

SPE-178308-MS

Impact Of Reversible Invert Emulsion Drilling Fluid Rheology On Productivity

E. E. Okoro, ACE University of Port Harcourt; A. Dosunmu, and B. Oriji, University of Port Harcourt; S. Iyuke, University of the Witwatersrand Johannesburg

Copyright 2015, Society of Petroleum Engineers

This paper was prepared for presentation at the Nigeria Annual International Conference and Exhibition held in Lagos, Nigeria, 4–6 August 2015.

This paper was selected for presentation by an SPE program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of SPE copyright.

Abstract

Drilling muds are multi-component fluid systems designed to perform several functions during drilling operation and as a drill-in fluid under varying conditions of temperature and pressure. The use of conventional oil-base mud for drilling can bring with it an associated trade-off in formation damage. For a drilling engineer, oil-base muds control reactive shales, improve penetration rates and enhance overall drilling efficiency. For a reservoir engineer, the oil-wet state of the wellbore and filtercake may present a skin challenge. Reservoir productivity impairment resulting from using oil-base mud takes many forms. It may relate to plugging of completion equipment and gravel packs by poorly displaced oil-wet filtercake. Due to this oil-wet state, oil mud filtercakes and other oil-wet materials deposited during the drilling process are not easily dispersed or removed by cleanup chemicals. Emulsions composed of non-dispersed oil mud and displacement fluids often remain within the wellbore. During production operation, the flow from the reservoir can mobilize these oil-wet materials, plugging completion equipment and pore space. This may significantly impair well performance regardless of its design purpose. The most obvious solution for avoiding oil mud related productivity impairment would be to drill the formation with water-base mud. However, drilling engineers often use oil-base muds to minimize risk and efficiently reach extended drilling targets. The problems associated with oil-mud filtercake cleanup and change over operation during completion operations has prompted this study. Operators and service companies develop and apply novel technologies to improve drilling efficiency and maximize hydrocarbon recovery. This paper presents a review on the principle behind formulation and development of reversible mud with nano additives that will eliminate the hard choice that the drilling engineers have to choose between improving drilling performance and decreasing the risk of completion impairment; they can have both requirements in a single mud system.

Keywords Emulsion mud, Surfactant, Drill-in fluid, Micelles, Rheology, Emulsifier

Introduction

The ever-increasing global demand for energy because of massive industrialization has moved the petroleum industry to target increasingly deeper oil and gas reservoirs that are in hostile and challenging environments. The drilling operation has evolved from vertical, inclined, horizontal to sub-sea and deep

sea drilling and these complex formations need specialized drilling fluids to achieve the objective. In order to meet the challenges, an extensive research towards the development of these specialized categories of drilling fluids for utilization within the rock formations and reservoir section has been on over the last decade. These studies have been directed towards the need for an improved mud system that meets both drilling and drill-in requirements; and can be successfully applied for drilling operations in complex formations and under elevated thermal and pressure conditions (Ezell, et al., 2010).

Shah et al., (2010) stated in their study that, adequate understanding of the impact of drilling fluid rheology, so as to selectively design drilling fluids that could address the wide range of difficulties encountered in oilfield drilling operations; is one key portfolio that has received considerable attention. As a result, the inherent concern on how they could be substantially modified for success becomes very critical to justifying oil and gas industry project economics. Since reservoir type and drilling process adopted to harness the reservoir fluid is unique, the drilling fluid has to be customized to suit the drilling process and reservoir conditions.

One of the keys to the design of the drilling fluid system and optimization of wellbore productivity is by retaining the natural reservoir rock permeability and wettability. This is to be ascertained by studying the complex, interdependent physical interactions and chemical reactions occurring downhole between the reservoir rock fluid, rock mineral and the drill-in fluids utilized. The way of damaging and reducing productivity of a formation include reservoir invasion and plugging by fine particles, reservoir rock wettability change and formation of emulsion droplets resulting in channel blockage (Ezell et al., 2010). During drilling operation, invasion of drilling fluid filtrate can cause formation damage. The potential for damaging a producing zone during construction of a wellbore begins with assessment of the drilling fluid rheology (Patel and Growcock, 1999). These damages are often irreversible no matter how technical and expensive the treatment process is, this is because the original reservoir rock permeability and wettability is never restored.

Drilling the pay zone (the reservoir) is an important part of the drilling procedure; thus, drilling mud may be adequate for drilling the rest of the well but not acceptable in the pay-zone. Whereas formation damage created by the mud is acceptable in a non-productive interval, it cannot be accepted in the reservoir section. What is needed is a mud that can control leak-off without creating permanent damage. The mud may require special treatment and occasionally, a change out of the mud to a non-damaging fluid. To mitigate these problems, the most popular method used is a mud changeover procedure put in place to replace the conventional drilling fluids with drill in fluids designed to be less invasive and damaging to the formation while drilling the payzone. The rationale behind this procedure has raised recent concerns as a result of downtime required for its execution as well as mud costs and complexity of implementation knowing that drilling fluids are time dependent (Bui et al., 2012). However, advances in drilling research showed that fluid type and constituent has a major effect on the well productivity.

Therefore, there is need to develop new drilling fluids to serve both purposes of drilling the entire formation and provide less invasive drilling for the payzone in order to reduce the cost of drilling.

Drilling and Drill-In Fluids

Drilling fluids or drilling muds are terms that apply to fluids used to help maintain well control and remove drill cuttings from boreholes or wellbores drilled in the earth. Drilling fluids are used in petroleum drilling operations and are a mixture of clays, chemical additives, water and oils. Its primary use is to conduct rock cuttings within the well. The drilling mud must be designed such that it can transport the cuttings to surface while circulating, suspend the cuttings when the rig pump is off (not circulating) and drop the cuttings out of suspension at the surface (Fadaïro et al., 2012).

The drilling mud column hydrostatic pressure must be high enough to prevent an influx of formation fluids into the wellbore, but the pressure should not be too high to avoid formation fracture. The heavier or denser the mud, the more pressure it exerts. The drilling muds help in cooling and lubricating the

bottom hole assembly (BHA). The mud must be selected and or designed so that the physical and chemical (Shale mineral-drilling mud interaction) properties of the fluid allow these functions to be fulfilled (Okoro and Dosunmu, 2014).

An optimum drilling fluid according to Fadairo et al., (2012) is one which removes the rock cuttings from the bottom of the borehole and transports them to the surface, hold cuttings and weight materials in suspension when circulation is stopped and also maintains pressure. The optimum drilling fluid also does this at minimum handling cost and bearing in mind the Health, Safety, Environment (HSE) policy.

In formations that are sensitive to fluid, the total time that the sensitive zone is exposed to the drilling mud may be critical. Once a section of the well (formation) that is known to be sensitive is penetrated, drilling operation should continue as quickly as possible until casing can be cemented over the sensitive formation zone.

It is common practice to use both water-based drilling fluids and non-aqueous drilling fluids when drilling various sections of the same well. Water-based drilling fluids are generally used in the upper hole sections of the well while the non-aqueous drilling fluids tend to be used in the more technically demanding hole sections. The fluid composition may also need to be continually modified within each hole section as shown in figure 1.

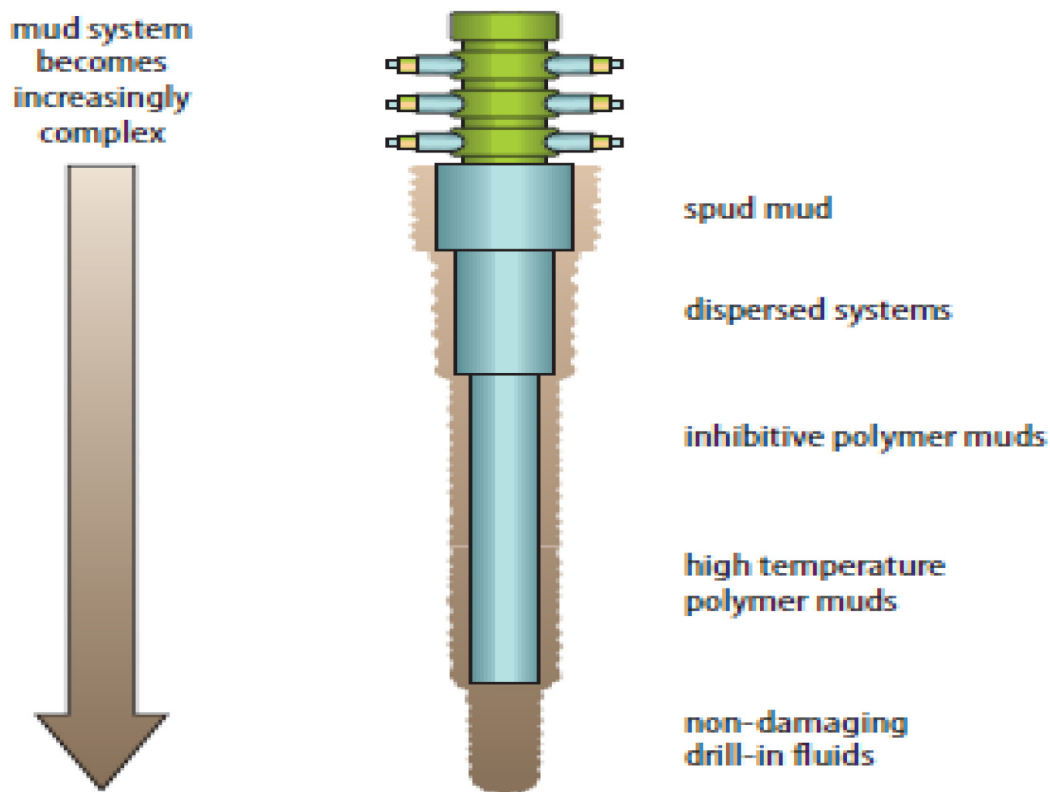


Figure 1—Drilling Fluid Composition Requirements (Source: OGP / IPIECA)

According to Williamson (1997), one of the golden rules for vertical wells is that formation damage caused by drilling should if possible be eliminated in the reservoir (pay zone). This concept has also been extended to horizontal and highly deviated wells. The clear objective for any well is that it should perform to the full potential of the formation it penetrates and remain stable throughout its life time. Drilling the payzone is one of the most important parts of the drilling procedure, thus drilling fluid that is required or adequate for drilling the rest of the well may not be acceptable in the pay zone. The most important aspects

of a drilling fluid from a formation damage point of view are to prevent loss of the drilling fluid filtrate and to make sure that the filtrate that is lost will not react with the formation to reduce permeability.

One of the major factors in optimizing wellbore connectivity and retaining the natural reservoir rock permeability and wettability is to ascertain and quantify the complex, often interdependent physical interactions and chemical reactions occurring downhole between the reservoir rock fluid and minerals and the drill-in / completion fluids used (Ezzat et al., 2008).

A drill-in fluid is a fluid that enables a well to be drilled through the reservoir formation and causes a minimum amount of damage to the reservoir; allowing production to be maximized or a drill-in fluid is drilling fluid that is used when drilling operation is about to penetrate pay zone or penetrate horizontal drilling.

Vickers et al., (2008) suggested in their study that both water-based drilling fluid and Invert Emulsion-based fluids can be reservoir drill-in fluids.

Howard and Downs (2005) stated that formate brines have been in regular use as reservoir drill-in fluid and completion fluids since 1993 and can add significant value to well construction projects by:

1. Increasing well productivity
2. Reducing the risk of non-productive time (NPT) incidents
3. Improving well integrity and lifetime
4. Enabling complex well constructions
5. Facilitating access to difficult reserves
6. Reducing waste disposal costs and
7. Reducing waste liability

Butler et al., (2000) in their study on low-skin horizontal completions highlighted that one means of preventing damage to productive formations is accomplished by minimizing whole fluid invasion. The majority of modern drill-in fluids do a reasonably good job of minimizing matrix invasion when pore geometry is known, as this is a fairly well-founded science. They also noted that, to maximize well performance, well planning must involve contingencies to allow a broad range of formation types and permeabilities to be drilled and completed without undue damage from invasion.

General Drilling Fluid Properties

Rheology is a key property which influences different aspects of the drilling operation and it is critical to the safe and successful execution of a well. In reality the fluids used in the oil and gas industry for drilling and drill-in operation are thixotropic in nature. They possess time-dependent properties. The fluid structure continually breaks down with time upon applying shear stress but upon rest the fluid structure is rebuilt (Vickers et al, 2008).

Azim et al. (2011) after detailed review of the drilling experience of the past wells drilled through the Zubair formation, observed that the wellbore instability problems showed a pattern with strong evidence of time-dependency. Although it is important that drilling fluids have the lowest possible impact on the productivity of the well, it is also important to know that the drilling fluid has to provide a trouble-free drilling phase in the drilling operation. Fluid density, hole cleaning efficiency, filtrate control and well hydraulics must all be optimized to agreed parameters. Density of drilling fluids is normally obtained by the addition of solids with high specific gravity. Calcium carbonate is used to provide density but as its specific gravity is considerably lower than barite, almost twice as much is required to give the similar density effect as barite. Fluids that use calcium carbonate to provide high density can have poor rheological profiles with high plastic viscosities due to high solid loading. Some fluid systems which utilize high concentrations of calcium carbonate use micronized grades so the weighting agent almost becomes self suspending.

Viscosity is an essential aspect of any drilling fluid design. It is imperative that drill cuttings are removed efficiently from the wellbore and gel strength must be high enough to suspend cuttings when the rig pumps are turned off.

Filtration control is vital to the success of any drilling fluid system performance. The relationship between fluid loss and formation damage is mainly linear. The greater the act of entering of filtrate into the formation, the higher the damage will be. Fluid loss should be tightly controlled and in particular there should be a focus on minimizing spurt/sudden loss. Extensive research has observed from literature the behaviour of different filtration controllers that starches are the best for this purpose. Other fluid loss controllers can be more efficient at reducing fluid loss but starch has repeatedly proven to be less damaging and easier to remove either by backflow or enzyme/acid post treatment. A biocide should be added when starch is used to prevent bacteria degradation of the polymer and the growth of biomass which in itself can be a damage mechanism. Asphaltic materials are mainly used for invert emulsion mud systems but can also be soluble in aqueous fluid so they can be used to control fluid loss in both (1 – 5ppb) (Vickers et al., 2008).

Current Development in Drilling Fluids

Various grades of Petroleum based oils are used to meet the variety of needs in drilling technology but diesel oil is most widely used oil component in both oil-in-water muds and water-in-oil emulsion muds. Diesel oil is used to improve the rheological properties and control filtration losses, promote lubrication while drilling and minimizing the problems associated with stick pipes. One of the major problems related to almost all kinds of drilling fluids containing an oleic phase is their stability at HTHP conditions because the stability decreases with increase in temperature as the number of collisions between the droplets increases (Jha et al., 2014).

The use of paraffinic based mineral in the place of diesel oil in drilling fluids has gained interest in the petroleum industry. Mineral oil based drilling fluid systems possess the same properties but have some disadvantages over diesel oil based emulsion drilling fluids. It should be noted that the result of laboratory toxicity test have shown that mineral oil based drilling fluids are less toxic than diesel oil based fluids. Tests have also indicated that oil retention properties of mineral oil based drilling fluids are lesser than diesel based drilling fluids (Jha et al., 2013). Invert emulsion based mud type of mineral oil can be considered to be low viscosity drilling fluids.

Dosunmu and Ogunrinde (2010) in their research to develop an environmental friendly oil based mud used palm oil and groundnut oil in their study. They observed that the oil based drilling fluid form with the palm oil and groundnut oil have good rheology when compared with diesel based oil mud and when these oil based muds (palm oil and groundnut oil based muds) were disposed in a corn farm, it did not have any effect on the plants.

The reversible invert emulsion drilling fluids are type of emulsion based drilling fluids that can be reversibly converted from water-in-oil (W/O) emulsion to oil-in-water (O/W) emulsion and back to W/O emulsion with the help of an acid-base chemical switch. It is an innovative approach to use the emulsion based drilling fluids for their optimum performance in drilling operation. The reversible invert emulsion systems are simple and easy to run. The surfactant in its non-protonated form is non-ionic and remains relatively unaffected by brines. The non-ionic character of the surfactant makes it compactable with other oil-based drilling fluid additives and it's not specific to the type of base oil in the continuous phase. However, in the presence of water-soluble acids these surfactants are in protonated form (regular emulsifiers) and forms oil-in-water emulsion. The surfactant can be protonated using any number of water-soluble inorganic or organic acids (Patel and Growcock, 1999).

The oil wet surfaces of the drill cuttings can be converted to water-wet surfaces which is more environmentally friendly. The filter cake clean up becomes easy for completion operation compared to W/O invert emulsion muds.

Reversible Invert Emulsion Drilling Fluid

A reversible invert emulsion drilling fluid is a drilling fluid that can be readily and reversibly be converted from a water-in-oil emulsion to an oil-in-water emulsion. It exhibits the best performance for drilling, as is typical for oil-based muds while retaining all the advantages of water-based drilling fluids. The formulation of reversible invert emulsion drilling fluid system is similar to oil-based drilling fluid systems in terms of both composition and performance, except for the emulsifiers (Patel and Growcock, 1999).

The emulsifiers used in the reversible invert emulsion fluid plays an important role in the performance characteristics of this drilling fluid. The surfactants used in this reversible system form a very stable invert emulsion in the presence of alkaline materials (example, lime); and on the presence of water-soluble acids, these surfactants become direct emulsifiers and form direct emulsions. The invert emulsion prepared using the surfactant can be converted to a direct emulsion by adding acid and back to an invert emulsion by treating with base.

The reversible mud was invented to perform as well as a conventional OBM system, plus the proper cleanup efficiency of a conventional WBM system. A very complex system, which possesses the ability to interchange its properties, while being efficient in drilling with oil-external phase, controls reactive shale, increase ROP and provides borehole stability; and water-external phase for an enhanced clean-up and a minimal impact on the completion state.

The reversible change from oil-wet to water-wet is performed in the presence of water soluble acids by changing the pH in the mud System. The purpose is to keep a high pH during drilling, that maintains the filter cake and separates the reservoir from the wellbore; after drilling operations are completed the pH is lowered below 7 (<6) for the complete removal of the filter cake. This will provide connectivity between the reservoir and the wellbore (Chiriac and Eric, 2014).

The chemical nature and property of the surfactants used in the reversible invert emulsion muds play an important role in the performance of these fluid / mud systems. The reversible emulsion property of these surfactants allows the drilling fluid to be changed from an invert emulsion to regular emulsion at different stages of the drilling / completion operation using an acid-base chemical switch (Patel, 1999). The reversible nature of the emulsion systems allows the muds to achieve optimum production, minimal environmental impact and cost control.

Advantages of Reversible Emulsion Mud

1. Maximized drilling performance while oil-wet;
2. Good clean-up while water-wet;
3. Easy reversed with pH changes;
4. Good shale inhibition and Stable wellbore;
5. Reduces waste generation;
6. Easy removal of filter cake;
7. Enhanced drilling experience;
8. No remedial treatments needed.

Green et al., (2001) in their lab work which has been validated by application of this reversible emulsion drill-in fluids in West Africa, observed that both production and injection wells have exceeded what was expected from use of a conventional invert emulsion. They also noted that the wells were completed with less rig time and lower cost for the completion and clean up.

Surfactant

A Surfactant is an amphiphilic molecule, comprising of a hydrophobic tail group with a carbon chain length greater than or equal to 16 and a hydrophilic head group.

Surface active surfactants, are amphiphilic compounds that can be represented by the symbol H-L. The hydrophobic or lipophilic part of the molecule (L) is generally a hydrocarbon chain. On the other hand, the hydrophilic part of the molecule (H) contains heteroatoms such as O, N, S, P. Depending upon the kind of dissociation of their hydrophilic group in water, the surfactants are classified as:

1. *Anionic* Surfactants (H = ester sulfate, carboxylic or phosphoric acid, sulfonate, etc.).
2. *Cationic* Surfactants in which H is generally a quaternary ammonium.
3. *Nonionic* Surfactants, the hydrophilic group of which is generally a polyether chain (poly ethylene oxide) condensate.
4. *Amphoteric* or *zwitterionic* surfactants that bear both anionic and cationic polar groups, such as betaine or sulfobetaine (Salager, 1994).

Although there is a great variety of substances which bear the H-L type of molecular formula, it can be said that they behave quite similarly in spite of their differences. Each L-H ionic or neutral molecule exhibits a dual polar/a polar affinity, and its overall behavior depends essentially on the balance of its hydrophilic and lipophilic features. In any case a surfactant solution always presents a very characteristic property, i.e., either H or L possess a strong affinity for the solvent, while the other undergoes a repulsion from it.

If a surfactant is in a sufficient concentration in a solution, then the surfactant molecules can form micelles. A micelle is an aggregate of surfactant molecules dispersed in a solution. A surfactant in an oil fluid system can form reverse-micelles with the hydrophobic tails in contact with the hydrocarbon solvent, sequestering the hydrophilic head in the centre of the reverse-micelle.

The reversible nature of the emulsion systems allows the muds to achieve optimum production, minimal environmental impact and cost control. The emulsifiers in reversible invert emulsion muds offer a unique opportunity for operators to control the wettability properties of the mud.

Surface and Interface Activity of Surfactant

At the air-water surface and at the oil-water interface, the medium undergoes a strong and sharp change in polarity, i.e., a situation which favors the orientation of the H-L molecules in a direction perpendicular to the surface or interface. In such perpendicular positioning, the hydrophilic head group is wetted by the aqueous solution, while the hydrophobic “tail” is out of the polar environment. As a matter of fact this is the only position which results in favorable interactions of both parts of the surfactant, and this is why a surfactant molecule is always seeking a superficial or interfacial location.

The variation of the superficial free energy, i.e., the superficial tension, with the surfactant concentration in the aqueous phase can be seen as a way to detect the onset of micellization. In the case of an oil-water interface, the situation would be more complex because the surfactant molecules can partition into both liquid phases.

Since the interfacial tension change does not bring any more information than the superficial tension change, the latter is preferred for the sake of simplicity. [figure 2](#) shows the change in surface tension versus the surfactant concentration in the aqueous phase at equilibrium with the surface. Starting at an initial value corresponding to pure water (72 dyne/cm or mN/m), the surface tension decreases as the surfactant concentration increases. In this first zone (I) most surfactant molecules which are introduced in the aqueous phase are driven to adsorb at interface. As a consequence the adsorption (concentration at interface in mole/area) increases rapidly, which triggers a strong decrease in surface tension, i.e., in surface free energy.

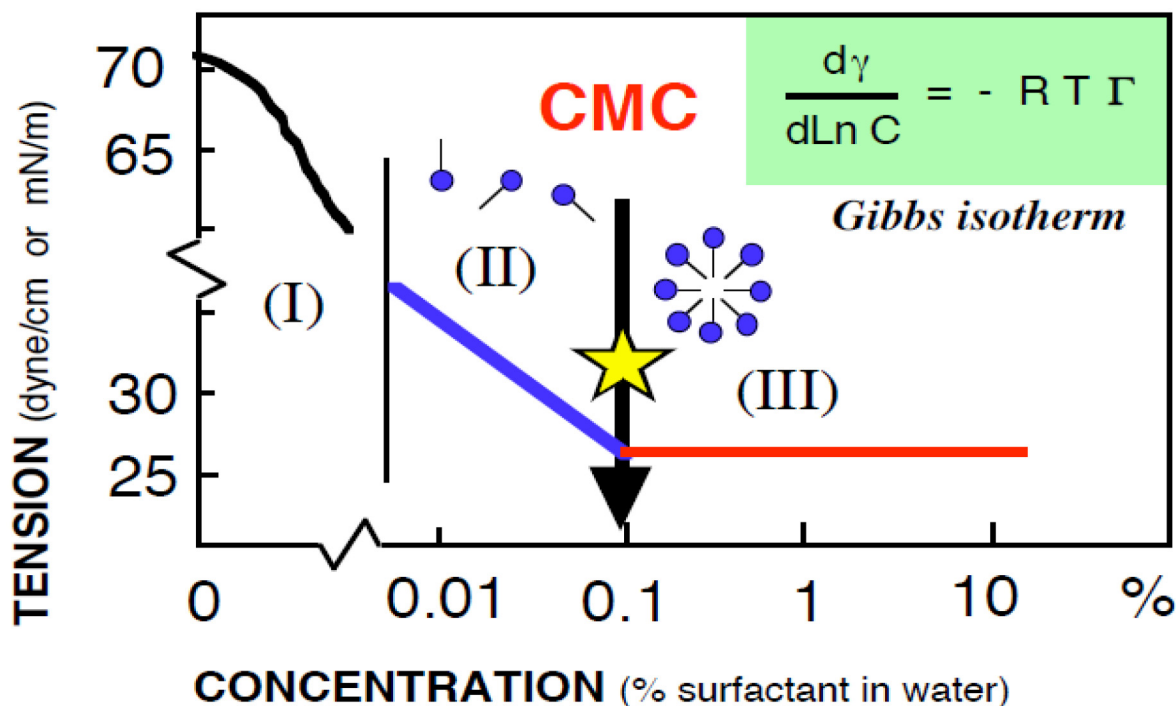


Figure 2—Surface Tension Vs Surfactant Concentration (Source: Salager, 1994)

When the adsorbed molecules become densely packed, there is no more room at interface, and the adsorption becomes constant. The Gibbs isotherm formula allows us to know that the adsorption is proportional to the slope of the γ -logC curve. As a consequence a saturated surface will result in a straight line variation on the γ -logC plot, example, zone II on figure 2. When more and more surfactant molecules are introduced into the systems, the adsorption remains essentially constant and thus these additional molecules are to be solubilized in the aqueous solution, a not so favorable situation because it involves the contact between the surfactant hydrophobic tail and water.

If a surfactant is in a sufficient concentration in a solution, then the surfactant molecules can form micelles. A “micelle” is an aggregate of surfactant molecules dispersed in a solution. A surfactant in an oil solution can form reverse- micelles with the hydrophobic tails in contact with the hydrocarbon solvent, sequestering the hydrophilic heads in the center of the reverse-micelle. Conversely, a surfactant in an aqueous solution can form micelles with the hydrophilic heads in contact with the surrounding aqueous solvent, sequestering the hydrophobic tails in the micelle center. The surfactant must be in a sufficient concentration to form a reverse-micelle or micelle, known as the critical micelle concentration. The critical micelle concentration is the concentration of surfactant above which reverse-micelles or micelles are spontaneously formed (Fisk, 2013).

The variation allows the determination of the critical micelle concentration (CMC).

Micelles and Critical Micelle Concentration

At some point the aqueous solution gets *saturated* by the surfactant molecules and the surfactant solution undergoes a transition and passes into zone III (see figure 2), in which the tension remains constant as more and more surfactant is added to the solution. In most cases the surfactant solution does not exhibit a precipitation as it would occur to ordinary solutions when the saturation is reached. Instead the surfactant *solubilization* starts occurring under a new form, i.e., the micelle formation.

In aqueous medium, micelles can gather several tens and even a few hundreds of molecules; the size and the geometry (spherical, cigar, rod-like) depends upon the surfactant molecular structure as well as upon the physicochemical environment (Salager, 1994).

The critical micelle concentration (CMC) is the transition between zone II and III typical patterns (figure 2 above). It does not actually correspond to an exact concentration but rather to some range of concentration, which can be widespread for systems containing mixtures of surfactants with quite different characteristics. The CMC is usually taken as the concentration at which the first micelles appear, an event that can be monitored through a change in the variation of several properties, not only surface tension, but also the cryoscopic lowering or the electrolytic conductivity.

The mostly used method to determine the CMC is the measurement of surface tension (all types of surfactant) and the measurement of electrolytical conductivity (ionic surfactants).

Effect of the Surfactant Structure

According to Salager (1994), the surfactant CMC depends upon both its hydrophilic head group (type, size, counterion) and its lipophilic tail group (length, branching).

Hydrophobe Tail Group

In aqueous medium, the CMC has been found to decrease as the number of carbon atoms in the hydrophobic group increases. Most experimental data can be fitted with a relationship of the type: (Salager, 1994)

$$\log \text{CMC} = A - B N \quad 1$$

Where N is the number of methylene groups - CH₂ - contained in the hydrophobic group when it is a linear hydrocarbon; A is a constant that depends upon the hydrophilic group and B is a proportionality factor (0.5 for non-ionics, 0.3 for ionics). The benzene ring is found to be equivalent to 3 methylene groups.

The branching of the hydrophobe is quite an important factor. It has been found that the CMC increases considerably with the branching, a tendency which matches the increase of aqueous solubility of the surfactant with their branching.

This remark explains that the relationship between log CMC and the number of methylene groups in the hydrophobe is no longer linear for chains longer than 15 methylene groups; in effect such long chain tend to fold, a conformation which decreases the interactions with the solvent.

Hydrophilic Group

As far as the CMC is concerned, the most important characteristic of the hydrophilic group is its charge or lack of charge. It has been pointed out that the electrostatic repulsion between neighboring ionic polar heads in a micelle is an unfavorable effect that increases the CMC. Another reason for the polyether (polyethylene oxide) non-ionics to have a lower CMC, is the presence of two methylene groups in each ethylene oxide link; this results in less face-to-face polar repulsion between oxygen atoms.

All these arguments corroborate that the CMC is a measurement of the overall hydrophile-lipophile balance of the surfactant (Salager, 1994).

On the other hand both the hydrophile type and the eventual counterion, have a strong effect on the CMC. The more dissociated, and the more ionized the ionic surfactant is, the stronger is the interaction with the water molecules, and the more hydrophilic is the polar group. This theory explains why a single sulfate group turns very hydrophilic a surfactant such as dodecyl sulfate, while at least 8 ethylene oxide groups are required to obtain a slight hydrophilicity in a nonionic surfactant.

The CMC of nonionic surfactants of the polyethylene oxide type has been reported to be related with the number of ethylene oxide groups per molecule (EON) according to a relationship of the following type (Salager, 1994).

$$\log \text{CMC} = A' + B' \text{EON} \quad 2$$

Where, A' is a constant characteristic of the hydrophobe, and B' a multiplicative factor in the 0.02–0.03 range.

These empirical relationships corroborate that the CMC is directly linked with the hydrophilic-lipophilic balance of the surfactant. It has been found that the CMC is also related to the aggregation number, although it is rather a trend than a relationship: in general the aggregation number increases with the hydrophobic character of the surfactant, i.e., when the CMC decreases.

Electrolytes

When electrolytes are added to an aqueous solution, most substances result less soluble than in an electrolyte-free solution. In some case the reduction in solubility leads to the actual precipitation of a solid phase, a phenomenon which is often called “salting - out”. This effect is generally attributed to the reduction of the solvation of the polar group.

On the other hand the addition of an electrolyte results in an increase of the ionic strength in the neighborhood of the micelle, where it produces some screen effect which decreases the electrostatic repulsion between the polar head groups. Both effects tend to facilitate the gathering of the surfactant molecules into micelles, and as a consequence both tend to reduce the CMC.

Table 1—Developments in Drill-in Fluids

REFERENCE	TECHNIQUE	SUBJECT	BASE MUD
Patel, 1998	The surfactant used in the reversible invert emulsion fluids are strong invert synthetic emulsifier in the presence of lime.	Reversible Invert Emulsion Drilling Fluids- A Quantum Leap in Technology	Emulsion-based Mud
Patel and Grow Cock, 1999	Synthetic ester was used in the reversible invert emulsion mud and it offers a unique opportunity to control the wettability properties.	Reversible Invert Emulsion Drilling Fluids: Controlling wettability and minimizing formation damage	Emulsion-based Mud
Butler et al., 2000	Brine-based drilling fluids was formulated and used as drilling and drill-in fluid to productive formation.	New Generation Drill-in fluids and clean up methodology lead to low-skin Horizontal completions	Brine-based Mud
Dobson et al., 2000	The fluid formulation includes the use of calcium and/ or zinc bromide as a base brine, minimal concentration of calcium carbonate as bridging material.	Application of a novel water-based drill-in fluid for Geopressured horizontal wells	Water-based Mud
Green et al., 2001	A reversible invert emulsion was used as drill-in fluid to minimize formation damage and it has been validated by applying it in West Africa.	Minimizing formation damage with a reversible invert emulsion drill-in fluid	Emulsion-based Mud
Horton et al., 2004	Additives of low solid content were used to form a high density reservoir drill-in fluid.	A new biopolymer-free, low solids, high-density reservoir drilling fluid	Divalent Cation-based brine Mud
Howard and Downs, 2005	Formate brines were used as reservoir drill-in and completion fluids.	Formate fluids optimize production rate	Formate-based Mud
Roedbro et al., 2007	The study was conducted with an oil-based fluid that uses the micronized barite technology to allow improved drilling hydraulics in a well with a narrow mud weight window and minimum invasion in a high permeability reservoir.	The design of high performance drill-in fluids with a view to maximizing production and minimizing cost	Oil-based Mud
Ezzat et al., 2008	A high-density calcium chloride/calcium bromide brine blend was used as the base fluid to achieve and maintain the required fluid density without addition of insoluble weight material.	High density brine-based drill-in fluid improved reservoir productivity in Gas field offshore Egypt	Brine-based Mud
Amanullah et al., 2011	Nano-based fluids were formulated using a blend of nanos and nano-stabiliser to study the rheological and filtration properties, and evaluate its suitability for oil and gas field application.	Preliminary test results of Nano-based drilling fluids for oil and gas field application	Nano-based Mud
Leong, 2013	A rheology modifier named VisPlus is added into the invert emulsion drilling fluid or invert oil drilling fluid to improve drilling fluid rheology.	Study of the rheological properties of various oil-based drilling fluids	Emulsion-based Mud
Zhang et al., 2014	Use of Amine anti-collapse water-based drilling fluid with strong inhibition for solving hydration swelling of shale.	Study and application of Amine based anti-collapse drilling fluid in Sulige Gas field	Amine-based Mud
Okoro, Dosunmu, Oriji and Iyuke, 2015	Will use locally sourced surfactant reverse-micelles and nano-additives to form a reversible mud.	This Research	Emulsion-based Mud

Most West Africa (Nigeria and Angola) offshore present a lot of drilling challenges. Difficult well trajectories and drilling conditions are often addressed by using oil-base mud (OBM) to improve efficiency and reduce drilling risk. These OBM when used close to the reservoir section has been observed by engineers to reduce productivity and injectivity below expectation and difficult to remediate. The ability to efficiently manage drilling operations is critical to well's economic success; the need to operate safely, especially through critical sections of the well can slow down drilling operations for repeated flow

checks. As drilling operations push the limits of depth, temperature, mechanical friction and completions technology, new muds such as reversible mud systems are evolving to meet the challenges. For drilling fluids to function in an effective manner, it must have the correct heat transfer and fluid-flow characteristics. This reversible mud system will provide the drilling performance and formation control of an oil-base mud with the filtercake removal efficiency and non-damaging characteristics of a water-base fluid. Using this mud system, drilling engineers will be able to optimize both drilling and reservoir drill-in operations; thereby reducing non-productive time (NPT) associated with drilling operation.

The integration of reservoir mud technology, reversible emulsion mud system and optimum delivery system in this study, will produce a threefold increase in production while minimizing cost and risk.

Conclusion

Overall the industry has kept up with the growing demand of drilling fluids for numerous unique applications. The addition of oil can improve the performance of water based drilling fluids as evidenced by improvement in rheological and lubricating properties. This review report the principle use in the development of new generation emulsion based drilling fluids that represent a mid way solution among performance during drilling operation, economic and environmental considerations. The reversible emulsion technology uses surfactants that allow the drilling fluid to cycle between oil-wetting and water-wetting as frequently as one desire. The clean ups obtained in the field by the use of these reversible invert emulsion drilling fluid as drill-in fluid have resulted in production rate that are about 2.5 times the anticipated rates.

Acknowledgments

The authors wish to express their thanks to World Bank for offer of Ph.D scholarship at World Bank African Centre of Excellence, Institute of Petroleum Studies, University of Port Harcourt.

Reference

- Adeleye Sanmi Apaleke, Abdulaziz Al-Majed and M. Enamlu Hossain, 2012. Drilling Fluid: State of the Art and future Trend. SPE 149555, presented at the SPE North Africa Technical Conference and Exhibition held in Cairo Egypt, 20–22 February.
- Adesina Fadairo, Olugbenga Falode, Churchill Ako, Abiodun Adeyemi and Anthony Ameloko, 2012. Novel Formulation of Environmentally Friendly oil based Drilling mud. Open Science, <http://dx.doi.org/10.5772/51236>.
- Alexandru Chiriac, Erik Gydesen Søgaaard and Kirsty Houston, 2014. *Aalborg University Esbjerg*, Master Thesis, Oil and Gas Technology K10og-3-F14; School of Engineering and Science AAUE, Denmark.
- Arvind D. Patel and Frederick B. Growcock, 1999. Reversible Invert Emulsion Drilling fluids: Controlling Wettability and minimizing formation damage. SPE 54764, paper presented at SPE European Formation Damage Conference held in Netherlands, 31 May-1 June.
- Arvind D. Patel, 1998. Reversible Invert Emulsion Drilling fluids – A Quantum Leap in Technology. IADC/SPE 47772, paper presented at IADC/SPE Asia Pacific Drilling Technology held in Jakarta, Indonesia, 7–9 September.
- Azim S. A., Mukherjee P., Al-Anezi S. A., et al., 2011. Using integrated Geomechanical study to resolve expensive wellbore instability problems while drilling through Zubair shale/sand sequence of Kuwait: a case study. Proceedings of the SPE/IADC Middle East Drilling Technology Conference and Exhibition, October, pp. 229–242.
- Binh Bui, Arild Saasen, Jason Maxey, Mehmet E. Ozbayoglu, Stefan Z. Miska, Mengjiao Yu and Nicholas E. Takach, 2012. *Viscoelastic properties of Oil-based Drilling fluids. Annual Transactions of the Nordic Rheology Society*, Vol. 20.

- Butler, B. A., Sharp, K. W., McDaniel, D. R. and Bump, D. M., 2000. New Generation Drill-In fluids and cleanup methodology lead to Low-Skin Horizontal completions. SPE 58741, paper presented at SPE International Symposium on Formation Damage held in Lafayette, Louisiana, 23–24 February.
- Dosunmu, A. and Ogunrinde, J., 2010. Development of environmentally friendly drilling fluid from Palm oil and Groundnut oil. SPE-140720-MS, SPE Technical paper presented at NAICE at Tinapa 3–6 August.
- Ezell, R. G., Ezzat, A. M., Horton, D. and Partain, E., 2010. State of the Art Polymers fulfil the need for High temperature clay-free Drill-in and completion fluids. AADE-10-DF-HO-01, paper presented at the AADE fluids Conference and Exhibition held at Houston, Texas, April 6–7.
- Ezzat, A. M. and Stefano D'Angelo, 2008. High Density Brine-based Drill-In fluid improved Reservoir producibility in Gas field offshore Egypt. SPE 112950, paper presented at SPE North Africa Technical Conference and Exhibition held in Marrakech, Morocco, 12–14 March.
- Green, T. C., Headley, J. A., Scott, P. D., Brady, S. D., Haynes, L. L. and Pardo, C. W., 2001. Minimizing formation damage with a Reversible Invert Emulsion Drill-in fluid. IADC/SPE 72283, paper presented at the IADC/SPE Middle East Drilling Technology conference and Exhibition held at Muscat, Bahrain, 22–24 October.
- James V. Fisk, 2013. A Drilling fluid containing a surfactant having a high boiling point and a long chain Tail group. Patent, WO2013126138A1, PCT/US2012/071536.
- Jean-Louis Salager, 1994. Surfactants in aqueous solutions, Laboratory of Formulation, Interfaces rheology and processes. Universidad De Los Andes, Merida-Venezuela; Version 1.
- Okoro Emeka Emmanuel and Adewale Dosunmu, 2014. Experimental Analysis of shale for Evaluating shale Drilling fluid interaction in Agbada formation. *British Journal of Applied Science & Technology*, 4(35): 4878–4907.
- Popov S. G., Natsepnskaya A. M., Okromelidze G. V., Garshina O. V., Khvoyscin P. A., Grebrev F. N. and Nekrsova I. L., 2013. The innovative approach to use of emulsion drilling fluid-Reversible Inverted Drilling Fluid, SPE 168661, SPE Conference on fields development under complicated conditions and Arctic region, Moscow, Russia, October 15–17.
- Praveen Kumar Jha, Vikas Mahto and Saxena, V. K., 2013. Study the rheology and filtration properties of oil-in-water emulsion for its application in oil and gas well drilling. *J. Pet. Enrr. Technol.*, 3, 25–30.
- Praveen Kumar Jha, Vikas Mahto and Saxena, V. K., 2014. Emulsion based drilling fluids: An Overview. *International Journal of ChemTech Research*, Vol.6, No.4, pp2306–2315.
- Praveen Kumar Jha, Vikas Mahto and Saxena, V. K., 2014. Emulsion based drilling fluids: Overview. *International Journal of ChemTech Research*, Vol.6, No.4, pp 2306–2315.
- Robert L. Horton, James W. Dobson, Jr., Kim O. Tresco, Dave A. Krox, Taylor C. Green and William E. Foxenberg, 2001. A New Biopolymer-Free, Low solids High Density Reservoir Drilling fluid. SPE 68965, paper presented at the SPE European Formation Damage Conference held in the Hague, Netherlands, 21–22 May.
- Ryan Van Zanten, Jeff J. Miller and Chris Baker, 2012. Improved stability of Invert Emulsion fluids. IADC/SPE 151404, paper presented at the IADC/SPE Drilling Conference and Exhibition held at San Diego, California, 6–8 March.
- Shaikh Abdul Azim, Pritish Mukherjee, Salah Ali Al-Anezi, Basel Al-Otaibi and Badr Al-Saad, 2011. Using integrated Geomechanical study to resolve expensive wellbore instability problems while drilling through Zubair shale/sand sequence of Kuwait: A Case study. SPE/IADC 148049, paper presented at the SPE/IADC Middle East Drilling Technology conference and Exhibition held at Muscat, Oman, 24–26 October.
- Singh, H. N., Swarup, S., and Saleem, S. M., 1979. *J. Colloid Interface Sci.*, 68, 128.

-
- Siv Howard and John Downs, 2005. Formate fluids optimize production Rate. AADE-05-NTCE-05, paper presented at AADE National Technical Conference and Exhibition held at Houston, Texas, April 5–7.
- Stephen Vickers, Alistair Hutton and Bill Halliday, 2008. Drill-In fluid Design, getting it right from the start. AADE-08-DF-HO-05, paper presented at AADE Fluids Conference and Exhibition held at Houston, Texas, April 8–9.
- Stephen Vickers, Alistair Hutton, and Bill Halliday, 2008. Drill-in fluid design, getting it right from the start. AADE-08-DF-HO-05, paper presented at the AADE fluids conference and exhibition held at Houston, Texas, April 8–9.
- Subhash N. Shah, Narayan H. Shanker and Chinenye C. Ogugbue, 2010. Future challenges of Drilling fluids and their Rheological measurements. AADE-10-DF-HO-41, paper presented at the AADE fluid Conference and Exhibition held in Houston, Texas, 6–8 April 6–7.