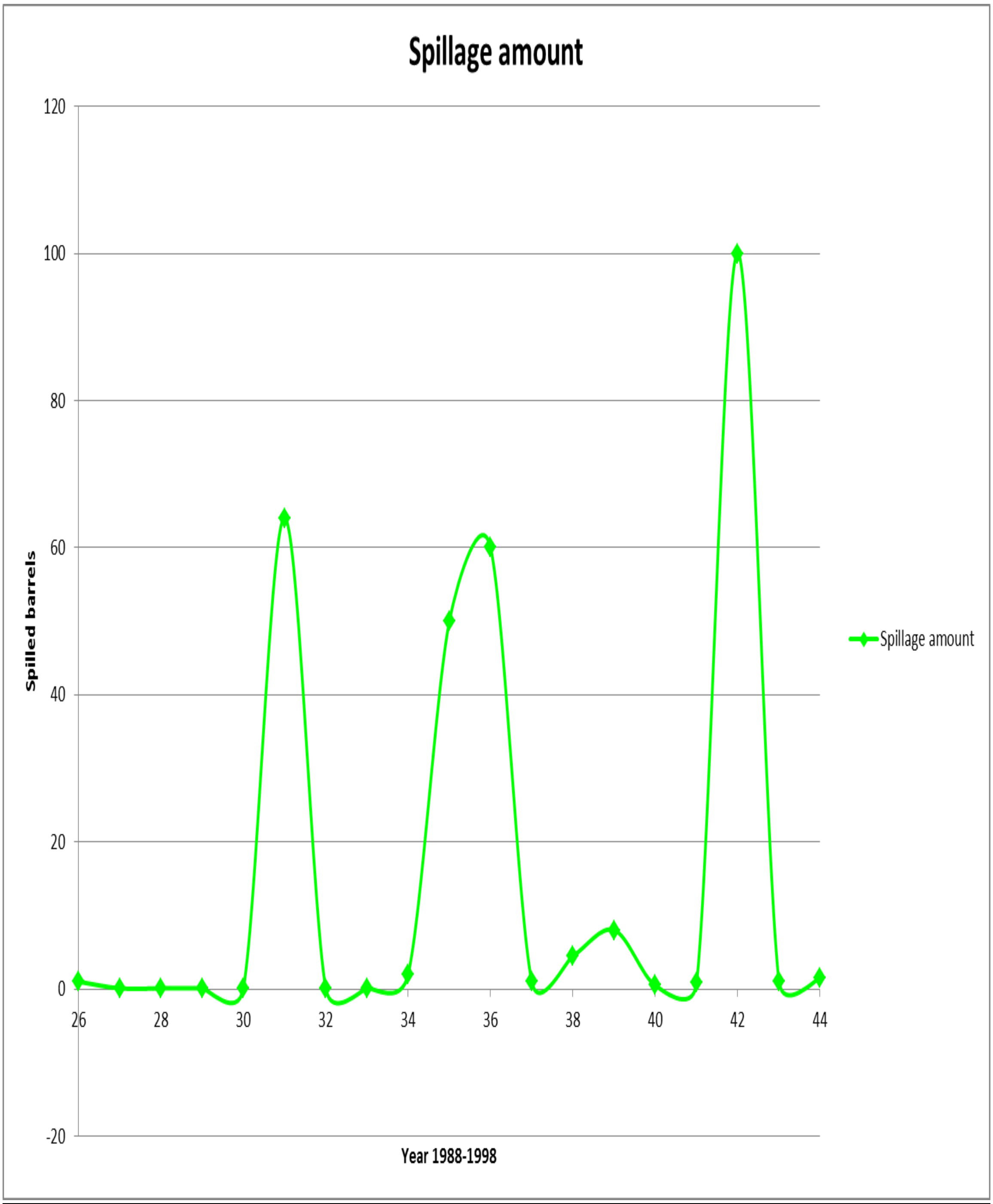

Figure 25: Amount of spilled product during blowout

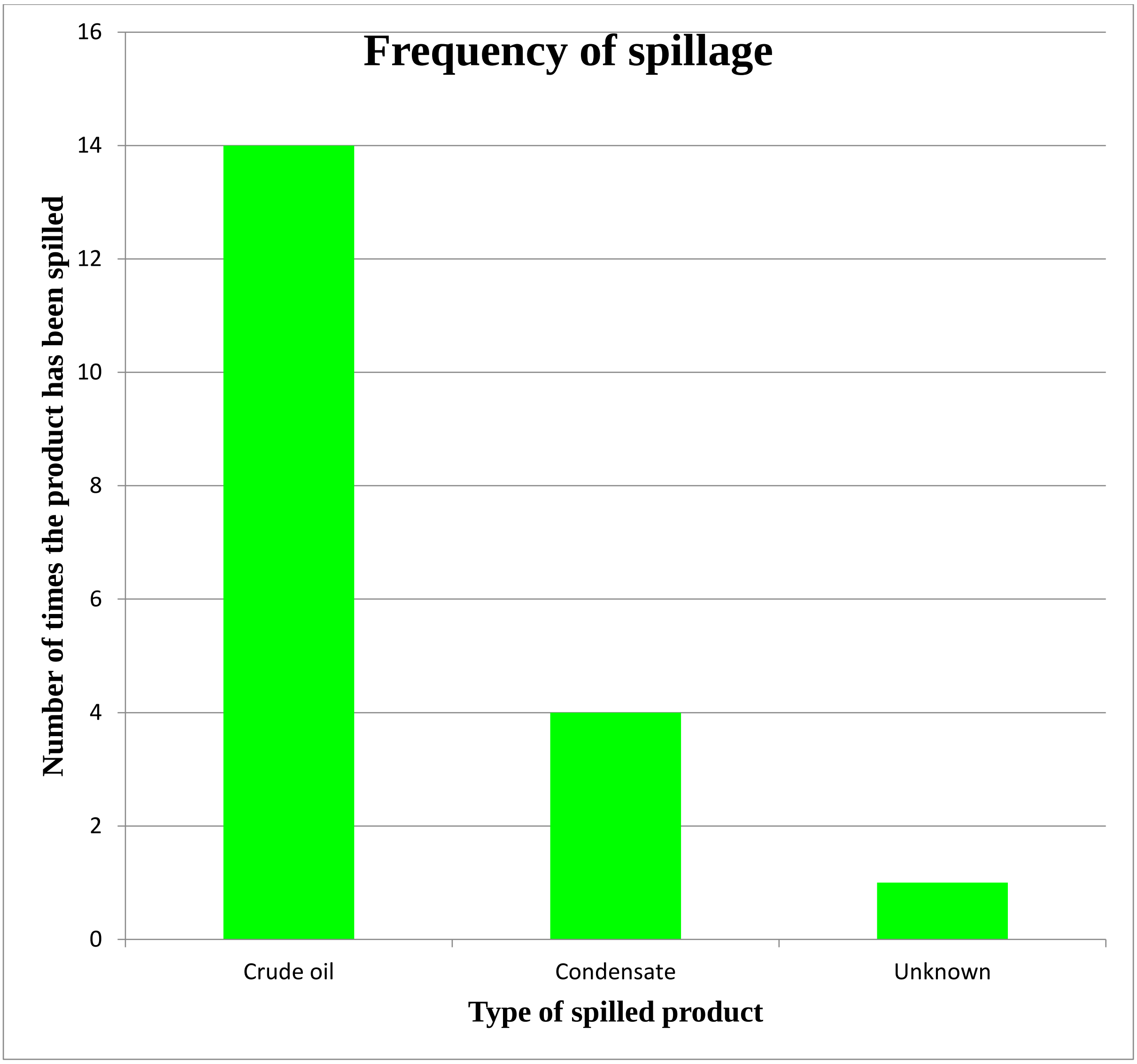

Figure 26: Product spilled amount

7. CONCLUSION AND RECOMMENDATION

7.1 CONCLUSION

Blowouts can be controlled multiple techniques such as Collapse of open hole wellbore (also known as Bridging), Closing the blowout preventer (BOP), Pumping Cement slurry (Cement), Capping, Depletion of small reservoirs, Install equipment, Pumping Mud, and Drilling Relief wells and many more. All these methods works in limited environment and they have their weaknesses as discussed in previous chapters. Therefore regardless of existing techniques, kicks still reaches the surface undetected because of present loops/weaknesses in these methods. For example increase in returning mud volume has a weakness of causing late recognition in long wells. This is the method that can be applied beyond drilling when the model I developed can be integrated into sensors which can be installed at the bottom of the well after abandonment or at every casing shoe to detect any increase in volume. Increase in rate of penetration is limited to drilling only and it cannot be applied in other operations. The flow with pumps off can also be applicable in operations that doesn't involve drilling anymore such as workover and completion. The other means to detect kicks earlier is the proper applications of Managed pressure drilling though this is limited to drilling operations only. These all would enable earlier detection of kicks so that it can be circulated out. The most popular methods for circulating out an influx are Drillers method, Engineers method and Volumetric method. When a kick causes a blowout, dynamic killing can be used to stop the supply of burning fuel (oil or gas). Most of kick detection methods applies only within drilling operations, therefore the way of applying them beyond drilling operations is necessary. For instance in the discussed blowouts, most of disasters occurred during workover operations, so methods in other operations together with detectors or sensors can be very useful to try to detect and control influxes.

Regarding the discussed cases (Macondo, Montara blowouts and Blowouts in Norwegian continental shelf) proved beyond doubt that technology, human errors and shortage of knowledge among crew members is a major cause of blowouts. Shortage of enough training and knowledge can be backed by the Macondo well incident investigation that suggested that the crew needed adequate training to recognize sign of these incidents. Also it was obvious that the failure of crew in The Snorre A (2004) field, one of the Norwegian continental shelf events to establish the source of leakage and reasons for alarms to sound which enabled gas to flow to the platform was shortage of enough knowledge and training. National commission investigation on Macondo well incident suggested that the crew needed enough training, so upgrade of technology and training regularly is very crucial. According to (The Snorre A blow-out (2004)) reports, It had taken the crew about 2 hours and 6 minute from the first gas alarm sounded until they were in a position to confirm that a blowout was about to happen. This means the techniques and sensors or operators failed to pinpoint the location of leakage accurately, and therefore leakage of gas continued until when the blowout occurred.

Outflow of fluid during production. According to the objective of this thesis we concentrated on unwanted influx of fluid, but in the process of production the pressure in the wellbore is reduced and wellbore with casing is perforated to allow inflow of fluids (oil or gas) to the wellbore and pumped to the surface. While pumping fluid to surface, sometimes it can overpower available controlling structures/barriers and flows to unwanted areas and hence blowout. So if there is an outflow of fluid during production which leads to blowout, it is not part of unwanted influx. Therefore outflow of fluids during production cannot be termed as unwanted influx.

Improper transfer of information between those elements of the organization seems to have contributed to the lack of transfer of knowledge of geological conditions on the Haltenbanken. This caused the sudden and unexpected pressure change and drilling into gas containing formations which resulted into a blowout. Therefore a proper way of passing information from designers, or section to section or administration to workers on the rig should be emphasized.

7.2 RECOMMENDATION

Apart from the existing methods and equipment to prevent the kick and hence a blowout, they are still insufficient to completely prevent a flow of kick into wellbore. So I would recommend improvement of methods based on their weaknesses as identified earlier in this thesis. From time to time technological improvement and changing in the way of practice has been helping to reduce the frequency of blowouts but influxes still occurs.

The development of an advisory program with steps and procedures of every operation will mostly reduce the probability of human errors. Also kick detection methods needs to be extended to other operation such as workover and completion. The technology is still not very sufficient to be relied upon completely, therefore improvement of available equipment and sensors and frequent testing would ensure that none of the technology would dysfunction in time of disasters. I would recommend also the increase in number of switches that would help to control or switch the BOP and they should be kept away from areas where they can be reached by fire easily during disasters.

In case of over working to reduce cost, this should be addressed carefully to ensure workers do not undergo fatigue while at work. The system should be developed in such a way that it's not only an operator on the screen that can see abnormality inside wellbore or at well head but also the system should interpret the abnormality and advice on the way forward.

The tests that are supposedly meant to identify the influxes like negative pressure test, should not be stopped just because it costs money but because the results makes sense and help to prevent the kick just in case it occurs. Training is also crucial to working crew and frequent update on technology changes and advancement. Also regulators should enhance supervision on different tests conducted on integrity of wellbore or seeing if sensors and barriers works perfectly.

Alarms tends to sound without any threat or danger sometimes. Instead of ignoring any alarm thinking that it is technological or system fault cannot be accepted. It is better to act even in false alarm rather than ignoring the alarm that indicates the danger. I would recommend every alarm to be handled with seriousness even if it doesn't reveal any influx or threat.

8. APPENDIX

Table 2:Different blowouts around the world (Wikipedia contributors, 2017)

Year	Rig Name	Rig Owner	Type	Damage / details
1955	S-44	Chevron Corporation	Sub Recessed pontoons	Blowout and fire. Returned to service.
1959	C. T. Thornton	Reading & Bates	Jackup	Blowout and fire damage.
1964	C. P. Baker	Reading & Bates	Drill barge	Blowout in Gulf of Mexico, vessel capsized, 22 killed.
1965	Trion	Royal Dutch Shell	Jackup	Destroyed by blowout.
1965	Paguro	SNAM	Jackup	Destroyed by blowout and fire.
1968	Little Bob	Coral	Jackup	Blowout and fire, killed 7.
1969	Wodeco III	Floor drilling	Drilling barge	Blowout
1969	Sedco 135G	Sedco Inc	Semi-submersible	Blowout damage
1969	Rimrick Tidelands	ODECO	Submersible	Blowout in Gulf of Mexico
1970	Stormdrill III	Storm Drilling	Jackup	Blowout and fire damage.
1970	Discoverer III	Offshore Co.	Drillship	Blowout (S. China Seas)
1971	Big John	Atwood Oceanics	Drill barge	Blowout and fire.
1971	Wodeco II	Floor Drilling	Drill barge	Blowout and fire off Peru, 7 killed.
1972	J. Storm II	Marine Drilling Co.	Jackup	Blowout in Gulf of Mexico
1972	M. G. Hulme	Reading & Bates	Jackup	Blowout and capsize in Java Sea.
1972	Rig 20	Transworld Drilling	Jackup	Blowout in Gulf of Martaban.
1973	Mariner I	Sante Fe Drilling	Semi-sub	Blowout off Trinidad, 3 killed.
1975	Mariner II	Sante Fe	Semi-	Lost BOP during blowout.

		Drilling	submersible	
1975	J. Storm II	Marine Drilling Co.	Jackup	Blowout in Gulf of Mexico.
1976	Petrobras III	Petrobras	Jackup	No info.
1976	W. D. Kent	Reading & Bates	Jackup	Damage while drilling relief well.
1977	Maersk Explorer	Maersk Drilling	Jackup	Blowout and fire in North Sea
1977	Ekofisk Bravo	Phillips Petroleum	Platform	Blowout during well workover.
1978	Scan Bay	Scan Drilling	Jackup	Blowout and fire in the Persion Gulf.
1979	Salenergy II	Salen Offshore	Jackup	Blowout in Gulf of Mexico
1979	Sedco 135F	Sedco Drilling	Semi-submersible	Blowout and fire in Bay of Campeche Ixtoc I well.
1980	Sedco 135G	Sedco Drilling	Semi-submersible	Blowout and fire of Nigeria.
1980	Discoverer 534	Offshore Co.	Drillship	Gas escape caught fire.
1980	Ron Tappmeyer	Reading & Bates	Jackup	Blowout in Persian Gulf, 5 killed.
1980	Nanhai II	Peoples Republic of China	Jackup	Blowout of Hainan Island.]
1980	Maersk Endurer	Maersk Drilling	Jackup	Blowout in Red Sea, 2 killed.
1980	Ocean King	ODECO	Jackup	Blowout and fire in Gulf of Mexico, 5 killed.
1980	Marlin 14	Marlin Drilling	Jackup	Blowout in Gulf of Mexico.
1981	Penrod 50	Penrod Drilling	Submersible	Blowout and fire in Gulf of Mexico.
1985	West	Smedvig	Semi-	Shallow gas blowout and fire in

	Vanguard		submersible	Norwegian sea, 1 fatality.
1981	Petromar V	Petromar	Drillship	Gas blowout and capsize in S. China seas.
1983	Bull Run	Atwood Oceanics	Tender	Oil and gas blowout Dubai, 3 fatalities.
1988	Ocean Odyssey	Diamond Offshore Drilling	Semi-submersible	Gas blowout at BOP and fire in the UK North Sea, 1 killed.
1988	PCE-1	Petrobras	Jackup	Blowout at Petrobras PCE-1 (Brazil) in April 24. Fire burned for 31 days. No fatalities.
1989	Al Baz	Sante Fe	Jackup	Shallow gas blowout and fire in Nigeria, 5 killed.
1993	M. Naqib Khalid	Naqib Co.	Naqib Drilling	fire and explosion. Returned to service.
1993	Actinia	Transocean	Semi-submersible	Sub-sea blowout in Vietnam. .
2001	Ensco 51	Ensco	Jackup	Gas blowout and fire, Gulf of Mexico, no casualties
2002	Arabdrill 19	Arabian Drilling Co.	Jackup	Structural collapse, blowout, fire and sinking.
2004	Adriatic IV	Global Sante Fe	Jackup	Blowout and fire at Temsah platform, Mediterranean Sea
2007	Usumacinta	PEMEX	Jackup	Storm forced rig to move, causing well blowout on Kab 101 platform, 22 killed.
2009	West Atlas / Montara	Seadrill	Jackup / Platform	Blowout and fire on rig and platform in Australia.
2010	Deepwater Horizon	Transocean	Semi-submersible	Blowout and fire on the rig, subsea well blowout, killed 11 in explosion.
2010	Vermilion	Mariner Energy	Platform	Blowout and fire, 13 survivors, 1

	Block 380			injured.
2012	KS Endeavour	KS Energy Services	Jack-Up	Blowout and fire on the rig, collapsed, killed 2 in explosion.

Table 3:Blowout date, and operation that was going on during blowout and amount of spilled product (Frank G, 2014)

#	Blowout date	Water depth	Well type*	Duration (days)	Operation	Spillage (bbl)	Product spilled	OCS Region
26	18-Sep-80	105	D	4	PR	1	Crude Oil	GOM
27	12-Jan-81	36	E	1	DR	0.09	Condensate	GOM
28	27-Feb-81	48	D	1	WO	0.09	Crude Oil	GOM
29	26-Jul-81	48	D	6	CO	0.09	Crude Oil	GOM
30	19-Oct-81	44	D	1	CO	0.09	Crude Oil	GOM
31	28-Nov-81	340	D	1	WO	64	Crude Oil	GOM
32	7-Feb-82	141	D	0.5	WO	0.09	Crude Oil	GOM
33	14-Jul-82	38	D	57	WO	0.09	Crude Oil	GOM
34	20-Jul-83	68	E	1	DR	2	Crude Oil	GOM
35	23-Feb-85	190	D	0.33	WO	50	Crude Oil	GOM
36	20-Mar-87	126	D	3	CO	60	Condensate	GOM
37	6-Sep-87	104	D	1	WO	1	unknown	GOM
38	9-Apr-88	48	D	0.08	PR	4.5	Crude Oil	GOM
39	9-Sep-90	214	D	4	WO	8	Condensate	GOM
40	9-Oct-90	186	D	0.04	WO	0.5	Crude Oil	GOM
41	11-Nov-91	80	E	1	DR	0.8	Condensate	GOM
42	26-Dec-92	186	E	3	DR	100	Condensate	GOM
43	22-Feb-98	87	D		PR	1.1	Crude Oil	GOM
44	8-Jul-98	51	D	22	PR	1.5	Condensate	GOM

KEY TO THE TABLE

Well type	
E	Exploration

D	Drilling

Operation (what letters stands for)
E = Exploration
CO = Completion
D = Development
PR = Production
PRH = Production – Hurricane
SIH = Shut-In – Hurricane
TA = Temporary Abandonment or Leaking TA
WO = Workover
PA = Permanent Abandonment or Leaking PA
DR = Drilling

Table 4:Sample of data used in modelling of rate of penetration

DMEA(m)	ROP(m/h)	RPMA(rpm)	RPMB(rpm)	RSD(N/A)	TRQ(kN.m)	TVA(N/A)	WHP(N/A)	WOB(tonne)
2369.2	16.67	-999.25	132.26	0.01	13.81	49.13	6.53	5.97
2369.3	16.67	-999.25	132.15	0	13.8	49.12	6.56	6.07
2369.3	16.67	-999.25	132.28	0.01	14.2	49.07	6.58	6.02
2369.3	16.67	-999.25	132.09	0	13.87	49.13	6.65	5.94
2369.3	16.67	-999.25	132.02	0.01	14.34	49.15	6.63	5.96
2369.3	16.67	-999.25	132.2	0	14.57	49.2	6.56	6.04
2369.3	16.67	-999.25	132.18	0	14.11	49.22	6.56	5.96
2369.3	16.67	-999.25	132.01	0	14.48	49.21	6.67	5.95
2369.3	16.67	-999.25	132.2	0.02	14.51	49.22	6.68	6.44
2369.3	16.67	-999.25	132.4	0.01	13.44	49.17	6.67	6.66
2369.3	16.67	-999.25	132.15	0.01	13.82	49.15	6.52	6.11
2369.3	16.67	-999.25	132.02	0.01	13.24	49.19	6.6	5.26
2369.3	16.67	-999.25	132.01	0	12.73	49.23	6.61	4.63
2369.3	16.67	-999.25	132	0	13.2	49.16	6.64	4.15
2369.3	16.67	-999.25	132.19	0	13.17	49.06	6.5	3.6
2369.3	16.67	-999.25	132.24	0.02	13.68	49.03	6.53	2.51
2369.3	16.67	-999.25	132.03	0.01	13.66	49.02	6.52	2.47
2369.3	16.67	-999.25	132.09	0.01	13.65	49.13	6.52	3.07
2369.4	16.67	-999.25	132.14	0	14.02	49.18	6.61	3.56
2369.4	16.67	-999.25	132.07	0.01	13.81	49.22	6.55	3.94
2369.4	16.67	-999.25	132.06	0.01	13.49	49.21	6.51	4.04
2369.4	16.67	-999.25	132.2	0	13.2	49.15	6.5	4.3
2369.5	16.67	-999.25	132.21	0.01	13.41	49.05	6.53	4.45
2369.5	16.67	-999.25	132.25	0	13.64	49.11	6.55	4.48
2369.5	16.67	-999.25	132.25	0	13.93	49.12	6.59	4.49
2369.5	16.67	-999.25	132.32	0	13.85	49.13	6.64	4.58
2369.6	16.67	-999.25	132.32	0.01	13.58	49.12	6.7	4.66
2369.6	16.67	-999.25	132.27	0.01	13.03	48.96	6.64	4.8
2369.6	16.67	-999.25	132.26	0.01	13.23	48.9	6.6	4.94
2369.6	16.67	-999.25	132.42	0	13.44	48.93	6.5	4.99
2369.6	16.67	-999.25	132.31	0	13.28	49.02	6.53	5.03
2369.7	16.67	-999.25	132.25	0.01	13.68	49.07	6.56	5.09
2369.7	16.67	-999.25	132.35	0	13.56	49.08	6.49	5.12
2369.7	16.67	-999.25	132.26	0	13.06	49.01	6.59	5.2
2369.7	16.67	-999.25	132.14	0	12.73	48.93	6.69	5.21

Table 5: Sample of data used in modelling the probability of kick in relation to depth

Volume original(litres)	V-remained(litres)	TVD1(m)
25000	22000	2369.2
25000	21950	2369.3
25000	21900	2369.3
25000	21850	2369.3
25000	21800	2369.3
25000	21750	2369.3
25000	21700	2369.3
25000	21650	2369.3
25000	21600	2369.3
25000	21550	2369.3
25000	21500	2369.3
25000	21450	2369.3
25000	21400	2369.3
25000	21350	2369.3
25000	21300	2369.3
25000	21250	2369.3
25000	21200	2369.3
25000	21150	2369.3
25000	21100	2369.4
25000	21050	2369.4
25000	21000	2369.4
25000	20950	2369.4
25000	20900	2369.5
25000	20850	2369.5
25000	20800	2369.5
25000	20750	2369.5
25000	20700	2369.6
25000	20650	2369.6
25000	20600	2369.6
25000	20550	2369.6
25000	20500	2369.6
25000	20450	2369.7
25000	20400	2369.7
25000	20350	2369.7
25000	20300	2369.7
25000	20250	2369.8
25000	20200	2369.8
25000	20150	2369.8
25000	20100	2369.8
25000	20050	2369.8
25000	20000	2369.8
25000	19950	2369.9
25000	19900	2369.9
25000	19850	2369.9
25000	19800	2369.9
25000	19750	2369.9
25000	19700	2370
25000	19650	2370
25000	19600	2370

Definition of Parameters for rate of penetration

```
load('lindidata.mat')
%      K1=78                  %drillability    constant    for    limestone
K=69                         %drillability    constant    for    sandstone
%                                                                      RPM=
%                                                                      WOB=
d_bit=17.5*2.54/100
%                                                                      d=0.5
%                                                                      d=1
 d=1.5
%                                                                      d=2
m=length                                                               (RPM)
ROP1=zeros                                                             (m,1);
MD1=zeros(m,1);
MD1=MD/1000;
%                                    plot                         (MD1,ROP)
 for                                                                 k=1:m
   ROP1(k)=(K)*(RPM(k)/60)*((WOB(k)/d_bit))^d;
 end
%                                         plot                    (ROP1,MD)
%                                    plot                         (MD,ROP1)
%                                         hold                           on
%                            plot                                  (MD,ROP)
plot                          (ROP,                                     MD)
 xlabel('Rate            of           penetration          (m/h)','color','m')
 ylabel('Measured                    depth                   (m)','color','m')
 title ( 'MODEL OF RATE OF PENETRAION FOR WELL 47-12-25')
```

Definition of Parameters for volume increase

```
load('lindifour')
%       K1=78                 %drillability    constant    for    limestone
r1=5*2.54/100
r2=5.5*2.54/100
r3=17.5*2.54/100
A_pipe = pi* r1^2
A_pipeouter = pi* r2^2
A_bit = pi* r3^2
m=length (TVD)
V_influx=zeros (m,1);
% MD1=zeros(m,1);
% MD1=MD/1000;
% plot (MD1,ROP)
 for k=1:m
% ROP1(k)=(K/1000)*(RPM(k)/60)*((WOB(k)/d_bit))^d;
  V_influx(k) = V_total(k)-(V_remained(k) + (A_pipe+ A_bit- A_pipeouter)* TVD1(k));
 end
plot ( V_influx,TVD1)
% plot (TVD1,V_influx)
 xlabel('Volume of influx (m cubic)','color','m')
 ylabel('True vertical distance (TVD) (m)','color','m')
 title ( 'MODEL FOR VOLUME INCREASE IN THE WELL 47-12-25')
```

r1 = 0.1270

r2 = 0.1397

r3 = 0.4445

A_pipe =0.0507

A_pipeouter = 0.0613

A_bit =0.6207

m =311

Table 6: Frequency of blowouts per 10 years

Year	Number of blowouts per 10 years
1955-1965	5
1966-1976	16
1977-1987	16
1988-1998	5
1999-20012	8

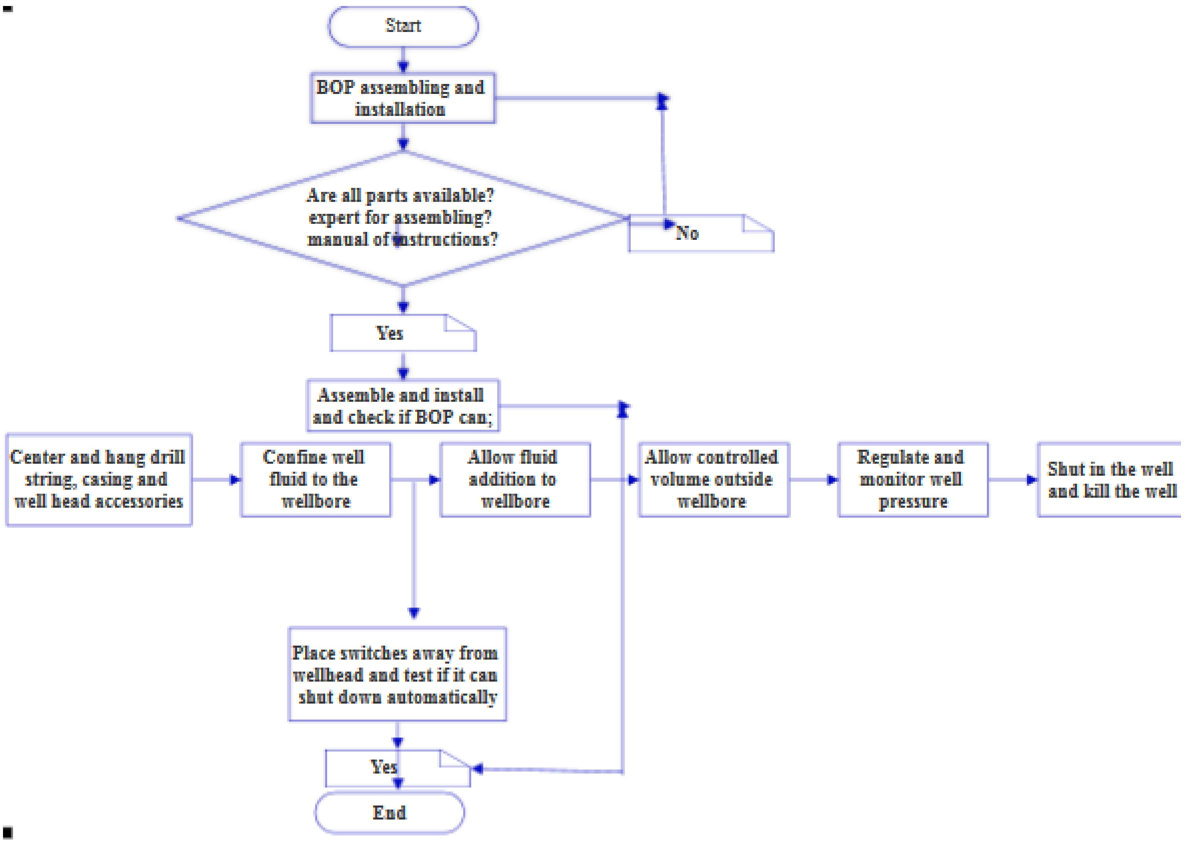

Figure 27: BOP illustration of advisory program

9. REFERENCES

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