AADE-05-NTCE-79

Deepwater Drilling Fluids – What's New?

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This paper was prepared for presentation at the AADE 2005 National Technical Conference and Exhibition, held at the Wyndam Greenspoint in Houston, Texas, April 5-7, 2005. This conference was sponsored by the Houston Chapter of the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individuals listed as author/s of this work.

Abstract

Deepwater drilling involves some unique issues in offshore exploration and development that pose significant additional challenges to the operator. High cost and potentially troublesome drilling conditions are driving the development of new and highly innovative technologies. The chosen drilling fluid for a deepwater operation should have rheological properties that will provide optimum hole cleaning along with minimum equivalent circulating density (ECD) and minimal tendencies for gelation at cold mud-line temperatures. This fluid should also ensure stable borehole conditions for extended periods, possess excellent lubricity and provide protection against gas hydrate formation. Highly inhibitive fluids with low dilution and consumption rates are of considerable benefit in minimising logistics and supply problems.

The latest generation, state-of-the-art synthetic base drilling fluid is formulated to comply with the stringent environmental regulations of the Gulf of Mexico and represents a quantum leap in deepwater drilling fluid performance. Endowed with a substantially lower tendency for cold temperature gelation, this fluid helps achieve a lower ECD compared with conventional synthetic base fluids and much lower pressure fluctuations due to pipe movement and pump operation. Drilling fluid losses downhole are substantially lower and this has been demonstrated in the field on numerous deepwater projects.

At the same time, the increasing level of environmental concern and legislation associated with the use of invert emulsion drilling fluids has driven the search for water-based drilling fluids that will provide oil-based drilling fluid performance and be environmentally acceptable in all offshore areas of the world. Introduced in the Gulf of Mexico over the last two years, this high-performance water-based drilling fluid helps prevent hydration and disintegration of claystones, especially in troublesome gumbo-type formations. Drilling performance closely approaches that attained with synthetic base drilling fluids, maintaining excellent hole condition and drilling rate.

Based on case histories in the Gulf of Mexico, the enhanced performance attributable to both these systems will be described.

Introduction

The low fracture gradient of the formations in many deepwater basins can place severe limitations on mud weight and ECD. The difficulty of operating in this narrow mud weight/fracture gradient window tends to be made worse by the impact of cold temperature on the drilling fluid in the riser. In ultra-deep water, the water column can represent up to 50 to 60% of the final well depth and thus has a major impact on drilling fluid temperature, especially when the drilling fluid is allowed to remain static for an extended period. Without circulation, the temperature of the fluid in the blow-out preventer (BOP) stack and lower riser can reduce to the sea-bed temperature in less than 12 hours.

The cooling effect of the water column results in markedly increased drilling fluid rheology which, in turn, tends to increase drilling fluid ECD. Under static conditions, significant gelation can occur in an invert emulsion fluid and the pressure required to break this gel structure, on re-establishing circulation, can be high.

Data from downhole pressure-measurement tools clearly demonstrates the high-pressure transients that can be impressed upon the borehole when the mud pumps are turned on or off. These pressure fluctuations can easily span 0.1 SG (~1 ppg) during connections and exceed the fracture gradient in a deepwater well if precautions are not taken. High gels can also cause problems of excessive swab and surge and, during a test phase, can hinder the transfer of pressure required to operate downhole test tools.

The effect of the reduced temperature on the fluid in the kill and choke (K & C) lines in deep water is a particular concern and many well-control events in deep water are characterised by substantial mud loss during the pump start-up phase of well kill operations.

Thus, managing the effect of temperature and pressure on the rheology of a drilling fluid can be crucial to the successful drilling and completion of deepwater wells. Measures to minimise gelation and rheology increase at low temperature and high pressure will help prevent the generation of high downhole circulating pressures. This will assist in minimising the risk of inducing wellbore breathing or severe losses.

Latest Generation Synthetic Base Mud

These issues have prompted the design of products and systems specifically for deepwater drilling. However, a step-change in performance was required to help cut the high cost of synthetic base mud losses in deepwater drilling operations. This step-change has been delivered by the introduction in the Gulf of Mexico of a clay-free synthetic invert emulsion drilling fluid that demonstrates substantially reduced low-temperature gelation effects. The elimination of organo-clays or organo-lignites in the fluid's composition, a first for the industry, results in significantly reduced ECD compared with conventional synthetic base drilling fluids. Gel strengths are fragile and easy to break with substantially lower pressure spikes recorded by downhole pressure-while-drilling measurements, both on breaking circulation and from swab and surge during pipe movements in and out of the borehole.

This system was originally introduced to comply with U.S. Environmental Protection Agency (EPA) regulations in the Gulf of Mexico governing discharge of cuttings drilled with synthetic base mud (SBM) and to provide benefits in both shallow and deepwater drilling environments.

Originally based on a blend of vegetable ester and internal olefin base-fluids, further development now allows the system to be formulated with alternative synthetic base fluids. The system meets and exceeds all of the expectations of an oil or synthetic base drilling fluid, including excellent shale inhibition, high drilling rate and excellent hole cleaning. The high, but fragile, gel strengths assure good cuttings suspension without incurring barite sag. Flatter, stable rheology is obtained from 40°F to over 350°F at mud densities to 17 ppg. The viscosifier and filtrate loss agents designed for this system work far more quickly than conventional additives and there is no waiting for multiple circulations before mud properties come into line with requirements.

Rheology control of the system is accomplished through the use of custom emulsifiers and surfactants. This is a major step change from the commonly used organophilic clays. By controlling interaction between the oil, water and solids that make up the fluid, a true gel structure is created similar to that of a water based fluid. This structure is augmented by use of a swelling polymer and the combination results in the new fluid's ability to eliminate sag without the use of organo-philic clays. The viscoelastic properties of this structure and the fact that it is disrupted relatively easily provides the lower ECD and surge and swab pressures.

The new system is highly resistant to contaminants, including salt-water flows. No treatment for carbon dioxide (CO_2) contamination is necessary as there is no detrimental effect from CO_2 on the system. Hydrogen sulphide may be treated out using the usual zinc-based or iron-based scavengers.

As a result of the unique formulation of this system, product requirements are minimised, resulting in approximately 40% less material required at the rig for fluid maintenance. Less material means fewer crane lifts at the rig-site, reduced transportation costs and reduced worker exposure.

Pay-Zone Drilling

The use of a new polymeric filtration-control agent endows the system with a plugging and sealing ability in low-permeability zones and microfractures. For higher-permeability sections, the system is treated with plugging/bridging agents in the normal way without adversely affecting the unique rheology profile of this system.

The cake-building characteristics of this system have been demonstrated using the permeability plugging apparatus (PPA) run with 5 micron, 35 micron and 60 micron disks and a 10.2 ppg fluid. The base fluid, containing no bridging materials, outperformed all other fluids on the 5 micron and 35 micron disks. Bridging material was only required (at 15-20 ppb) to achieve acceptable PPA results on the 60 micron disk. The fluid was tested at 250ºF and 1,500 psi. A scanning electron microscope (SEM) photograph of the filter cake, on a 35 micron disk, is shown in Figure 1. No evidence of mud penetration into the PPA disk was observed.

The formation damage potential was assessed by conducting return permeability comparison tests between the new system and a standard low toxicity mineral oil-based mud using Berea sandstone. Both were weighted to 1.28 SG (10.7 ppg) with 70/30 oil water ratios and 275,000 ppm chloride water phase salinity. The tests were conducted using an automated return permeameter at 1,500 psi confining pressure and 200ºF. The new SBM gave 97% return permeability compared with 48% from the standard low toxicity oil mud, and a cake lift-off pressure of less than 1 psi.

Field Performance

Field usage has amply demonstrated that the new system can provide enhanced hole cleaning with reduced ECD and no instances of barite sag. Downhole drilling-fluid losses while drilling, tripping, running casing and cementing have been up to 80% lower than on offset wells drilled with conventional SBM. This outcome has been experienced on a number of projects, resulting in increased efficiency, cost savings and, in some cases, casing points have been extended. The system has been used to drill depleted zones and known loss zones with minimal losses by pretreating the system with bridging agents and lost-circulation material. Figure 2 shows the ECD obtained on one well using the new system compared with the ECD obtained on a nearby offset well using a conventional SBM.

An indication of the stability of the system was provided in the first field trial when two salt-water flows occurred shortly after displacing to the new system. The resulting impact on the fluid was minimal with no significant change in viscosity. Similarly, mud weight increases following several gas influxes were tolerated effortlessly. Careful monitoring of mud weight and pressure-while-drilling data has given no indication of any barite sag in any of the wells to date.

On one recent deepwater well drilled by a major operator, the downhole mud losses for this difficult well were expected to be over 9,400 bbl, based on offset well experience. As a result of the reduced ECD and careful fluids management, the actual mud losses were around 2,600 bbl, representing a saving of over $1,350,000 in mud cost. The overall reduction in well construction cost was estimated to be at least $3,750,000.

On another well, a 14.3 ppg field mud was used to drill 8 ½ inch hole with 5 7/8 inch drill-pipe to over 24,000' in a hole deviated to over 55º. The ECD of this fluid was only 0.1 ppg higher than that experienced on the offset wells drilled using 5 inch drill-pipe.

Figure 3 shows how a major operator reduced drilling fluid losses by using the new SBM. On six offset wells, an average of 1,750 bbl of mud was lost per well. With the new system, losses were reduced to 250 bbl per well, an immediate saving of some $250,000 per well in direct mud cost alone.

Another operator, a major independent, has used the new system on numerous wells in the Gulf of Mexico. The drilling manager stated that the new system's unique performance has saved him a minimum of $500,000 per well in reduced mud losses and saved rig time.

High Performance Water-Based Drilling Fluid

One of the challenges of using oil-based and synthetic base drilling fluids has been the increasing level of environmental concern and legislation associated with their use. These challenges have driven the search for a high-performance water-based drilling fluid (HPWBDF) that will provide oil-based drilling fluid performance and be environmentally acceptable in all offshore areas of the world.

The HPWBDF has demonstrated outstanding performance in the highly reactive, gumbo-making shales of the Gulf of Mexico. Based on a modified poly-acrylamide chemistry, this system has none of the drawback of PHPA systems and has demonstrated an ability to deliver the excellent hole conditions, cuttings integrity and drilling rates normally associated with synthetic-base mud. The system meets and exceeds all EPA standards for discharge of water-based fluids using the recommended product mix.

This exceptionally inhibitive water-based fluid is formulated with soluble salts and/or glycol to inhibit hydrate formation. The system is clay-free and exhibits very stable yield point and gel strength values from 40° to 300°F. The unique polymer chemistry that controls rheological properties provides shear-thinning at the bit for fast drilling, yet can ensure the efficient capture and removal of drill solids. The wellbore remains stable and in-gauge, reducing the need for frequent wiper trips. Typical formulations exhibit low friction coefficients for minimal torque and drag and high return permeability.

Two unique proprietary polymeric additives help minimise shale hydration almost instantaneously. One polymer is a potent flocculent that is effective at low concentrations, allowing the encapsulation of drill solids as they are produced at the bit. The second polymer prevents hydration and disintegration of clay-rich formations, especially in troublesome gumbo-type formations found in deepwater drilling.

In some areas of the Gulf of Mexico, when drilling with conventional water-based fluids, gumbo boxes must be cleaned every few hours as they become plugged with large, sticky lumps of clay. The HPWBDF system "coats" the highly reactive clays, preventing them from adhering together, so the clay is easily removed from the system in baseball-sized and smaller pieces. Field results show that bit and BHA balling, a problem that can seriously affects drilling rate, is dramatically reduced with this drilling fluid. The bit and bottom-hole assembly (BHA) emerge from the wellbore with minimal solids build-up, significantly decreasing the need to spend expensive rig time removing accretion from the BHA and bit.

The system additives mix into the base fluid rapidly, without the viscosity hump that can occur with other polymer systems. Should cuttings begin to show slight degradation, additions of flocculent and inhibitor can correct the problem in one circulation. Fluid loss control is managed with proven, effective starch-based additives. No commercial clay additions are necessary. The system is especially well-suited for rigs with limited deck space, or those operations where synthetic base fluid drill cuttings are not currently permitted for discharge.

On one deepwater well, the system was used to drill over 4,000 ft of 17 inch hole and over 3,000 feet of 12¼ inch hole. No wiper trips were required and, at the end of the interval, the methylene blue test (MBT) result (the standard measure of clay content) was an exceptionally low 7.5 ppb, compared with 25 to 30 ppb for a typical PHPA polymer fluid under equivalent drilling conditions. Drilled solids were flocculated, encapsulated and easily removed from the system with conventional solids control equipment. At the shakers, the cuttings appeared crisp and glossy, indicating excellent inhibition.

For optimum performance, the system is run with 15 to 24% sodium chloride or combined sodium and potassium chloride salts. The fluid can be weighted up to 17 ppg and has the potential to be recycled. Tests using Berea sandstone show that the drilling fluid leaves a very thin, slick filter cake with minimal formation penetration and very low lift-off pressures. The low dilution and mud consumption rates make the system especially well-suited for rigs with limited deck space or remote operations.

Field experience has shown that the system can be effective from below the 20 inch casing to total well depth (TD). The HPWBDF has less colloidal content than invert systems, enabling enhanced penetration rates of 100 feet per hour or more and a lower ECD than conventional water-based or synthetic base drilling fluids. Figure 4 shows an example where the ECD measured using a downhole pressure while drilling service is 0.3 ppg lower than that for a conventional synthetic base mud in the same hole section (12 ¼ inch) on an offset well.

Conclusions

Since the introduction of this clay-free SBM in 2002, it has been used across the Gulf of Mexico in over 140 wells under a variety of conditions with over 90 of these in deep water. The system has been exposed to bottom-hole temperatures as high as 177°C (350°F), while exhibiting extremely stable viscosity to below 4°C (40ºF) and at mud densities to 2.0 SG (16.7 ppg). It has been used in water depths to over 8,000 feet and in wells exceeding 28,000 feet in total depth.

The system has demonstrated excellent suspension and hole cleaning properties, while remaining shear sensitive, and is highly resistant to contamination. In reservoir sections, minimal invasion and superior return permeability have been observed. Gelation tendencies at low temperature are minimal, compared with a conventional synthetic base mud. The low ECD has assisted operators in dealing with a narrow mud weight/fracture gradient drilling window, with substantially reduced risk of severe losses.

The drilling performance of the HPWBDF approaches and closely replicates that expected from a synthetic or oil-based fluid, with all drilling targets achieved or exceeded. Stable hole conditions are achieved with no bit-balling or sticking tendencies downhole. Good hole cleaning is achieved along with excellent cuttings separation at the shakers. Low fluid dilution and consumption rates ensured reduced levels of drilling fluid discharge and environmental impact. This system is also clay-free and of low colloidal content, endowing it with lower ECD than alternative systems and making it ideal for deepwater drilling.

Acknowledgements

The author would like to thank the management of Halliburton for their support and permission to publish this paper.

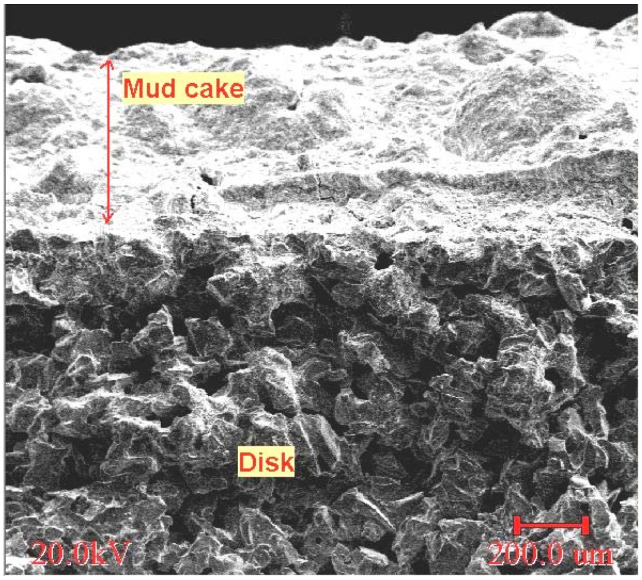

Figure 1: SEM photograph of the 35 micron PPA aloxite disk with mud filter cake. No evidence of mud penetration.

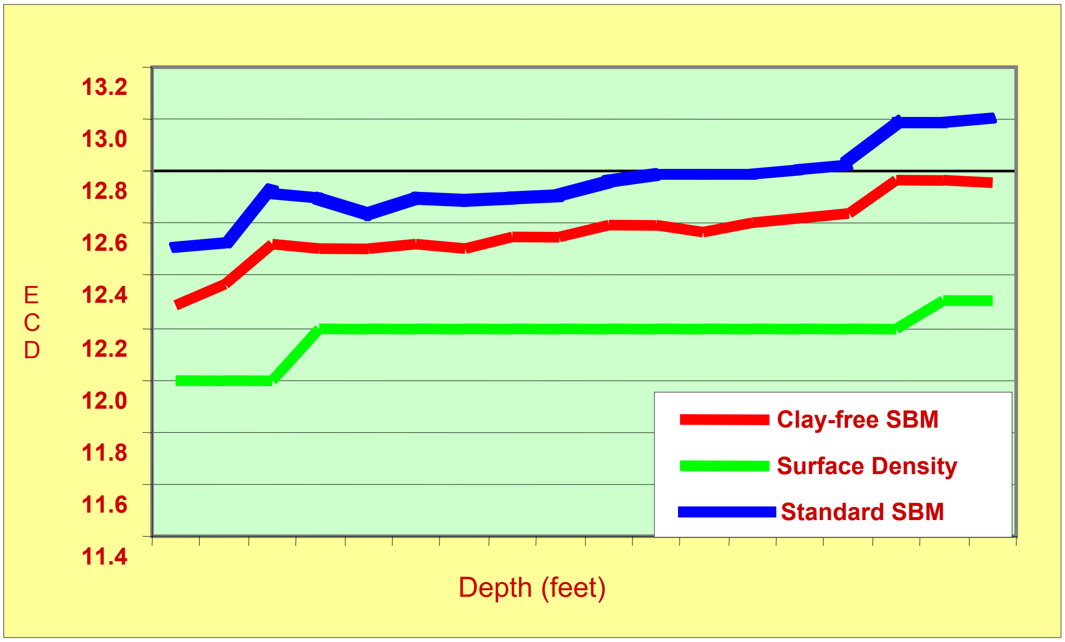

Figure 2: ECD in ppg of the clay-free synthetic base mud, using a downhole pressure measurement tool, compared with that of a conventional SBM used on a nearby offset well in deepwater Gulf of Mexico.

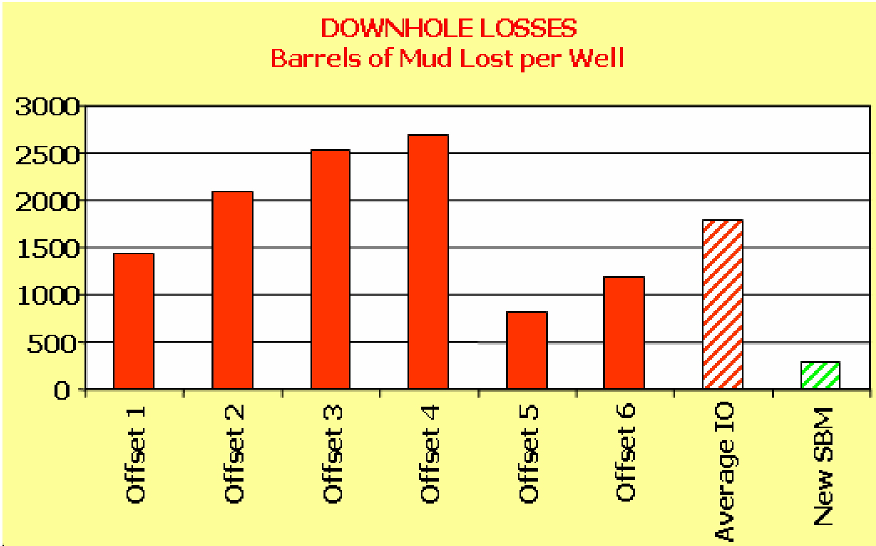

Figure 3: Mud loss reduction and cost savings achieved for a major operator in the Gulf of Mexico

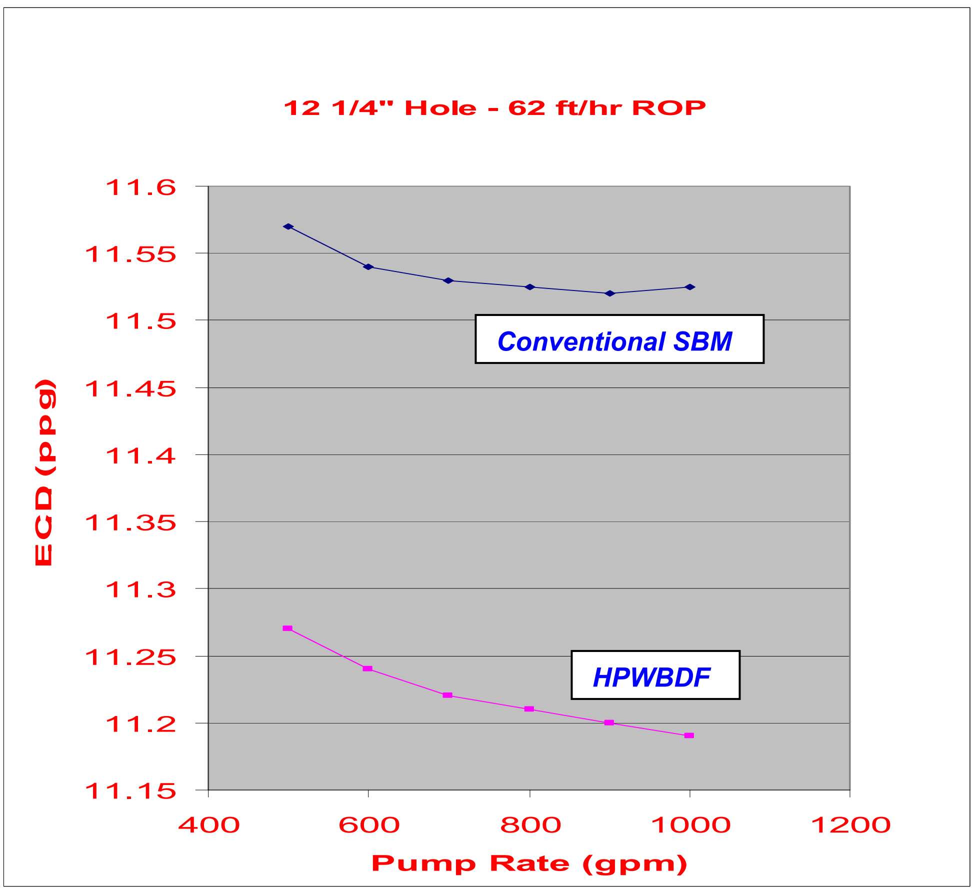

Figure 4: ECD of the HPWBDF, using a downhole pressure tool, compared with a conventional SBM on a nearby offset well