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ΕΠΙΒΛΕΠΩΝ ΚΑΘΗΓΗΤΗΣ **ΓΕΩΡΓΑΚΟΠΟΥΛΟΣ ΑΝΔΡΕΑΣ**

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ARISTOTLE UNIVERSITY OF THESSALONIKI

MASTERS PROGRAM

HYDROCARBONS EXPLORATION AND EXPLOITATION

DISSERTATION THESIS

SPECIAL
DRILLING MUD CHEMICAL ADDITIVES
FOR DEEP DRILLING

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PREFACE

This thesis is the completion of the master's education in Hydrocarbons: exploration and exploitation. It is the product of the last semester's project spanning a two year Master program ''HYDROCARBONS EXPLORATION AND EXPOITATION'', School of Geology, Faculty of Science.

Several people have contributed not only academically but also practically and without their enormous support, suggestions and insight this thesis would not have been possible. Therefore, firstly, I would like to pay my respects to my head supervisor professor Andreas Georgakopoulos for his time, valuable input and encouragement throughout the entire master period. Furthermore, I would like to thank my fellow classmates for their tremendous help throughout the whole process.

I would also like to thank Anna Vlachakis for her constructive comments to the thesis.

Finally, I would like to thank my family and friends for being helpful and supportive during my time studying at Aristotle University.

ABSTRACT

What is the role of the various additives used to synthesize the drilling mud while a drilling operation? Drilling mud additives are being used to assure the success of drilling and maintain stability throughout the operation. Someone may say drilling fluids are designed to solve or minimize many drilling problems.

From the early stages of the first drilling fluids to the sophisticated contemporary systems, drilling mud has been the heart of drilling operations. Its circulation circuit, required functions and chemical composition are presented.

My goal for this thesis was to prepare a document that could serve as a short guide for drilling mud purposes and composition. For the most part, I oriented the review towards the role of drilling mud additives and their contribution to mud properties. I chose to discuss each item in this review in the order in which it is encountered in any other book with relevant content.

CONTENTS

Thesis structure and reading guide:

The thesis begins with an abstract which summarizes the aim and purpose of the thesis. The Abstract is followed by chapter 1 where the history and recent developments of the drilling mud are briefly mentioned. In this chapter, the circulation system of drilling mud and drilling fluid functions are presented as well.

In chapter 2, initially, the different types of drilling mud are described and a small section of this is dedicated to stale stability. Afterwards, in the second part the various adding agents and their contribution are thoroughly examined. Deep and ultra deep drilling challenges are also mentioned here.

The conclusive chapter follows. A list of referenced literature is shown in the chapter named bibliography.

CHAPTER 1

Historical Data Of Rotary drilling

Rotary drilling is used for a variety of purposes, such as drilling oil, gas, water, geothermal and petroleum storage wells, for mineral assay coring and for mining and construction projects. One of the most significant applications, however, is oil and gas drilling. The rotary method employs a sharp, rotational drill bit to bite its way through the earth's crust. It is very widely used in petroleum industry because of its ability to cut through even the most challenging and hardest formations.

This method of making a hole or a well relies on continuous circular motion of the bit to break rock at the bottom of the hole. Rotary drilling is a nearly continuous process, because cuttings are removed as drilling fluids circulate through the bit and up the wellbore to the surface. This is the reason why rotary drilling is much more efficient than the alternative method, cable tool drilling. Cable tool operations are discontinuous and cuttings removal is inefficient. This difference in efficiency becomes particularly significant as hole depth increases.

Historically, most oil and gas wells drilled since about 1900 have been drilled by the rotary drilling method. This method was developed originally in France in 1860's, however, it did not catch on at first because drilling companies believed petroleum only lay in hard formations where cable tool drilling was the norm. In the 1880's two brothers, named Baker gained reputation for drilling successful water wells in the soft formations of the Great Plains in the US. The rig they used was a rotary unit with a fluid circulating system. This system proved equally successful in the soft unconsolidated rocks of Texas. In 1900, several unsuccessful attempts to drill the great Lucas well at Spindletop provided the proving ground for rotary drilling[1].

Antun Lucas believed there was oil under the dome of Spindletop. He set out to use rotary drilling to find it. Eventually he performed the first rotary drilled well, the Lucas Gusher[2].

Drilling was difficult at first as Lucas and his men ran into the same problems that other drillers had faced along the Texas coastal plain. There is little in the way of rock at the surface in that part of the world. Instead, oil wildcatters had to drill through several hundred feet of sand. This made the hole prone to caving in on them. To help solve this problem, one of Lucas's drillers, Curt Hamill, came up with a solution that was revolutionary at the time. Instead of pumping water down the hole to flush out the cuttings produced by the action of the drill, he used mud. This proved to help not only in retrieving the cuttings, but just as importantly, it was determined that the mud stuck to the sides of the hole and kept it from caving in making it far more beneficial and thus mud has been used in almost every drill hole around the world ever since.

The drilling fluid consisted of water, finely ground cuttings from the hole and clays from local surface soils.

Today, the drilling mud system is far more complicated and sophisticated and is considered to be a major consideration in drilling operations. Here is a definition of drilling muds[3]:

''*The term drilling mud refers to a liquid, gas, or gasified liquid circulating continuum substance used in the rotary drilling process to perform any or all of the various functions required in order to successfully drill a usable wellbore at the lowest overall well cost*.''

Drilling Mud Circulation

HOW MUD CIRCULATION SYSTEM IS ACCOMPLISHED

The mud circulation system is used to circulate drilling fluid down through the drill string and up the annulus, carrying the drilled cuttings from the bottom hole to surface (Drilling fluids engineering manual, 2015). The functions of the drilling fluid will be thoroughly discussed in a subsequent chapter – Drilling Fluids. However, the two main functions of the drilling fluid are to clean the hole of cuttings made by the bit as it proceeds into the ground and to exert a hydrostatic pressure sufficient to prevent formation fluids entering the well. Mud circulation and cuttings removal are two interdependent processes that run continuously during drilling operations.

The main parts of grill mud circulation system are:

- mud pits/ tanks
- mud pumps
- pipes and hoses

- mud return line
- shale shaker

Here is how circulation systems flows[4,5]:

The mud is mixed and conditioned in the mud pits and then circulated downhole by large pumps (slush pumps). The mud is pumped through the standpipe, kelly hose, swivel, kelly and down the drillstring. While, being pumped down the drill string, the mud lubricates and cools the bit. At the bottom of the hole the mud passes through the bit by jetting out of the drill bit's nozzles which weakens the formation thereby making it easier to drill. Thus it emerges via the annulus, carrying cuttings up to surface. The mud's viscosity carries cuttings out of the hole and its density creates more pressure in the well than in the formation, preventing the well blowing out.

On surface the mud is directed from the annulus, through the flowline (or mud return line) and before it re-enters the mud pits the drilled cuttings are removed from the drilling mud by the solids removal equipment. This happens at the shale shakers primarily. The shale shaker that receives the flow of drilling fluid and is directly connected to and at the end of the flow line has a metal container on its head. This container is called possum belly or back tank and its purpose is to slow the flow of drilling mud. Here is where usually the gas trap or gas extractor is placed.

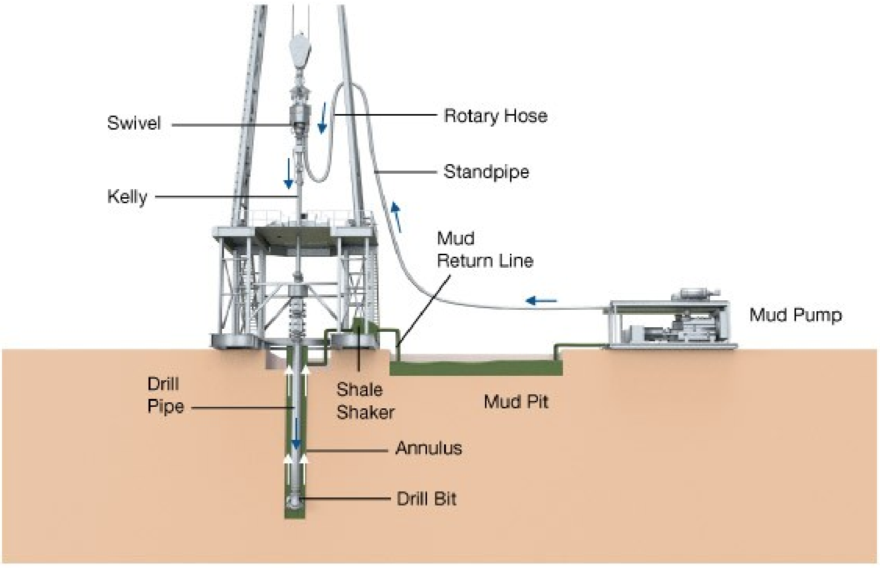
When on the main part of shale shakers, mud begins to be processed. Firstly, it passes through screens which trap the materials from the borehole, before being cycled back into the system which delivers mud to the head of the drill bit. This recirculation process is designed to cut down on waste by reusing as much mud as possible. Depending on the materials being drilled, several screens may be needed to trap the materials, and sometimes the materials themselves are also coated in mud, which means that they will need to be cleaned even after filtration.

Once the drilled cuttings have been removed from the mud it is re-circulated down the hole. The mud is therefore in a continuous circulating system.

The properties of the mud are continuously checked on the rig site. If chemicals addition is needed for properties modification or maintenance will occur in the mud pits, or mud with the required properties will be mixed in separate mud pits and slowly mixed in with the circulating mud.

When the mud pumps are switched off, the mud will stop flowing through the system and the level of the mud inside the drillstring will equal the level in the annulus. The level in the annulus will be equal to the height of the mud return flowline. If the mud continues to flow from the annulus when the mud pumps are switched off, then an influx from the formation occurs and the well should be closed in with the blowout preventer stack. If the level of fluid in the well falls below the flowline when the mud pumps are shut down losses are occurring, meaning that the mud is flowing into the formations.

The main components of the circulating system are shown below[6].



Picture 1: Drilling mud is continuously circulated throughout the whole drilling process.

SOLIDS CONTROL EQUIPMENT: CLEANING THE MUD

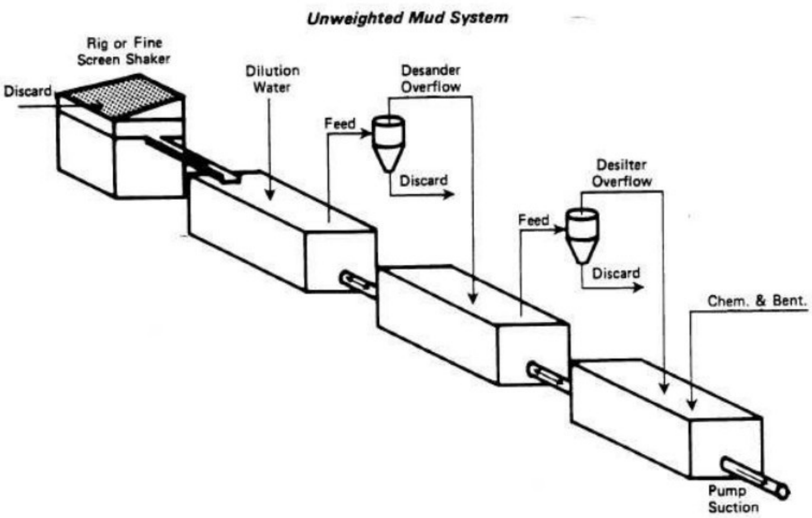
Initially, drilling mud may contain two types of solids, those of bentonite which range in size up to 10 microns; and the barite which ranges from about 5 to 80 microns. Once the mud has been circulated round the system, it will contain suspended drilled cuttings along with some gas and other contaminants. These must be removed before the mud is recycled. cuttings range from large chips to the finest colloidal particles (<1μm) (Geehan & McKee, 1989).

The role of solids control equipment is complex: it has to discard the cuttings, retain as much barite as possible and keep enough colloidal material to maintain viscosity. That is why cuttings removal equipment performance is a sum of many factors, including the size of the mesh for the shale shaker screen, flow rate and density of the drilling mud and the size of the cuttings.

Here is how a typical solids control workflow functions:

Firstly, The mud passes over a shale shaker, which is basically a vibrating screen. This will remove the larger particles, while allowing the residue (underflow) to pass into settling tanks. The finer material can be removed using other solids removal equipment. Particles smaller that 75 to 100 mm are removed by desanders, desilters and mud cleaners. After that, if the mud contains gas from the formation it will be passed through a degasser which separates the gas from the liquid mud. Degasser operates like a conventional gas-liquid separator. Then the mud proceeds to a mud cleaner and, if necessary, part of the mud flow can then be cleaned by a centrifuge. Having passed through all the mud processing equipment the mud is returned to the mud tanks for recycling.

A typical arrangement of solids control equipment is shown in the following image[7].



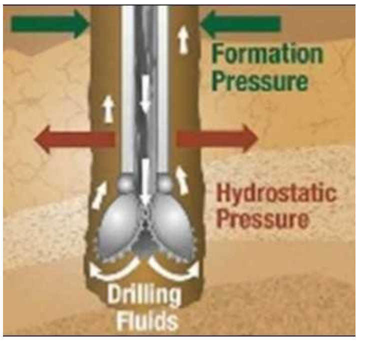
Picture 2: The mud passes through shale shakers into the mud pit where solids are periodically removed. After that mud can be led to a degasser, proceed to the mud cleaner, return cleaned to next pit or move to the centrifuge. The final pit is where reserve mud being added and pumped downhole.

DRILLING MUD FUNCTIONS

The objective of a drilling operation is to drill, evaluate and complete a well that will produce oil and/or gas efficiently. Drilling fluids perform numerous functions that help make this possible. The responsibility of performing these functions is held jointly by the mud engineer and those who direct the drilling operation. The duty of those charged with drilling the hole includes maintaining drilling mud quantity and quality to the predefined level. The proper mud composition leads to efficient mud functions. The functions that drilling mud performs could constitute a long list. Here drilling mud's roles are categorized in the main following functions.

The most common drilling fluid functions are[8]:

1. Remove cuttings from the well
2. Suspend and release cuttings
3. Control formation pressures
4. Seal permeable formations
5. Maintain wellbore stability
6. Minimize reservoir damage
7. Cool, lubricate, and support the bit and drilling assembly
8. Transmit hydraulic energy to tools and bit
9. Ensure adequate formation evaluation
10. Control corrosion
11. Facilitate cementing and completion
12. Minimize impact on the environment and drilling personnel.



Picture 3[9]: Borehole pressures equilibrium

''Drilling mud is defined as the fluid that is required to carry out the drilling operation with minimum possible damages[10].''

1 and 2. Cuttings removal and suspension: transporting cuttings to surface

Removing drilled cuttings from the well which are generated by the bit is drilling mud's main goal. To do this, drilling fluid is circulated down the drillstring and through the bit, entrapping the cuttings and carrying them up the annulus to the surface. This process is called cuttings removal or hole cleaning process. To accomplish this, the fluid should have adequate suspension properties to help ensure that cuttings and commercially added solids, such as barite weighing material, do not settle during static intervals. Cuttings transportation
is a function of cuttings size, shape and density combined with Rate of Penetration (ROP), drillstring rotation, and the viscosity, density and annular velocity of the drilling fluid (Drilling fluids engineering manual, 2015).

Viscosity
Rheological properties of drilling mud have a major impact on hole cleaning. Low viscosity muds, for example, water based muds, make it difficult for cuttings to circulate out of the well because they settle rapidly. Generally, higher viscosity muds improve cuttings suspension. Most drilling muds are thixotropic, which means they form a gel when circulation has stopped. Static conditions can occur during pipe connections and other situations but the cuttings can still be suspended. Muds that have the characteristic of shearthinning and have elevated viscosities at low annular velocities have proven to be the most efficient in hole cleaning.

Velocity
In general, the higher the annular velocity, the more efficient is cuttings removal. Still, thinner drilling fluids with high velocities may cause turbulent flow. This helps cleaning up the hole but it can also cause other drilling or wellbore problems.

- Slip velocity: is called the rate at which a cutting settles in a fluid. Its value is generated from its density, size and shape, as well as the viscosity, density and velocity of the drilling fluid. When the annular velocity of the drilling fluid is greater than the slip velocity of the cutting, the cutting can be transported to the surface.
- Transport velocity: is the net velocity at which a cutting moves up the annulus.
- In the simple case of a vertical well:

  Transport velocity = Annular velocity – slip velocity
- The velocity analysis for cuttings transport in high-angle and horizontal wells is more complex. The transport velocity as defined for vertical wellbores is completely different for deviated holes, since the cuttings settle to the low side of the hole across the fluid's flow path and not in the direction opposite to the flow of drilling fluid, meaning towards

the bottom hole. In horizontal wells, cuttings accumulate along the bottom of the wellbore, forming cuttings beds.

Density
High-density fluids help cuttings removal by increasing the buoyancy forces acting on the particles, making it possible to remove them from the well. Compared to fluids of lower density, high-density fluids may clean the hole effectively even in cases where the mud has lower annular velocity and lower rheological properties. Yet, a drilling mud weighing much more than what is needed to balance formation pressures has a negative impact on the drilling operation as it can cause formation fracturing. Therefore, mud weight should never be increased for hole-cleaning purposes.

Drillstring rotation
High rotary speed is another factor that helps hole cleaning. The circular component being introduced to the annular flow path aids cuttings removal. The type of flow is called helical or spiral flow around the drillstring. The drill cuttings near the wall of the hole, where poor hole-cleaning conditions exist, are being forced to be move back into the higher transport regions of the annulus. This method is adequate for removing cutting beds in high-angle and horizontal wells when it is possible to apply.

3. Formation pressure control: prevent well-control issues

The pressure of drilling fluid in the well bore needs to exert hydrostatic. Under normal drilling conditions, drilling fluid pressure should balance or exceed the formations pressure to prevent an influx of gas or other formation fluids. So, as the formation pressure increases, the drilling mud density increases to maintain a safe margin and prevent "kicks" or "blowouts". However, if the fluid becomes too heavy and the density too high, the formation can break down and drilling fluid will be lost in the resultant fractures. As a result , hydrostatic pressure will be reduced. With this pressure reduction an influx from a pressured formation may occur. Therefore, maintaining the appropriate fluid density for the wellbore pressure regime is critical to safety and wellbore stability.

4. Seal permeable formations

When mud column pressure exceeds formation pressure, mud filtrate invades the formation depositing a filter cake of mud on the wellbore wall. Mud should be designed to form a thin filter with low permeability to limit the invasion. If the mud cake filter is too thick problems like tight hole conditions, poor log quality, stuck pipe, lost circulation and formation damage may occur. In highly permeable formations with large pore throats, mud could invade the formation if the size of mud solids is analogous. In such cases bridging agents are used to seal the large openings.

5. Preserve wellbore stability

Maintaining the optimal density of drilling-fluid not only aids contain balance formation pressures, but also helps prevent hole collapsing and shale destabilization. The wellbore has to be clean of obstructions and free of tight spots, so that the drillstring can be moved freely in and out of the hole (tripping). After a hole has reached the planned depth, the wellbore should remain stable for completion. under static conditions while casing is run to the bottom, and cemented the hole section must be clean and clear. The drilling-fluid program should indicate the density and physicochemical properties most likely to provide the best results for a given interval.

6. Minimize formation damage

While the formation is being drilled it gets exposed to the drilling fluid and consequently to any solids and chemicals contained in that fluid. Some fluid and/or fine solids invasion to the formation is inevitable, though the invasion scale and the subsequent formation damage can be limited with careful fluid design that is based on testing. Formation damage also can be contained by careful management of downhole hydraulics.

7. Cool and lubricate the drillstring

The bit and drillstring rotate at high speed (revolutions per minute) all or part of the time during drilling operations. The circulation of drilling fluid through the drillstring and up the wellbore annular space helps reduce friction and cool the drillstring. Excessive torque and drag are common problems encountered in drilling wells, especially i f they are directional or extended reach wells. The mud system reduces the torque and drag by lubricating the hole and the drill string, thus allowing maximum rotational energy to be used at the bit, as well as allowing the bit to advance. The drilling fluid lubricates the drill bit and helps the movement of the drill pipe and bottomhole assembly (BHA) through angles that are created intentionally by directional drilling and/or through tight spots that can result from swelling shale. Oil-based fluids and synthetic-based fluids provide a higher degree of lubricity, and so are the preferred fluid types for high-angle directional wells. Some water-based polymer systems also provide lubricity matching that of the oil- and synthetic-based systems.

Typical coefficients of friction for casing and open hole sections for various types of drilling fluids are given below:

	Cased hole	**Open hole**
Air	0.35-0.55	0.40-0.60

Foam	0.30-0.40	0.35-0.55
Lignosulfate	0.20-0.25	0.20-0.30
Polymer	0.15-0.22	0.20-0.30
Oil Base	0.10-0.20	0.15-0.20

Table 1: Coefficient of friction corresponding to the drilling fluid used in an open hole and a cased hole section.

8. Transmit hydraulic energy to tools and bit

Hydraulic energy can be used to maximize rate of penetration by mending cuttings removal at the bit. It also provides power for mud motors to rotate the bit and for Measurement While drilling (MWD) and Logging While Drilling (LWD) tools.

Fluids with higher densities, plastic viscosities and solids create higher drillstring pressure losses. By using a small ID drill pipe or tool joints, mud motors and MWD/LWD tools, the amount of pressure available for use at the bit is reduced. Efficient transmission of hydraulic energy to drilling tools and the bit is possible by using low-solids, shear-thinning drilling fluids or those that have drag reducing characteristics, such as polymer fluids.

Generally in shallow wells, sufficient hydraulic horsepower usually is available for efficient drill bit cleaning. On the other hand, as the hole depth increases drillstring pressure losses increase as well. At a certain depth there will be insufficient pressure to clean the bit. This depth can be extended by carefully controlling the mud properties.

9. Provide information about the wellbore

Because drilling fluid is in constant contact with the wellbore, it reveals substantial information about the formations being drilled, and serves as a conduit for data collected downhole by tools on the drillstring and through wireline-logging operations performed when the drillstring is out of the hole. The fluid should have the correct chemical properties to help prevent or minimize the dispersion of drilled solids, so that these can be removed efficiently at the surface. Otherwise, these solids can disintegrate into ultrafine particles that can damage the producing zone, and block drilling efficiency. The drilling fluid’s ability to preserve the cuttings as they travel up the annulus directly affects the quality of analysis that can be performed on the cuttings. These cuttings serve as a primary indicator of the physical and chemical condition of the drilling fluid. An optimized drilling-fluid system that helps produce a stable, in-gauge wellbore can enhance the quality of the data transmitted by downhole measurement and logging tools as well as by wire line tools.

10. Control corrosion

Preventing equipment impact by controlling chemical corrosion is another drilling mud responsibility. At the rig site, the equipment used to pump or process fluid is susceptible to various forms of corrosion so it should be checked constantly for signs of wear from friction or chemical corrosion. In general, low pH exacerbates corrosion caused by dissolved gases such as oxygen, carbon dioxide and hydrogen sulfide (Dhiman, 2012). That is why a significant drilling mud function is to keep corrosion at an acceptable level. Providing corrosion protection is necessary not only for metal surfaces but also for rubber or elastomer goods. Elastomers used in blowout-prevention equipment are tested for compatibility with the proposed drilling-fluid system to ensure that safety is not compromised.

11. Facilitate cementing and completion

The drilling fluid must produce a wellbore into which casing can be run and cemented smoothly. For a successful well completion, mud must remain fluid and minimize pressure abnormalities to avoid fracture-induced lost circulation. Moreover, mud should have a thin and slick filter cake to smoothen cuttings, cavings or bridges in the wall of the wellbore. The mud must have low viscosity and low, non-progressive gel strengths.

12. Minimize impact on the environment and drilling personnel.

Environmental impact

After drilling operations, drilling mud becomes a waste that has to be disposed of according to local environmental regulations. Engineers desire fluids with low environmental impact that can be disposed of near the rig site. Different environmental regulations apply for every fluid type depending on location and its characteristics of location and density of human populations, the local geographic situation (offshore or onshore) high or low rainfall, proximity of the disposal site to surface and underground water supplies, local animal and plant life, and others.

Personnel impact

Continuous testing and monitoring of the drilling fluid is required by specially trained personnel. In the fluid's documentation indication of treatment and safety hazards are clear for any type of fluid. Regulations to protect human and natural environment are also indicated and checked by worldwide regulatory agencies.

WHEN FUNCTIONS CLUSH

A particular mud function may be affected by different mud properties. Even if one or two properties are altered to control a drilling mud function, another property may be changed as well. A mud engineer should recognize mud properties influence on all functions and the relative effect on each function. For instance changes in mud weight help to pressures control, but mud weight also influence annular pressure losses and lost circulation control. Furthermore, a high mud viscosity might improve hole cleaning, yet it might decrease hydraulic productiveness and/ or lower the penetration rate.

To accomplish the required functions usually tradeoffs in treating and maintaining fluid characteristics are needed. These tradeoffs are understood and manipulated by experienced rig personnel.

CHAPTER 2

Introduction

Apparently, fresh water is one of the oldest muds used in the industry. In fact, the term ''mud'' is believed to have been first used when fresh water and surface soils were mixed to develop a viscous fluid that could increase the hole cleaning properties of the fluid.

Nevertheless, gone are the days when drilling mud comprised of only clay and water. Nowadays, drilling mud in order to perform its multiple tasks, comprise a variety of components. Several additives are supplemented to the base fluid, water or oil, to make the desired final fluid.

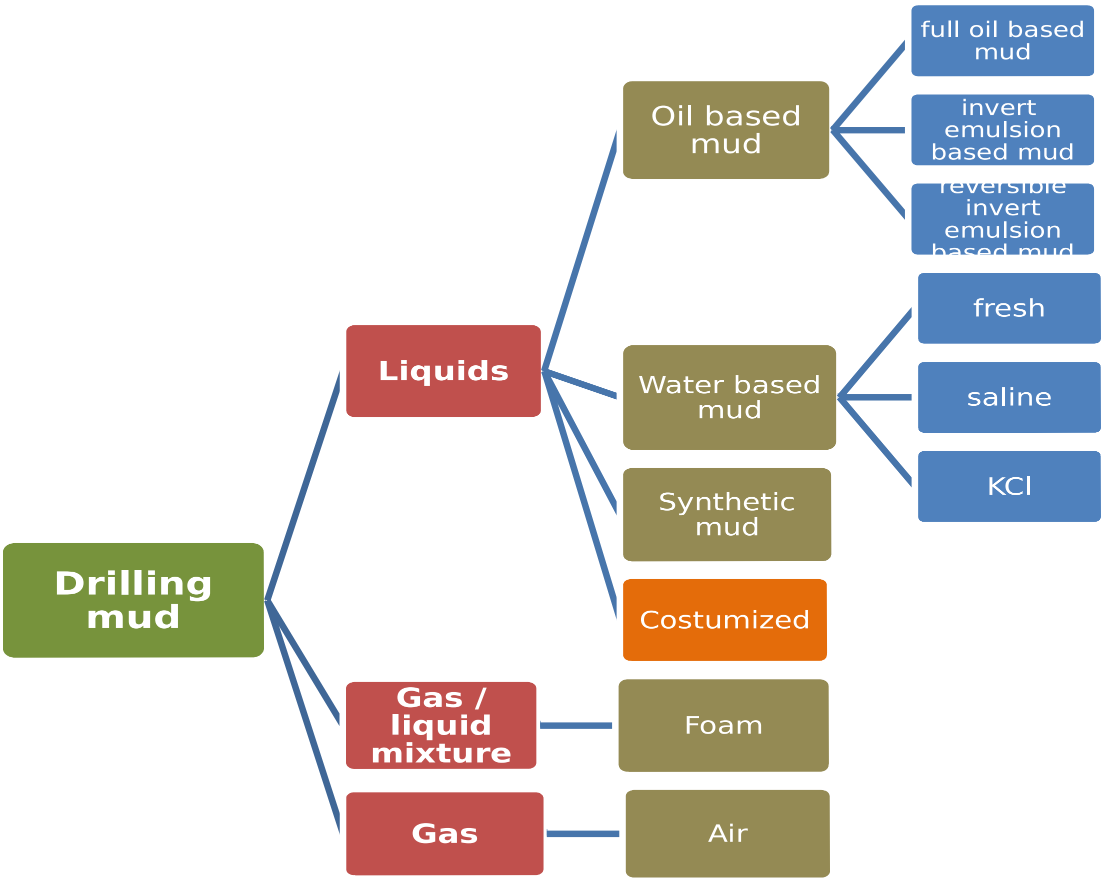
Drilling mud represents 5-15% of total drilling cost (Bloys et al., 1994). Maintenance of drilling fluid properties define the total well costs. The cost of the drilling fluid itself may be relatively small, however, its properties affect the rate of penetration, the avoidance of delays due to formation failure, loss of circulation, stuck pipe etc. Two are the main goals of mud type and additives selection are waste control and cost efficiency.

The wide diversity of drilling fluid types calls for a wise selection based on a fluid that suits the well and the formation being drilled. The choice of fluid type is influenced by the design of the well, the anticipated formation pressures, rock mechanics, formation chemistry, the desire to keep producing formation undamaged, temperature, environmental regulations, logistics and economics.

Many types of drilling fluids are used in the industry. Major categories include air-, water-, and oil-based fluids. Each has many subcategories based on purpose, additives, or clay states. A comprehensive description of major types of mud systems will be presented. Due to the large variety of muds presently in use, it is impossible to describe all of the systems. Omission of a mud type in this discussion does not dismiss it as an important mud in some operations.

Drilling Mud Composition

Drilling fluids are complex systems that consist of a variety of additives. The type and amount of the drilling fluid and the corresponding additives depends on the drilling method employed and the type of reservoir to be drilled (Shah, Shanker & Ogugbue, 2010). Drilling fluids can be broadly classified as liquid or gases. Water, oil, and gas-based muds can all be used, with products ranging from true muds made with materials like bentonite clays, to synthetic drilling muds[11]. Although pure gas or gas-liquid mixtures are used they are not as common as the liquid based systems. The water based systems are the most commonly used muds world-wide. The use of air as a drilling fluid is limited to areas where formations are competent and impermeable.



WATER BASED MUDS

Solid particles are suspended in water or brine. Oil may be emulsified in the water, in which case, water is termed the continuous phase. Normally the composition is water and bentonite. They are environment friendly and therefore the drill cuttings can be disposed of easily.

In more detail, water based muds (WBM) are composed of:

- ✓ Liquid water phase (continuous) to provide initial viscosity. Water can be fresh or sea (brine).
- ✓ Reactive fractions (addition of clay or polymers) to provide further viscosity and yield point to lift cuttings or keeping them in suspension.
- ✓ Inert fractions include low-gravity and high gravity solids to provide the required density.
- ✓ Chemical additives to control mud properties.

Water

The base fluid may be fresh water, seawater, brine, saturated brine, or a formate brine. Fresh water is used as the base for most of these muds, but in offshore drilling operations salt water (seawater) is more readily available. The type of fluid selected depends on anticipated well conditions or on the specific interval of the well being drilled. For example, the surface interval typically is drilled with a low-density water or seawater based mud that contains few commercial additives. After surface casing completion, drilling continues with a WBF unless well conditions require displacing to an oil- or synthetic-based system.

Reactive fractions

Some solids (clays) react with the water and chemicals in the mud and are called active solids. The activity of these solids must be controlled in order to allow the mud to function properly.

The types of clays used are the bentonitic clay and attapulgite. Bentonite is a member of montmorillonite group and can be used only with fresh water. It is a very common additive and widely used because it gives the proper rheological (non Newtonian shear thinning) and filtration control (low fluid loss under differential pressure) properties. Attapulgite is also called salt gel and it can be used in both fresh and salt water.

Inert fractions

- ✓ The solids which do not react within the mud are called inactive or inert solids like Barite.
- ✓ The other inactive solids are generated on the course of the drilling process by the drill bit. Low gravity include sand and chert. High gravity solids are added to increase the density of mud ("weighted

mud"). High gravity solids are usually Barite, Lead sulfides (galena) and Iron ores.

Chemicals

- ✓ Chemical additives are used to control viscosity, yield point, and gel. There two types of chemical additives : thinners and thickeners.
  - Mud thinners (phosphates, chrome lignosulfonate, surfactants)
  - Mud thickeners (lime or cement, polymers)
- ✓ Linear, cross linked, synthetic or biopolymers can be used in conventional WBM as viscosifying agents.
- ✓ A viscoelastic surfactant (VES) drilling mud uses a surfactant having both viscous and elastic properties and so it can reheal itself and restore rheological characteristics. Even though is more expensive compared to conventional WBM, it does not require frequent mud conditioning and thus saves a significant amount of rig time.

Table illustrating a typical WBM composition in volume (Stamataki, 2017):

Typical WBM composition	**Vol. %**
water (all salinity ranges)	80
reactive fractions (clays)	3
low gravity solids (sand)	5
high gravity inert solids (barite)	6
chemical additives: thinners and thickeners	6
	100

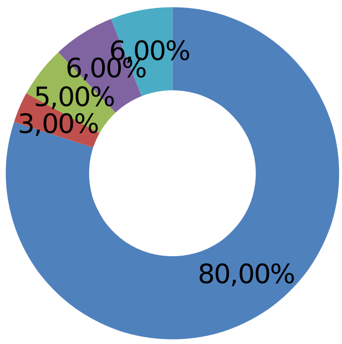


Table 2: Typical composition of WBM in volume

The major disadvantage of WBM is that can cause shale instability. The infiltration of mud cake containing water to water sensitive formations results in formation damage. Many efforts have been made to fix this. One new approach is to enhance the mud with a buffer. Blocking and plastering additives such as starches and celluloses, polyacrylamides and asphalts can be used. Cations addition like calcium and potassium contributes to clay maintenance. This is achieved via cation exchange. By replacing the sodium ion Na^+ of the clay in the shale with the K^+ and Ca^+ a more stable and hydration resistant rock is created.

A new type of WBM that combines potassium chloride KCl with a polymer called partially hydrolyzed polyaclylamide KCl-PHPA mud stabilizes shale by coating it with a protective layer of polymer. The role of KCl is to stop formation from breaking up when attacked by an aqueous solution (Bloys et al. 1994).

The introduction of KCl-PHPA mud reduced the frequency and severity of shale instability problems so that deviated wells in highly water-reactive formations could be drilled, although still at a high cost and with considerable difficulty. Since then, there have been numerous variations on this theme, as well as other types of WBM aimed at inhibiting shale.

The infiltration of mud from the wellbore to the surrounding shale is controlled by the chemical potential difference between the various species in the mud and the corresponding species within the formation. Mud's chemical potential is controlled by its hydrostatic pressure in the wellbore and its chemical composition.

Shales are the most common rock types encountered while drilling for oil and gas and give rise to more problems per meter drilled than any other type of formation. In addition, the inferior wellbore quality often encountered in shales may make logging and completion operations difficult or impossible. Shale stability will be discussed in more detail later in this chapter.

Over the years, actions have been taken to limit, or inhibit, interaction between WBMs and water-sensitive formations. In the 1970s, the industry turned increasingly towards oil-based mud (OBM) as a means of controlling reactive shales.

<u>OIL BASED MUDS</u>

Oil-based muds are similar in composition to water-based except that the continuous phase is oil. These systems also called invert oil emulsion mud (IOEM). In a system such as this, water may make up a large percentage of the volume, but oil is still the continuous phase. The water is dispersed throughout the system as droplets.

This type of drilling fluid is comprised of solid particles suspended in oil. OBM’s do not contain free water that can react with the clays in the shale. Water or brine is emulsified in crude oil or diesel which is the continuous phase. Solids are considered inactive as they do not react with oil. Oil-wetting is essential to ensure that particulate materials remain in suspension. The surfactants used for oil-wetting also can work as thinners. OBM can also be formulated with linear olefins and paraffins.

Table illustrating a typical WBM composition in volume (Stamataki, 2017):

Typical OBM composition	Vol. %
water (all salinity ranges)	30
Oil (diesel)	54
low gravity solids (sand)	3
high gravity inert solids (barite)	9
chemical additives: thinners and thickeners AND $CaCl_2$ or NaCl	4
	100

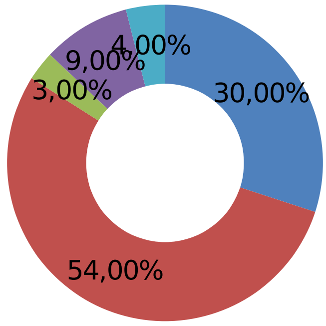


Table 3: Typical composition of OBM in volume

The ratio of the oil percentage to the water percentage in the liquid phase of an oil-based system is called its oil/water ratio. Oil/water ratio range from 65/35 to 95/5, but usually a ratio from 70/30 to 90/10 is used. Full-oil muds have a very low water content (<5%) whereas invert oil emulsion muds may have anywhere between 5% and 50% water content.

Barite, an inactive additive is used to increase system density, and bentonite is used as the primary viscosifier in most OBM. The emulsified water phase also acts as a viscosifier. When deep wells are being drilled many additives degrade at the high temperatures encountered. These High pressure/High temperature conditions (HPHT) lead to fluid loss. In particular, bentonite gels develop with extremely high viscosities and yield points and show loss of filtration (Mihalakis et al., 2004). To tackle such operational problems, various types of thinners are added, which stabilize drilling muds. Organophilic lignitic, asphaltic and polymeric materials are added as thinners to help control drilling mud in these extreme conditions.

In addition, oil-based systems may contain lime for pH maintenance, hydrogen sulfide (H_2S) and carbon dioxide (CO_2) gases effects resistance, and emulsion stability enhancement.

Shale stability is one of the main reasons of using an oil-based system. The key benefit of high-salinity water phase is that prevents shales from hydrating, swelling, and sloughing into the wellbore. Calcium chloride brine is added in most conventional oil-based mud, which appears to offer the best inhibition properties for most shales.

Most OBM are invert emulsions formed by droplets of aqueous fluid surrounded by oil, which comprises the continuous phase. A layer of surfactant o the surface of the water droplet acts like a semi permeable membrane that separates the aqueous solution in the mud from the formation and its water. Water will pass through this membrane from the solution with the lowest concentration of salt to the one with the highest. This is the phenomenon of osmosis. To maintain shale stability using OBM engineers have to ensure that the ionic concentration of the salts in the aqueous phase (internal) of the mud is adequately high, so that the chemical potential of the water in the mud equal to or lower than that of the formation water in the shale. If both solutions have the same chemical potential, water will not move, resulting an unchanged shale. When the water in the internal phase has a lower chemical potential that the fluid in the formation, water travels from the shale to the mud, resulting a dry rock. Unless dehydration is excessive, this drying out usually leaves the wellbore in good condition.

Apart from no shale swelling, OBM advantages also include excellent fluid loss control, efficient drill bit lubrication, adequate cuttings removal, temperature stability, a reduced risk of differential sticking and low formation damage potential. Oil-based muds therefore result in fewer drilling problems and cause less formation damage than WBM's and they are therefore very popular in certain areas.

Their disadvantages include poor bonding between the cement and formation because of oil wet surfaces, poor filter cake clean up and possible seepage into aquifers and environmental hazards, so they require more careful handling to avoid pollution control than WBM's. They are also more expensive.

The use of OBM would probably have continued to expand through the late 1980s and into the 1990s but for the realization that, even with low-toxicity mineral base-oil, the disposal of drilled cuttings contaminated by OBM can have a lasting environmental impact. This, in turn, has stimulated intense activity to find environmentally acceptable alternatives and has boosted WBM research.

In recent years a new approach has been followed, so that the base oil in OBMs has been replaced by synthetic fluids such as esters and ethers. The development of synthetic-based fluids in the late 1980s provided new options to offshore operators who depend on the drilling performance of oil-based systems to help hold down overall drilling costs but require more environmentally-friendly fluids.

SYNTHETIC BASED MUD

One way to replace the oil phase in OBM is with synthetic chemicals. Synthetic based muds are similar to oil based mud expect that the base fluid comprises of a synthetic material instead of oil. This allows the reproduction of the excellent properties of OBM with a more rapidly biodegraded continuous phase.

Typical chemicals for synthetic phase include esters, ethers, polyalphaolefins, linear olefins and linear alkyl benzenes. The first generation SBM was made using polyalphaolefins, esters or ethers. It had a high kinematic viscosity which made it pumping unwindly. The second generation SBM is an improvised version which is made up of linear alpha olefins, linear paraffins and isomerized olefins. It has low kinematic viscosity and can be operated at a low pump pressure.

The aromatic content is low compared to OBM and hence it is less toxic and more environmental friendly. Their main disadvantage is the higher cost compared to conventional OBM although their use may decrease significant drilling expenses in total.

REVERSIBLE INVERT EMULSION DRILLING MUD

This type of drilling mud are customized, meaning they are designed at will, to facilitate drilling operations, increase well productivity and minimize economic waste of the formation being drilled.

A reversible invert emulsion drilling mud demonstrates the characteristics of an emulsion and these of an invert emulsion drilling fluid system. They can be transformed from water/oil emulsion to oil/water emulsion triggered by a chemical alteration. Specifically, the surfactants contained in one emulsion are being protonated and deprotonated without changing their structure. This technology is a combination of both the W/O and O/W emulsions advantages. Thus, the oil wet surfaces of the drill cuttings can be converted to water-wet surfaces so these systems are more environmentally friendly. Filter cake clean up becomes easy compared to W/O inverted emulsions.

Pneumatic systems most commonly are used in areas where formation pressures are relatively low and the risk of lost circulation or formation damage is relatively high. The use of these systems requires specialized pressure-management equipment to help prevent the development of hazardous conditions when hydrocarbons are encountered.

GAS/ AIR DRILLING FLUIDS

Air drilling fluids are generally used in underbalanced drilling and where there is no contact with reservoir hydrocarbons or water. Drill cuttings are removed by a high velocity stream of air or natural gas. Foaming agents are added to remove minor inflows of water if present. The advantages of air drilling process include high rate of penetration, better hole cleaning, no solid contamination, no formation damage, no lost circulation etc. This results in less number of trips in and out of the wellbore and makes the process economical. However, there are also two important disadvantages: air cannot support the sides of the borehole and air cannot exert enough pressure to prevent formation fluids entering the borehole.

MIST

Mist drilling occurs when water is injected into the airstream. Mist is used instead of dry air when the encountered formation produces small amounts of water. The limitations of unstable wellbore and sometimes economics still apply, as in dry air. The functions of mist are the same as those of dry air.

FOAM FLUIDS

Gas-liquid mixtures (foam) are most often used where the formation pressures are so low that massive losses occur when even water is used as drilling fluid. This can occur in mature fields where depletion of reservoir fluids has resulted in low pore pressure. Besides underbalanced conditions, foam fluids are used in deepwater and ultra-deep water drilling where the operating pressure interval is limited. In such a case, a slight increase in mud density will cause micro/macro fractures and that subsequently will cause fluid influx into the wellbore due to high pore pressure. This calls for a better control over the equivalent circulating density (ECD).

Foam fluids generally comprise of 5-25% liquid phase and 75-95% gaseous phase. The liquid phase could be fresh water or brines. The gaseous phase is usually an inert gas. A surfactant is used as a stabilizer and it comprises about 5% of the fluid system. Heavy brines or barites can be used to weighted up the fluid system. Their advantage compared to air drilling fluids is their superior cuttings transportation ability. There are two types of foam drilling fluids:

a. a stable foam which is a regular foam fluid system with water or brines as a continuous phase and gas as a dispersing phase, and

b. a stiff foam consisting of viscosified water or brine as a continuous phase and gas as a dispersed phase.

Shale stability

Drilling formations consist of shales over 75%, and shale instability causes over 70% of wellbore problems. The problems include hole collapse, tight hole, stuck pipe, poor hole cleaning, hole enlargement, plastic flow, fracturing, lost circulation, well control (Manohar, 1999). As a result drilling costs are related to wellbore stability. Instability is a function of the imbalance between the rock stress and strength when a hole is drilled and the formations are exposed to drilling fluids. In particular, instability is affected by both shale (e.g. mineralogy, porosity) and of the drilling fluid contacting it (e.g. wettability, density, salinity and ionic concentration).

A distinguish shale characteristic is its sensitivity to drilling fluids especially water. Interaction of drilling fluid with shale alters its strength and the adjacent to the borehole pore pressure. Shale strength normally decreases and pore pressure increases as fluid enters the shale.

The controllable parameters that influence the formation reaction are drilling fluid, mud weight, well trajectory, and drilling/ tripping practices. Chemical stability problems occur because the near wellbore pore pressure and strength are adversely affected by drilling fluid/shale interaction as shale is left exposed to drilling fluid. Apparently the chemical stability is time dependent, unlike mechanical instability, which occurs as soon as we drill new formations.

Chemical instability problems are prevented by proper drilling fluid selection, suitable mud additives to minimize/delay the fluid/shale interaction, and by shale exposure time reduction.

Actions towards improving shale stability have as main objective to prevent, minimize, delay or use to our advantage the interaction of the drilling fluid with shale. Such actions include:

- Use of effective sealing agents, thixotropic drilling fluid (high viscosity for low shear rates), and lower mud weight /ECD. This would minimize fluid penetration into fractures.
- Increase capillary pressure to prevent fluid entry into shale pore throats by using oil base muds or synthetic muds consist of esters, poly alpha-olefin and other organic low-polar fluids.

Drilling Type selection Criteria

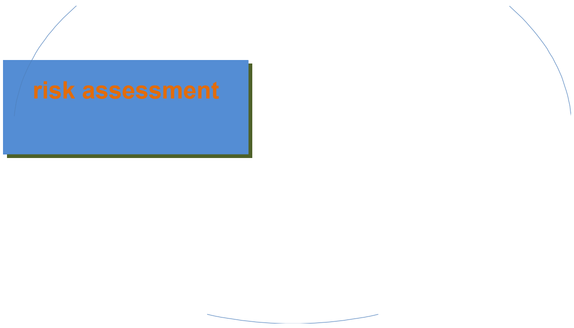
The main criterion used for the design of a drilling fluid program is generally minimum overall well cost. Other criteria that are considered include: production concerns, exploration concerns, environmental impact, safety, application performance, and logistics (Azar & Samuel, 2007). The considerations that must be taken into account when selecting drilling muds to drill a well are:

- Well type
- Problem formations
- Drilling rig
- Producing formations and kind of production
- Casing program
- Makeup water
- Potential corrosion
- Environmental impact
- Availability of products in international operations

Commonly upper hole sections typically are drilled with low density water based muds. Depending on formation types, downhole temperatures, directional-drilling plans, and other factors, the operator might switch to an OBF or SBF at a predetermined point in the drilling process. High-performance WBFs also are available to meet a variety of drilling challenges. Depending on the location of the well, the drilling-fluid system can be exposed to some or all of the below conditions:

- Salt water flows
- Influxes of carbon dioxide and hydrogen sulfide
- Solids buildup
- Oil or gas influxes
- Extreme temperatures at both ends of the scale

The drilling-fluid specialists who prepare drilling-fluid programs should be aware of the operational and environmental challenges posed by any well. Working closely with each other they can plan for the scope of conditions that are likely to be encountered, and generate a program that is both safe and cost-effective.


risk assessment

Drilling Mud Additives Classification

The success of a well completion and cost management depends considerably on the drilling fluid. Moreover, formation evaluation and well productivity also depend on drilling fluid. As a consequence the control of drilling fluid's properties is a day to day concern not only for the mud engineer but for the drilling, production and logging engineers as well.

To satisfy the design factors, drilling mud provide a variety of properties. Five main features are usually defined by the well program and monitored during drilling. These are rheology, density, fluid loss, solids content and chemical properties, and they all can be manipulated using additives.

The purpose of using mud additives is to enhance the following properties required for drilling:

1. Density/ Weight
2. Viscosity
3. Filtration control
4. Rheology control/ thinning/ dispersing
5. pH control/ Alkalinity
6. Lost circulation control
7. Surface activity modification
8. Lubrication
9. Flocculation
10. Shale stabilization
11. Protection from toxic and corrosive agents

To achieve the proper drilling mud composition the following classes of materials are being used:

<u>DENSIFIERS/ WEIGHTING MATERIALS</u>

These compounds are dissolved or suspended in drilling mud to increase its density. Densifiers are used to control formation pressures and to help contend the unstable formations that may be encountered while drilling. Any substance that is denser than water and that does not adversely affect other properties of the drilling fluid can be used as a weighting material. Some of them are shown in the table below (New Mexico Institute of Mining and Technology, 2012):

Material	Principal component	Specific Gravity
Galena	PbS	7.4-7.7
Hematite	Fe_2O_3	4.9-5.3
Magnetite	$Fe_3 O_4$	5.0-52
Iron Oxide	Fe_2O_3	4.7
Ilmenite	$FeO.Ti_2$	4.5-5.1
Barite	$BaSO_4$	4.2-4.5
Domolite	$CaCO_3.MgCO_3$	2.8-2.9

Table 4: Weighting materials

<u>SOLUBLE SALTS</u>

Soluble salts are used firstly in workover and completion operations to formulate solids-free fluids. Fluid densities ranging from 9.0 to 21.5 ppg can be attained, depending on the salt(s) used.

The table below outlines the maximum densities that can be attained for single-salt systems at a temperature of 70° F (New Mexico Institute of Mining and Technology, 2012). Although sodium chloride and calcium bromide increase the density of water-base and oil-base fluids, they are usually added for reasons other than to increase density.

Salt	Density
Potassium chloride (KCl)	Weights up to 9.7 ppg
Sodium chloride (NaCl)	Weights up to 10.0 ppg
Potassium bromide (KBr)	Weights up to 11.6 ppg
Calcium chloride ($CaCl_2$)	Weights up to 11.6 ppg
Calcium bromide ($CaBr_2$)	Weights up to 15.3 ppg
Zinc bromide ($ZnBr_2$)	Weights up to 21.5 ppg

Table 5: Maximum densities of soluble salts

VISCOSIFIERS

These compounds are used to improve a drilling fluid's ability to remove cuttings from the wellbore and to suspend cuttings and weight materials during periods of non circulation. As viscosifiers commonly used clays and natural or synthetic polymers. A list of some of the materials used to provide viscosity to drilling fluids is given below:

1. Bentonite: Sodium/calcium aluminosilicate
2. Sepiolite: Hydrous magnesium silicate
3. Attapulgite: Hydrous magnesium aluminum silicate
4. Organophilic Clays

1. **Bentonite** is added to fresh water or to fresh-water muds for one or more of the following purposes:

- to increase hole-cleaning capability
- to reduce water seepage or filtration into permeable formations
- to form a thin, low-permeability filter cake
- to promote hole stability in poorly cemented formations
- to avoid or overcome loss of circulation.

2. **Sepiolite** is hydrated magnesium silicate that closely resembles attapulgite. Sepiolite gives stable viscosity to 700° F. It is apparently converted to a smectite when the temperature of the drilling fluid exceeds 300° F. Sepiolite is used in geothermal drilling as a viscous sweep for hole

cleaning and as a substitute for attapulgite. API specifications for sepiolite are the same as those for attapulgite.

3. **Attapulgus clay** is usually called attapulgite, which makes up 80 to 90% of the commercial product. Montmorillonite, sepiolite and other clays, and quartz, calcite, or dolomite make up the remainder. As a drilling-fluid material, attapulgus clay is called gel salt, or brine gel, because it is used as a suspending agent in salt solutions. When placed in water, attapulgite does not swell like bentonite, but must be dispersed by vigorous. Attapulgite is used in drilling fluids solely for its suspending qualities. Its suspending qualities are not adversely affected by dissolved salts. Its usual application is in muds of higher salinity than sea water.

4. **Organophilic Clay**

Organorhilic clays referred to minerals whose surfaces have been coated with a chemical to make them oil-dispersible. Bentonite, attapulgite and sepiolite (rod-shaped clays) are treated with oil-wetting agents during manufacturing and are used as oil-mud additives.

- Organophilic bentonite are used in oil muds to build rheology for cuttings lifting and solids suspension. They also contribute to low-permeability filter cake.
- Organophilic attapulgite and sepiolite are used in oil muds strictly to build gel structure, which may not be long lasting due to shear degradation as the mud is pumped through the bit.

FILTRATION CONTROL METERIALS

Filtrate is the liquid portion of the mud system that is driven through a filter cake and into the formation by the differential between the hydrostatic pressure of the mud column and the formation pressure.

Filtration control agents reduce the amount of filtrate lost from the drilling fluid into a subsurface formation. Bentonite, various manufactured polymers, starches, and thinners or deflocculants all function as filtration-control agents. Organophilic lignite is an amine-treated lignite commonly used for filtration control in oil-base muds and synthetic-base muds.

	Function
Bentonite	Provides a good basic filter cake.
Carboxymethyl cellulose (CMC)	Reduces filtration rate by coating solids and by minimizing flocculation. Starts breaking down at 300°F.
Starch	Reduces filtration rate by coating solids; will spoil in fresh-water environment where pH is less than 11.5. A salt concentration of 250,000 ppm will break down at temperatures of 275°F.
Lignosulfonates	Reduce filtration by deflocculating the mud. Also, increase the viscosity of the filtrate, start breaking down at 300°F.
Lignites	Reduce filtration by deflocculating and plugging open spaces in the filter cake. Start breaking down at 300°F.

Table 6: Common fluid-loss additives

Filtrate loss is controlled essentially by three different mechanisms:

1. *Deflocculation*—Flocculation is a condition in which clays, polymers or other charged particle become attached and form a structure or "floc". Deflocculants are used to inhibit this tendency. A deflocculated filter cake preferentially packs to form a thinner, less permeable cake. That is why, materials that act as deflocculants also reduce filtrate loss.
2. *Viscosity*—The more viscous the liquid phase that is being forced through the filter cake, the lower the filtration rate. The most popular way to increase the viscosity of the liquid phase is by using high molecular weight polymers.
3. *Compressibility*—A third means to control filtrate loss is to create a compressible filter cake by using colloidal materials, such as bentonite and some asphaltic derivatives that compress and/or deform to plug pore spaces.

RHEOLOGY CONTROL METERIALS

Basic rheological control is achieved by controlling the concentration of the primary viscosifiers used in the drilling fluid system. However, when control of viscosity and gels cannot be efficiently achieved by this method, materials variously called thinners, dispersants, or deflocculants are used. These materials reduce the viscous and structure-forming properties of the drilling fluid by changing the physical and chemical interactions between solids and/or dissolved salts.
Materials commonly used as thinners in water-base drilling fluids can be broadly classified as:

1. Plant tannins
2. Phosphates
3. Lignites
4. Modified lignosulfonates
5. Low-molecular-weight synthetic water-soluble polymers (sodium polyacrylates).

ALKALINITY / pH CONTROL MATERIALS

Alkalinity and pH-control additives are used to optimize pH and alkalinity in water-base drilling fluids. Properties of many drilling fluid system like the detection and treatment of contaminants such as cement and soluble carbonates are depended from pH. pH also affects the solubility of many thinners and divalent metal ions such as calcium and magnesium, and influences the dispersion or flocculation of clays.
The most commonly used materials that control pH are the alkali and alkaline earth hydroxides: NaOH, KOH, $Ca(OH)_2$ and $Mg\ (OH)_2$.

LOST CIRCULATION MATERIALS (LCMs)

Lost-circulation materials can be broadly defined to include any material that seals or bridges against permeable or fractured formations to inhibit the loss of whole drilling fluid. An enormous variety of materials have been used to bridge, mat, and/or plug voids to combat loss of circulation. These materials can be divided into four categories: fibrous materials, flake materials, granular materials, and blends containing fibrous, flake, and granular materials.

- **Fibrous lost circulation materials** include such products as shredded sugar cane, cotton fibers, hog hair, shredded automobile tires, wood fibers, sawdust, and paper pulp. These materials have relatively little rigidity and can be forced into large openings where they bridge over and form a mat or base. This mat effects a seal when solids from the drilling fluid deposit on it. If the openings are too small for the fibers to enter, a bulky external cake susceptible to easy removal may form on the walls of the hole. Fibrous materials are not recommended for use in oil-base muds.
- **Granular lost-circulation materials** are products such as ground nut shells and ground carbonates that are used to bridge and plug the openings in porous formations. The materials are available in fine, medium, and course grades. They tend to accumulate just inside the opening of the pore and form a bridge. To accomplish this, the materials must contain particles the approximate size of the opening and a gradation of smaller particles to effect the seal. Granular materials may be used in oil-base muds.
- **A blend** is a product containing a mixture or blend or fibrous, flake, and granular materials. Blended products containing cellophane flakes are not recommended for use in oil-base muds.
- **Slurries** such as cement, and diesel-bentonite mixtures are also used to combat loss of circulation by squeezing of the material into the thief zone. Slurries exhibit high filtrate loss, which results in the deposition of a thick filter cake that fills and plugs the void.

LUBRICATING MATERIALS

Lubricating materials are designed to reduce torque and drag between drill pipe and the formation. They are incorporated into the filter cake and/or are attracted as a film to metal surfaces. The resulting oil film and slick filter cake substantially reduce torque during pipe rotation and drag during trips.
Diesel oil, asphaltic compounds, extreme-pressure lubricants, synthetic oils and long-chain alcohols are used to impart lubricity to drilling fluids. Diesel oil and synthetic oils, in amounts ranging from 3 to 10% by volume, are used on a limited basis. Vegetable oils, animal oils, and mineral seal oils are also used to impart lubricity, as are such products as graphite, polymer or glass beads, and gilsonite.

FLOCCULATING MATERIALS

Flocculating materials cause solids to coagulate so that they can be more easily removed from water-base systems. They also work to change the viscous properties of the drilling fluid. Salt, hydrated lime, gypsum (hydrated calcium sulfate), and synthetic polymers are often used to promote flocculation and the subsequent removal of colloidal-size drilled solids. Guar gum and some acrylic polymers are also very effective total flocculants when used in low concentrations in clear-water drilling fluids. Lime and gypsum are also used to increase the carrying capacity of water-base spud muds by flocculating the bentonite and drilled solids. Flocculation is promoted by modification of the surface charge of the solid particles, as with salts, or by adsorption and bridging between particles, as with high-molecular-weight polymers.

POLYMERS

Organic polymers used in drilling fluids may be broadly classified by origin and composition. Some, such as starches and guar gum, occur naturally, and are ready for use after slight processing. Others, such as xanthum gum, XCD, are produced by natural processes in a carefully controlled environment. Still others, such as derivatives of the starches and gums, and sodium carboxymethyl cellulose, might be called semi-synthetic. Another class of polymers includes petrochemical derivatives, such as the polyacrylates and ethylene oxide polymers, which are purely synthetic.

The use of polymers in drilling muds has become progressively more sophisticated, and the range and versatility of polymers is continually being extended. They are often specifically designed for a particular drilling situation, even to the extent that clays may be entirely replaced by polymers when drilling water-sensitive shales or water-producing zones. Polymeric materials are used as surfactants, emulsifiers, foaming agents, stuck pipe additives, lubricants, and corrosion inhibitors in addition to functioning as flocculants, deflocculants, viscosifiers, filtration-control agents, and to improve rheological properties of the drilling fluid. Polymers characteristics corresponding to functions are illustrated in the following table (New Mexico Institute of Mining and Technology, 2012).

Function	Main Characteristics
Viscosity	High molecular weight
Viscosity and gelation properties	High molecular weight and highly branched structure
Viscosity in salt properties	High molecular weight and nonionic or highly substituted anionic types
Deflocculation	Low molecular weight negatively charged at alkaline pH values
Flocculation	High molecular weight with charged groups to adsorb onto clays
Surfactant	Hydrophobic group and hydrophobic group on same molecule
Filtrate loss additive	Form colloidal particles or bridging action with solids

Table 7: Fluid functions derived from Polymer characteristics

INORGANIC MATERIALS

Inorganic materials section is presented in a form of a table composed by the name of chemical compound, its uses and the concentration typically used. Table illustrating most common inorganic materials used (New Mexico Institute of Mining and Technology, 2012).

Chemical compound	Uses	Concentration
Ammonium Acid Phosphate $[(NH_4)_2HPO_4]$ / Diammonium phosphate (DAP)	Used with polyanionic cellulose polymer as a shale inhibitor.	Range from 2.0 to 8.0 lb/bbl.
Ammonium bisulfite $[NH_4HSO_3]$ / Ammonium sulfite $[(NH_4)_2SO_3\ H_2O]$	Used as an oxygen scavenger to reduce corrosion of iron.	Recommended excess of sulfite is 100 to 300 ppm.
Calcium bromide $[CaBr_2$, $CaBr_2$ $6H_2O]$	Natural brine. Used in the preparation of dense salt solutions.	
Calcium chloride $[CaCl_2$, $CaCl_2\ H_20$, $CaCl_2\ 2H_2\ 0$, $CaCl_2\ 6H_2O]$	Used in hole-stabilizing oil muds, in calcium treated muds, in the preparation of dense salt solutions for completion and workover and for lowering the freezing point of water muds.	Range from 10.0 to 200.0 lb/bbl.
Calcium hydroxide $[Ca(OH)_2]$	Skin irritant. pH of solution is 12.4. Used in lime muds, high-calcium-ion muds, and for the removal of soluble carbonates.	Range from 0.5 to 20.0 lb/bbl
Calcium oxide [CaO]	Evolves heat on slaking to form hydrated lime. Strong irritant. Used in oil muds for the formation of calcium soaps and removal of water. Used mainly as slaked lime in water muds.	
Calcium sulfate $[CaSO_4]$; $CaSO_4$ $2H_2O]$ Anhydrite, gyp plaster, gypsum	Nontoxic. Source of calcium ions in gyp muds.	Range from 2.0 to 8.0 lb/bbl.
Chromic chloride $[CrCl_3\ 6H_2O]$	Used in crosslinking xanthan gum.	Range from 0.1 to 0.5 lb/bbl.
Chromium potassium sulfate $[\ CrK(SO_4)_2\ l2H_2O]$	Toxic. Same use as chromic chloride.	
Magnesium chloride $[\ MgCl_2\ 6H_2O]$	Added to brine used in drilling carnallite, to avoid hole enlargement.	
Magnesium hydroxide $[Mg\ (OH)_2]$	Same use as magnesium oxide.	
Sodium bicarbonate $[NaHCO_3]$ - baking soda	Used to counteract cement contamination of bentonite water muds.	Range from 0.5 to 5.0 lb/bbl.
Sodium carbonate $[Na_2HCO_3]$	Principal use is for removal of soluble salts from makeup waters and muds, some use in clay beneficiation.	Range from 0.2 to 4.0 lb/bbl.

Sodium chloride [NaCl]	Used as produced or as prepared brine in completion and workover operations to saturate water before drilling rock salt; to lower freezing point of mud; to raise the density (as a suspended solid) and act as a bridging agent in saturated solutions, and in hole-stabilizing oil muds.	Range from 4 to 109 lb/bbl.
Sodium hydroxide [NaOH]	Toxic. Used in water muds to raise pH, to solubilize lignite, lignosulfonate, and tannin substances, to counteract corrosion, and to neutralize hydrogen sulfide.	Range from 0.2 to 4.0 lb/bbl.
Sodium nitrate [$NaNO_3$]	Used as an oxygen scavenger (limited) and as a tracer in drilling mud.	
Sodium sulfite [Na_2SO_3]	Used as oxygen scavenger at concentrations of 0.05 to 0.1 ppb, to maintain concentration of 100 to 300 ppm.	
Zinc bromide [$ZnBr_2$]	Used to prepare dense salt solutions. Irritant to tissues.	
Zinc carbonate [$ZnCO_3$] basic zinc carbonate $2ZnCO_3 3Zn(OH)_2$, zinc oxide ZnO, zinc hydroxide $Zn(OH)_2$	These basic zinc compounds are only slightly soluble, hence they do not affect mud properties; but zinc sulfide is even less soluble, and, therefore, removes hydrogen sulfide from mud.	Range from 0.5 to 5.0 lb/bbl.
Zinc chloride [$ZnCl_2$]	Used to prepare dense salt solutions Irritant to tissues.	
Zinc sulfate [$ZnSO_4H_2O$]	Used with sodium dichromate as corrosion inhibitor.	Range from 0.1 to 0.5 lb/bbl.

Table 8: Most common inorganic materials

DEEP WATER AND ULTRA-DEP WATER DRILLING CHALLENGES

At this point, is it considered necessary to briefly report the challenges a drilling operation faces when in deep or ultra deep waters. Deepwater is considered any water depth deeper than 1.500 ft and ultra-deepwater waters deeper than 7.000 ft. Such extreme environments are more and more often drilled nowadays.

The most common drilling mud related concerns in deepwater drilling are presented. The intrinsic characteristics of the subsurface environment are the cold water, narrow operating windows and gas hydrates (McLean et al., 2010). The ten domains that are mainly affected and discussed below are:

1. lost circulation
2. mud properties
3. solids transport
4. stuck pipe
5. wellbore stability
6. shallow gas hazards
7. gas hydrates
8. reservoir productivity
9. environmental issues
10. fluid related logistics.

1.

A new approach to reduce lost return incidents is using flat-rheology synthetic-based mud systems. Low fracture gradients are the main reason for severe lost circulation. Narrow drilling windows result from the requirement to handle downhole pressures and wellbore stability issues.

These systems are used in combination with wellbore strengthening materials that allow use of higher mud densities without losing circulation.

Deepwater conditions exhibit wide temperature and pressure variations. Flat-rheology SBMs are less sensitive in cold temperatures than conventional systems where viscosity increases exponentially with cold temperatures. Controlling viscosity means controlling lost circulation, but it also means endangering hole cleaning efficiency and barite sag mitigation where temperatures and pressures are higher. The goal of these systems is to maintain balance between desired functions.

- low circulation
- good hole cleaning
- barite suspension

2.
Developing flat-rheology profile synthetic based fluids which are less sensitive to temperature and pressure variations is the latest approach in overcoming deep water drilling challenges. Such profiles can be attained

with redesigned emulsifier packages (emulsifier and wetting agent), rheology modifiers and viscosifiers. Furthermore, deepwater applications improved with the introduction of micronized weight materials for both aqueous and non-aqueous drilling muds. Such materials are barite, manganese tetroxide and ilmenite.

3.
Addressing solids removal issues is unquestionably a function that requires properties that conflict the most with other drilling fluid's requirements. Engineering compromises often occur trying to efficient transport solids to surface while not exceeding fracture gradients and jeopardizing wellbore stability. Hole cleaning and barite suspension especially in directional wells have been considerably improved with the introduction of micronized weight materials. These materials help achieve velocity, density and rheology desired properties even in narrow drilling windows. This approach decreases the mass of the weght-material particles in a great extend, and enhances suspension tendencies under both statin and dynamic conditions.

4.

When drilling in areas known to be prone to stuck pipe as well as while running casing, drilling engineers choose invert emulsion fluids because they demonstrate high lubricity features. In such cases drilling mud functions clash. While slow running speeds are risky to provoke stuck pipe incidents, they relieve lost circulation.

5.

Wellbore stability problems are directly related to water sensitive and chemically reactive shales. As far as conventional fluids are considered, research has continued to optimize water activity in synthetic and oil based mud.

6.

Typically, riserless drilling is used on shallow water-flow zones. Until hazard confirmation, drilling with seawater with bentonite is used. After that, while drilling the interval weighted mud is used.

7.

Both aqueous based muds and synthetic based muds provide temperature suppression. Still, properly formulated SBM perform a better level of hydrate inhibition. For an aqueous based fluid to perform accordingly, it has to prevent hydrate formation at the lowest temperature and to the highest corresponding pressure it is anticipated to be exposed. To achieve that additives like clay, lignite, lignosulfonate and polymers can be used. Problem being no knowing their impact on stabilizing hydrates.

Oil based and synthetic based drilling muds are preferred when drilling in deep and ultra-deep waters when hydrates are expected, because:

- Hydrates form only in water phase of these muds because of the salinity of the internal phase (brine). Internal phase weights 20-25% or higher calcium chloride
- Gases dissolve in oil and synthetic muds so they do not move up the wellbore to the mudline causing kicks. Kicks are restrained at depths with high enough temperature to prevent hydrates formation.

8.

Greater reservoir productivity is achieved by minimizing production target damage. Using the right drilling mud is essential for production integrity. Such a fluid is the reversible emulsion type combining the benefits of a conventional oil-based mud with the cleanup properties derived from biopolymer calcium carbonate additives of water based drilling mud. This conversion is achieved by changing the pH of a non-aqueous system to replicate a WBM's cleanup of the deposited filter cake.

9.

High performance characteristics featured in SBMs prevent problems arising from long drilling time. Reduction of the pollution risk associated with extended time on location is one more reason to choose a high sophisticated type of drilling fluid like these.

The steps have been made towards deepwater drilling improvement from the drilling fluid aspect are summurized in

- the introduction of flat-rheology SBMs to manipulate the adverse effects of wide variations in temperature and pressure on rheological properties
- the development of micronized weighting agents foe effevtive hole cleaning and barite sag avoidance
- the implementation of reversible reservoir drilling muds for maximun performance and adequate cleanup.

Table 9 - Comparison of key components of Conventional SBM and Flat-Rheology SBM

Table 1 - Comparison of key components of Conventional SBM and Flat-Rheology SBM

Components	Conventional SBM	Flat-Rheology SBM
Organophilic Clay	Organophilic Bentonite Typically 4-6 lb/bbl	Similar but with 50% lower concentration
Emulsifier	Blend of surfactants	Modified to improve performance
Wetting Agent	Surfactant	Different chemistry with no adverse solids interactions
Fluid Loss Control	Polymer	Polymer
Rheology Modifier	Fatty Acid Based	Fatty Acid Based
Viscosifier	Polyamide	Polyamide

CONCUSIONS

Drilling mud has kept up with the growing demands of drilling operations. Numerous unique applications are now possible both for conventional drilling mud systems and for unconventional ones that have proven to be adequate for the drilling industry. Regardless, there is no evidence at this point that any existing type is panacea for all drilling conditions that can eliminate every presented challenge. Continued refinement of drilling mud technology is expected in order to confront more demanding wells in the future.

Even if the best mud system for delicate formations could be designed, continuous monitoring and control of drilling muds are crucial for successful drilling. As the mud circulates and interacts with formations and drilled solids its composition continually changes. When concentrations of various mud additives are continually monitored and maintained, the desired results could be achieved. Simultaneously with the development of more effective mud systems, understanding of shale/fluid interaction is necessary. Completely satisfactory answers to questions such as: which drilling fluid to use for drilling a particular formation, or how long can we keep the hole exposed to a particular fluid without causing wellbore instability, can be given only after such an understanding.

In view of drilling costs it is imperative to minimize potential drilling failures and assess future risks.

As new technology frontiers of extreme places drilling are explored there will be need for more sophisticated and temperature stable systems. Customized fluids should be studied further. Still, traditional drilling mud types development is always a promising field.

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