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I would like to dedicate this thesis to my mother, I know I don't tell her often but I really love her and admire her so much.

Abstract

Macondo blowout also known as the Deep Water Horizon incident has been one of the biggest oil field disaster in history. It has also become an effective case study for the Health Safety and Environmental aspects of the Petroleum Industry.

This thesis deals by exhaustively comparing the GAP between the Macondo blowout with the regulations, recommended practices, guidelines, Industry standards and codes that existed prior to the blowout (Pre-Macondo) and what was actually implemented in case of deep water horizon as well as analyzing it with the current Norwegian / International Standards and codes (Post-Macondo).

To understand the GAP analysis, it is necessary to understand the background of the Macondo incident so that the reader could understand the discrepancies between Pre-Macondo and Post-Macondo more fully, therefore this thesis starts by exhaustively performing a review of literature on the series of events that led to the Macondo blowout, safety systems that were employed at Deepwater Horizon followed by the GAP analysis which forms the basis for the discussion and conclusion at the end.

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I. Introduction

In 2010, a major well blow out incident occurred on the Deepwater Horizon Drilling rig. The incident happened on Macondo well located in Canyon Block 252, Mississippi offshore. This thesis investigated and analyzed the GAPs between the BP design and well established regulations/standards and codes.

I.1 Scope and limitations

The Macondo blowout incident happened following a series of events which led to formation fluids entering the wellbore undetected and on April 20th the blowout occurred. The blow out was followed by the Deepwater horizon (the rig) sinking to the sea floor and hydrocarbon started flowing directly in to the sea to cause the biggest environmental disaster. It lasted for 87 days while leaking vast amount of hydrocarbons and causing huge oil spill as well as damaging fauna and flora. The environmental impact of the blowout in the Gulf of Mexico is still being discussed and researched, the incident also traumatized the livelihood of many people.

Therefore covering every aspect of the Macondo blowout is out of scope in this thesis. The GAP Analysis is performed based on a) the events leading to the blowout and b) their causes and effects. The aftermath of the blowout is out of scope in this master thesis. In the industry, GAP Analysis is an effective and cost efficient tool to identify key components, processes or procedures that need immediate attention or improvement. They are mainly used as a benchmark prior to maintenance activities, recertification or upgrading of existing system or part of a system. It is usually performed for every item (section) of given recommended practice/ standard and codes.

The Macondo blowout incident concerns many number of standard & codes, guidelines etc. Therefore showing the technical gaps of every item is vast and would not fit in the limitations of a master thesis. Therefore after examining all the relevant standards and codes, guidelines, recommended practices only the items /sections that are of major w.r.t. the Macondo blowout incident have been documented in this thesis.

I.2 Background

On April 20, 2010, a mile beneath the ocean disaster struck following a series of events in the world's biggest blowout, unfortunately eleven people perished and also several others were greatly injured in the initial explosion. Thirty six hours later the fire and explosion on the rig caused the rig to sink to the sea floor, hydrocarbons from the reservoir continued to flow in to the ocean. The release of hydrocarbons lasted for 87 days following the blowout.

In March 2008, British Petroleum (BP) had received exclusive rights to drill Mississippi Canyon Block 252 for over 34$ million from the Minerals Management Service (MMS), Block 252 is a nine square mile plot in the Gulf of Mexico. Initially BP had planned to drill the well to a target depth of 20200 feet and the well was originally proposed to be an exploratory well and to be transformed to a production well if found viable[1].

The Macondo well gave BP numerous challenges from the start and posed an array of risks including high pore pressures, lost circulation events, selection of long string production casing versus liner tie back, choice and selection of centralizers and the risk of channelling during cementing, cement slurry design, well testing, temporary abandonment sequences.[1]

The Macondo blowout was caused due to the well integrity failures which led to the loss of hydrostatic pressure on the well. The crucial failure of the BOP failing to shut the well in case of emergency ultimately caused gas to expand in the riser and form large gas cloud on the rig. This was followed by the initial explosion, resulting in unimaginable and traumatizing loss of life/injuries and one of the biggest environmental disaster in the world.

I.3 Purpose

The Macondo blowout is one of the worst disaster in the oil and gas industry history, causing human causalities and environmental pollution of great magnitude. Over the years, it has been a case study for HSE, maintenance and inspection.

This thesis involves the GAP Analysis between the key findings & the causes of the Macondo blowout and their prescribed Recommended Practices, Guidelines, Standards and Codes. The tasks involve an exhaustive literature study on the various causes and effects of the Macondo blowout incident and mapping them on to the respective standards & codes and analyzing the possible GAP between them.

The main purposes of this thesis are as follows:

1. Why did Macondo happen?
2. What were the contributing events that led to the blowout?
3. Standards and codes are used to give the operators and services companies, the minimum requirement that they should follow, did the companies follow the minimum standards? If yes, then were the minimum standards and codes wasn't sufficient or outdated or does it need change?
4. What are technical gaps between the operators' / Service Company's recommended practice and what they actually followed?
5. Following the Macondo event, what are the changes that were made to Norwegian standard (NORSOK D-010) to avoid such an event in the NCS?
6. Every operator/service companies have their own recommended practices, when an operation/task is performed. These involved companies now have their own recommended practices, usually the operator has the final say on the direction of the operation, but what are the worst case scenarios?
7. What are the effects when a service company feels that an operator's decision is against its own recommended practices and / or international regulations/guidelines?

I.4 Study Methodology

The following reports form the basis for the thesis:

1. *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling*, *Report to the President* by National Commission on the BP Deepwater Horizon Oil Spill (2011)
2. Final Report on the Investigation of the Macondo Well Blowout' by Deepwater Horizon Study Group (2011)
3. The US Coast Guard (Uscg)/Bureau of Ocean Energy Management, Regulation and Enforcement (Boemre) Joint Investigation Team (Jit) by Deepwater Horizon Incident Joint Investigation (2010)
4. Deepwater Horizon Incident Joint Investigation by BP Incident Investigation Team (2011)

Secondary sources include recommended practices, guidelines, MMS regulations and International Standards and Codes which are referred to in the above reports. Other sources include articles, presentations, reports, websites which have been appropriately referenced as footnotes and/or end note citations along with references section at the end.

II. Literature Review

This chapter presents a brief review on the Macondo well design, which forms the basis for GAP Analysis study.

II.1 Location

The Macondo well is situated in the Mississippi canyon, it is a very vast oil rich area, where other numerous wells have successfully been drilled and produced prior to Macondo well. The Macondo well is situated in the block 252, about 65 km south east of the American state Louisiana, about 23 square km in area, see figure 1.

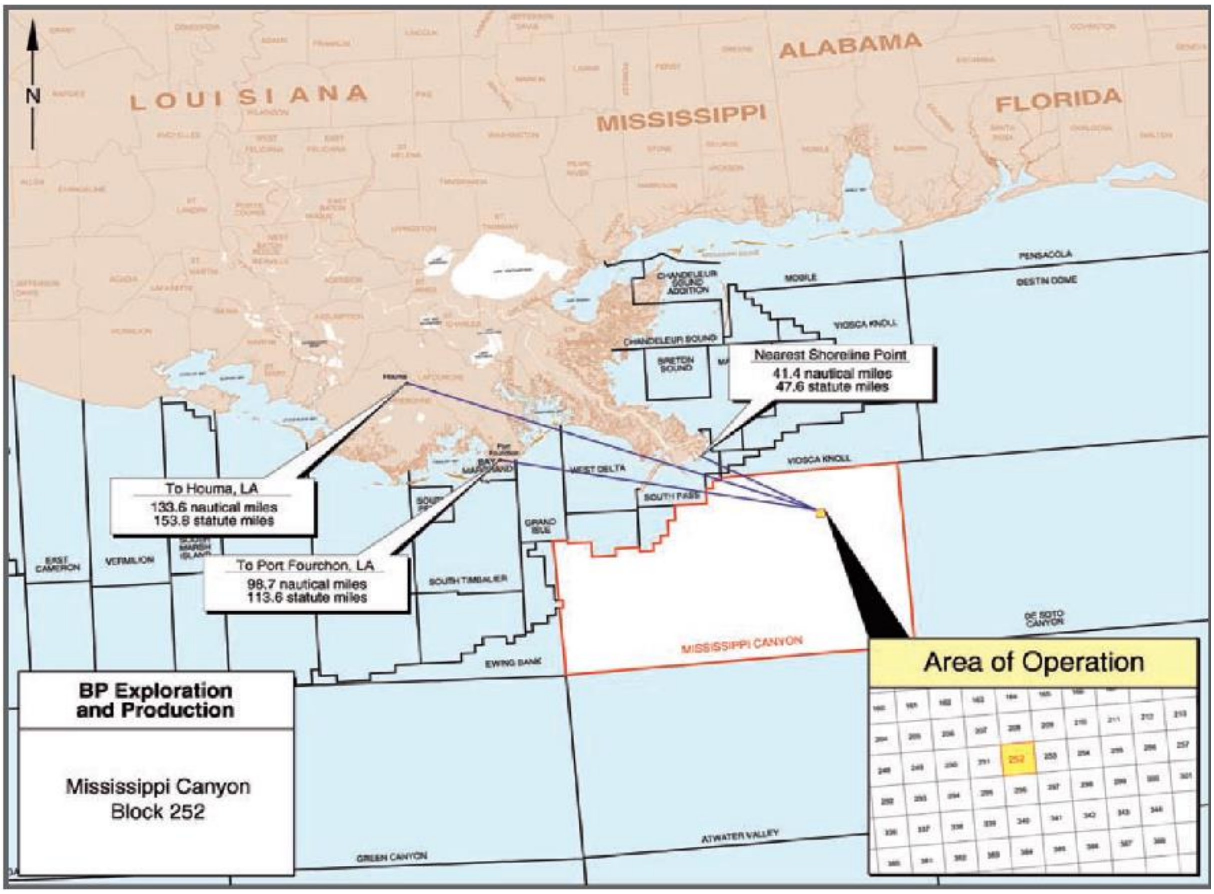

Figure 1-Location of the Macondo Well [1]

[1] BP, Deepwater Horizon Accident Investigation Report, Pg.15

II.2 Deepwater Horizon Arrives

British Petroleum (BP) had been operating the Macondo well situated in the Mississippi Canyon in Block 252, they had contracted Transocean's drill ship called the 'Marianas' for drilling operations, Marianas used an anchoring system with the help of mooring chains.

In October 2009, the drilling of the Macondo well spudded[2] with a water depth of almost 5000ft, the initial estimate of the reservoir was supposed to be 50-100 million barrels of crude. However the engineers had not made the relevant tests to confirm the size of the field or the actual reservoir estimation before the blowout in April 2010[2].

With almost 1$ million/day rig rate, BP had originally planned to complete drilling of the Macondo well in 51 days. In November 2009, the well was drilled up to the depth of 3000ft with the Marianas but following the event of hurricane Ida, the Marianas was damaged, disconnected and taken to shipyard for repairs. In January 2010, the Deepwater horizon from Transocean which was already on contract with BP was called to replace the damaged Marianas and after appropriate approval from the Mineral Management Service (MMS), further drilling continued from 6th February 2010[2].

II.3 Safety System Employed on the Deepwater Horizon:

II.3.1 Blowout preventer

The BOP (Figure 2) is a multi-layered stack of valves used as a drilling tool and as well as an emergency safety equipment typically weighing over hundreds of tons and primarily used to shut-in a well in the event of a well control issue such as kicks or if a sudden increase in wellbore pressures occurs. BOP primarily consisting of the following:

- Annular Preventer- donut shaped rubbed seals around the outside of the pipe sealing the well see figure 3.
- Variable Bore Rams- these are circular metal bars that when initiated seals the annulus of the pipe see figure 4.
- Blind Shear Rams- when initiated these rams cut through the pipe and seals the well bore completely see figure 5.

[2] The starting of drilling operations on a new well, usually referred to the drill bit hittin the seafloor.

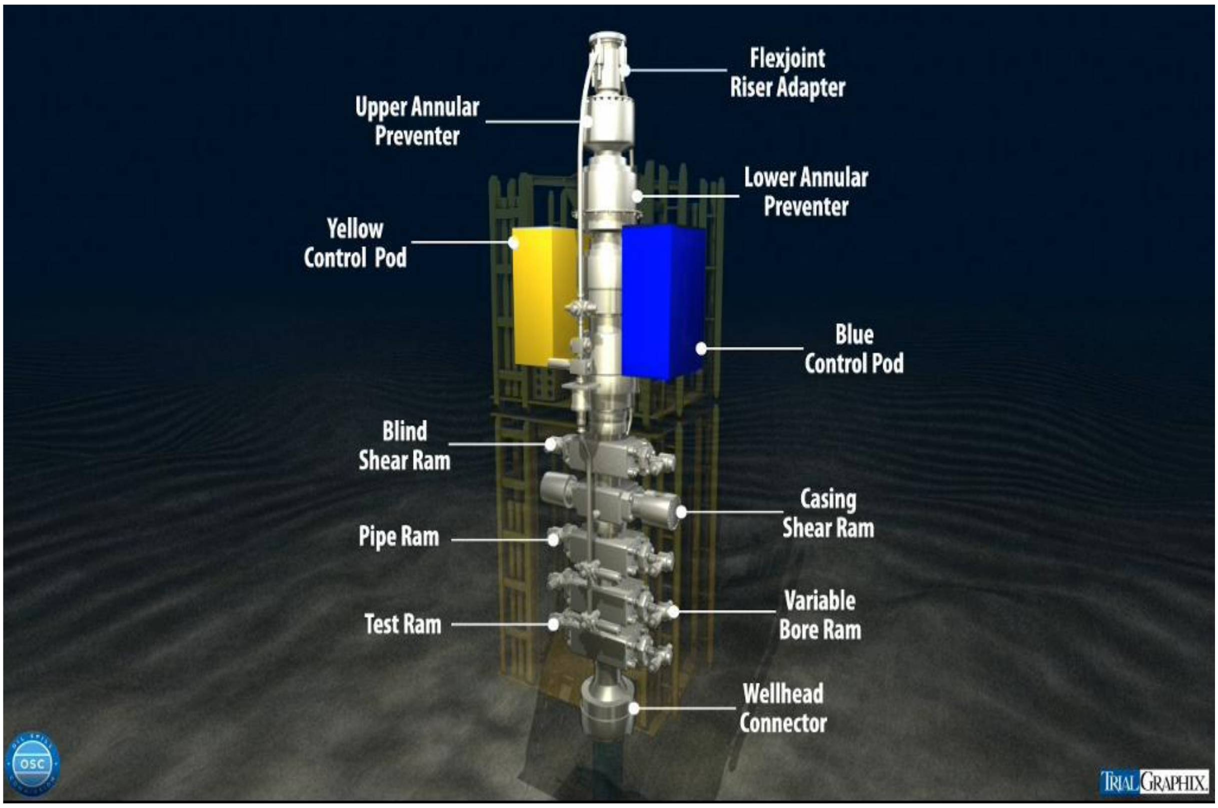

Figure 2-Blowout Preventer[3]

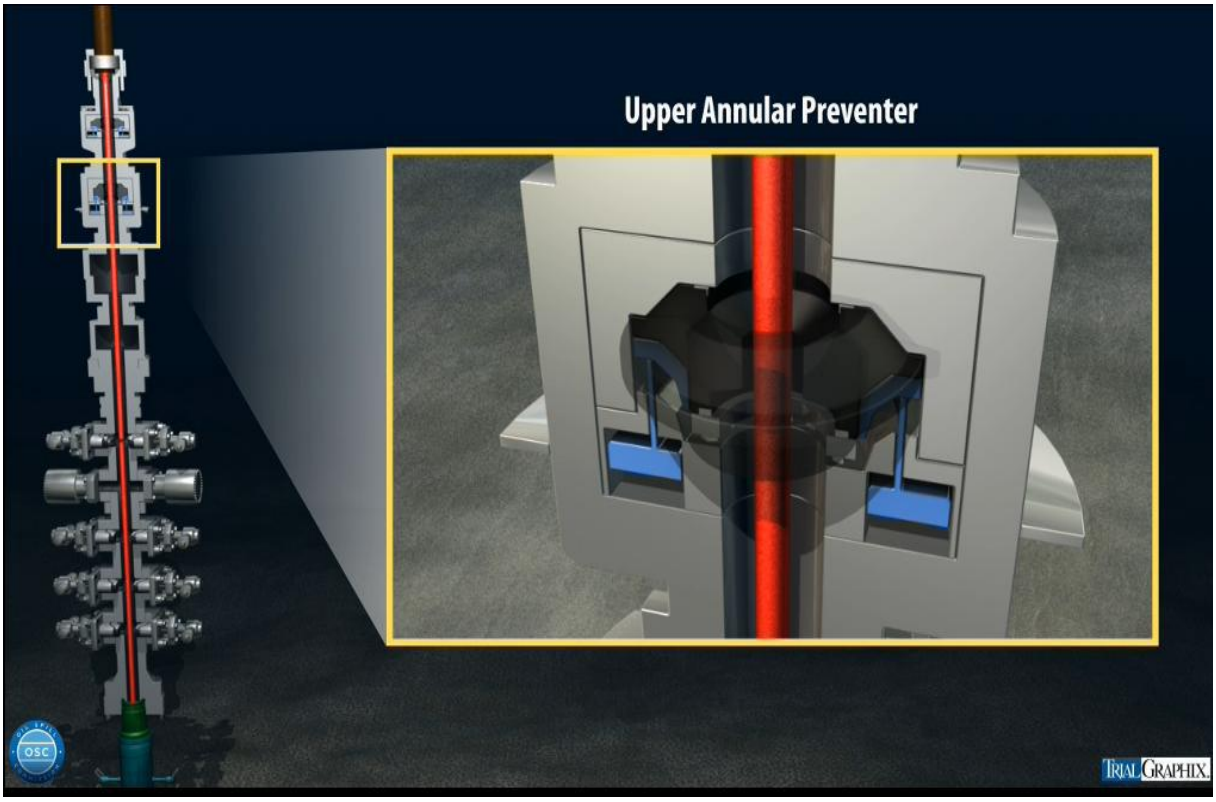

Figure 3-Annular Preventer[4]

[3] Image Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, Op. ct. 24.
[4] Image Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, Op. ct. 24.

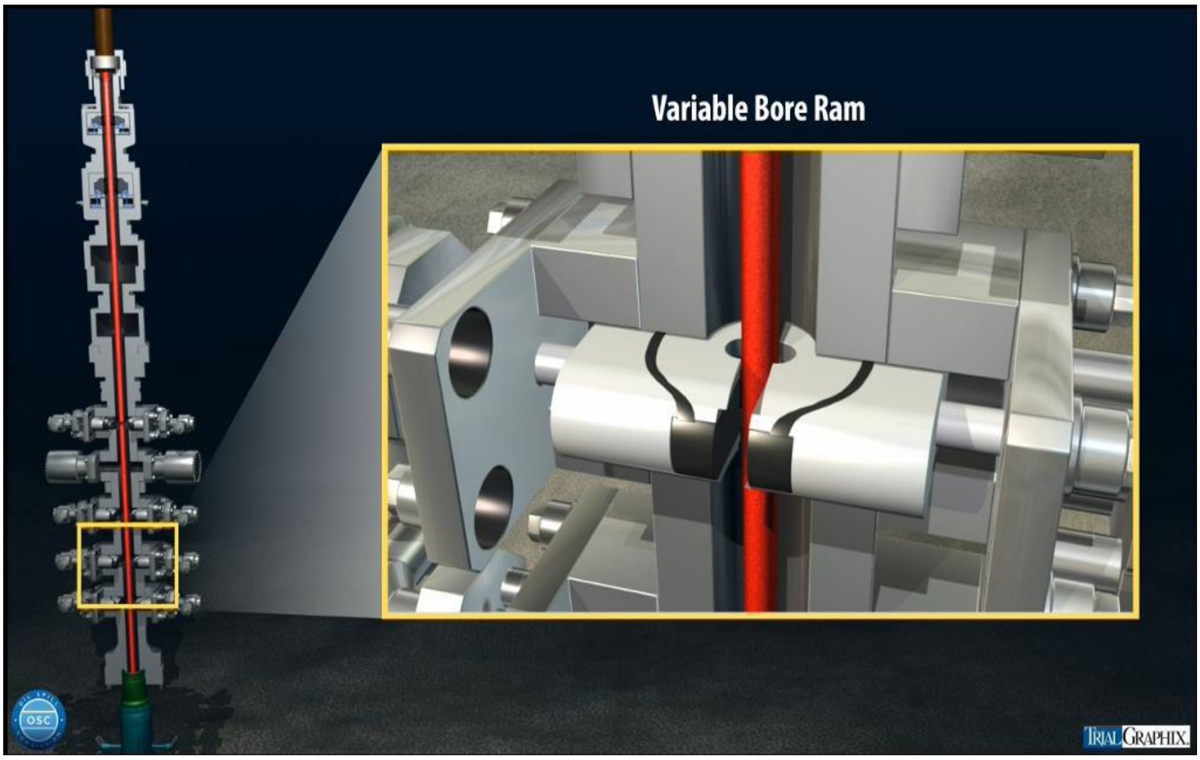

Figure 4-Variable Bore Ram (VSR)[5]

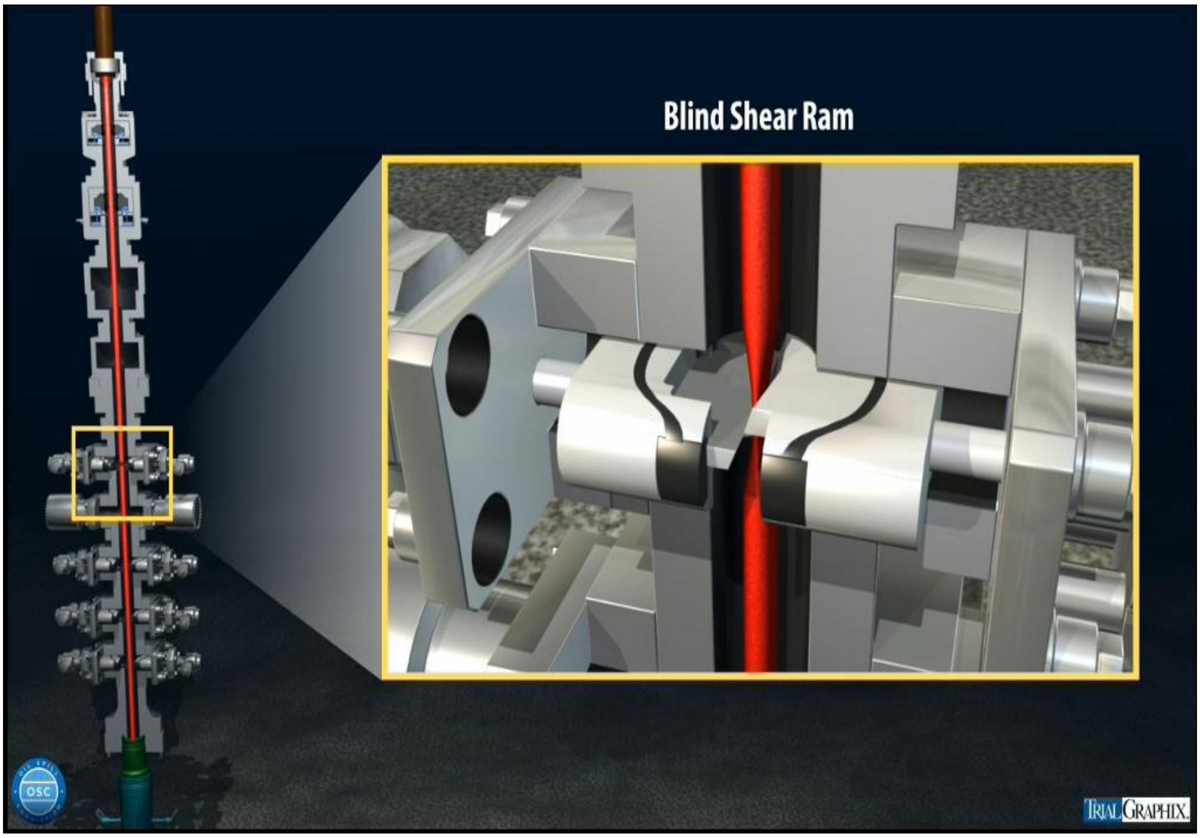

Figure 5-Blind Shear Ram (BSR)[6]

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[5] Image Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, Op. ct. 24.
[6] Image Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, Op. ct. 24.

II.3.2 Emergency Disconnect System (EDS)

In case of emergency, EDS can be activated by pressing on a switch located at any of the following a. driller's control panel b. bridge c. subsea engineer control room. Communication signals are sent through the multiplex umbilical cables (MUX cables) to initiate the BSR to cut the pipe and seal the well. The hydraulic power to initiate the BSR comes from the hydraulic line (conduit) of the accumulator tank[7] situated on the rig. The conduit also supplies hydraulic power to the control pods as well as to the accumulator on the lower BOP stack, see figure 6. Once initiated the BSR would seal the well and disconnect the lower marine riser package from the BOP and disengage the rig from any communication to the subsurface and any possible flow path, w.r.t blowout[3] .

II.3.3 Automatic Mode Function ("Deadman System")

The automatic mode functions (AMF) also called the 'Deadman system' seal the well bore completely in case the BOP loses any kind of communication with the rig i.e. electrical lines, fiber optic communication, and hydraulic line from the rig, see Figure 6. This AMF has two separate control pods (blue and yellow) independent of each other connected to the accumulator bottles mounted on the lower BOP stack, it is capable of delivering around 4000psi (pounds per square inch) to the blind shear rams to cut the pipe inside the BOP and seal the well bore. One of the most critical component of the control pods were the batteries used to deliver the necessary power in case of loss of communication (i.e. electrical power, hydraulic power) through the MUX cables from the rig and secondly the solenoid valves which trigger the delivery of 4000psi closing pressure to the BSR[3, 4].

[7] Accumulator tanks are situated on the surface rig, they are driven by two triplex pumps, these pumps store pressurized fluid and supply then via the hydraulic conduit/line to the accumulator bottles on the lower BOP stack, the accumulator bottle also has hydraulic communication to both the control pods.

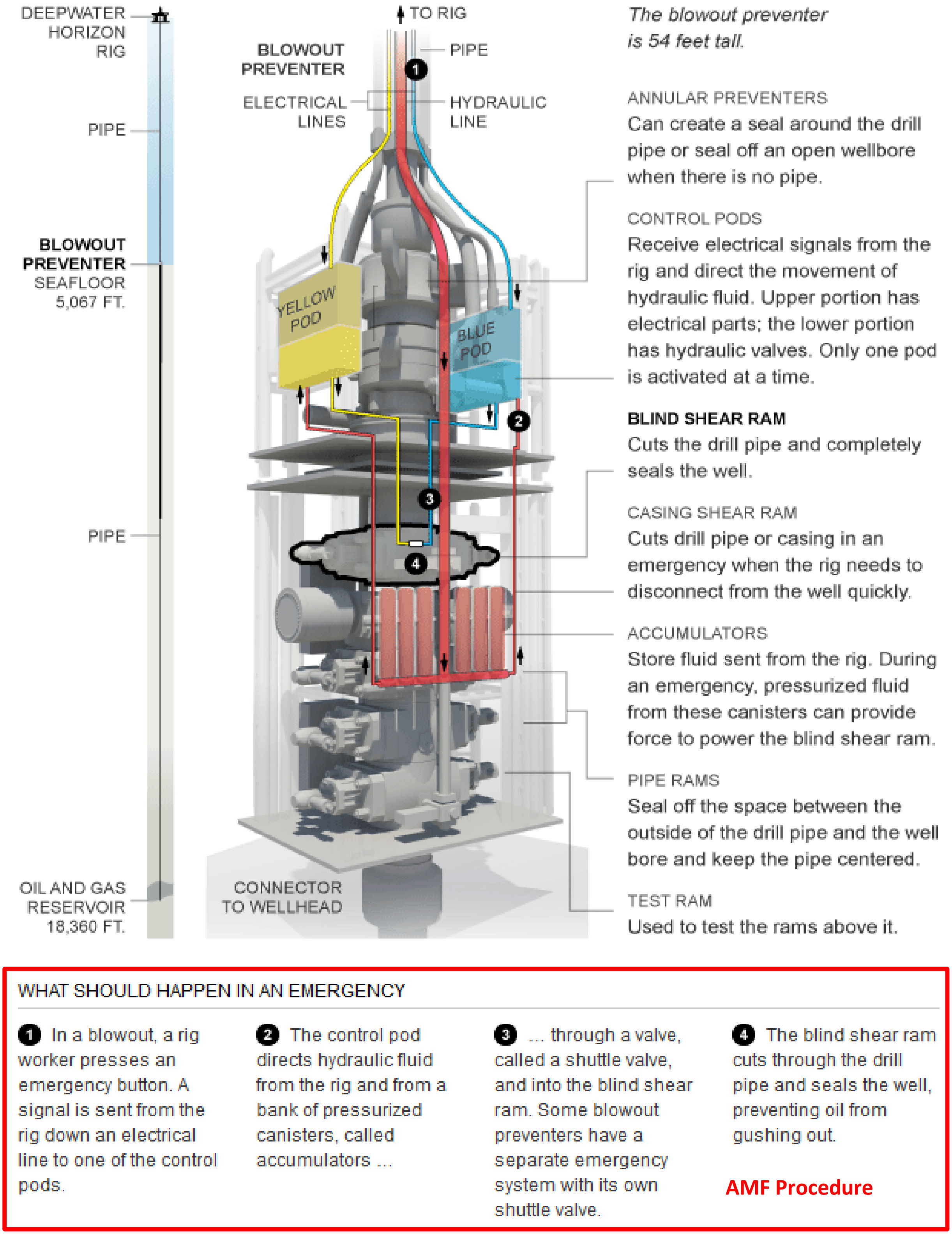

Figure 6-Schematics and purpose of a BOP [8]

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[8] Image Source Investigating the Cause of the Deepwater Horizon Blowout - Interactive Graphic - NYTimes.com, http://www.nytimes.com/interactive/2010/06/21/us/20100621-bop.html [Accessed 27 May 2014]

II.3.4 Diverter System

When large amount of gas kick is seen above the BOP (i.e. in the riser) the gas expands exponentially and when gas expands it also takes a large amount of drilling mud along with it at very high rate. This in effect displaces the heavier drilling mud used to keep the hydrostatic overbalance on the formation. Kick occurrences are common, when they happen it should be safely dealt with. This is done by various methods the drillers are experienced with (i.e. drillers method, wait and weight method etc.). As a last line of defense in case of a kick above the BOP, the diverter system is employed. [5]

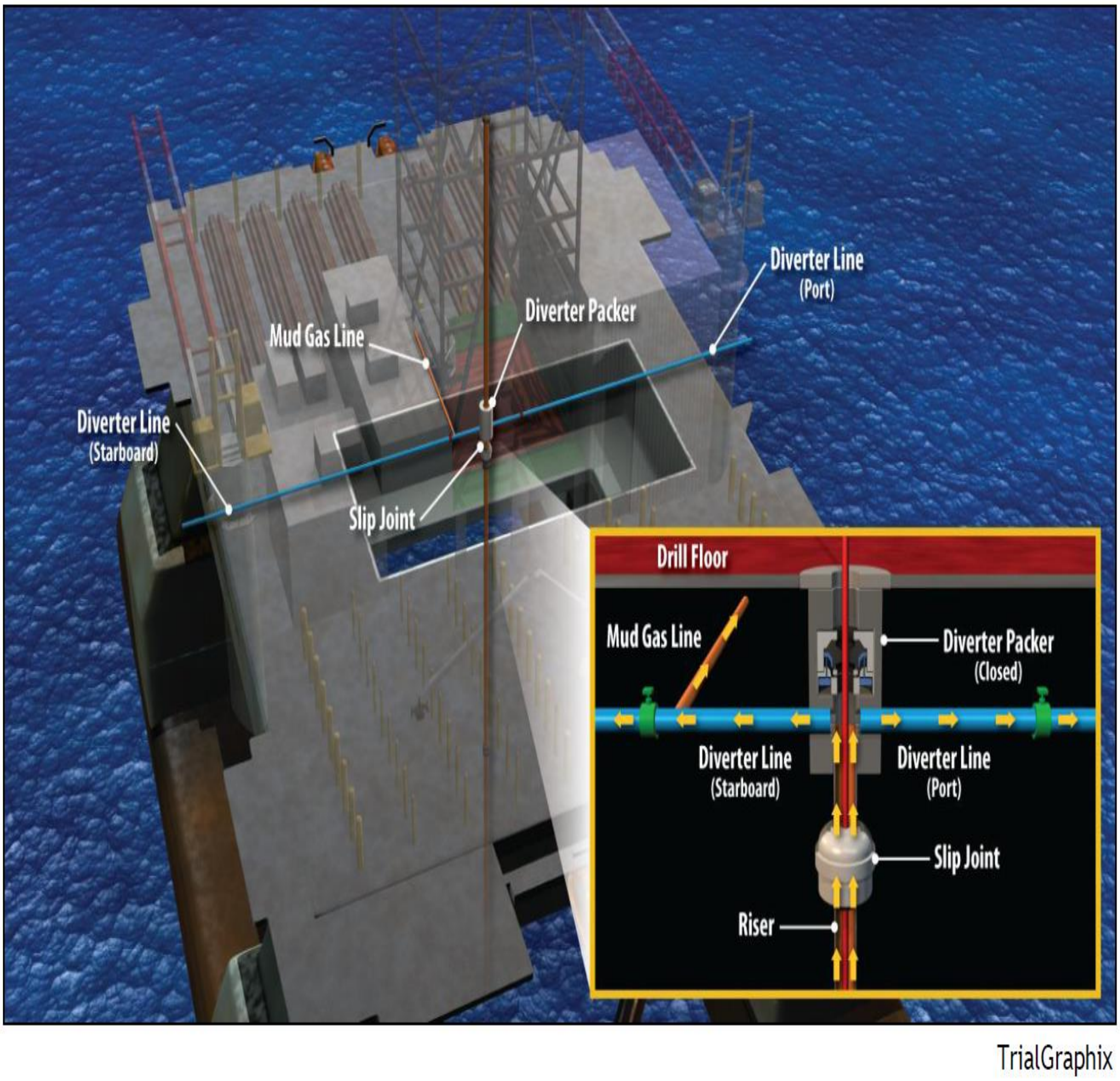

Figure 7-Diverter System[9]

[9] Image Source: National Commission on the BP Deepwater Horizon Oil Spill Offshore Drilling, *Macondo: The Gulf Oil Disaster, Chief Counsel's Report,* 2011, Pg.195

In the Deepwater Horizon, the diverter system had two large 14inch diameter pipes as shown in figure 7, connected to the riser via a slip joint. The two diverter lines (starboard side and port side collectively called as overboard) go to the opposite side of the rig. On the starboard side of the diverter line there is a valve through which MGS system (mud gas separator system) is connected. The MSG system is a collection of valves, pipes, tanks, pits which is used to separate drilling mud and gas from the kick.[5] The maximum working pressure of the MGS system is 15psi, above which a relief line to starboard overboard is opened through a bursting disk of 15psi, see figure 8.

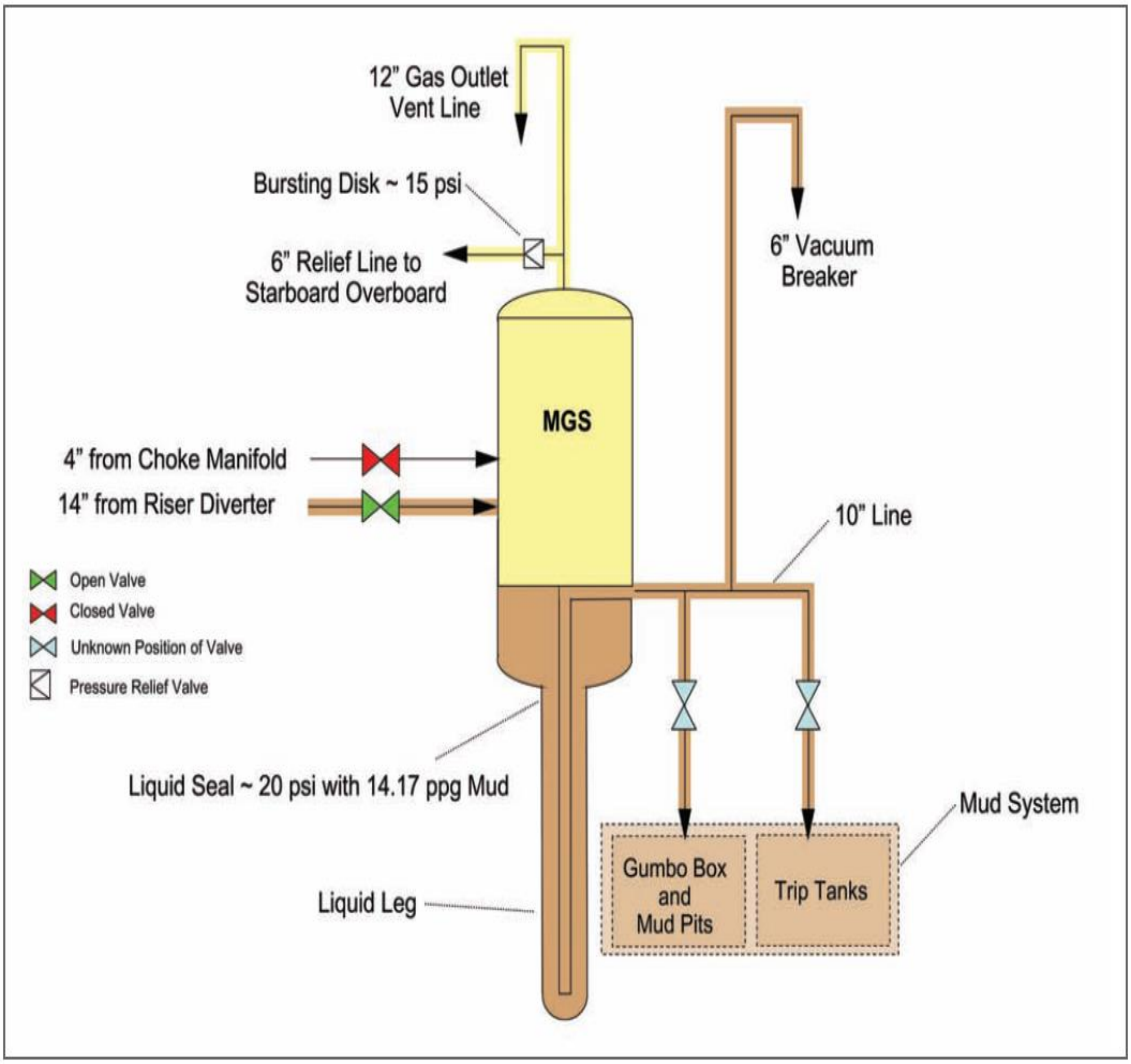

Figure 8-Deepwater Horizon Mud Gas Separator Schematics[10]

[10] Image Source: Deepwater Horizon Study Group, *Final report on the investigation of the Macondo well blowout*, 2011, Pg.69

When there is a kick above the BOP, the drillers basically have two choices, they could either choose to let the kick go overboard or through the MGS system. MGS system is utilized for lower kick size, so that the gas bearing drilling mud can be separated safely. The expensive drilling mud can be reused while the gas is discharged safely through the flaring system on top of the derrick. When the larger kick occurs, the MGS would not be able to handle such large volume of gas bearing mud. In case the MGS is used for large volume of kick, large cloud of flammable gas builds up on the rig and could lead to ignition and explosion, so the kick has to be discharged overboard in to the sea.[5]

In Deepwater horizon, the diverter packer situated on the top of the slip joint just below the rig had around 500psi working pressure. [5]

II.4 Events Leading to the Blowout:

II.4.1 Stuck Pipe

In October 2009 the Macondo well experienced a kick during drilling operations followed by another kick on March 8th 2010 and resulted in a stuck pipe inside the wellbore. All attempts to pull the stuck pipe free failed. They had to side track the well around the stuck pipe to continue drilling. The well also experienced lost returns several times causing considerable delay in schedule and millions of dollar over budget[4].

II.4.2 Lost Circulation Event

Lost circulation is the loss of drilling fluid in to the formation, the drilling mud instead of being circulated up the annulus, flows in to the formation. This could be due to natural fractures in the formation or overbalanced drilling see figure 9.

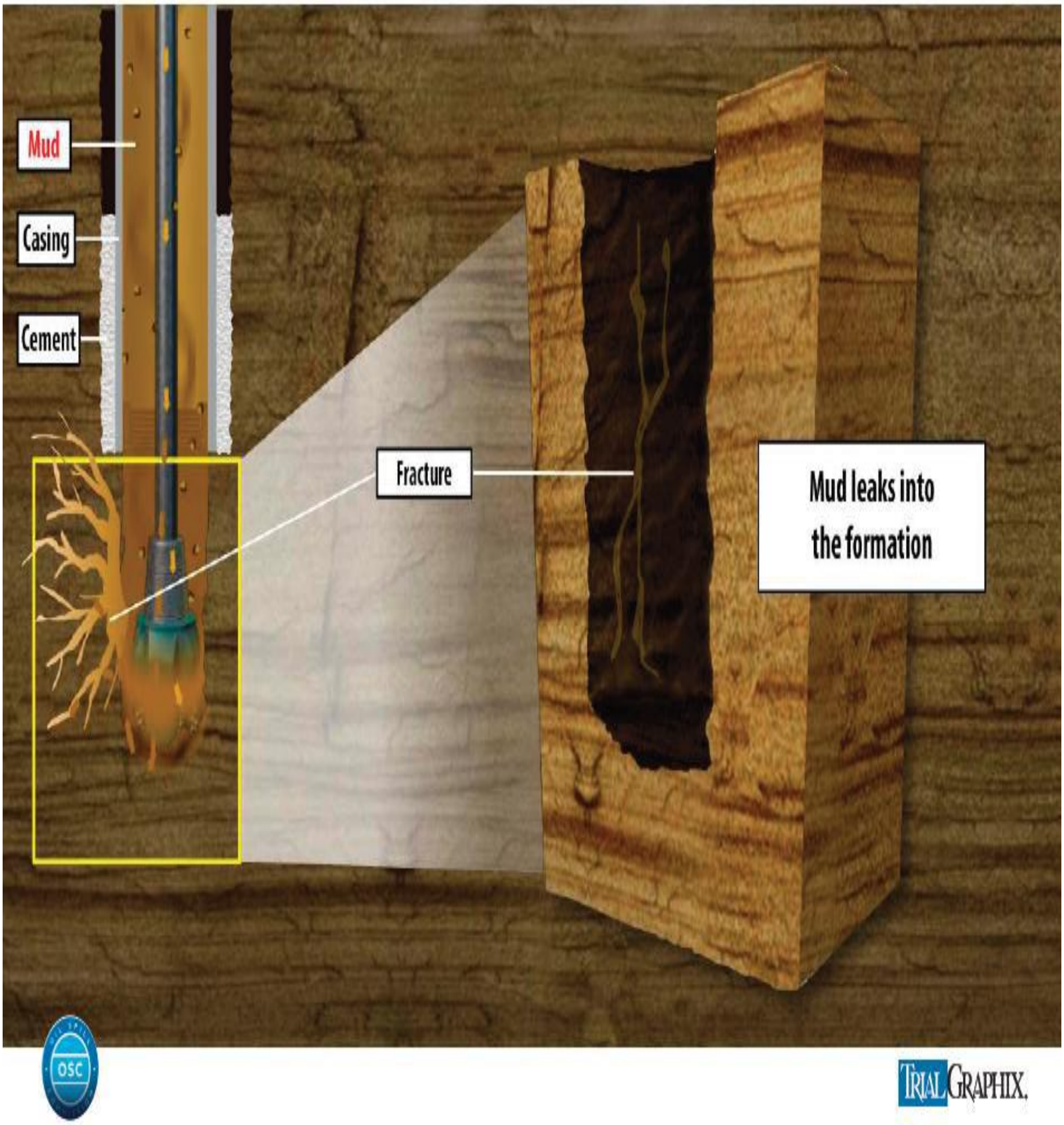

Figure 9-Lost Circulation[11]

[11] Image Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, Op. ct. 24.

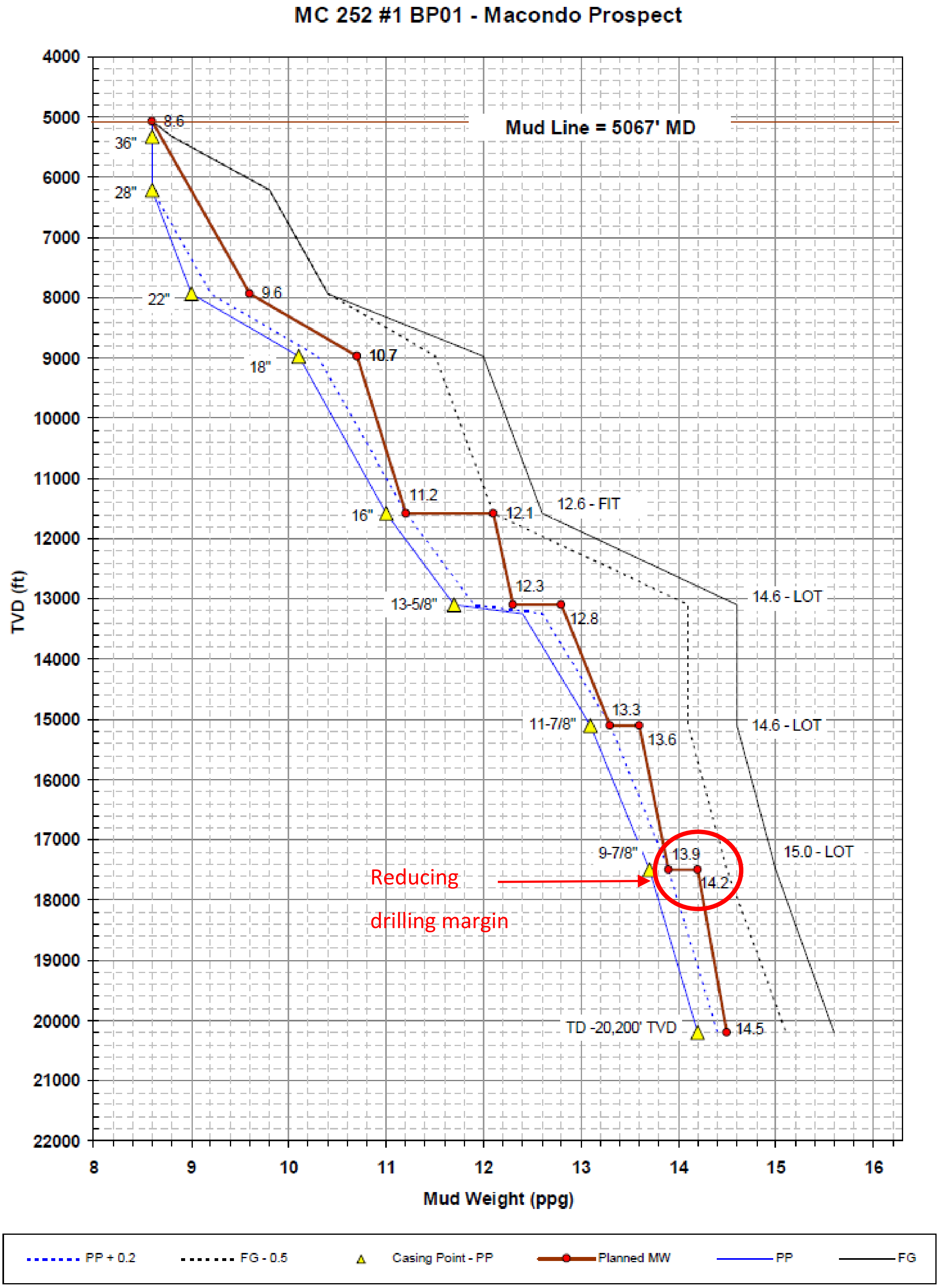

Figure 10-Macondo Well Pore Pressure Fracture Gradient Plot[12]

[12] Source: Investigation, D.H.I.J., *The US Coast Guard (USCG)/Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Joint Investigation Team (JIT).* 2010. Pg.29

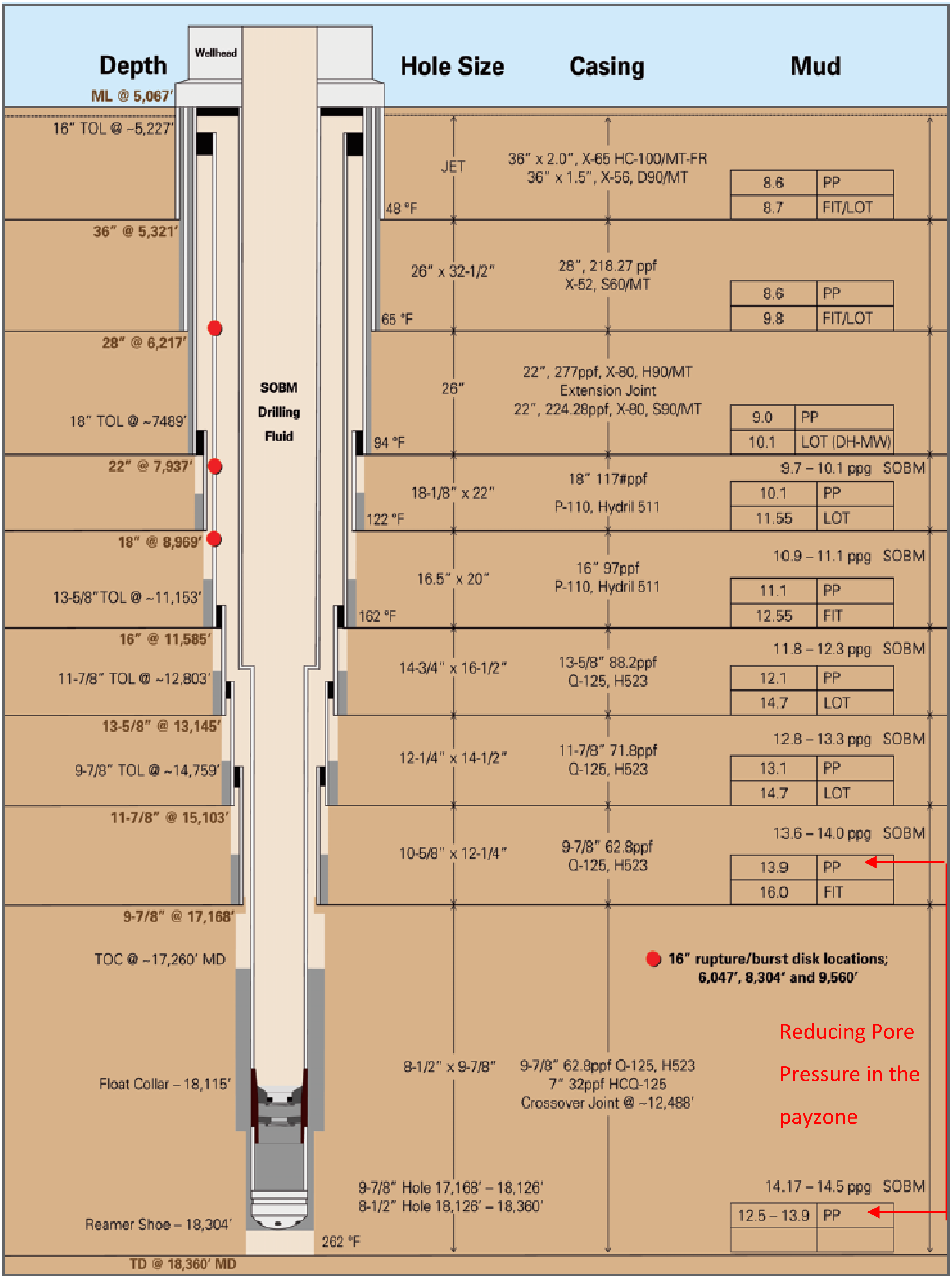

Figure 11-Macondo Well- Actual Casing design and setting depth[13]

[13] Image Source: BP, Deepwater Horizon Accident Investigation Report, Pg.19

According to BOEMRE[14] regulations, drilling mud should typically be at least 0.2 ppg (pounds per gallon) above the pore pressure (pp) of the formation to stop the influx of hydrocarbons in to the well and at least 0.5ppg less than the fracture gradient to stop uncontrolled mud loss in to the formation. As seen on figures 10, 11 from 17000 ft. onwards the drilling margin had become very small for BP and from figure 12 BP had lost up to 4000 barrels of drilling mud (between ~17000 feet and ~18000 feet) in to the formation. Therefore this limited the total well depth to 18360 ft. less than the originally planned 20200 ft. This also led BP to change the well casing program.

Open Hole Interval below 9 7/8-in Liner @ 17,168 - FIT 15.98 PP 13.9						
Date	Depth	MW	Losses	PP	Remarks	Hydrocarbon Zones
2-Apr	17,007 - 17,321	14.3			17,168 FIT 16.22 PPG	17,684 - 17,693 M-57C 14.1 PPG
3-Apr	17,321 - 17,835	14.5	233 bbls		17,723 - GeoTap 14.15 ppg (PP)	17,786 - 17,791 M-56A 13.1 PPG
3-Apr	17,835 - 17,909	14.3				
4-Apr	17,909 - 18,195	14.3		12.58 @ 18,089	Schematic - 12.6 ppg at 18,066	18,061 - 18,223 M-56E 12.6 PPG
4-Apr	18,215 - 18,250	14.4	639 bbls		Lost full returns	
5-Apr	18,260	14.0	1263 - Total			
6-Apr		14.0	1586 - Total			
7-Apr		14.0				
8-Apr		14.0				
9-Apr	18,360	14.0			called TD	

Reducing Pore Pressure from 14.1 ppg to 12.6 ppg and the mud weight used to drill as well as the losses which occured

Figure 12-Drilling margin and Lost circulation data[15]

The drilling company Transocean dealt with the lost circulation by pumping down the kill pills (circulation control pills) and controlled the incident. This incident played a pivotal role in shaping the direction of BP and the service companies' w.r.t operations and incidents that followed.

[14] On October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS), was replaced by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of a major reorganization. http://www.boemre.gov/ [Accessed 24 May 2014]
[15] Investigation, D.H.I.J., *The US Coast Guard (USCG)/Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Joint Investigation Team (JIT).* 2010. Pg.29

II.4.3 Revised total depth and choice of casing string

Following the lost circulation events described above, BP and Transocean controlled the mud loss by LCM pills and decided to install the 9 7/8'' casing at 17168' from the original 19650', see figure 14. BP continued to drill the open hole section for the production casing and faced difficulties with the drilling margin (see figure 10), from 17168' (9 7/8'' casing shoe) to 18223' where the pore pressure kept reducing from 14.1 ppg to 12.6ppg,

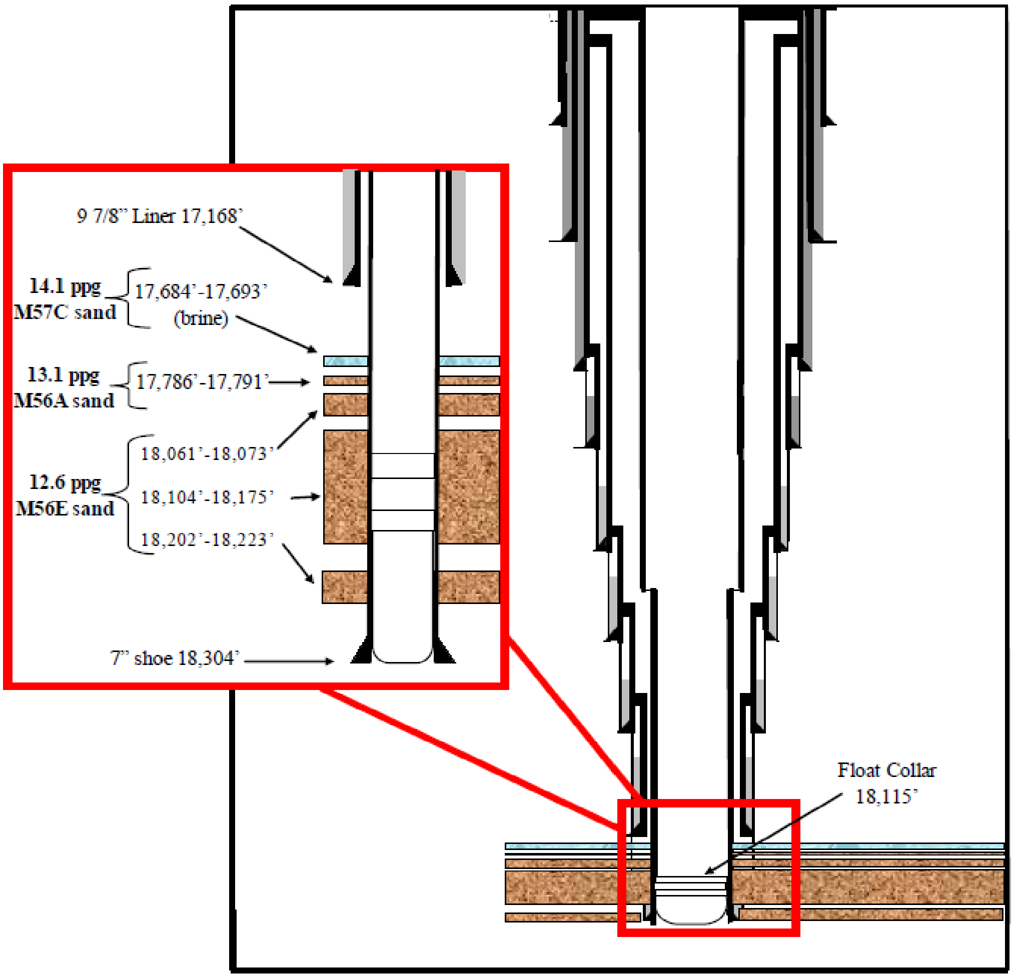

Figure 13-Macondo Well Shoe Track and Hydrocarbon Intervals[16]

Therefore the drilling mud equivalent circulating density (usually 14.1+ 0.2 ppg above pore pressure) was fracturing at the bottom of open hole interval (12.6 ppg pore pressure) while overbalancing the top of the open hole interval (14.1 ppg pore pressure). Figuratively

[16] Image Source: Investigation, Deepwater Horizon Incident Joint, *The US Coast Guard (USCG)/Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Joint Investigation Team (JIT),* Pg. 36

BP and the service companies ran out of drilling margin, so decided to revise the total well depth at 18360’ from the original well total depth of 20200’.

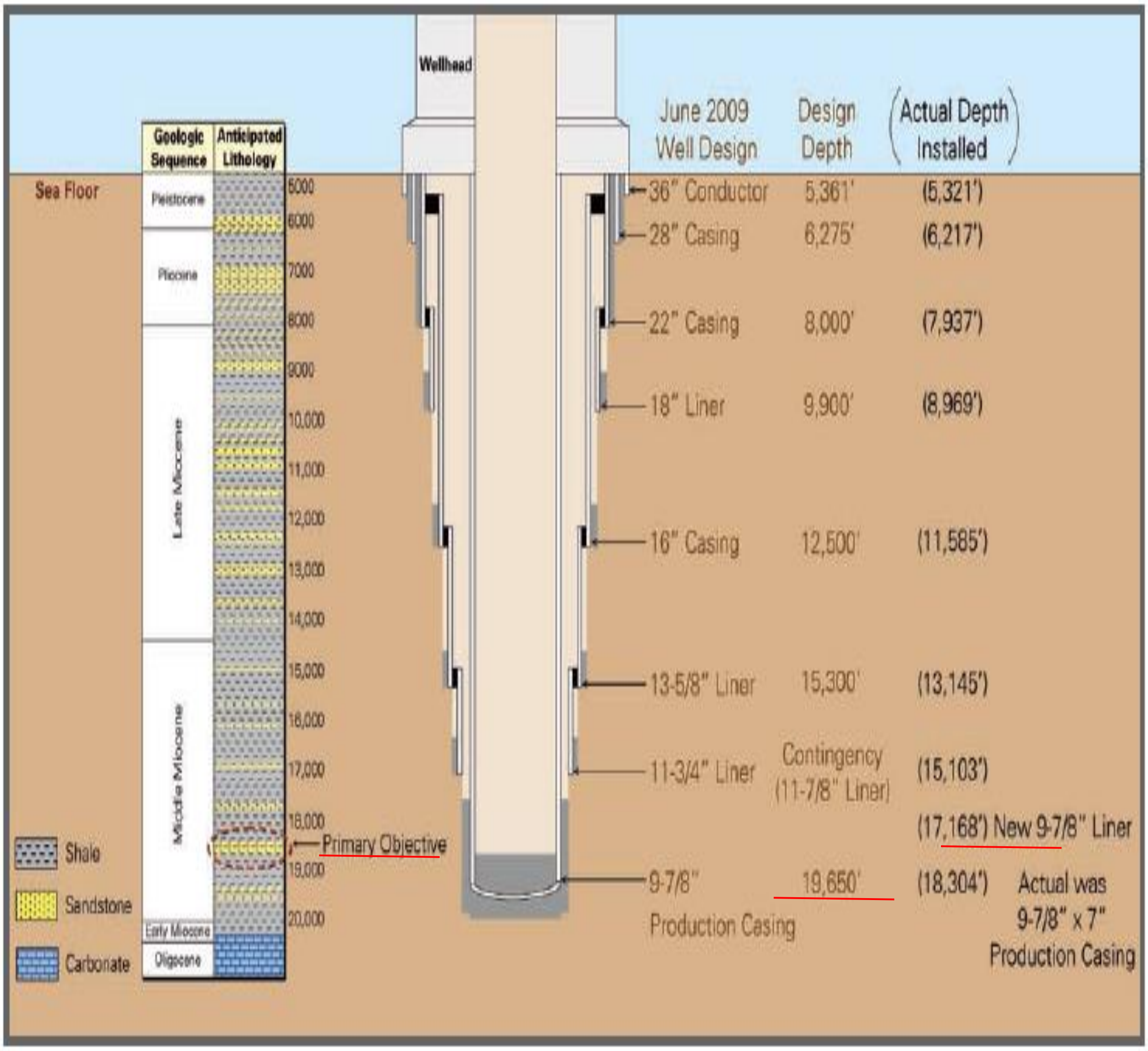

Figure 14-Geology, Original Well Design and Installed Depth[17]

At 18360’ the wellbore was still inside the primary sandstone reservoir see figure 14, which forced BP to reconsider their original long casing string design (*“ a “long string“ production casing—a single continuous wall of steel between the wellhead on the seafloor, and the oil and gas zone at the bottom of the well”[1]).* They had two options, see figure 15, one was to go with the originally planned long string production casing and the other a shorter string called a liner tie back production casing string (“ *a “liner”—a shorter string of casing hung lower in the well and anchored to the next higher string”[1]*).

[17] Image Source: Deepwater Horizon Accident Investigation Report, BP, Pg. 16

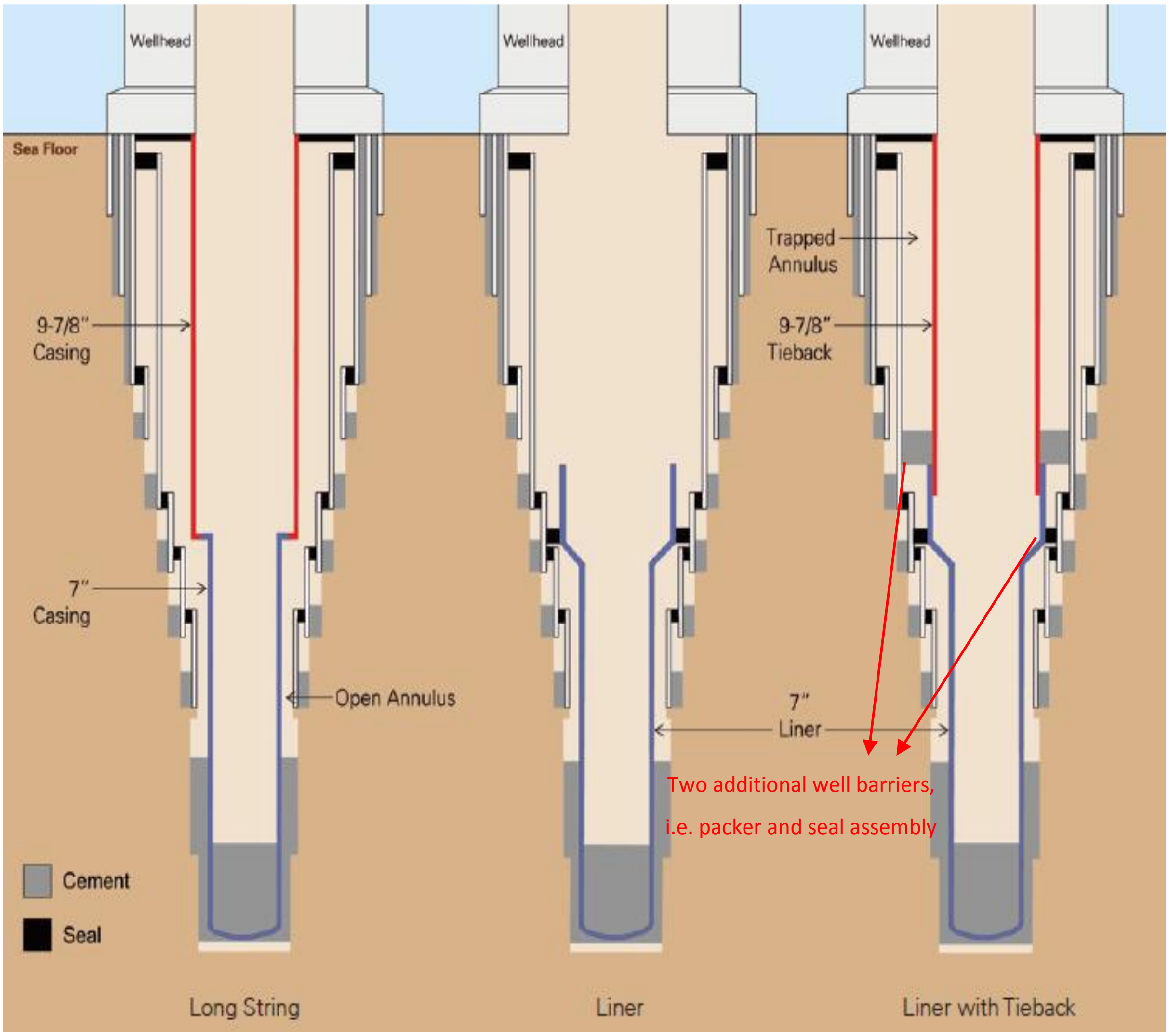

Figure 15-Long string, Liner and Liner with Tieback[18]

A liner tie back string is expensive and although it provides two additional well barrier (i.e. the liner has to be sealed to the previous 9 7/8'' casing by a packer as well a seal assembly at the tie back junction, figure 15) to hydrocarbon flow path, it has risks w.r.t mechanical integrity failure at the tie back junction, increased annular pressure build-up due to fluid expansion by heat transfer during production (the annulus of the 7'' liner string is sealed at top by the tie-back seal assembly and casing shoe at the bottom, therefore if there is a the pressure build-up, there are no means to bleed off) [4].

Therefore BP had asked their cementing contractor Halliburton to also perform an analysis of a long string cemented using a nitrogen foam cement (*more on cementing follows*) with 6 centralizers (BP originally planned to use 21 centralizers, but only 6 were available on Deepwater)[4] .

[18] Image Source: BP, Deepwater Horizon Accident Investigation Report, Op. ct. 12, p75

Halliburton reported that the long string with 15 centralizers could have a) cement channeling problems b) moderate gas flow problems and most importantly c) damage the formation during cementing due to abrupt change in pore pressure from 14.1 ppg to 12.6 ppg as discussed earlier. This is one of the reasons why BP chose the nitrogen foam cement mix, they then switched to a liner tie back string solution with 15 centralizers[19]. The primary cement job in a liner is much easier due to successful cement lift due itself to lower ECD[20]. Finally BP evaluated and called on an in-house BP cementing expert to evaluate both the options and finally with certain changes to cementing parameters decided to go with the long string producing casing (7inch at the bottom tapered to 9 5/8inch at the top)[2, 4]

II.4.4 Centralizers

*"*A device fitted with a hinged collar and bowsprings to keep the casing or liner in the center of the wellbore to help ensure efficient placement of a cement sheath around the casing string. If casing strings are cemented off-center, there is a high risk that a channel of drilling fluid or contaminated cement will be left where the casing contacts the formation, creating an imperfect seal"[21], see figure 16.

BP had planned to use 21 centralizers for its long string casing design, they had only six centralizers with built in stop collars[22] available on Deepwater and therefore ordered additional fifteen from Weatherford. BP had again asked Halliburton to analyze the design of the long string with six centralizers (Halliburton actually analyzed with seven centralizers, for unknown reason).

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[19] BP, "Forward Plan Review" [internal, undated] Source: Investigation, Deepwater Horizon Incident Joint, *The US Coast Guard (USCG)/Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Joint Investigation Team (JIT), Sep 2011, Pg. 37*

[21] Schlumberger Website, Oilfield Glossary, Accessed: May 28 2014, Ref: http://www.glossary.oilfield.slb.com/en/Terms/c/centralizer.aspx

[22] Stop collars are used to restrict the movement of the centralizers, they are either built on to the centralizer already made or can be strapped on the centralizer separately.

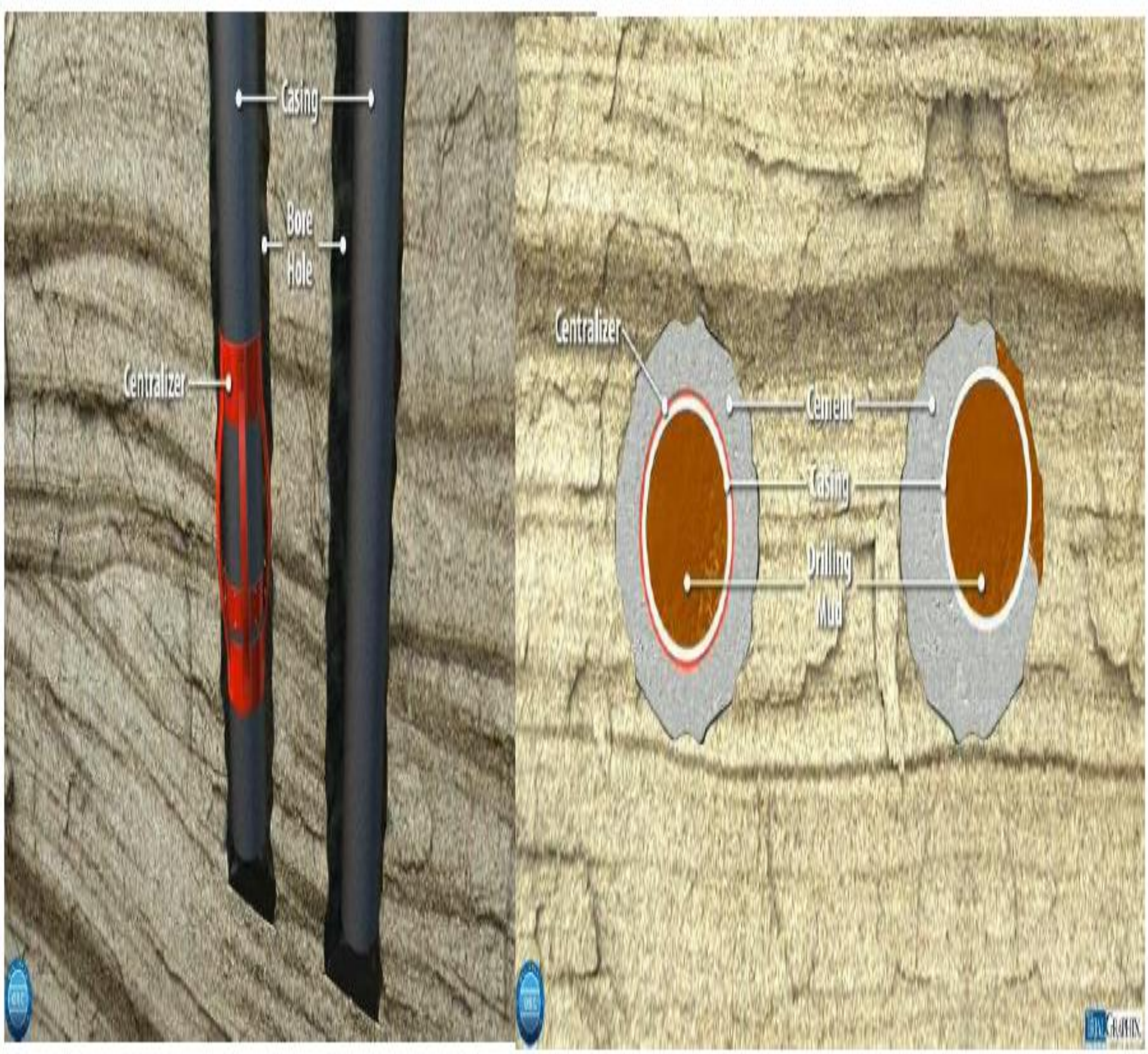


Figure 16-Centralizers[23]

BP received the fifteen centralizers and found that they were of the wrong type with separate stop collars and decided to go ahead with just using the six that were available on the rig. Before receiving the analysis report from Halliburton, BP installed the long casing string with six centralizers, the report (BP received the final report after the blowout) concluded that severe gas flow problems were likely to occur, the report also contained vital compressive strength analysis of the cement[1, 4] .

[23] Deepwater Horizon Study Group, *Final report on the investigation of the Macondo well blowout,* Centre for Catastrophic Risk Management, University of California at Berkeley. 2011 Pg. 33

II.4.5 Cementing

II.4.5.1 Slurry Design

Only a few days before completing the drilling of the well, BP and Transocean had to do one of the most important jobs to perform, i.e. cementing the casing, also called the primary cement job. They had contracted Halliburton to perform the cement job for the casing.

BP and Halliburton had decided to use the cutting edge nitrogen foam technology for the cement job, which was back then the latest technology with some or no actual field history. In the nitrogen foam technology, cement mix has nitrogen gas in it to reduce the density of the cement mix without compensating the strength. This was a very interesting decision since, given the previous lost circulation event and the challenging drilling window/margin, BP did not want to have any more well control incidents and possibly decided to go ahead with the new technology that promised to work without damaging the formation. But the nitrogen foam technology in its inception had some controversial lab test reports done by Halliburton which showed that the foam cement was mostly unstable except for the last test which showed the contrary[1].

BP and Halliburton performed the cement job and assumed that they had a good primary cement job, therefore did not perform crucial (not mandatory) test i.e. cement bond logging (CBL) test. The CBL was supposed to be done by Schlumberger crew, who were already available on the rig but BP sent the Halliburton and Schlumberger technicians home immediately following the cement job. This already set the stage for a gas leak and a potentially blowout in the making.

II.4.5.2 Full Displacement Vs Partial Displacement

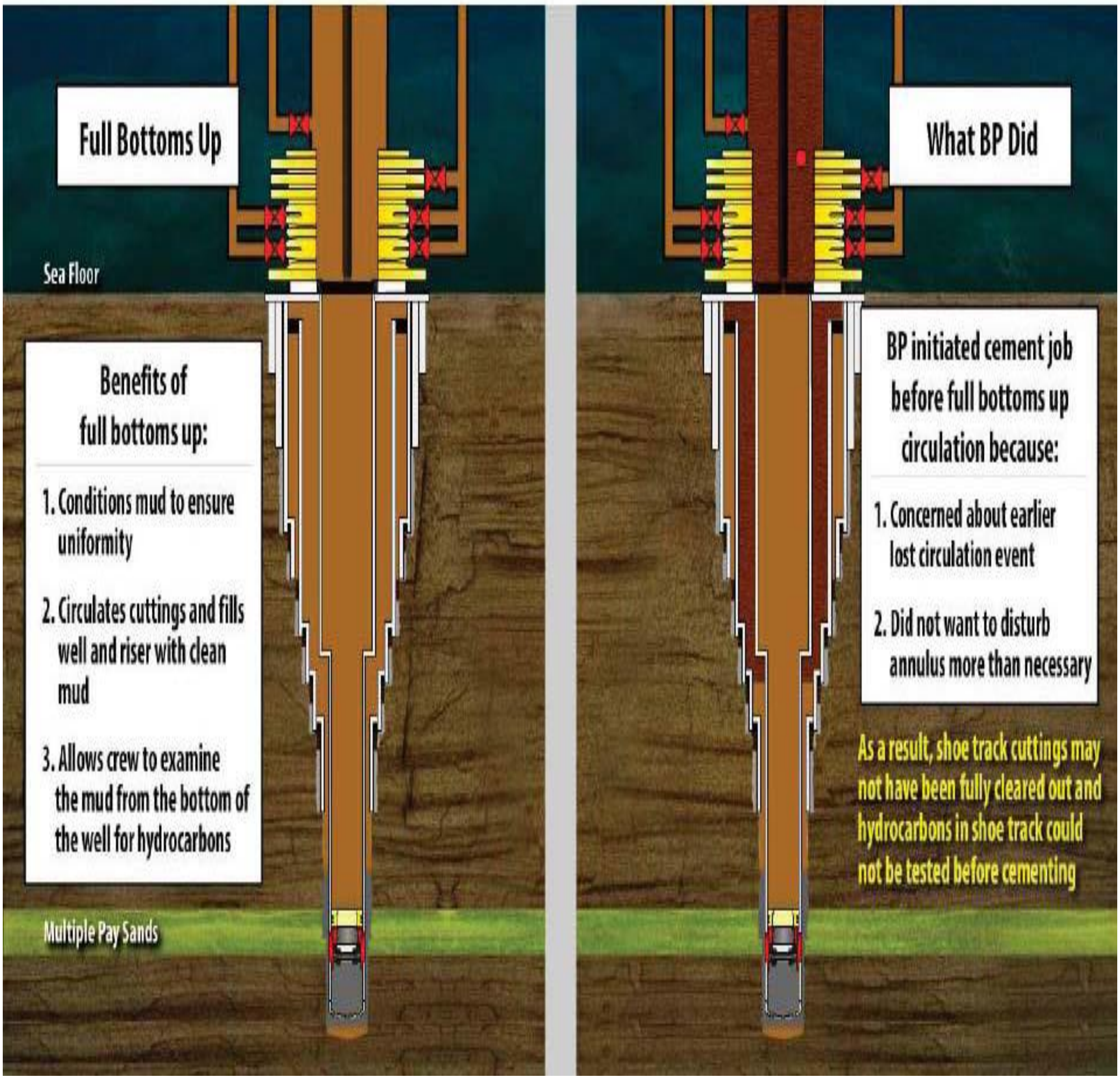


Figure 17-Illustration of conventional Bottoms up VS what BP did[24]

It is widely accepted in the industry to perform a full bottoms up of the well bore prior to primary cementing. Full bottoms up circulation of the wellbore would clean the annulus from any drilling cut debris and stops contamination of the cement see figure 17. It is done by pumping base oil, spacer and cement mix into the well, to displace the existing drilling mud all the way to the trip tank on the rig see figure 18. The mud-logger can perform useful tests to examine the drilling mud for any residual hydrocarbons in case the formation was flowing

[24] Deepwater Horizon Study Group, *Final report on the investigation of the Macondo well blowout,* Centre for Catastrophic Risk Management, University of California at Berkeley. 2011 Pg. 37

already in the wellbore. But BP, given the fact of the previous washout and the lost circulation materials used to plug the formation, were concerned and decided to only perform a partial displacement of the drilling mud. ''BP circulated approximately 350 barrels of mud before cementing, rather than the 2,760 barrels needed to do a full bottoms up circulation.[1]"

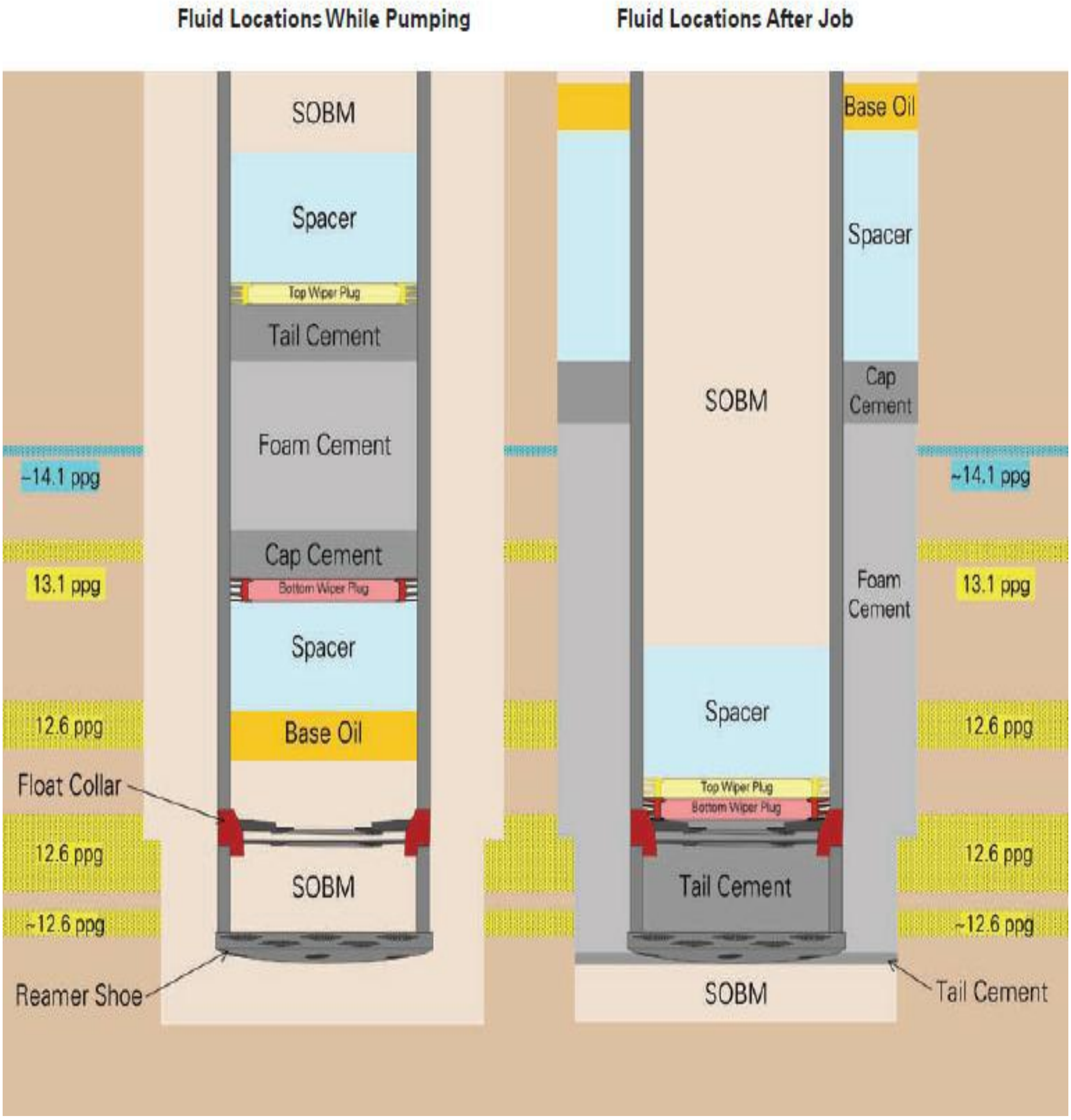


Figure 18-Cement Fluid Locations[25]

[25] Deepwater Horizon Study Group, *Final report on the investigation of the Macondo well blowout,* Centre for Catastrophic Risk Management, University of California at Berkeley. 2011 Pg. 37

The flow rate at which the cement mix is to be pumped is very important. Higher flow rate means increased cement and is synonyms with a good cement job, on the down side it also causes increased pump pressure resulting in increased ECD, which might lead to lost circulation/formation damage. BP were concerned.

Additionally, BP used only 60 barrels of cement mix to cement 500ft above the uppermost hydrocarbon bearing zone and 800ft for the principal hydrocarbon zone. This is considered as a relatively low volume to give a good cement placement (that more cement volume means less contamination and an increased efficiency). But BP chose to use only the bare minimum volume of cement with a slight margin for error. Increased cement volume causes higher PPG exerted on the annulus of the liner/casing shoe, potentially causing damage to the formation[1]. Therefore BP decided to do only a partial displacement 500ft above the payzone. A comparison of partial displacement vs full displacement is shown in figure 17.

It is to be noted that a wiper plug is used to separate the cement and spacer from contamination while it is being pumped in to the casing. Bottom wiper plug separates the cap cement and spacer whereas top wiper plug separates the spacer and tail cement mix see figure 18, the wiper plug has a inbuilt disc which should be burst between 900 psi to 1100psi to allow cement circulation, the bottom wiper plug actually burst at 2900psi[4] (it can be identified by an abrupt spike in the pump pressure reading)

II.4.5.3 Float Collars

Float collars are double-check valves on the top of a casing shoe or at the bottom of a casing string, see figure 19. When activated/converted it only allows flow through one direction and stops back-flow. In the Macondo well, BP used a Weatherford Model M45AP (see Appendix D) mid-bore auto-fill float collar[4]. There is an auto fill tube inside the float collars which keeps the two flapper valves held open by default. When the final production casing is run in to the well it results in excess volume (increased ppg) of the casing and therefore the equivalent drilling mud has to be removed/displaced. This is done by displacing the excess volume (increased volume due to running the casing) through the circulating ports in the auto fill tube. Once the casing is run and set, the base oil, spacer and cement mix are pumped in to the casing and up in to the annulus of the liner through flow ports at the bottom

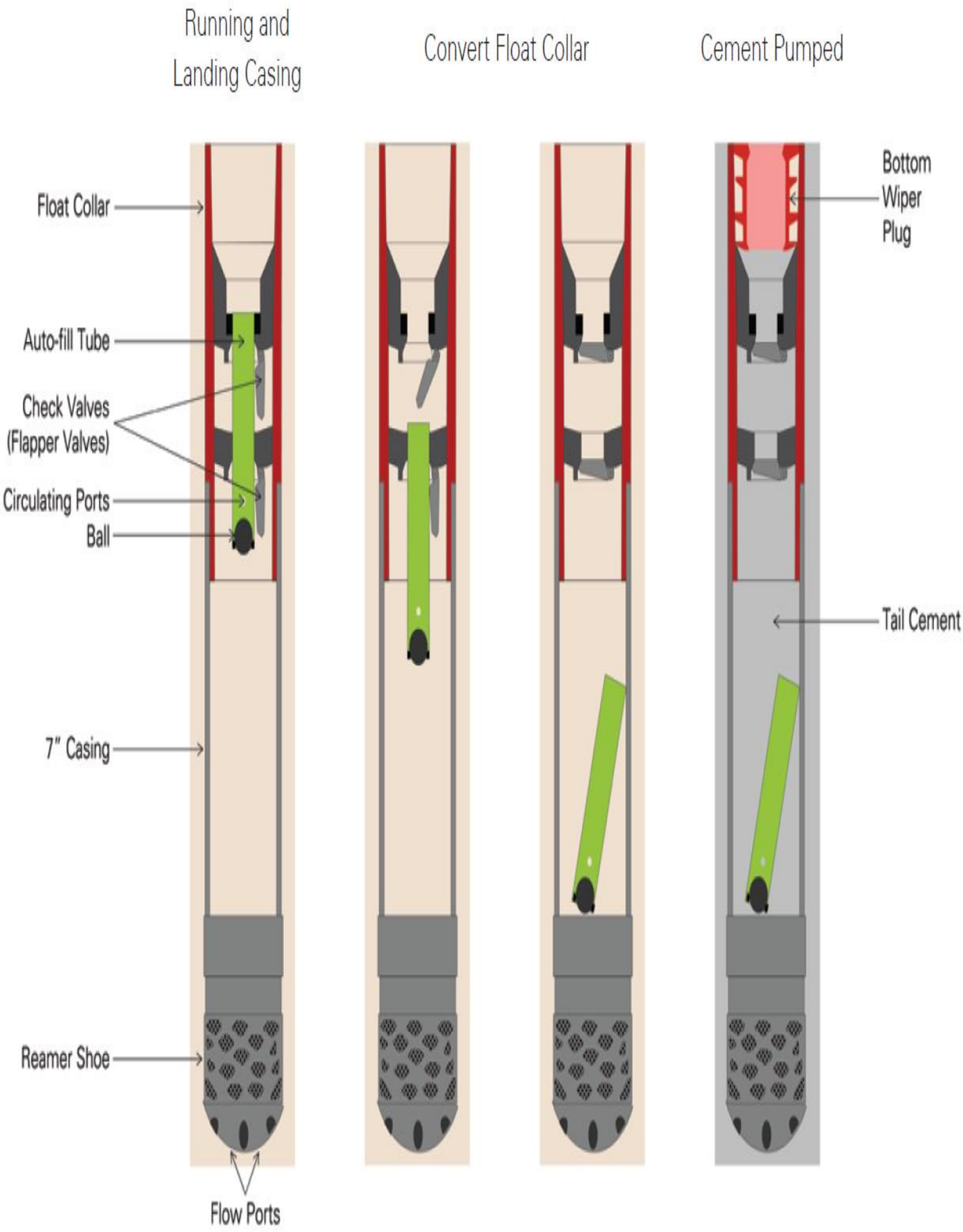


Figure 19-Float Collar conversion[26].

[26] Deepwater Horizon Study Group, *Final report on the investigation of the Macondo well blowout,* Centre for Catastrophic Risk Management, University of California at Berkeley. 2011 Pg. 35

of the casing shoe as shown in figure 19. Once the required Top of Cement (TOC) is reached the casing is pressurized from the rig at an optimal flow rate to convert the float collars (the increasing pressure displaces the auto fill tube into the shoe track[27] below, this closes the flapper valves). In case the float collar does not convert (the auto fill tube is not displaced), the flapper valves are still held open and reverse flow is possible i.e. flow from the annulus of the liner, this reverse flow could be cement or drilling mud or even hydrocarbons in case the cement is contaminated and/or did not set in place.

In Macondo, after the cement was pumped in to the annulus, the casing was pressurized to convert the float collar, but BP noticed that the casing shoe at the bottom could be plugged. According to Weatherford specifications the float collar should convert around 500-700psi (see appendix D) but BP, only on their ninth attempt, managed to finally convert the float collar at a whopping 3142 psi at a flow rate of around 4 bpm (weather ford specifications say 5-7 bpm, see appendix D). In any case they were not even sure if the float collar had actually been converted.

II.4.6 Temporary Abandonment before disengaging Deepwater Horizon

After the cementing operations, the well was due for temporary abandonment[28]. In order to do this, the Deepwater Horizon had to a) remove the BOP and the riser from the wellbore b) set a cement plug well below the seabed and c) put in a lock down sleeve on the well head. Lock down sleeve is used to keep the existing casing hanger and the seal assembly from moving out of place, the movement can be caused when high pressure fluids are flowing upwards in turn lifting the casing. Figure 20 shows the Status of the well before and after temporary abandonment.

[27] Shoe track is the space between the float collar at the top and the casing shoe at the bottom, typically filled with cement and acts as a well barrier element

[28] Temporary abandonment is the procedure in which expensive drilling rigs disengage from operations prior to completions and production so that cheaper and smaller production rigs are brought in to perform further operations

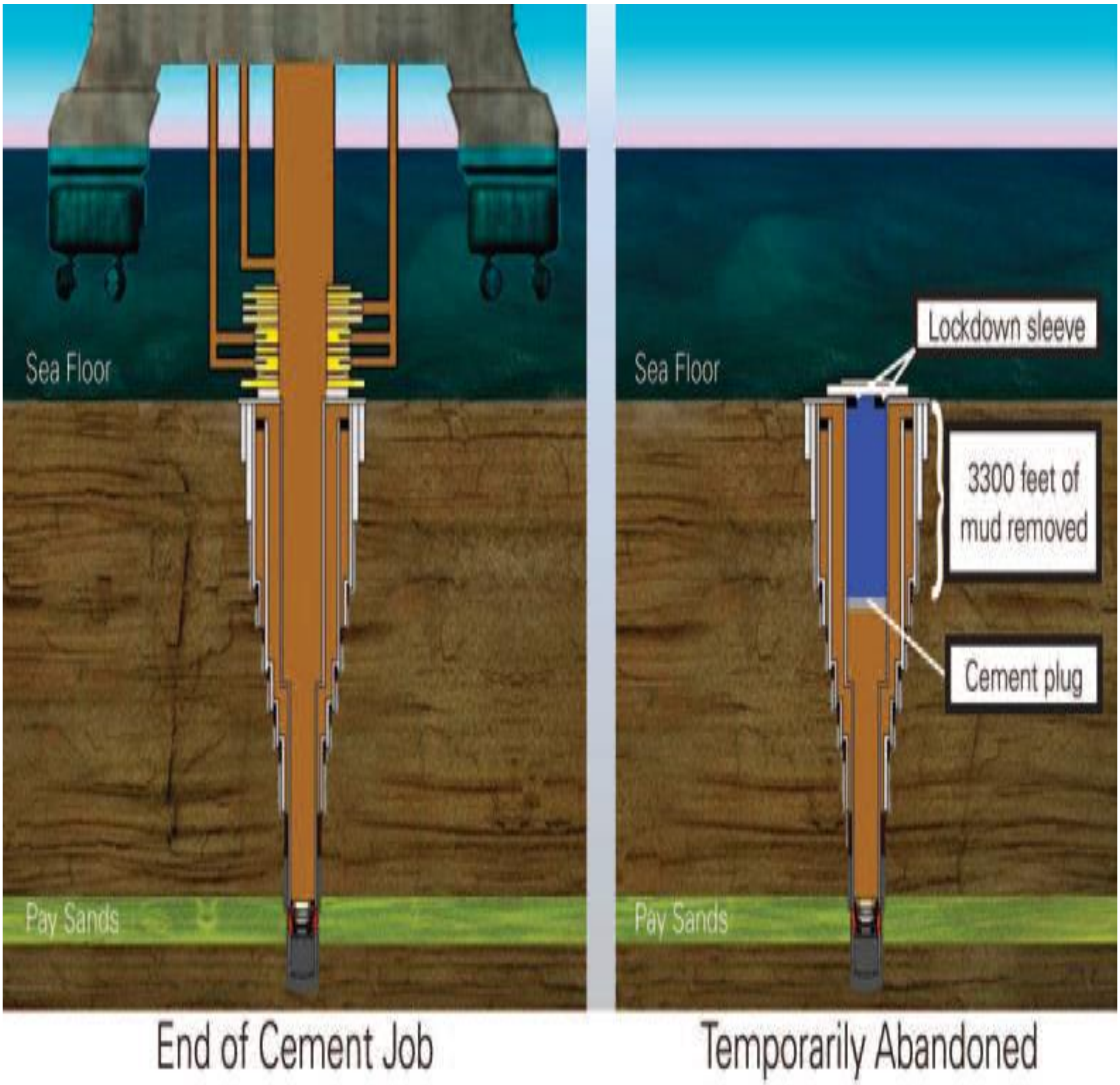


Figure 20-Status of the well before (left) and after temporary abandonment (right) with the cement plug[29]

BP decided to put the cement plug at 3300ft below the sea floor (8367ft from the rig) on contrary to 6000ft originally planned. they also decided to put the lock down sleeve after the surface cement plug is set and not vice versa as originally planned[1].

[29] Image Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *Report to the President*, 2011. Pg. 103

The following figure shows the sequence of operations BP planned for the temporary abandonment in the Macondo well.

1. Perform a positive-pressure test to test the integrity of the production casing;
2. Run the drill pipe into the well to 8,367 feet (3,300 feet below the mud line);
3. Displace 3,300 feet of mud in the well with seawater, lifting the mud above the BOP and into the riser;
4. Perform a negative-pressure test to assess the integrity of the well and bottom-hole cement job to ensure *outside* fluids (such as hydrocarbons) are not leaking *into* the well;
5. Displace the mud in the riser with seawater;
6. Set the surface cement plug at 8,367 feet; and
7. Set the lockdown sleeve.[61]

Figure 21- BP's Temporary abandonment sequence [30]

II.4.6.1 Well Testing

Before the well is to be handed over to completions well testing should be performed i.e. the Positive pressure testing (PPT) and Negative pressure testing (NPT). They are done to test the integrity of the well barrier i.e. testing the cement job, wellhead hanger seal etc. In accordance with the temporary abandonment plan as explained before, positive and negative pressure test were conducted by BP as follows.

II.4.6.1.1 Positive Pressure test

In a positive pressure test, pressure is built up in the well by pumping additional fluids, to check if the pressure is sustained over a period of time. In case there is a leak in the barrier envelope, the pressure will not stay constant over time. BP pumped the well to 250 psi and waited for 5 minutes and then pressured again up to 2500psi and watched for 30 minutes, see figure 22.

[30] Source: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *Report to the President*, 2011. Pg. 104

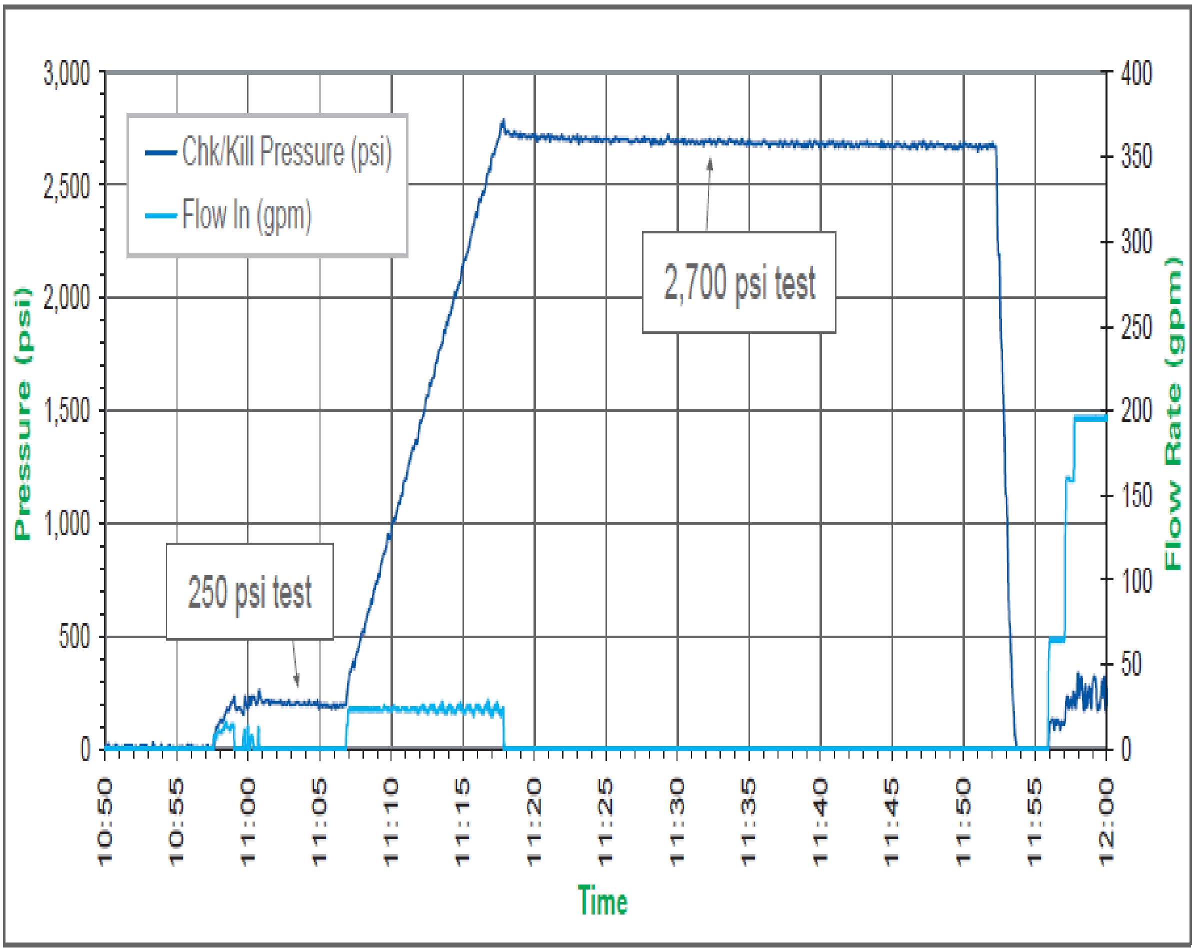


Figure 22-Positive Pressure Test[31] (Macondo Real time data)

The pressure inside the pipe was stable and constant. The positive pressure testing was considered adequate and conclusive.

II.4.6.1.2 Negative Pressure Test

Unlike the positive pressure testing, in a negative pressure test, the well is actually made to flow, in other words the well is underbalanced. This also checks for the well barrier integrity.

The negative pressure test is conducted by displacing heavy drilling mud in the casing with seawater, since seawater is of lower density and replacing heavier drilling mud causes lower hydrostatic pressure on the formation, thus stimulating underbalanced conditions, in effect replicates conditions viable for flow from the formation in to the well bore, if the primary cement and the casing shoe had a good cement job, the well should not see any flow

[31] Deepwater Horizon Accident Investigation Report, BP, 2011 pg. 83

in spite of being underbalanced. This was the only real test to check the integrity of the casing shoe and also to check if the formation is already flowing in to the well bore.

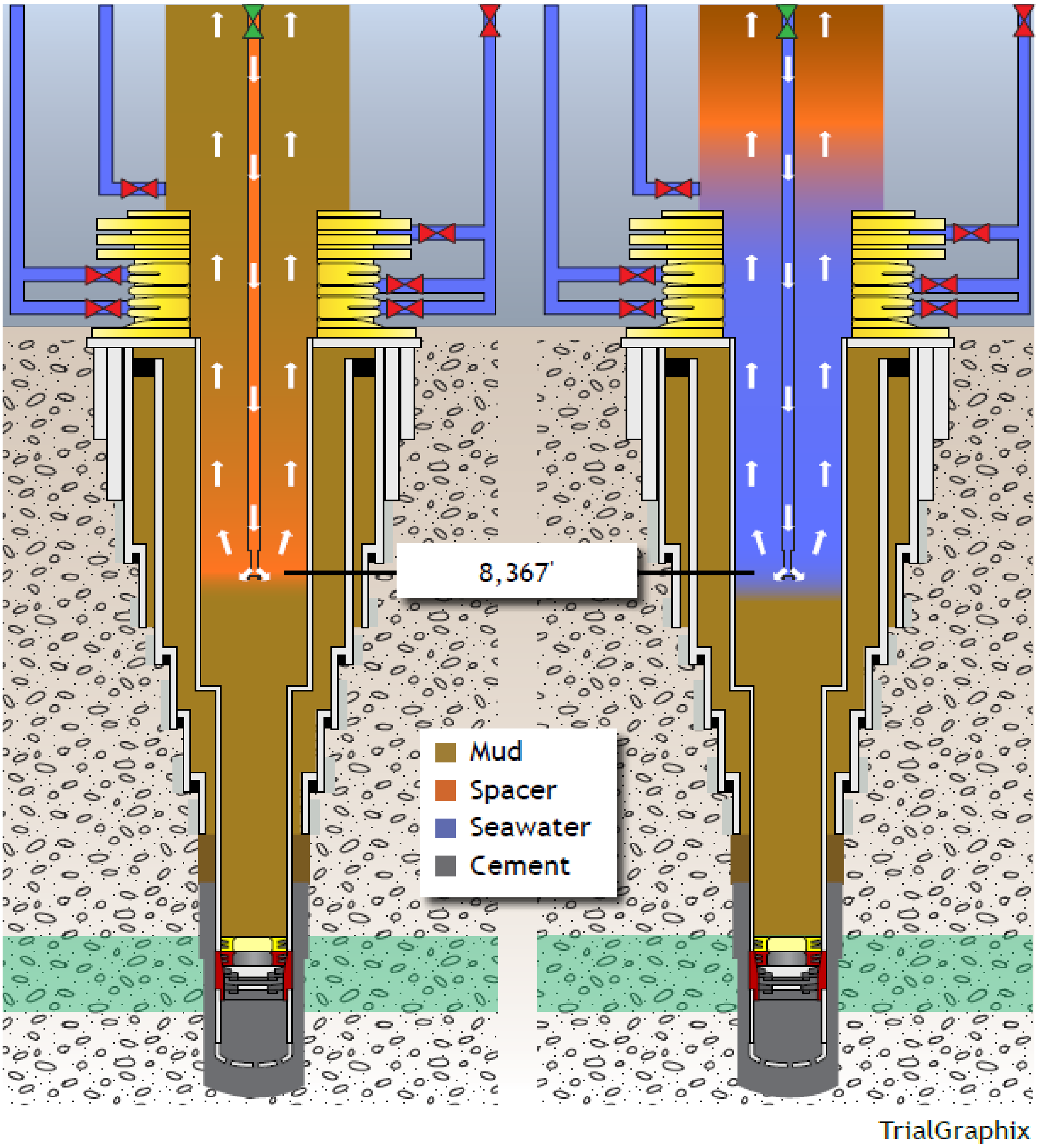


Figure 23-Negative Pressure Test[32]

[32] Image Source: National Commission on the BP Deepwater Horizon Oil Spill Offshore Drilling, *Macondo: The Gulf Oil Disaster, Chief Counsel's Report,* 2011. Pg 141

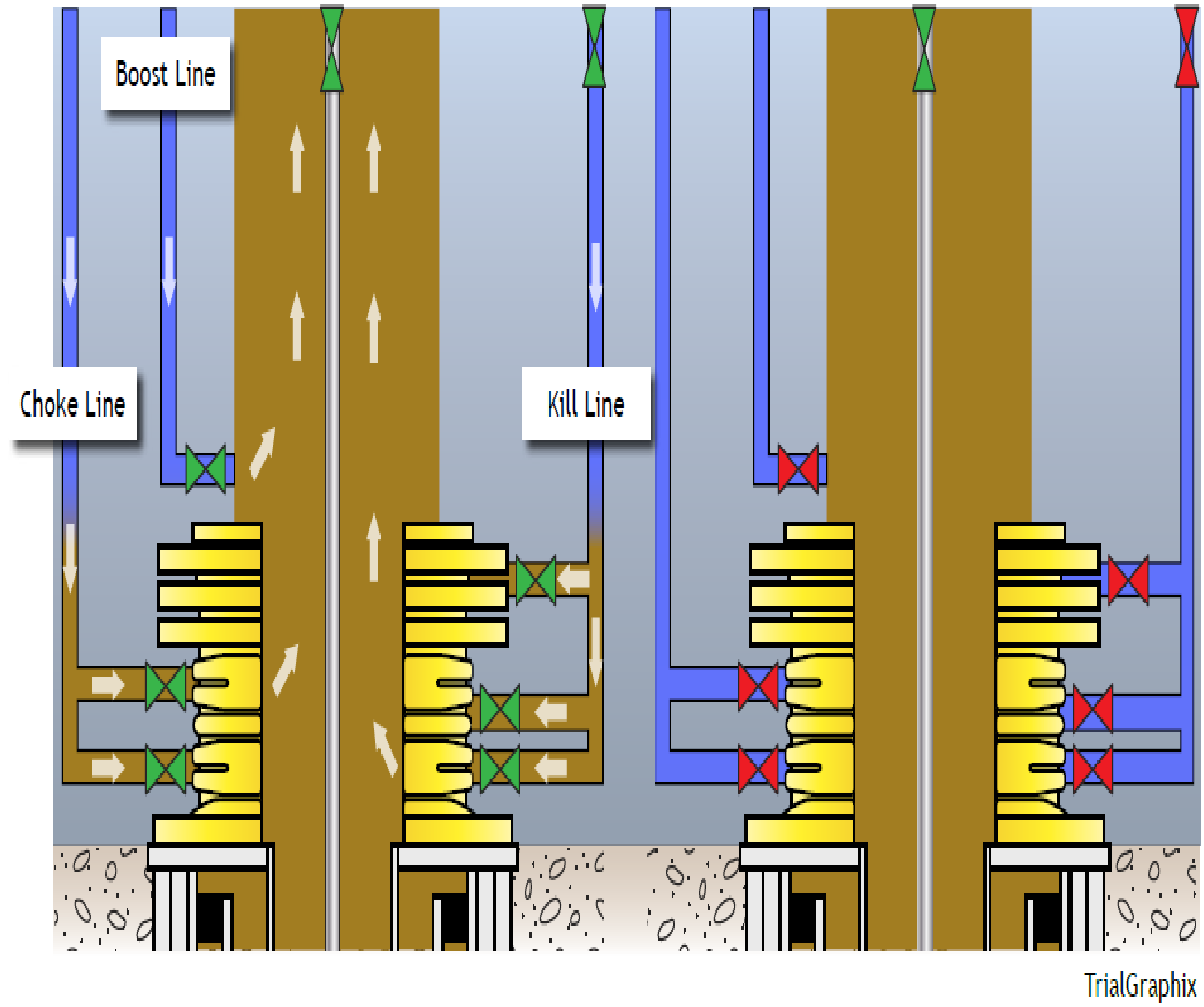


Figure 24-Valves and Lines in a Negative Pressure Test[33]

To conduct the negative pressure test see figure (23), first BP closes and runs the drill pipe to 8367ft followed by pumping of spacer and seawater through the drill pipe, the sea water displaces the heavier drilling mud. There are choke, kill and boost lines accelerates the pumping of seawater and removes drilling mud faster, see figure (24). Once this is accomplished it is followed by closing off the annular preventer in the BOP (choke, boost and kill line are also closed). This is very crucial to note, since the annular preventer removes the hydrostatic pressure of the column of drilling mud and spacer in the riser (5037ft above the mud line).

[33] Image Source: National Commission on the BP Deepwater Horizon Oil Spill Offshore Drilling, *Macondo: The Gulf Oil Disaster, Chief Counsel's Report,* 2011. Pg 149

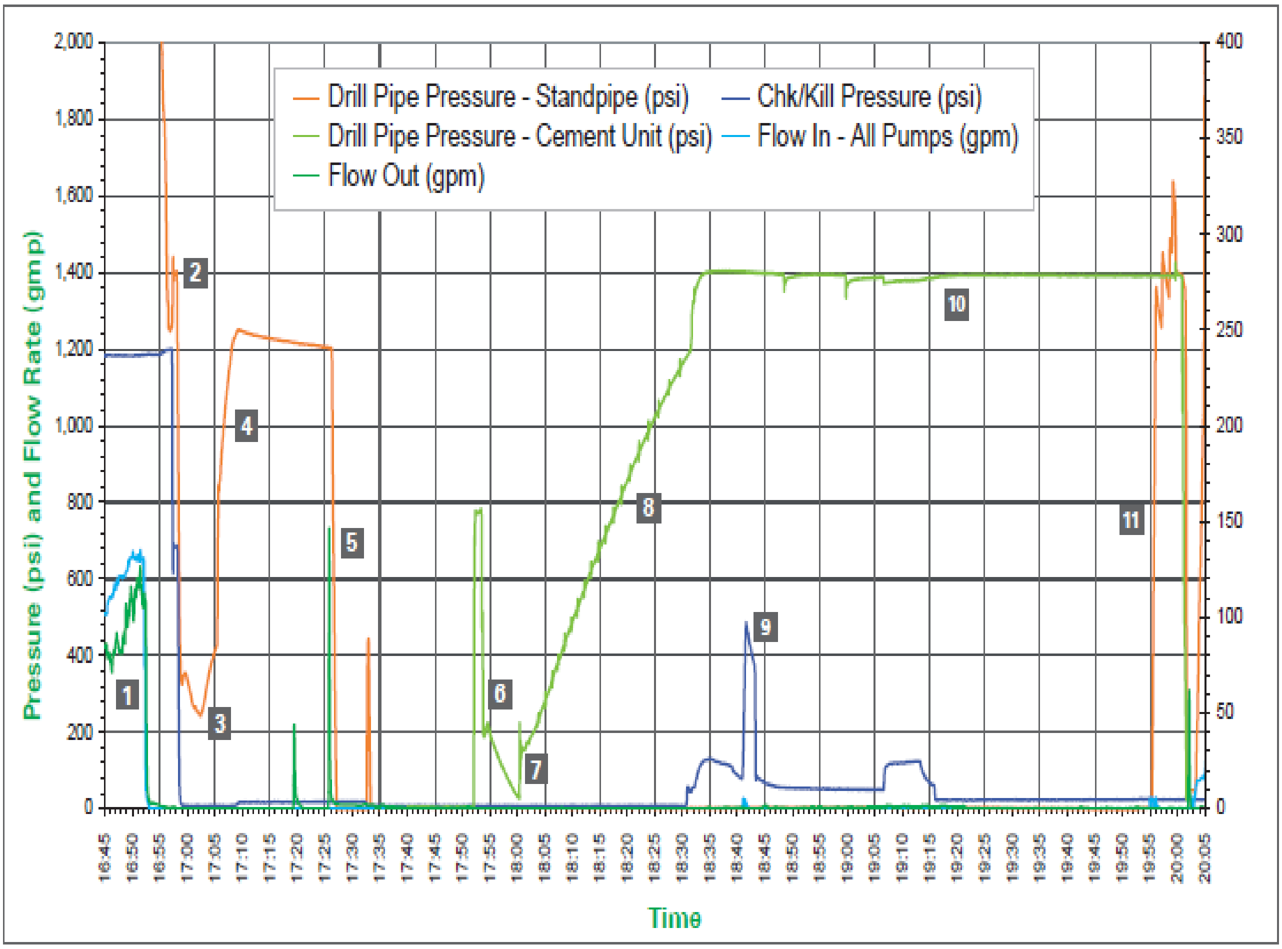
After the annular preventer is shut in, the valve in the drill pipe is opened to release the pent-up pressure (bleed-off any unreleased pressure) and the well is made to flow and finally the drill pipe pressure[34] is brought to 0psi (because the drill pipe is open to atmospheric pressure). Once the drill pipe pressure is brought to zero psi, the drill pipe valve is closed along with the kill line valve

For a successful negative pressure test, after initial flow in the drill pipe (due to pent up pressure), the pressure before and after shut in should be zero psi, with little or no fluid flow.

The first negative pressure test in Macondo showed a sign of problem, after initial bleed off, the pressure in the well could never be brought towards zero i.e. the drill pipe pressure stayed at 260psi and also returned water to the rig. Following this, the rig crew shut the drill pipe valve and observed 1262psi, first negative test failed[5]. See figure 25.

Meanwhile, the rig crew noticed falling spacer level in the riser so dedicated to close the annular preventer tight and perform the second negative test, during the second test the drill pipe pressure was bled to 0psi but the drill pipe returned around 15 barrels of fluid, unusually large volume, following the bleed-off the drill pipe was shut in again only to see the pressure shot up to 773psi, the second negative pressure testing failed[5].

[34] The drill pipe pressure should be equal to the kill line pressure during the negative pressure test, as both the lines are connected to the same vessel in the BOP and experience the same pressure.



1 Spacer displacement complete; mud pumps stopped.

2 Annular preventer closed; attempt to bleed drill pipe pressure to zero.

3 Drill pipe pressure decreases to only 273 psi; annular preventer leaking.

4 Drill pipe pressure increases as annular preventer leaks; hydraulic closing pressure increased to seal annulus.

5 Drill pipe pressure bled to zero for negative-pressure test.

6 Decision made to conduct negative-pressure test via kill line; kill line opened; 3 bbls to 15 bbls bled to cement unit.

7 Shut in kill line at cement unit, drill pipe pressure starts to increase.

8 Drill pipe pressure slowly increases to 1,400 psi.

9 Fluid pumped into kill line to confirm full; kill line opened to mini trip tank for monitoring.

10 Discussion ongoing about 'annular compression' and 'bladder effect' while monitoring kill line; drill pipe pressure static at 1,400 psi.

11 Negative-pressure test concluded, declared a success; preparation made to continue displacement.

Figure 25-Negative Pressure test[35] (Macondo Real time data)

[35] Source: Deepwater Horizon Accident Investigation Report, BP, 2011 pg. 88

Finally BP decided to bleed off the pressure using the kill line instead of the drill pipe during the third negative pressure test, on the third NPT, they had open kill line valve and managed to bring the pressure down to 0psi but this resulted in excessive flow through the kill line as well, when the kill line was shut in, the drill pipe pressure again shot up to 1400psi. Evidently the third test had also failed, it was actually a symptom of the bad cement job and that the hydrocarbons have actually started to leak (the reservoir pressure was around 1400psi). Since they had an anomaly in the tests from different pipes (i.e. drill pipe, kill line), they decided to ignore the sign on the false pretense based on bladder effect/ false echo and continued further while declaring that the third negative pressure testing as successful[5].

Negative Pressure Test (NPT)	**Drill pipe/kill line, Bleed off Pressure (psi)**	**Flow out Volume**	**Drill pipe/kill line, Shut in Pressure(psi)**
First NPT	260	excessive	1262 on drill pipe and kill line
Second NPT	0	excessive	773 on drill pipe and killl line
Thrid NPT	0	excessive	1400 on drill pipe and 0 on kill line[36]

Summary of the negative pressure tests at Macondo well.

[36] The kill line pressure and drill pipe pressure should have been the same, the 0 psi pressure might possibly be due to the kill line being plugged on the third attempt to show. this 0 psi on the kill line was the reason the BP and Transocean crew declared the third negative pressure test a success.

III. GAP Analysis

This chapter deals with the GAP analysis of the Macondo blowout with their prescribed Standards and Codes, Regulations, Guidelines and Recommended Practices. This Chapter investigates and analyzes the major technical gaps of the Deepwater Horizon. First section deals with highlighting the well-established standards and codes that were used to perform the GAP Analysis, second section contains the technical gaps between the operator / Service Company's recommended practice and what they actually followed and the Third section contains the changes that were made to Norwegian standard (NORSOK D-010) to avoid such an event in the NCS

III.1 Petroleum Industry Standards

"The petroleum and natural gas industries use a great number of standards developed by industry organisations, through national and regional standardisation bodies, by the individual companies in the industries and by international standards bodies. The use of these standards enhances technical integrity, improves safety, reduces environmental damage, and promotes business efficiencies that result in reduced costs. The current, intensified period of international standards development reflects the global nature of the industry and the imperative to operate more effectively and reduce costs further. International standards for the petroleum and natural gas industries is the area that is the focus of the International Association of Oil & Gas Producers (OGP) through its Standards Committee[6]" .

The following guidelines, recommended practices, regulations, standards and codes are of critical importance for the GAP Analysis.

III.1.1 NORSOK Standard

"NORSOK standard is developed with broad petroleum industry participation by interested parties in the Norwegian petroleum industry and is owned by the Norwegian petroleum industry represented by The Norwegian Oil Industry Association (OLF) and Federation of Norwegian Manufacturing Industries (TBL)[7]" .

III.1.1.1 NORSOK D-010- "Well integrity in drilling and well operations"

The NORSOK D-010 is an important Norwegian Standard and Code for operators and service companies, it deals with well barrier design, risk assessment, drilling activities, well testing operations, completion operations, production & well intervention activities and acceptance criteria for various drilling and well operations.

III.1.2 API RP 65- "Isolating Potential Flow Zones During Well Construction"

API RP 65 is an important standard and code for the cementing operations, post cement job activities as well as casing shoe testing.

III.1.3 MMS Regulations (Pre-Macondo)

Minerals Management Service (MMS) was the US government administrative agency in charge of leasing, auditing, inspection etc. It is similar to the NPD (Norwegian Petroleum Directorate) in Norway. They had various regulations set forth for operators / service companies' w.r.t petroleum exploration, drilling, completions, production and abandonment.

III.1.4 BP/Transocean's Recommended Practices

BP and other service companies have their own internal recommended practices and guidelines for every operations in the petroleum industry. These guidelines are substantially based on their own experience within the industry. The companies in addition to their guidelines also use other relevant, well established Standards and Codes in conjunction with their own guidelines.

III.2 GAP Assessment

III.2.1 Technical GAPs between Deepwater Horizon Blowout Incident Vs Various International Regulations / Standards & Codes

The Following GAP Analysis focuses on highlighting what BP and other service companies actually followed in the Macondo well prior to April 20th Blowout while mapping them to the relevant Mineral Management Service Regulations, API Standards and Code, British Petroleum's Internal Standards, Transocean's Internal Standards, whenever applicable.

NOTE:

The main sources for the following GAP analysis includes

1) Literature review of this thesis

2) All the footnotes included in this thesis,

3) References section of this thesis

4) Color denotes that recommendation;

For example

1 : is a High Impact GAP

2: is a Medium Impact GAP

3: is a Low Impact GAP

#	Base design followed in the Macondo Well	GAP w.r.t BP/Service Company Guidelines
1	BP had ran out of the drilling margin and had set the production liner casing shoe inside the reservoir section (M56 formation) and terminated the well at 18360ft from originally planned 20200ft. A consolidated shale section starting at ~20000ft was the original casing shoe bearing geology.	" BP internal guidelines for total well depth specify that drilling should not be stopped in a hydrocarbon interval, unless necessary due to operational, pressure and safety issues.[79] **Typically, total depth is not called in a sand section because placing the casing shoe – the section of the casing between the bottom of the wellbore and the float valve – in a laminated sand-shale zone increases the likelihood of cement channeling or contamination due to washout, and creates difficulties in logging well data.[80] "[4]**
	GAP Analysis*: BP had terminated the well at 18360 feet since they had run out of drilling margin, at 18360 feet, the well was actually terminated inside the sand stone reservoir section. This decision laid the foundation for the series of events that led to the actual Blowout on April 20th 2010.*	
2	BP decided to place the Top of Cement (TOC) of the production liner casing just 500ft above the upper most reservoir section, just enough to comply with the MMS regulations, which only asked for minimum 500ft above the uppermost reservoir zone. It was mandatory for BP, according to its own guidelines to perform a cement evaluation technique. But in Macondo BP decided to accept the primary cement job on the fact that they had no cement loss in to the formation based on fluid volume in vs fluid volume out calculation.	"BP's engineering technical practices require that personnel determine the top of cement by a "**proven cement evaluation technique**" if the cement is not 1,000 feet above any distinct permeable zones.[149] The acceptable proven techniques identified in BP's internal guidelines are cement evaluation logs, cement column back pressure, and temperature logs. BP's guidelines do not identify lift pressure or lost returns to be proven techniques for evaluating a cement job.[150] "[4]
	GAP Analysis: *In case BP had followed their internal guidelines, the cement bonding logs could have helped BP identify the poor cementing or shoe track contamination if any. (The CBL was never*	

	performed to is it very hard to say what was the exact cause of the failed cement)	
3	BP and Transocean crew had no means to cross verify their negative pressure test result or even to interpret the results of the negative pressure test.	"Both BP and Transocean had general requirements for positive and negative testing, but neither provided specific guidelines for how the tests were to be performed or how the results from the tests were to be interpreted."[2]
	GAP Analysis*: Had there been any specific guidelines, then the rig crew could have interpreted the excessive flow and pressure built up on the drill pipe when it was shut in during the negative pressure tests. Instead of performing consecutive negative pressure test, the rig crew would have considered the test failed and could have sort advice or suggestions from onshore experts / personnel and possibly could have understood that well had started flowing. Rig crew could have had more time on an action plan to mitigate the consequences of the blowout.*	
4	Halliburton's own analysis of the cementing for the Macondo well, using 7 centralizers and nitrogen foam cement mix, showed that the cement slurry was unstable except for the last report (which was stable) but this third lab report was only sent to BP days after the actual blowout had happened.[1]	"Halliburton's post-blowout laboratory worksheets dated May 26, 2010, show that the foam-slurry cement did not meet American Petroleum Institute Recommended Practice ("API RP") 65.95"[4]
	GAP Analysis: *" laboratory tests conducted by Chevron on behalf of the National Commission on the BP Deepwater Horizon Oil Spill and Deepwater Drilling ("Presidential Commission") showed that the foamed cement slurry used on the Macondo well was not stable."[4]*	
5	The annular tolerance of the production line casing and the wellbore was 0.75 inches only. [4]	"Halliburton also recommends that, to improve the probability of success in the primary cementing job, "[t]he best mud displacement under optimum rates is achieved when annular tolerances are approximately 1.5 to 2.0 inches." " [4]
	GAP Analysis: *Higher annular tolerance gives higher volume of cement and at optimal cement flow rate can give a good cement job and could have potentially withheld the formation in flux in to the casing.*	

6	In the Macondo well, the float collar was at the top of the casing shoe adjacent to the reservoir sand section, followed by shoe track and then shoe with circulating ports at the bottom.	"BP chose to land the float collar across a hydrocarbon-bearing zone of interest in the Macondo well, instead of at the bottom of the shoe."[4]
	GAP Analysis*: If the float collar had been at the bottom of the casing shoe (casing shoe comes with flapper valves at the top or at the bottom), even if the flapper valves had failed to convert, the shoe track adjacent to the formation would not have been contaminated along with the lighter drilling mud in the rat hole. Additionally the casing shoe (shoe track + unconverted flapper valves + shoe) could have possibly held well barrier integrity against the formation fluid (when the float collars are moved to the bottom, the shoe track is at the top of the casing shoe and is now occupied with cement adjacent to pay zone).*	
7	BP performed the third negative pressure test on the kill line.	The negative pressure test procedure for BP, written by Lindner, an employee of MI-SWACO (BP's contractor) specified as follows "Lindner's procedure specifically instructed, as step two, to "[d]isplace choke, kill, and boost lines and close lower valves after each."[216] The procedure did not instruct the personnel to re-open the choke and kill lines, which would be necessary to perform a negative test on either line. In any event, Lindner presciently noted at the end of the procedure that "[g]ood communication will be necessary to accomplish a successful displacement. If you are not sure, stop and ask."[217] "[4]
	GAP Analysis: *Had BP followed the procedure as described, they would have at least had to clarify if a negative pressure test on a kill line can be accepted. After the first two negative pressure tests failed, BP chose to open the kill line valve and performed the third negative test on it.*	

8	BP had used the mud gas separator to direct the gas flow, instead of overboard in to the sea, which was possible via two 14 inch pipes situated at portside and starboard side of the rig.	"Transocean's well control handbook indicates that if gas has migrated or has been circulated above the BOP stack before the well is shut in, the choke manifold and mud gas separator may no longer be available to control the flow rates when the gas in the riser reaches the surface.[273] Both companies recommend using the diverter lines when flow rates are too high for the mud gas separator."[4]
	GAP Analysis*: The mud gas separator should only be used to direct well kick of smaller quantity without overwhelming the diverter system, when the kick flows through the separator, the gas and mud are separated and the gas is flared off safely at the top of the rig.*	

#	Base design followed in the Macondo Well	GAP w.r.t MMS Regulations prior to Macondo Blowout
9	During the events of Temporary Abandonment, BP had actually decided to set the cement plug at 3300ft below the seafloor, this caused the displacement of 3300ft of drilling mud with lighter seawater prior to negative pressure testing.	"As part of BP's plan to temporarily abandon the well, BP intended to install a 300 ft. cement plug in the well at a depth of approximately 3,300 ft. below the seafloor to prevent wellhead seal area contamination and to provide sufficient weight from the drill string to set the lockdown sleeve. **MMS regulations require the plug in the production casing be set no more than 1,000 ft. below the mudline,** (seafloor).[74] This plan required two important interconnected simultaneous operations: displacement of the drilling mud with seawater and offloading the drilling mud to a supply vessel."[2]
	GAP Analysis: *If BP had followed the MMS regulation to place the cement plug at 1000ft below the mudline, then that would not have displaced 2300ft of heavier drilling fluid's hydrostatic pressure on the formation. Hypothetically, even if the following negative pressure test had failed (at this point the formation had actually started following in to the well) the BP team would still have been able to install the cement plug and the lockdown sleeve. And when the production rig was brought in with*	

	its own BOP, it could have identified and / or dealt with the formation flow more effectively. And the Deepwater horizon with its faulty drilling BOP when moved to a new well, has to be tested prior to installation according to NORSOK D-010 Rev.3, 2004 (or its equivalent international standard) which was in effect during 2010, this could have helped notice the faulty control pods.	
10	BP did not perform the negative pressure tests based on any guidelines or procedure, they had done the test based on the experience of the rig crew and likely had no possible way of verifying the results with any benchmark standards.	" While the MMS had requirements for positive pressure testing of the casing, the MMS did not have any specific requirements or guidelines for the negative pressure testing."[2]
	***GAP Analysis**: Had there been any specific guidelines, then the rig crew could have interpreted the excessive flow and pressure built up on the drill pipe when it was shut in during the negative pressure tests. Instead of performing consecutive negative pressure test, the rig crew would have considered the test failed and could have sort advice or suggestions from onshore experts / personnel and possibly could have understood that well had started flowing. Rig crew could have had more time on an action plan to mitigate the consequences of the blowout.*	
11	The Halliburton's OptiCem analysis that BP had asked for did say that the nitrogen cement slurry in the Macondo well with long string production casing likely results in gas flow problems. BP still chose to go ahead. Before receiving the report from Halliburton, BP installed the long casing string with six centralizers.	"Halliburton's best practices document also addresses gas flow potential. It states: Although gas flow may not be apparent at surface, it may occur between zones, which can damage the cement job and eventually lead to casing pressure at the surface. The OptiCem program can be used as a tool to determine the gas flow potential of any primary cement job."[4]
	***GAP Analysis:** If BP had waited for the OptiCem Report they could have known valuable information on the condition of the 'cement column' in the annulus. They would have known that they had poor cement job, cement contamination as well as crucial information on the compressive strength of the cement.*	
12	Based on the requirement of MMS, BP did not have to perform mandatory function test of the BOP shear rams, it only needed	"The MMS regulatory response was to require operators to submit documentation showing that the shear rams that they used in their BOP were capable of

	to provide documentation showing that the BOP was capable of shearing the pipe and MMS regulation did not specify anything about third party verification or proof of the same.	shearing pipe in the hole under maximum anticipated surface pressures."[4]
	GAP Analysis: *It should be noted that the MMS regulation specifies w.r.t. maximum anticipated surface pressure and not the maximum working pressure (in the newer regulations following Macondo blowout, maximum working pressure is used, for example in NORSOK D-010 rev 4, 2013, Annexure A, Table 38, the casing shear rams are to be tested to a maximum of 70% working pressure).*	

#	Base design followed in the Macondo Well	GAP w.r.t API Regulations
13	The tail cement had 16.74 ppg (nitrogen foam cement) and the rat hole had been filled with 14.0 pgg (synthetic oil based mud). [4]	**API RP 65-2** **Section 5.8.4 Rathole** says "Rathole beneath the casing shoe can lead to contamination of cement during placement, or drilling fluid can swap with the cement after placement. These can result in poor strength development, pockets of drilling fluid, or a wet shoe. Rathole length should be minimized or filled with densified drilling fluid."[8]
	GAP Analysis*: Since the rathole was filled with a lighter fluid, the heavier tail cement could have been mixed with the drilling mud in the rathole, this could have led to the contamination of the cement in the casing shoe and the production liner annulus.*	
14	BP proceeded to perform the primary cement job and other succeeding operations (float collar conversion, negative pressure test etc.) even without the compressive strength analysis report from Halliburton.[4]	**API RP 65-2** **Section 4.6.3 WOC Guidelines Prior to Removing a Temporary Barrier Element** says "If design and operational parameters indicate isolation of potential flow zones, cement **shall** be considered a physical barrier element only when it has

<table>
<tr><td></td><td></td><td>attained a minimum of 50 psi compressive or sonic strength. The 50 psi compressive or sonic strength threshold exceeds the minimum static gel strength value needed to prevent fluid influx. Local regulations shall be adhered to with regards to WOC. However, caution should be exercised when the specified
WOC time is less than the time required for the cement to reach a strength of 50 psi."[8]</td></tr>
<tr><td></td><td colspan="2">GAP Analysis: Only a compressive strength analysis of the cement job would give information on Waiting on Cement (WOC), the time required to achieve minimum 50psi compressive strength. As seen from the API regulation, the cement job can only be considered as a well barrier element, only if it had achieved at least 50psi compressive strength, without the report from Halliburton BP could not have known the current compressive strength of the cement job.</td></tr>
<tr><td>15</td><td>BP had instructed Halliburton to perform OptiCem models for the primary cement job, with 6 centralizers at 'varying spacing' but the Halliburton's OptiCem model used incorrect data, it had used 7 centralizers as well as centralizer spacing to be 45feet.[4]</td><td>API RP 65-2
Section 5.4.2 Centralizers
says "Appropriate casing centralization is important to successful cement placement and zonal isolation. Casing centralizers exist in many models and designs and are generally categorized as either rigid, solid or bow-spring models. Auxiliary functionalities such as flow diversion and mechanical friction-reduction are also available. Custom-built centralizers are available for either slimhole or extremely large annular clearances."[8]</td></tr>
<tr><td></td><td colspan="2">GAP Analysis: It is not known why Halliburton used incorrect information, either way the Halliburton OptiCem report had not reached BP prior to the blowout, BP still choose to proceed to subsequent operations following cementing.[4]</td></tr>
<tr><td>16</td><td>BP and Transocean attempted the float collar conversion following primary cementing of the production liner, which</td><td>API RP 65-2
Section 5.10.2 WOC</td></tr>
</table>

	was followed by temporary abandonment sequence.	says "Operations on the well following cementing should be done in such a way that they will not disturb the cement and damage the seal or cause the cement to set improperly."[8]
	GAP Analysis: *Following the pumping of primary cement mix, BP proceeded to convert float collar even without the compressive strength analysis from Halliburton, the float collar should have converted at 500-700 psi at optimal flow rate see Appendix D. But the float collar was assumed to be converted at 3142 psi. It is possible that this high pressure could have disturbed or damaged the cement barrier and contributed largely to the blowout.*	
17	BP performed a partial displacement of the drilling mud prior to cementing.	"Consistent with API RP 65, Halliburton's internal cementing best practices document also advises that full well circulation be performed prior to cementing".[4]
	GAP Analysis: *With concerns of lost circulation events prior to cementing, BP decided to perform only a partial drilling mud displacement, which means that not all of the drilling mud (which was used to drill the open hole internal from ~17000ft to ~18000ft) were removed. There is a possibility that drill cuts might still be suspended in the annulus and this had a serious consequence on cement slurry channelling i.e. cement slurry flows on the wider side of the wellbore with stagnant drilling mud on the other side (contamination of cement).*	

III.2.2 Technical GAPs between NORSOK D-010 Revision 3, 2004 Vs NORSOK D-010 Revision 4, 2013 (Post-Macondo Blowout)

Following the Macondo Blowout on April 20th 2010, Standards Norway (NORSOK) has made drastic changes to the D-010 (**Well integrity in drilling and well operations**) to avoid such calamities in the Norwegian Continental Shelf (NCS) as well as to safe guard the high Health, Safety and Environmental (HSE) standards of Norway. The following tables performs the GAP analysis by showing the changes / updates of NORSOK D-010 (Revision 3, 2004) which existed before the Macondo Blowout and NORSOK D D-010 (Revision 4, 2013) which was revised post-Macondo.

NOTE:

The main sources for the following GAP analysis includes

1) Literature review of this thesis

2) All the footnotes included in this thesis,

3) References section of this thesis

4) Color denotes that recommendation;

For example

1 : is a High Impact GAP

2: is a Medium Impact GAP

3: is a Low Impact GAP

#	NORSOK D-010, Revision 3, 2004[9]	NORSOK D-010, Revision 4, 2013[7]
18	Critical casing cement is not addressed in NORSOK D-010, rev 3	**"3.1.9 critical casing cement** is defined as the casing cement in the following scenarios: the production casing / liner, when set into/through a source of inflow with hydrocarbons; the production casing / liner, when the same casing cement is a part of the primary and secondary well barriers; wells with injection pressure which exceeds the formation integrity at the cap rock."[7]
	GAP Analysis: *Following the Macondo blowout the critical casing cement definition sets more stringent standards for critical casing cement w.r.t HSE*	
19	**"3.1.38** **suspension** "well status, where the well operation is suspended without removing the well control equipment. Example - Rig skidded to do short term work on another well, strike, rough weather conditions, waiting on equipment, etc."[9]	**"3.1.54** **suspension** "well status, where the well operation is suspended without removing the well control equipment. **This applies to wells under construction or intervention** EXAMPLE Rig skidded to do short term work on another well, strike, WOW, waiting on equipment, etc."[7]
	GAP Analysis: *Suspension criteria now specifically includes wells under construction as well as intervention.*	

20	**"3.1.19** **permanent abandonment** "well status, where the well **or part of the well**, will be plugged and abandoned permanently, and with the intention of never being used or re-entered again"[9]	**"3.1.32** **permanent abandonment** "well status, where the well is abandoned permanently and will not be used or re-entered again"[7]
	GAP Analysis: *Only the entire well can be abandoned. Only a part of a well can no longer be permanently abandoned.*	
21	**"3.1.40** **temporary abandonment** well status, where the well is abandoned and/or the well control equipment is removed, with the intention that the operation will be resumed within a specified time frame (from days up to several years). **Example** - Pulling BOP for repair, re-entry at a later stage to perform sidetrack - or well test, skidding rig to do higher priority well work, assessment of well data and converting a well from an exploration to a development well, etc."[9]	**"3.1.56** **temporary abandonment – with monitoring** well status, where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested **NOTE** If the criteria cannot be fulfilled, the well shall be categorized as a temporary abandoned well without monitoring."[7] **"3.1.57** **temporary abandonment – without monitoring** well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested"[7]
	GAP Analysis: *Monitoring of the well (if possible) has been brought in Post Macondo.*	

<table>
<tr>
<td rowspan="2">22</td>
<td>“4.2.3.2 Function and number of well barriers
The function of the well barrier and WBE shall be clearly defined.
There shall be one well barrier in place during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled cross flow in the wellbore between formation zones.
There shall be two well barriers available during all well activities and operations, including suspended or
abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the
borehole / well to the external environment.”[9]</td>
<td>“4.2.3.1 Function and number of well barriers
The following number of well barriers shall be in place:”[7]
<table>
<tr><th>Minimum number of well barriers</th><th>Source of inflow</th></tr>
<tr><td>One well barrier</td><td>a) Undesirable cross flow between formation zones
b) Normally pressured formation with no hydrocarbon and no potential to flow to surface
c) Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapour)</td></tr>
<tr><td>Two well barriers</td><td>d) Hydrocarbon bearing formations
e) Abnormally pressured formation with potential to flow to surface</td></tr>
</table>
</td>
</tr>
<tr>
<td colspan="2">GAP Analysis: Revision 4, describes the number of well barriers as ‘the minimum number of well barriers’ that should be at place during various well activities. Minimum two well barriers are required for hydrocarbon bearing zones and minimum one well barrier is required for hydrocarbon formation with no potential to flow to surface (i.e. for example, very low permeability).</td>
</tr>
<tr>
<td>23</td>
<td>“4.2.3.4 Initial verification of the well barrier
When the well barrier has been constructed, its integrity and function shall be verified by means of
• leak testing by application of a differential pressure,</td>
<td>“4.2.3.5 Verification of well barrier elements
When a WBE has been installed, its integrity shall:
a) be verified by means of pressure testing by application of a differential pressure; or</td>
</tr>
</table>

• functioned testing of WBEs that require activation, • verification by other specified methods."[9]	b) when a) is not feasible, be verified by other specified methods. **Well barrier elements that require activation shall be function tested.** A re-verification should be performed if: c) the condition of any WBE has changed, or; d) there is a change in loads for the remaining life cycle of the well (drilling, completion and production phase)."[7]

***GAP Analysis**: The BOP of the Macondo well supplied by Cameron was not required to be inflow tested prior to delivery to BP. Prior to Macondo blowout, it was not mandatory for equipment suppliers to perform a factory acceptance test (FAT), this substantially compromised to check the integrity of the parts of the BOP (i.e. control pods, solenoid valve etc. used in Deepwater horizon) in the Deepwater horizon.*

<table>
<tr>
<td>24</td>
<td>Well barrier depth position has not been illustrated in NORSOK D-010, Rev 3, 2004</td>
<td>
“9.6.2 Well barrier acceptance criteria
The following individual or combined well barriers/isolations shall be a result of well plugging activities:
Table 24 – Well barrier depth position
<table>
<tr><th>Name</th><th>Function</th><th>Depth position</th></tr>
<tr><td>Primary well barrier</td><td>To isolate a source of inflow, formation with normal pressure or over-pressured/ impermeable formation from surface/seabed.</td><td>The base of the well barriers shall be positioned at a depth were formation integrity is higher than potential pressure below, see 4.2.3.6.7 Testing of formation.</td></tr>
<tr><td>Secondary well barrier</td><td>Back-up to the primary well barrier, against a source of inflow</td><td>As above</td></tr>
<tr><td>Crossflow well barrier</td><td>To prevent flow between formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below.</td><td>As above</td></tr>
<tr><td>Open hole to surface well barrier</td><td>To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present.</td><td>No depth requirement with respect to formation integrity</td></tr>
</table>
The overburden formation including shallow sources of inflow shall be assessed with regards to abandonment requirements.”[7]
</td>
</tr>
<tr>
<td></td>
<td colspan="2">GAP Analysis: Rev 4 has included the depth position in a well barrier acceptance criteria, this is used to direct the operators/service companies in setting the cement plug, packer position etc.</td>
</tr>
</table>

25	**"15.22 Table 22 – Casing cement** **C. Design, construction and selection** 1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 General: Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 Conductor: No requirement as this is not defined as a WBE.	**"15.22 Table 22 – Casing cement** **C. Design, construction and selection** 1. A cement program shall be issued for each cement job, minimum covering the following: a) casing/liner centralization and stand-off to achieve pressure and sealing integrity over the entire required isolation length; b) use of fluid spacers; c) effects of hydrostatic pressure differentials inside and outside casing and ECD during pumping and loss of hydrostatic pressure prior to cement setting up; d) the risk of lost returns and mitigating measures during cementing. **2. For critical cement jobs, HPHT conditions and complex/foam slurry designs the cement program shall be verified independent (internal or external), qualified personnel.** 3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. **The tests shall provide thickening time and compressive strength development.** 4. The properties of the set cement shall provide lasting zonal isolation, structural support, and withstand expected temperature exposure. 5. Cement slurries used for isolating sources of inflow containing

<table>
<tr><td rowspan="2"></td><td>5.3 Surface casing: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed
5.4 Casing through hydrocarbon bearing formations: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones.
For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less.
6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability.
7. Requirements to achieve the along hole pressure integrity in slant wells to be identified."[9]</td><td>hydrocarbons shall be designed to prevent gas migration, including CO_2 and H_2S, if present.
6. Planned casing cement length:
a) Shall be designed to allow for future use of the well (sidetracks, recompletions, and abandonment).
b) General: Shall be minimum 100 m MD above a casing shoe/window.
c) Conductor: Should be defined based on structural integrity requirements.
d) Surface casing: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be at surface/seabed.
e) Production casing/liner: Shall be minimum 200m MD above a casing shoe. If the casing penetrates a source of inflow, the planned cement length shall be 200m MD above the source of inflow.
a. Note: If unable to fulfil the requirement when running a production liner, the casing cement length can be combined with previous casing cement to fulfil the 200m MD requirement."[7]</td></tr>
<tr><td colspan="2">GAP Analysis: Following the Deepwater horizon the 'critical cement job' definition has been brought in, and also for complex cement mix (i.e. nitrogen foam mix) laboratory test should be verified by a third party qualified personnel, this could be an independent in house department or a third party</td></tr>
</table>

	company. Once the primary cement job is completed any subsequent operations should only follow after the cement has been set (give the cement sufficient hardening time prior to subsequent operations). The critical cement should be made to prevent gas migration (gas flow problem).	
26	**"15.22 Table 22 – Casing cement** **D. Initial verification** 1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site."[9]	**"15.22 Table 22 – Casing cement** **D. Initial verification** **Cement should be left undisturbed until it has reached sufficient compressive strength.** 1. The cement sealing ability shall be verified through a formation integrity test when the casing shoe/window is drilled out. 2. The cement length shall be verified by one of the following: **a) Bonding logs: Logging methods/tools shall be selected based on ability to provide data for verification of bonding. The measurements shall provide azimuthal/segmented data. The logs shall be verified by qualified personnel and documented.** **b) 100 % displacement efficiency based on records from the cement operation** (volumes pumped, returns during cementing, etc.). Actual displacement pressure/volumes should be compared with simulations using industry recognized software. **In case of losses, it shall be documented that the loss zone is above planned TOC**. Acceptable documentation is job record comparison with similar loss case(s) on a reference well that has achieved sufficient length verified by logging.

		c) In the event of losses, it is acceptable to use the PIT/FIT or LOT as the verification method only if the casing cement shall be used as a WBE for drilling the next hole section. (This method shall not be used for verification of casing cement as a WBE for production or permanent abandonment.) 3. **Critical casing cement shall be logged** and is defined by the following scenarios: a) the production casing/production liner when set into/through a source of inflow with hydrocarbons; b) the production casing/production liner when the same casing cement is a part of the primary and secondary well barriers; c) wells with injection pressure which exceeds the formation integrity at the cap rock. 4. Actual cement length for a qualified WBE shall be: a) above a potential source of inflow/ reservoir; b) 50 m MD verified by displacement calculations or 30 m MD when verified by bonding logs. The formation integrity shall exceed the maximum expected pressure at the base of the interval. c) 2 x 30m MD verified by bonding logs when the same casing cement will be a part of the primary and secondary well barrier.

		d) The formation integrity shall exceed the maximum expected pressure at the base of each interval. e) For wells with injection pressure exceeding the formation integrity at the cap rock: The cement length shall extend from the upper most injection point to 30 m MD above top reservoir verified by bonding logs."[7]
	GAP Analysis: *The critical casing cement should be verified by cement bonding logs (CBL), full displacement must be done during critical cementing operation, and if lost circulation has been seen then the TOC must be above the loss zone. In the Macondo well, 4000 barrels of mud was lost between 17000ft-18000ft and the final TOC of the critical cement job was 17260ft. It should be noted that pressure integrity test/formation integrity test cannot be used to verify the cement job for well abandonment any more.*	
27	NORSOK D-010 Rev 3, 2004 does not comprehensively describes the details of a negative pressure test/ inflow pressure test.	**"4.2.3.6 Pressure testing of well barriers** **4.2.3.6.5 Inflow testing during drilling and well activities** Inflow testing is performed to verify the WBE's ability to withstand a pressure differential, e.g. when displacing the well to underbalanced fluid in preparation for subsequent operations such as completion, well testing, deep water riser disconnect, drilling out of casing below a permeable higher pressure zone, etc. The execution of an inflow test shall be described by a detailed procedure, which should contain the following information: a) an identification of the WBEs to be tested; b) **identification of the consequences of a leak;**

		c) **the risk of inconclusive results due to large volumes, temperature effects, migration, etc.;** d) **a plan of action in the event that leak occurs or if the test is inconclusive;** e) a schematic diagram showing the configuration of test lines and valve positions; f) all operational steps and decision points; g) **defined acceptance criteria for the test.** The following apply for the execution of an inflow test: h) the consequences of a failed inflow test shall be evaluated; i) where practicable, a pressure test shall be applied to the WBE to be inflow tested; j) the secondary well barrier shall be tested to ensure ability to withstand differential pressure should the inflow test fail; k) volume and pressure control shall be maintained at all times during displacement and testing; l) during inflow testing it shall be possible to displace the well back to overbalanced fluid at indication of flow or in case of inconclusive results; m) during displacement, non-shearable components shall not be placed across the BOP shear ram;

		n) **displacement to a underbalanced fluid shall be performed with a closed BOP and constant bottom hole pressure;** o) when the displacement is complete, the well shall be closed in without reducing the bottom hole pressure; p) the bottom hole pressure shall be reduced in steps to a pre-defined differential pressure; q) the pressure development shall be monitored for a specified time period for each step."[7]
	GAP Analysis: *In the Macondo well, the displacement of 3000ft of heavier drilling mud with lighter seawater was done without a closed BOP, it was done using the drill pipe, with the BOP-annular preventer closed around the drill pipe, in Rev 4 it has been prescribed to perform the displacement via the supplementary lines in the BOP (i.e. kill line, choke line, boost line) and that BOP should be closed at all times during displacement.* *When the Macondo rig crew conducted the first negative pressure test (test failed), they did not even consider that it could be caused due to hydrocarbon in-flux and that the primary cement job failed. Rev 4 clearly asks the operators/service companies to identify the risks of any inconclusive results i.e. excessive flow rate in the drill pipe and/or pressure built up in the drill pipe as was the case in Macondo.*	

28	**15.4 Table 4 - Drilling BOP** **Features** / **Acceptance criteria** **A. Description** — The element consists of the wellhead connector and drilling BOP with kill/choke line valves. **B. Function** — The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the well bore with or without tools/equipment through the BOP. **C. Design construction selection** 1. The drilling BOP shall be constructed in accordance with NORSOK D-001. 2. The BOP WP shall exceed the MWDP including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the well bore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented. 4. When running non shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non shearable item. 5. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV. 6. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity. 7. There shall be an outlet below the LPR. This outlet shall be used as the last resort to regain well control in a well control situation. 8. HTHP: The BOP shall be furnished with surface readout pressure and temperature. 9. Deep water: 9.1. The BOP should be furnished with surface readout pressure and temperature. 9.2. The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way. 9.3. Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.) 9.4 From a DP vessel it shall be possible to shear full casing strings and seal thereafter. If this is not possible the casings should be run as liners.	**15.4 Table 4 – Drilling BOP** **Features** / **Acceptance criteria** **A. Description** — The element consists of the wellhead connector and drilling BOP with kill/choke line valves. **B. Function** — The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the wellbore with or without tools/equipment through the BOP. **C. Design construction selection** 1. The drilling BOP shall be constructed in accordance with NORSOK D-001. 2. A risk analysis shall be performed to decide the best BOP configuration for the location in question. The risk analysis should take the following into account: a) position of different ram types; b) choke and kill line access position; c) ability to hang off pipe and retain ability to close shear ram, including contingency closure of rams if available; d) ability to centralize pipe prior to closing shear ram; e) back-up shear ram. 3. The BOP WP shall exceed the WDP including a margin for killing operations. 4. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the wellbore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented. 5. When running non-shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non-shearable item. Other activities should be coordinated in order to minimize the overall risk level on the installation while running non-shearable items through the BOP. 6. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV. 7. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity. 8. There may be an outlet below the LPR. This outlet shall not be used as a choke line unless a proper risk analysis has been performed. The number of flanges shall be minimized. 9. HPHT: The BOP shall be furnished with surface readout pressure and temperature. 10. Deep water: a) The BOP shall be furnished with surface readout pressure and temperature. b) The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way. c) Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.) d) From a DP vessel it shall be possible to shear full casing strings and seal thereafter, by use of a combination of casing shear ram and blind shear ram. Otherwise, the casings should be run as liners.
	GAP Analysis: *post Macondo, the Rev 4 has made changes to include a risk analysis of BOP configuration, this takes in to account a) the centralization of the pipe prior to the initiation of the BSR in case of an emergency, b) a back- up shear ram, c) contingency closure of rams if available. It is to be noted*	

	that during the events of the Macondo blowout, the ROV initiated auto-shear function succeeded to shear the pipe but failed to seal the wellbore as the pipe had been offset from the BSR blades. This in actuality was the cause of the catastrophic environmental disaster.

29

Annex A
(Normative)
Leak test pressures and frequency for well control equipment

Table A.1 - Routine leak testing of drilling BOP and well control equipment

	Frequency / Element	Stump	Before drilling out of casing: Surface	Before drilling out of casing: Deeper casing and liners	Before well testing	Periodic: Weekly	Periodic: Each 14 days	Periodic: Each 6 months
BOP	Annulars	MWDP 1)	Function	MSDP 1)	TSTP 1)	Function	MSDP 1)	WP x 0,7
	Pipe rams	MWDP	Function	MSDP	TSTP	Function	MSDP	WP
	Shear rams	MWDP	Function	MSDP	TSTP	Function		WP
	Failsafe valves	MWDP	Function	MSDP 3)	TSTP	Function	MSDP 3)	WP
	Well head connector	MWDP	MSDP		TSTP		MSDP	WP
	Wedge locks	Function						
Choke/kill line and manifold	Choke/kill lines	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	manifold	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	Valves	Function	Function	Function	Function		Function	
	Remote chokes							
Other equipment	Kill pump	WP 2)		MSDP			MSDP	WP
	Inside BOP	MWDP 2)		MSDP	TSTP		MSDP	WP
	Stabbing valves	MWDP 2)		MSDP	TSTP		MSDP	WP
	Upper kelly valve	MWDP 2)		MSDP			MSDP	WP
	Lower kelly valve	MWDP 2)		MSDP			MSDP	WP

Legend

WP	working pressure
MWDP	maximum well design pressure
MSDP	maximum section design pressure
Function	Function testing: testing shall be done from alternating panels/pods.
TSTP	tubing string test pressure
1)	Or maximum 70 % of WP
2)	Or at initial installation
3)	From above if restricted by BOP arrangement

NOTE 1 All tests shall be 1,5 MPa to 2 MPa/5 min and high pressure/10 min.

NOTE 2 If the drilling BOP is disconnected/re-connected or moved between wells without having been disconnected from its control system, the initial leak test of the BOP components can be omitted. The wellhead connector shall be leak tested.

NOTE 3 The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

Annex A - Test pressures and frequency for well control equipment

The tables in this section are requirements (shall).

Table 38 – Routine pressure / leak testing of drilling BOP and well control equipment

	Frequency / Element	Stump	Before drilling out of casing: Surface casing	Before drilling out of casing: Deeper casing and liners	Before well testing	Periodic: Weekly	Periodic: Each 14 days	Periodic: Each 6 months
BOP	Annular preventers	WDP[1]	Function	SDP[1]	WDP[1]	Function	SDP[1]	WPx0,7
	Pipe rams	WDP[14]	Function	SDP	WDP	Function	SDP	WP
	Shear rams	WDP	Function	SDP	WDP	Function[15]		WP
	BOP choke and kill valves[3]	WDP	WDP[6]	SDP	WDP	Function	SDP	WP
	Well head connector	WDP	WDP[12]		WDP		SDP	WP
	Ram locking system	Function[10]						
	Casing shear ram	Function	Function	Function	Function			
BOP control system	Shear boost system	Function						
	Accumulator precharge pressure	Check						Check[8]
	Hydraulic chambers[5]	WP						
Secondary emergency systems	Emergency Acoustic system	Function	Function[11]	Function[11]		Communication	Close one ram	
	All ROV hot stab functions	WP						
	Emergency disconnect system	Function	Function[9]					
	Deadman (el. & hyd.power lost)	Function	Function[9]					
	Autoshear (when disconnecting)	Function	Function[9]					
Choke/kill line and manifold	Choke/kill lines	WDP	WDP	SDP	WDP		SDP	WP
	Manifold valves[3]	WDP		SDP	WDP		SDP	WP
	Chokes	Function		Function	Function	Function	Function	
Other equipment	Kill pump	WP[2]		SDP			SDP	WP
	Inside BOP	WDP[2]		SDP	WDP		SDP	WP
	Stabbing valves	WDP[2]		SDP	WDP		SDP	WP
	Upper kelly valve	WDP[2]		SDP			SDP	WP
	Lower kelly valve	WDP[2]		SDP			SDP	WP
	Standpipe manifold	WP[2]		WP[4]			WP[4]	
	Kelly hose	WP[2]		WP[4]			WP[4]	
	Diverter system		Function[13]					
	Riser slip joint	WP [7]						

Legend

WP working pressure

WDP well design pressure

SDP maximum section design pressure

Function Function test schedule shall be developed for testing alternate combinations of all panels and pods. As a minimum one pod from one panel shall be tested each week.

1 Or maximum 70 % of WP

2 Or at initial installation

3 Choke/kill valves (BOP and manifold) of bidirectional type to be tested in the direction they can be exposed to pressure in a well control situation. Valve can be tested from above if it is not practicable to test due to restriction of BOP arrangement.

4 WP of pump liners

5 To include hoses, control pods etc.

6 Test to WDP downstream

7 Riser slip joint packers to be pressure tested to WP before installation.

8 Subsea accumulators on stump. Surface BOP accumulators on minimum 6 months interval. Surface shear boost accumulators on stump.

9 This test shall be performed with BOP installed on wellhead and is only required during commissioning or within 5 year of previous test.

10 Ram locking system to be tested with ram close system vented during ram pressure testing

11 Communication and function BSR

12 For subsea BOP include overpull test to 25 mT after landing, prior to pressure testing.

13 Diverter system to be fully function tested to verify the components intended operations

14 Variable bore rams should be tested with minimum and maximum planned pipe OD

15 If no toolstring through BOP

	GAP Analysis: *The acceptance criteria for the testing and verification of the drilling BOP, drastic changes has been made in Rev 4 following the Macondo blowout, this includes BOP control systems, secondary emergency systems which was not observed in Rev 3. The subsea accumulators at the lower BOP stack as was the case in Macondo should be checked every six months and the testing of BOP elements such as, ram locking system, casing shear ram should be function tested (testing alternate combinations of all control panels and control pods) every week.*

III.3 Major Investigations presented in the GAP Analysis

The table below shows the major investigations performed in this thesis, it highlights the item number of the GAP analysis (chapter III.2, Page 44-68), and the operations that were performed in the respective item number along with the GAP Analysis Impact. It also highlights the Operations Impact that caused the blowout. Only the items 1-17 of the GAP analysis were the direct causes of the Macondo blowout. Items 18-29 are the changes that were made in the NORSOK to prevent the blowout from happening in the NCS.

Item number of the GAP Analysis above	Operations	GAP Analysis Impact
1	Revised total depth and choice of casing string	Low
2	Cementing (Cement evaluation, CBL)	High
3	NPT (Negative Pressure Test)	Medium
4	Cementing (Centralizers, cement slurry design)	High
5	Cementing (annular tolerance)	Medium
6	Cementing (Float collar conversion)	Medium
7	NPT	High
8	Diverter system	High
9	Temporary abandonment (Placement of cement plug)	High
10	NPT	Medium
11	Cementing (OptiCem analysis report)	High
12	BOP (Function testing)	High
13	Cementing (high density fluid in the 'rathole')	High
14	Cementing (Compressive strength analysis)	High
15	Cementing (OptiCem analysis report)	Medium
16	Cementing (Float collar conversion)	Medium
17	Cementing (Partial displacement)	High

60% High Impact GAPs	35% Medium Impact GAPs	5% Low Impact GAPs

60 % due to Cementing	**17% due to NPT**	**23% due to Others**

IV. Discussion

To be able to understand the Deepwater Horizon incident, it is necessary to start with the complexity of the well, the Macondo well was not an easy well to drill. BP and its service companies (collectively called as 'companies' henceforth) in spite of being one of the front runners in the industry, faced immeasurable challenges in the Macondo well. The stuck pipe incident on the 8th April 2010 set the foundation for the major technical challenges that the companies would face in the future. The incident caused BP to side track the well, pushing them behind schedule. This was followed by many lost circulation events that the companies faced until they had reached the ~17000 feet towards the sandstone reservoir. From 17000ft onwards the well turned out be increasingly problematic.

BP had lost around 4000 barrels of expensive drilling mud in the open-hole interval from 17000 feet to 18000 feet, where the drilling margin ran out. This caused BP to prematurely set the total well depth. The revised well depth was inside the actual pay zone and it was against BP's own internal policy, but there was an exemption to this policy if there were any prior circulation losses while drilling as well as if the well had 'zero drilling margin'.

Following the revision of the total well depth, BP had to choose between a 'long string' production casing versus a 'short string' production liner tie-back casing. BP had decided to use the long string based on concerns that the short string would cause mechanical integrity problems at the tie back junction along with annular pressure built up. It is vital to note that the short string would have given BP two additional well barriers, but BP chose a long string on the balance of possibilities. The long string casing gave Halliburton (cementing contractor) serious challenges via reduced annular tolerance for cementing.

Given the fact of the lost circulation events along with the reducing drilling margin from 14.1 ppg (PP at ~17000ft) to 12.6 ppg (PP at ~18000ft) and the reduced annular tolerance, the companies had very few choices and decided to use an unproved nitrogen foam cement slurry with reduced density, which was considered to be just as strong as any other conventional cement slurry.

Additionally, BP chose to ignore the Halliburton's report that said with seven centralizers, the cement job would cause gas flow problems, which is even discussed as a main requirement in NORSOK D-010 standard. BP had performed a partial displacement of the drilling mud prior to cement job instead of a full displacement to the rig. The full displacement could have effectively cleaned the hole by removing the debris and providing smooth wellbore contact. It is possible that the partial displacement had suspended debris and led to channeling of the cement job that followed. This was a compromise against API 65 Recommended practices.

By this time, BP was behind schedule and any subsequent problems would just add fuel to fire, but the Macondo well was unforgiving, it kept throwing challenges to BP who were way behind schedule and increasingly drifting away from the budget. Furthermore, BP proceeded to convert the float collar of the casing shoe without receiving a compressive strength analysis from Halliburton that they had ordered. But before they were in actual possession of the report they proceeded forward, the compressive strength report would have given valuable information on the current state of the cement column (i.e. thickening time, Waiting on Cement etc.) which is a requirement in API 65. Also, if there had been any contamination of the cement slurry from the lighter drilling mud in the rat hole, it could have been inferred from the report. It is also unknown why BP did not follow the API 65 regulation, which clearly directs the companies to use higher weight fluid in the rat hole. It is possible that BP, given the state of the complex well bore issues (lost circulation events, zero drilling margin, uncertain cement slurry etc.), were worried about the formation damage. In addition to this, it is also crucial to remember that the wiper plug disc burst at 2900psi instead of 900psi-1100psi.

The float collar conversion at the end of the cement job did not go as planned, BP compromised on multiple parameters here as well. According to Weatherford specifications the float collar was supposed to convert at 500-700 psi at an optimal flow rate of 5-7 bpm but BP noticed to have converted at a staggering 3142psi at just 4 bpm. It is also not confirmed whether the float collar had indeed been converted. Interestingly, BP did not use higher flow rate, perhaps in view of increased ECD damaging the formation, which was in effect a compromise from the API 65 Regulations as well as Weatherford specification. Pressuring the casing at 3142 psi could have also damaged the annular cement.

Following the primary cementing, BP performed temporary abandonment sequence, which mainly included the setting of the cement plug, negative pressure test and placing a lock down sleeve. According to MMS regulations, the cement plug should be set not more than 1000 feet below the mudline during temporary abandonment. But BP chose to place the cement plug at 3300 feet below the mudline, which also meant displacing 3300 feet of heavy drilling mud with seawater. BP, according to its original plan, could have chosen to place the lock down sleeve before displacing the drilling mud. This could have acted as an additional well barrier.

The negative pressure test (NPT) was one of the most important symptoms that the well was in fact flowing. Since there wasn't any concrete regulatory clarification on the procedure or even on how to verify the results of the negative pressure test, BP had no means to benchmark its negative pressure test. Although BP had no means to benchmark the results with any regulatory guidelines, they could have followed Mr. Lindner's procedure on negative pressure test on the dot (see Chapter III.2.1, #7). Had they followed Mr. Lindner's procedure, they would not have done the third NPT on the kill line before clarifying with BP-onshore experts and likely found that the well was indeed flowing.

Finally when the kick started moving above the BOP as a result of the BOP failure, BP tried to discharge the kick through the mud gas separator instead of overboard in to the sea. This led to gas cloud built up and ignition followed by explosion. BP's internal guideline instructs rig crew to discharge large kick size overboard. Although the working pressure of the diverter packer is 500psi, much lower than the 1400psi formation pressure, it could have provided sufficient time to evacuate the rig crew. Eleven people could have been saved.

V. Conclusion

From this thesis it is possible to see the serious of events that led to the Macondo disaster and the worst case scenarios of such events, in spite of the various safety systems employed to prevent such a disastrous blowout. BP and its service companies took many major decisions which involved a lot of risks, assumptions and non-compliance of regulatory guidelines, including in-house recommended policies. Each such event snowballed with the subsequent event and resulted in the eventual blowout.

The Macondo well gave many signs and symptoms of the blowout, but the lack of oversight and preparedness of the decision makers contributed greatly to the blowout. It can be seen that the companies involved compromised greatly on the safety and made decisions on uncertainty. They did not follow the standards and code on many occasions. Even though Post-Macondo many of the standards & codes, guidelines and recommended practices were revised and updated significantly, the blowout could have been avoided if the companies had followed the guidelines, Standards & Codes that existed Pre-Macondo.

The Macondo blowout could have been avoided. The most important cause of the blowout is 'Human Errors'. The various regulatory guidelines, standards and codes exist to keep the petroleum industry in view with health, safety and environment. Although they exist, they are only a minimum benchmark. It is in hands of the operators and service companies to follow Best Available and Safest Technology (BAST).

From the Major Investigations (see Chapter III.3 Page 69), it is evident that 60% of the technical GAPs that caused the Blowout were of HIGH Impact, followed by medium impact GAPs at 35% and low impact GAPs at 5%. Additionally, 60% of the technical GAPS were due to Cementing, followed by 17% due to Negative Pressure Test and 23% for other activities.

From this thesis, it is evident that BP and its service companies made substantial compromises with respect to regulations and guidelines, some of which were their own internal recommended practices. I would like to remind this famous internet quote "Hope for the best, plan for the worst".

VI. Endnote Citations

Endnote Citation style used-Numbered

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7. (NORSOK), S.N., *Well integrity in drilling and well operations*, in *NORSOK D-010, Rev. 4*. 2013.

VII. References

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OLF - The Norwegian Oil Industry Association, ' Summary Report, Deepwater Horizon, Lessons Learned and Follow-Up', (2012).

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Robert Baligira, *The Effect of Macondo Blowout on Risk Analysis and Risk Management,* 2013, Master's thesis, University of Stavanger.

Appendices A

Summary of decisions made by BP and other Service companies

Decision	Was There A Less Risky Alternative Available?	Less Time Than Alternative?	Decision-maker
Not Waiting for More Centralizers of Preferred Design	Yes	Saved Time	BP on Shore
Not Waiting for Foam Stability Test Results and/or Redesigning Slurry	Yes	Saved Time	Halliburton (and Perhaps BP) on Shore
Not Running Cement Evaluation Log	Yes	Saved Time	BP on Shore
Using Spacer Made from Combined Lost Circulation Materials to Avoid Disposal Issues	Yes	Saved Time	BP on Shore
Displacing Mud from Riser Before Setting Surface Cement Plug	Yes	Unclear	BP on Shore
Setting Surface Cement Plug 3,000 Feet Below Mud Line in Seawater	Yes	Unclear	BP on Shore (Approved by MMS)
Not Installing Additional Physical Barriers During Temporary Abandonment Procedure	Yes	Saved Time	BP on Shore
Not Performing Further Well Integrity Diagnostics in Light of Troubling and Unexplained Negative Pressure Test Results	Yes	Saved Time	BP (and Perhaps Transocean) on Rig
Bypassing Pits and Conducting Other Simultaneous Operations During Displacement	Yes	Saved Time	Transocean (and Perhaps BP) on Rig

(National Commission on the BP Deepwater Horizon Oil Spill, *Deep water: the Gulf oil disaster and the future of offshore drilling, Report to President*, 2011. Pg. 125)

Appendices B

Decisions made during the Macondo well drilling and completion that increased risks

to leave well drilling liner overlaps uncemented
to delay installation of the lock-down for the production casing hanger seal assembly until after the riser mud was circulated out
to use single long string casing instead of liner and tieback
to use minimum positive pressure test on cemented production casing
to not use recommended casing centralizers
to not confirm proper conversion of float equipment
to perform only partial bottoms-up circulation to remove well debris before cementing
to run underbalance test with most of the drill pipe out of the well instead of running a full string to total depth
to not perform cement bond log on basis of cement lift pressures and absence of fluid losses during cementing
to not cement the annulus between production casing and drilling liner
to place sole reliance on float equipment and shoetrack cement to isolate bottom of production casing
to displace drilling mud from riser before setting plug in production casing
to set temporary abandonment plug at 3,300 ft below the seafloor
to use nitrogen in cement mix to lighten the slurry density rather than non-gaseous additives
to not perform proof tests of cement slurry mix to be used in cementing the production casing
to not use MMS approved plan for negative testing
to perform negative testing before cement could have fully cured (based on laboratory test data)
to not verify location of spacer before negative pressure test
to not verify functionality of negative pressure test system before and during negative tests
to perform multiple simultaneous operations preventing accurate determination of mud volumes
to not properly monitor mud pit volumes and flow out meter during displacement of drill mud with seawater during temporary abandonment
to not perform required maintenance of the blowout preventer
to not resolve conflicting information developed during the negative pressure testing
to use lost circulation material as spacer during drill mud—sea water displacement negative testing temporary abandonment operations
to place emergency alarms and response systems on *inhibit*—manual mode of operation
to divert well to the mud gas separator rather than overboard

(Investigation, Deepwater Horizon Incident Joint, *The US Coast Guard (USCG)/Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Joint Investigation Team (JIT)*, 2010, Pg.85)

Appendices C

STANDARDS FOR DRILLING, WELL CONSTRUCTION AND WELL OPERATIONS, RELEVANT TO THE MACONDO ACCIDENTS

Source: Robert Baligira, *The effect of Macondo Blowout on Risk Analysis and Risk Management*, 2013, Master's thesis, University of Stavanger, Pg. 98

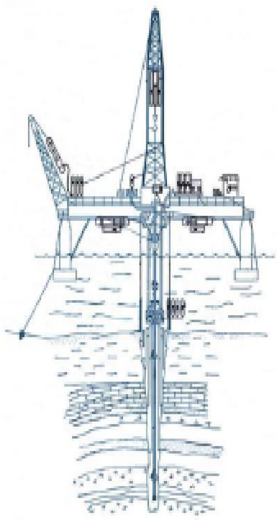
I. Engineering design, systems & equipment related documents:

API TR 6AF *Capabilities of API flanges under combinations of load*	ISO TR 10400/API TR 5C3 *Equations and calculations for the properties of casing, tubing drill pipe and line pipe used as casing or tubing*	ISO 13628-8/API RP 17H *Remotely operated tools and interfaces on subsea production systems* (under revision)
API Spec 16A /ISO 13533 ***Drill through equipment (BOPs)*** **(Revised)**	ISO 10405 *Care and use of casing and tubing*	ISO 13628-11/API RP 17B *Flexible pipe systems for subsea and marine applications*
API Spec 16C Choke and kill systems (Revised)	ISO 10423/API Spec 6A *Wellhead and Christmas tree equipment*	ISO 13679/API RP 5C5 *Procedures for testing of casing and tubing connections* (under revision)
API Spec 16D/ISO 22830 ***Control systems for drilling well control equipment and diverter equipment*** **(Revised)**	ISO 10426-1/API Spec 10A *Cements and materials for well cementing*	ISO 13680/API Spec 5CRA CRA casing and tubing
API Spec 16RCD *Drill through equipment rotating control devices*	ISO 10426-2/API Spec 10B-2 *Testing of well cements* (under revision)	ISO 14224/API Std 689 Collection and exchange of reliability and maintenance data for equipment
API RP 49 Recommended practice for *drilling and well servicing operations involving hydrogen sulfide*	ISO 10426-3/API Spec 10B-3 *Testing of deepwater well cement formulations*	ISO 14310/API Spec 11D1 Packers and bridge plugs
API Std 53 BOP ***equipment systems for drilling wells*** **(Revised)**	ISO 10426-4/API Spec 10B-4 *Preparation and testing of foamed cement slurries at atmospheric pressure* (under revision)	ISO 15156/NACE MR 0175 *Materials for use in H2S-containing environments in oil and gas production*
API RP 59 *Well control operations*	ISO 10426-5/API Spec 10B-5 *Determination of shrinkage and expansion of well cement formations at atmospheric pressure*	ISO 19901-6/API RP 2MOP *Marine operations*
API RP 64 *Diverter systems equipment and operations*	ISO 10426-6/API Spec 10B-6 *Methods of determining the static gel strength of cement formulations*	ISO 19901-7 Stationkeeping systems for floating offshore structures and mobile offshore units (under revision)
API RP 65-1 ***Cementing shallow water flow zones in deep water wells*** **(Revised)**	ISO 10427-3/API RP 10F *Performance testing of cementing float equipment*	ISO 19904-1 *Floating offshore structures—Monohulls, semi-submersibles and spars*
API RP 65-2 ***Isolating potential flow zones during well construction*** **(Revised)**	ISO 11960/API Spec 5CT *Casing and tubing for wells* (under revision)	ISO 20815 *Production assurance and reliability management*
API RP 90 *Annular casing pressure management for offshore wells* (under revision)	ISO 11961/API Spec 5D Steel drill pipe	ISO 23251/API Std 521 *Pressure relieving and depressuring systems* (under revision)
API RP 90-1 (formerly RP 90) *annular casing pressure management for offshore wells* (under revision)	ISO 13354 *Shallow gas diverter equipment*	ISO 28300/API Std 2000 *Venting of atmospheric and low-pressure storage tanks* (under revision)
APPEA *Australia offshore oil and gas title holder self-audit checklist*	ISO 13624-1/API RP 16Q *Design, selection and operation of marine drilling riser systems*	ISO 28781 *Subsurface barrier valves and related equipment*
DNV OS-C101 *Drilling plant*	ISO 13625/API 16R *Marine drilling riser couplings*	**NORSOK D-001** ***Drilling facilities*** **(Revised)**
EI Guidelines for routine and non-routine subsea operations from floating vessels	**ISO 13628-1/API RP 17A** ***Design and operation of subsea production systems*** **(Revised)**	**NORSOK D-002** ***System requirements well intervention equipment*** **(Revised)**
EI Model code of safe practice, Part 17 Volume 1: High pressure and high temperature well planning	ISO 13628-2/API Spec 17J *Unbonded flexible pipe systems for subsea and marine applications*	NORSOK D-SR-007 *Well testing system* (under revision)
EI Model code of safe practice, Part 17 Volume 2: Well control during the drilling and testing of high pressure, high temp offshore wells	ISO 13628-4/API Spec 17D Subsea wellhead and tree equipment	**NORSOK D-010** ***Well integrity in drilling and well operations*** **(Revised —considered in API 96 and ISO 16530)**
EI Model code of safe practice, Part 17 Volume 3: High pressure and high temperature well completions and interventions	**ISO 13628-5/API Spec 17E** ***Subsea umbilicals*** **(Revised)**	Norwegian Oil and Gas 117 *Well integrity guideline*
IMO MODU (Mobile Offshore Drilling Units) Code	**ISO 13628-6/API Spec 17F** ***Subsea production control systems*** **(Revised)**	
	ISO 13628-7/API RP 17G *Completion/ workover riser systems* (under revision)	
	IEC 61892-7 *Mobile and fixed offshore units- Hazardous areas*	

Above table is done by 'Robert Baligira' adapted from (ISO/TC 67 MANAGEMENT COMMITTEE AHG INDUSTRY EVENTS (ISO/TC 67 MC N088), MARCH 1ST, 2011, OGP INTERNATIONAL ASSOCATIONS OF OIL &GAS PRODUCERS, NOVEMBER 2012)

II. Management related documents:

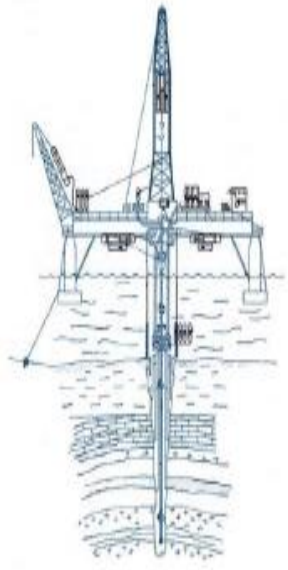
<u>Source:</u> Robert Baligira, *The effect of Macondo Blowout on Risk Analysis and Risk Management*, 2013, Master's thesis, University of Stavanger, Pg. 98

API Bull E3 *Environmental guidance document: Well abandonment and inactive well practices for U.S. exploration and production operations*	OGP 210 HSE *Guidelines for the development and application of HSE management systems* (under revision)	OGP 476 *Recommendations for enhancements to well control training, examination and certification*
API RP 75 *Development of a safety and environmental management program for offshore operations and facilities*	OGP 415 *Asset integrity - the key to managing major incident risks*	OGUK OP006 *Guidance on suspension and abandonment of wells* (under revision)
IADC HSE *Case guidelines for mobile offshore drilling units*	OGP 435 *A guide to selecting appropriate tools to improve HSE culture*	OGUK OP064 *Guidelines on relief well planning — subsea wells*
IADC *Deepwater well control guidelines*		OGUK OP065 *Guidelines on competency for wells personnel including example*
ISO 13702 *Control and mitigation of fires and explosions on offshore production installations* (under revision)		OGUK OP069 *Well integrity guidelines*
ISO 15544 *Requirements and guidelines for emergency response*		OGUK OP070 *Guidelines on subsea BOP systems*
ISO 17776 *Guidelines on tools and techniques for hazard identification and risk assessment* (under revision)		OGUK OP071 *Guidelines for the suspension and abandonment of wells including guidelines on qualification of materials for the suspension and abandonment of wells*
NORSOK Z-013 *Risk and emergency preparedness analysis*		OGUK SC033 *Guidelines for well operators on well examination and competency of well-examiners*

<u>Above table is done by 'Robert Baligira' </u>adapted from (ISO/TC 67 MANAGEMENT COMMITTEE AHG INDUSTRY EVENTS (ISO/TC 67 MC N088), MARCH 1ST, 2011, OGP INTERNATIONAL ASSOCATIONS OF OIL &GAS PRODUCERS, NOVEMBER 2012)

III. Documents in development

Source: Robert Baligira, *The effect of Macondo Blowout on Risk Analysis and Risk Management*, 2013, Master's thesis, University of Stavanger, Pg. 98

API TR PER15K-1 HPHT *Protocol for equipment rated greater than 15K PSI* **API Std 16AR (New)** ***Repair and remanufacture of drill-through equipment (working title)*** API Spec 17W – *Subsea capping stacks* API RP 90-2 *Annular casing pressure management for onshore wells* **API RP 96 Deepwater well design considerations (New)** API Bull 97/IADC *Well construction interface document* ISO TR 12489 *Reliability modelling and calculation of safety systems*		ISO 13628-16/API Spec 17L1 *Petroleum and natural gas industries — Design and operation of subsea production systems — Specification for flexible pipe ancillary equipment* ISO 13628-17/API Spec 17L2 *Petroleum and natural gas industries — Design and operation of subsea production systems — Guidelines for flexible pipe ancillary equipment* ISO 14998 *Completion accessories* ISO 17969 Guidelines on competency for wells personnel ISO 16339 *Well control equipment for HPHT (High Pressure High Temperature) drilling operations* ISO 16530 *Well integrity in the operational phase*

Above table is done by 'Robert Baligira' adapted from (ISO/TC 67 MANAGEMENT COMMITTEE AHG INDUSTRY EVENTS (ISO/TC 67 MC N088), MARCH 1ST, 2011, OGP INTERNATIONAL ASSOCATIONS OF OIL &GAS PRODUCERS, NOVEMBER 2012)

Appendices D

Weatherford Float Collar M45AP Specification:

Weatherford

REVISION	A.2
DATE	1/25/2011
DOCUMENT No.	D000446283

Float Equipment

Flow-Activated Mid-Bore Auto-Fill Float Collar Model M45AP

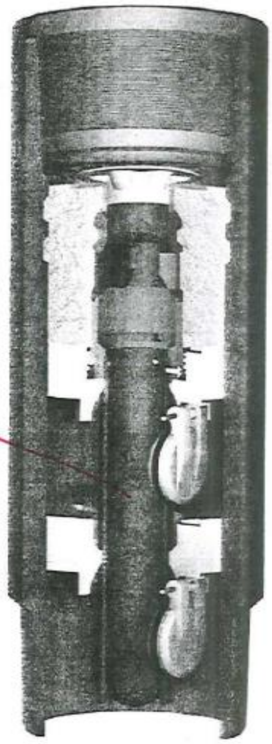
The Weatherford Flow-Activated Mid-Bore Auto-Fill Float Collar contains a surge reducing and debris tolerant PDC drillable valve that allows low circulating rates without conversion. It is recommended for use in wells where running string restrictions or high wellbore inclinations may prevent release of a trip ball from the surface. The integral landing plate accommodates Weatherford's WiperLok™ non-rotating cementing plugs

Applications:

- Pressure sensitive formations and close tolerance annuli, where surge reduction or fast running speeds are desirable.
- Wells with inclinations greater than 30° from vertical.

Features:

- Available in 6-5/8" through 8-5/8" casing sizes
- Large, open bores for solids tolerance and surge reduction
- Can be used in high deviation wellbore profiles
- Two valves for security.
- Flow-activated check valves
- Up to 4 bbl/min circulating rate prior to conversion (8 bbl/min optional)
- 5 to 8 bbl/min de-activation flow rate at 500 to 700 psi (9-13.5 bbl/min optional)
- 1.93" auto-fill diameter
- Valves have 2-3/8" bores after conversion.
- Auto-fill Tube/Cage Assembly made of composite materials
- PDC drillable components.
- Trip ball retained within valve assembly



Performance:

- Back pressure rating:
  - 5000 psi (6-5/8" - 7-5/8")
  - 3000 psi (8-5/8")
- Plug bump pressure rating with Wiperlok plugs:
  - 6800 psi (6-5/8" - 7")
  - 6500 psi (7-5/8")
  - 6400 psi (8-5/8")
- Temperature rating: 400°F (204°C).
- API RP 10F category: IIIC
- Maximum flow rate (24 hours): 10 bbl/min after conversion.
- Conversion pressure:
  - Standard: 500 - 700 psi.
  - Optional: 300 - 400 psi
  - (Conversion pressure is stenciled on float collar)
- Minimum flow area after conversion: 4.33 in^2.

Cementing Products

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EXHIBIT 2562

TREX-02562

WFT-MDL-00020469

Source: MDL 2179 Trial Docs, [Online] Available: http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-02562.pdf [Accessed 30/05/2014]

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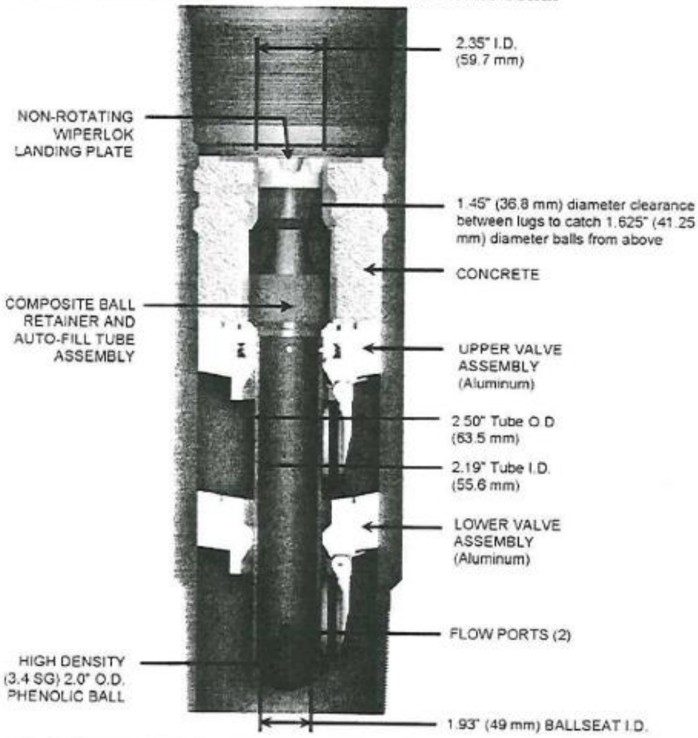
M45AP Flow-Activated Mid-Bore Auto-Fill Float Collar



SIZE in., (mm)	O.D. in., (mm)	GRADE	CASING WEIGHT RANGE lbs/ft	DRILLOUT I.D. in., (mm)	OVERALL LENGTH (8 RND & BTC) in., (mm)	BACK PRESSURE RATING psi	BUMP PRESSURE RATING psi
6-5/8 (168,3)	7.39 (187,7)	STD.	20.00-32.00	5.944 (150,98)	25.25 (641)	5000	6800
		P.G.	20.00-32.00	5.944 (150,98)			
7 (177,8)	7.66 (194,6)	STD.	20.00-32.00	6.351 (161,32)	25.25 (641)	5000	6800
		P.G.	23.00-38.00	6.270 (159,26)			
7-5/8 (193,7)	8.50 (215,9)	STD.	26.40-39.00	6.864 (174,35)	25.50 (648)	5000	6500
		P.G.	26.40-39.00	6.864 (174,35)			
8-5/8 (219,1)	9.63 (244,6)	STD.	24.00-49.00	7.992 (203,00)	25.75 (654)	3000	6400
		P.G.	32.00-49.00	7.845 (199,26)			

Note: These dimensions and weight ranges apply to Std. and P.G. 8-round and buttress float collars only. Other equipment may vary from the above specifications. Verify dimensions and weight ranges on labels furnished with equipment.

Source: MDL 2179 Trial Docs, [Online] Available: http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-02562.pdf [Accessed 30/05/2014]

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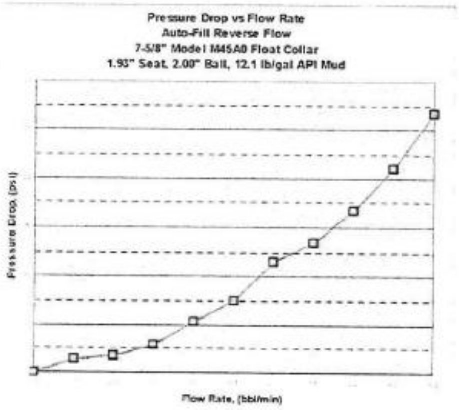
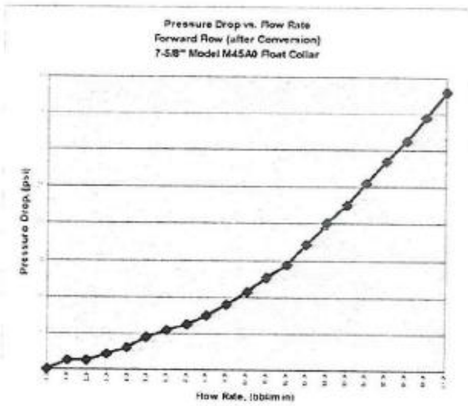
PRESSURE DROP



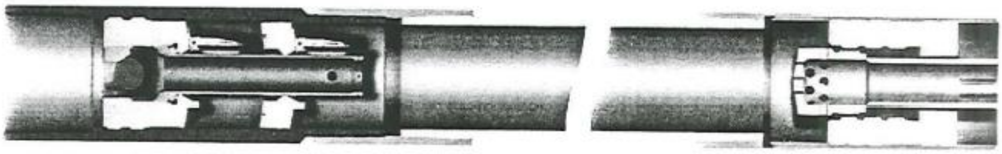
Auto-fill Mode



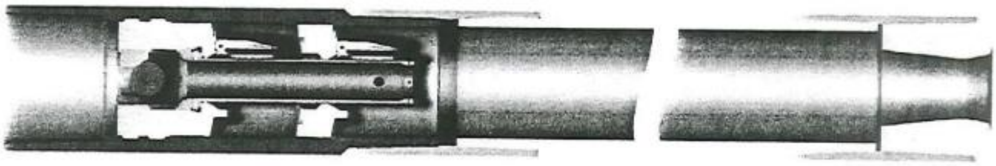
After Activation

RECOMMENDED GUIDE SHOE USAGE

MudMaster Filter Shoe with Hanging Collar (Recommended), M45A0 shown



Cemented or Composite Guide Shoe with 3-1/2" Bore, M45A0 shown



Source: MDL 2179 Trial Docs, [Online] Available:

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CONVERSION PRESSURE AND FLOW RATE

The Flow-Activated Mid-Bore Auto-Fill Float Collar has a pre-set conversion pressure. Conversion at 500 - 700 psi is achieved by four (4) #10-24 UNC brass screws. The Float Collar can be ordered with an optional conversion pressure of 300 - 400 psi. Two (2) #10-24 UNC brass screws produce the optional conversion setting of 300 - 400 psi. The pre-set conversion pressure is stenciled on the Float Collar's shell. Conversion flow rate will depend on fluid density.

STANDARD CONVERSION PRESSURE AND FLOW RATE IN VARIOUS FLUIDS WITH TWO - 0.578"Ø PORTS

(SHADED AREAS REPRESENT CONVERSION PRESSURE AND CORRESPONDING FLOW RATE)

density(ppg)	8.343	density(ppg)	12.2	density(ppg)	16
Water		12.2 ppg Mud		16 ppg Mud	
flow (bbl/min)	psi	flow (bbl/min)	psi	flow (bbl/min)	psi
0	0	0	0	0	0
0.5	2.6	0.5	3.8	0.5	5
1	10.5	1	15.4	1	20.1
1.5	23.6	1.5	34.6	1.5	45.3
2	42	2	61.4	2	80.6
2.5	65.7	2.5	96	2.5	125.9
3	94.5	3	138.2	3	181.3
3.5	128.7	3.5	188.2	3.5	246.8
4	168.1	4	245.8	4	322.3
4.5	212.7	4.5	311	4.5	407.9
5	262.6	5	384	5	503.6
5.5	317.8	5.5	464.7	5.5	609.4
6	378.2	6	553	6	725.2
6.5	443.8	6.5	649	6.5	851.1
7	514.7	7	752.7	7	987.1
7.5	590.9	7.5	864	7.5	1133.1
8	672.3	8	983.1	8	1289.3

NOTE: For conversion flow rates for fluid densities not listed in the chart above, the equation $Q = \sqrt{\frac{P}{1.259\rho}}$, where Q is flow rate in bbl/min, P is conversion pressure in PSI, and ρ is fluid density in lb/gal, approximates the value for conversion flow rate given pressure and fluid density for float collars with the 0.578" ports.

Source: MDL 2179 Trial Docs, [Online] Available: http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-02562.pdf [Accessed 30/05/2014]

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OPTIONAL – HIGH CIRCULATION CONVERSION PRESSURE AND FLOW RATE IN VARIOUS FLUIDS WITH TWO - 0.75"Ø PORTS

(SHADED AREAS REPRESENT CONVERSION PRESSURE AND CORRESPONDING FLOW RATE)

Density(ppg) 8.343		Density(ppg) 10.5		Density(ppg) 12.2		Density(ppg) 14	
Water		10.5 ppg Mud		12.2 ppg Mud		14 lppg Mud	
Flow (bbl/min)	psi	Flow (bbl/min)	psi	Flow (bbl/min)	psi	Flow (bbl/min)	psi
5.0	92.7	5.0	116.7	5.0	135.6	5.0	155.6
5.5	112.2	5.5	141.2	5.5	164.0	5.5	188.3
6.0	133.5	6.0	168.0	6.0	195.2	6.0	224.0
6.5	156.7	6.5	197.2	6.5	229.1	6.5	262.9
7.0	181.7	7.0	228.7	7.0	265.7	7.0	304.9
7.5	208.6	7.5	262.5	7.5	305.0	7.5	350.1
8.0	237.3	8.0	298.7	8.0	347.1	8.0	398.3
8.5	267.9	8.5	337.2	8.5	391.8	8.5	449.6
9.0	300.4	9.0	378.1	9.0	439.3	9.0	504.1
9.5	334.7	9.5	421.2	9.5	489.4	9.5	561.6
10.0	370.9	10.0	466.7	10.0	542.3	10.0	622.3
10.5	408.9	10.5	514.6	10.5	597.9	10.5	686.1
11.0	448.7	11.0	564.8	11.0	656.2	11.0	753.0
11.5	490.5	11.5	617.3	11.5	717.2	11.5	823.0
12.0	534.0	12.0	672.1	12.0	780.9	12.0	896.1
12.5	579.5	12.5	729.3	12.5	847.4	12.5	972.4
13.0	626.7	13.0	788.8	13.0	916.5	13.0	1051.7
13.5	675.9	13.5	850.6	13.5	988.4	13.5	1134.2
14.0	726.9	14.0	914.8	14.0	1062.9	14.0	1219.7
14.5	779.7	14.5	981.3	14.5	1140.2	14.5	1308.4
15.0	834.4	15.0	1050.2	15.0	1220.2	15.0	1400.2

$$Q = \sqrt{\frac{P}{0.445 \cdot \rho}}$$

NOTE: For conversion flow rates for fluid densities not listed in the chart above, the equation where Q is flow rate in bbl/min, P is conversion pressure in PSI, and ρ is fluid density in lb/gal, approximates the value for conversion flow rate given pressure and fluid density for float collars with the 0.75" ports.

MAKE-UP ON CASING STRING:

The Flow–Activated Mid-Bore Auto-Fill Float Collar should be run with a Weatherford MudMaster filter shoe. A guide shoe that has a minimum 3-1/2 inch bore inside diameter may also be run, but at an increased risk of debris settling above the float collar, possibly resulting in plugging or early conversion of the float collar. The 3-1/2 inch bore guide shoe will allow the Auto-Fill Tube to pass through the nose without plugging it off.

Make up the float collar onto the casing string at least one joint above the guide or filter shoe. Apply Weatherford Tube Lok ™ compound to the bottom six thread connections and the float collar threads. Apply to the pin thread only. This helps prevent the shoe joint from backing off during drill-out.

If a trip ball larger than 1.625" diameter will be used above the Flow–Activated Mid-Bore Auto-Fill Float Collar, a ball catching device should be included above the float collar to prevent it from being plugged off.

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RUNNING INTO THE WELL:

When running into the hole the valve should be monitored to confirm that fluid is filling the casing. Observation of fill can be accomplished by several methods. One is by watching the weight indicator and graph to ensure that the string is continually gaining weight and not decreasing or losing weight. Another is to use a thin sheet of paper such as newspaper placed over the top of the casing. The air being displaced out of the casing will blow a parachute effect on the paper. However, a careful grip should be maintained on the paper so as to prevent the paper from being pulled into the casing from a sudden vacuum formed by U-tubing effects.

Well conditions with small annular clearances can produce an overfilling effect, in which well fluids are displaced out of the top of the casing, rather than out of the annulus. This overfill can occur at the rig floor if the mud level is relatively close to the rig floor. This effect can be reduced or eliminated by increasing the weight of the fluid in the casing.

If the casing stops filling automatically, the casing should be filled from the surface and circulation established to clear cuttings and debris.

CIRCULATION:

Should it be necessary to circulate during the casing running operation, the circulation should be kept below 4 bbl/min to prevent premature deactivation of the auto-fill equipment. The duration of circulation should be limited to one hour at 4 bbl/min or eight hours at 2 bbl/min prior to conversion with the standard 0.578" ∅ ports. With the optional 0.75" ∅ ports, the duration of circulation should be limited to one hour at 8 bbl/min or eight hours at 4 bbl/min prior to conversion. If after extended circulation the surface pressure drops below the pressure shown in the Conversion Pressure and Flow Rate in Various Fluids tables for a given flow rate and fluid density (plus friction losses), circulation should be stopped. If higher circulation flow rates are required, the flow rate should be increased to convert the auto-fill valves to hold backpressure.

ACTIVATION OF THE CHECK VALVES:

A pressure of 500 psi to 700 psi (300-400 psi optional) is required to shear the Auto-Fill Tube from the Valve Assembly. The flow rate required to achieve this pressure is listed in the tables above and ranges from 5 to 8 bbl/min for the standard 0.578" ∅ ports or 9 to 13.5 bbl/min for the optional 0.75" ∅ ports, depending on fluid density. Pump at a flow rate that will exceed the 700-psi pressure drop for the corresponding fluid density. A reduction in pressure should be noted when the auto-fill tube is released. The auto-fill tube will then be pumped through the valve assembly.

CEMENTING:

Weatherford WiperLok non-rotating plug sets are recommended for use with Mid-Bore Auto-Fill Float Collars. The top cementing plug should be released while pumping cement. Pump an additional volume of cement equivalent to 10 - 15 feet (three to four meters) on top of the plug, if allowed, to improve drill-out. The displacement rate should be reduced to between 3 and 4 bbl/min to land plugs.

The maximum plug bump pressure is the allowable amount of pressure, above the displacement pressure, prior to bumping the plugs. The maximum plug bump pressures, by size, are listed in the chart included with this document

VERIFICATION OF CHECK VALVE FUNCTION:

If leakage occurs past the Mid-Bore Auto-Fill Valve after displacing cement, circulate the returned displacement volume though the valve, and check for proper operation of the flapper valves. This circulation will produce a forced

Source: MDL 2179 Trial Docs, [Online] Available: http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-02562.pdf [Accessed 30/05/2014]

opening and closing of the flappers. This will assist in removing debris from the valve, which could cause a malfunction.

DRILL-OUT:

Mid-Bore Auto-Fill equipment may be drilled with roller cone or PDC bits. Recommendations for roller cone and PDC bit drill-out can be found in the Weatherford Float Equipment Manual.

Source: MDL 2179 Trial Docs, [Online] Available: http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-02562.pdf [Accessed 30/05/2014]

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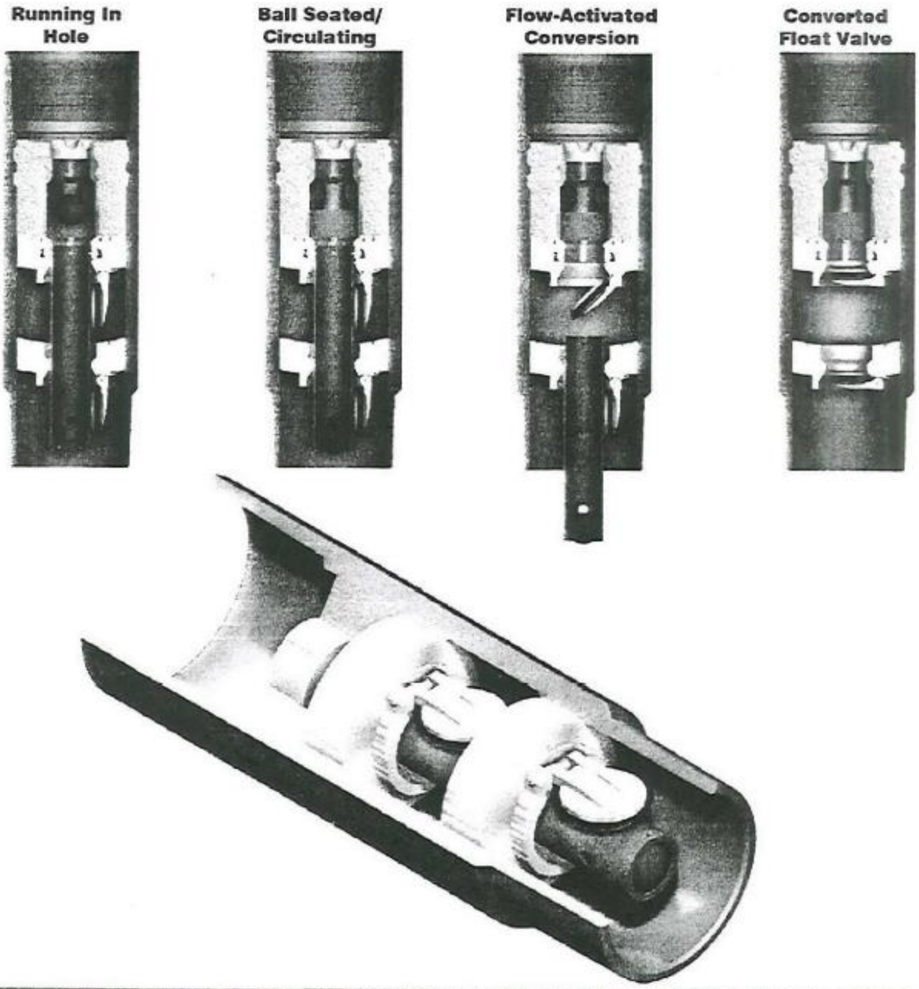
Weatherford

Flow-Activated Mid-Bore Auto-Fill Float Collar Model M45AP

OPERATIONAL SEQUENCE -



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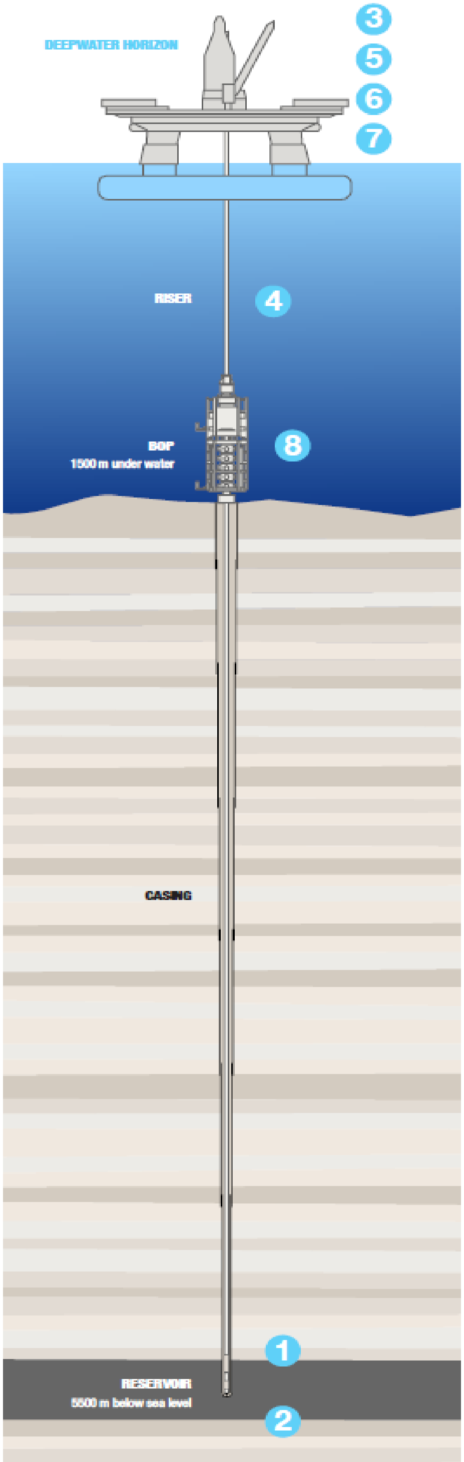
Appendices E

Macondo Blowout Main technical causes



Main technical causes

Well integrity was not established or failed

1 Annulus cement barrier did not isolate hydrocarbons
2 Shoe track barriers did not isolate hydrocarbons

Hydrocarbons entered the well undetected and well control was lost

3 Negative pressure test was accepted although well integrity had not been established
4 Influx was not recognized until hydrocarbons were in riser
5 Well control response actions failed to regain control of well

Hydrocarbons ignited on the Deepwater Horizon

6 Diversion to mud gas separator resulted in gas venting onto rig
7 Fire and gas system did not prevent hydrocarbon ignition

Blowout preventer did not seal the well

8 Blowout preventer (BOP) emergency mode did not seal well

(OLF, NOFO and NORWEGIAN SHIPOWNERS' ASSOCIATION, *Summary Report, Deepwater Horizon, Lessons learned and follow-up*, 2012, Pg.6 [Online] Avaliable: http://www.norskoljeoggass.no/Global/Publikasjoner/_H%C3%A5ndb%C3%B8ker%20og%20Rapporter/DWH%20rapporter/OLFs%20DWH%20rapport%20%202012.pdf Accessed: 16/04/2014)