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Meeting Deepwater Challenges with High Performance Water Based Mud

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Abstract

Market forces and a declining trend in reserves dictate that operators are increasingly forced to drill exploratory wells in deeper offshore waters. Over the past decade, this activity has created a demand for new drilling fluids technologies to address the challenges faced in such hostile environments and several innovative approaches have evolved.

The technical challenges faced by deepwater drilling fluids typically include pressure control problems owing to compressibility effects, hole cleaning issues, gas solubility, problems with in-situ gas hydrates and high potential for downhole losses owing to a narrow margin between ECD and formation breakdown. In the worst case this can lead to ultimate failure to meet the primary drilling objectives.

Conventional invert emulsion fluids can be carefully managed to deliver on many of these applications and much has been made of the benefits of OBMs which exhibit less variance in measured viscosity under extremes of pressure and temperature. However, these options do not address the primary shortfalls derived from running OBM in deepwater, nor do they possess the environmental attributes sought by regulatory bodies and operators alike.

This paper discusses the features and benefits of running a state of the art High Performance Water Based Mud (HPWBM) in combination with engineering excellence in deepwater. It includes detailed case histories of applications in the Gulf of Mexico, Brazil, Australia and the Turkish Black Sea where the HPWBM was used as an alternative to OBM in some of the most technically challenging wells in environmentally sensitive drilling areas.

Introduction

Oil based mud systems have long been the fluids of choice for many operators. These systems have been consistently proven as technically superior to conventional water based muds in the areas of borehole stability, ionic inhibition, rate of penetration, cuttings condition and sticking avoidance. Principally, the beneficial technical attributes are derived from the continuous organic phase and with the benefits being inherent in the base fluid, these muds are often considered easier to maintain and more tolerant to contaminants such as drill solids. It is therefore no surprise that for the most challenging wells, the "default selection" can be to select a non aqueous drilling fluid.

Deepwater drilling applications are generally challenging and are often high profile given the risk/reward factor. There can be a natural temptation to default to the selection of OBM. However, when examined in more detail it is evident that some of the inherent features of OBM can be counter-productive in the deepwater application, principally concerning the areas of downhole pressure control, compressibility, gas solubility and the increased prospect of downhole losses owing to a high ECD in combination with a low formation breakdown gradient. Some of these down-sides could be addressed by selecting conventional WBM, however such a proposal would often be something of a trade off in terms of drilling performance, where the well complexity and the demands on the drilling fluid may make such a proposal technically un-viable.

So called "flat rheology" oil based muds (FROBM) evolved to try to address some of the issues relating to pressure control in deepwater through ECD management. These fluids have been developed to exhibit less variance in measured viscosity under the extremes of pressure and temperature often found in deepwater applications. This is usually achieved by substituting the organo-philic clay content of the OBM with liquid rheology modifiers, complex emulsifier packages, oil wetters and additional stabilizers in combination with a low kinematic viscosity base oil to provide this "flat rheology" feature. However, while FROBM's can provide a more uniform ECD under pressure and temperature extremes, "uniform" does not necessarily equate to "uniformly low" and the effects of compressibility, lower FBG and gas compressibility still remain as inherent features of the organic continuous phase.

An alternative approach would be to revert to an aqueous fluid which raises the bar in terms of WBM drilling performance whilst at the same time mitigating the environmental risks and technical issues associated with oil based muds in deepwater. In order to be a technically viable alternative to OBM, this high performance water based mud (HPWBM) would be required to emulate OBM drilling performance in the areas of shale stability, clay stability, ROP, cuttings encapsulation, sticking avoidance and lubricity.

The OBM / WBM Deepwater Comparison

The differing technical attributes of non-aqueous and aqueous fluids are covered in detail in many publications. General opinion in terms of drilling performance over-whelming favors the former, however in other areas there are significant intrinsic benefits derived from aqueous fluids. When considered in combination, these factors may give cause to re-evaluate the drilling fluid selection for challenging, exploratory, deepwater operations. The following outlines some of the areas in which aqueous fluids hold a technical advantage in deepwater applications.

Compressibility

All non-aqueous fluids exhibit some degree of compressibility and expansivity under the influences of pressure and temperature in a well. As in the oilfield, for the purpose of this paper both phenomena will be collectively referred to as "compressibility". While the degree of compressibility will vary according to factors such as base oil type, oil water ratio, emulsifier type and concentration, as well as the external (non fluid) variables in a well, the consistent factor is that there will be a degree of compressibility and that this will lead to variances in mud density at various points in the annulus and therefore variance in the actual hydrostatic pressure applied to the formation. This problem can be more readily managed in lower pressured wells involving lower mud densities, or wells where there is less variance between surface temperature and bottom hole temperature such as shelf wells or land work. However, the problem becomes dramatically exacerbated in deepwater conditions owing to the high pressures and temperature variances involved. This is particularly evident during operations such as resuming circulation after trips or other long periods without circulation.

Aqueous fluids on the other hand are widely acknowledged as being non-compressible in relative terms. Therefore hydrostatic pressure control can be managed with much greater accuracy during drilling operations with water based mud.

Singamshetty et al.[1] conclude that although several sophisticated, validated hydraulics simulators exist to model compressibility effects on invert emulsions, the complexities involved are far reaching and that theoretical modeling does not always directly correlate with field evidence. This in part is attributed to the unpredictable nature of variable like temperature and pressure in exploratory wells, but also the dynamic effects can be difficult to predict. [2-3]

Figure 1 illustrates some equivalent static density (ESD) calculations generated by one such model, comparing a common OBM (mineral oil based) with a typical SBM (isomerized olefin) and a HPWBM (20% Sodium Chloride) in a deepwater example using typical water depths and temperature gradients encountered in such operations. Table 1 outlines some of the well and fluid parameters used in these calculations.

It is clear in this comparison that the desired bottom hole pressure is more likely to be readily accomplished and controlled with WBM than with OBM.

ECD Increment & Management

This phenomenon of pressure fluctuation through OBM compressibility in deepwater lead to the introduction of so called "flat rheology" oil based mud (FROBM) to the marketplace. These fluids were held out as a creative technique which exhibits less variance in measured viscosity under the influences of pressure and temperature. However, in comparison with WBM, a degree of compressibility is still very much apparent. Also, the complex nature of how the "flat rheology" is derived brings with it further field limitations.

Mullen et al. [4] discuss that FROBM's are designed to provide a fluid with an elevated but flat rheological profile in comparison with conventional OBM, yet provide a lower ECD, better hole cleaning and barite suspension.

The common technique used to derive flat rheology is firstly to select a base fluid with a low, flat kinematic viscosity profile over varying temperatures. In addition to this the organo-philic clay content is minimized and substituted with polymeric rheology modifiers. Another approach is to use temperature activated surfactants that interact with the low concentration of clay and build viscosity networks and structure by interaction. [5, 6]

A review of these systems found that this approach is valid in many cases. However, the ability to produce a flat viscosity profile is influenced by several mechanisms that cannot always be directly controlled or predicted. These include not only the variables of temperature and pressure, but also the interaction of rheological modifiers and drill solids, extreme sensitivity to changes in product concentrations, changing shear rates in the annulus and variations in alkalinity. Also, at bottom hole temperatures above 200°F dramatic increases in HTHP fluid loss are observed with significant water break out in the filtrate. Furthermore, a typical FROBM formulation will contain thirteen or more components, some of which are designed for complex interaction, whereas a conventional OBM can contain as few as five components and will generally demonstrate a greater degree of tolerance to well contaminants. It is obvious that a thirteen component system will be more difficult to engineer in the field than a five component system.

Regardless of whether the OBM is designed with flat profile or not, the incremental ECD with any invert emulsion system will likely be higher than with a water based mud. This is principally due to the fact that the latter is non-compressible in relative terms. However additional factors exists such as the fact that the formation and stabilization of an emulsion (as with OBM) will provide some viscosity in it's own right, whereas with WBM this is not an issue. Also, the viscosity of a HPWBM is derived from shear thinning polymers such as high quality xanthan derivatives or scleroglucans, rather than the clays or high gelling modifiers used in OBM's. Furthermore, the base fluid of a HPWBM (brine) is of a higher density than an emulsion of oil and brine, therefore fewer solids are required to reach desired mud density with a HPWBM than with an OBM.

Table 2 outlines HPWBM and FROBM formulations by component at the same final fluid density and shows the mud properties critical to ECD management. The differences in viscosity profile, gel progression and solids content are also illustrated in Figures 2-4.

Formation Breakdown and Fracture Propagation

Field evidence suggests that when drilling with a WBM, a borehole will have a higher formation breakdown pressure and fracture propagation gradient than would be attained with OBM in hole. This theory has been corroborated by several laboratory and test well studies, a widely publicized example being the DEA-13 joint industry project conducted in the mid 1980s.

As illustrated in Figure 5, the project clearly demonstrated an increased pressure requirement to initiate and propagate a fracture with WBM than in identical tests with OBM. Not only was it found that additional pressure was required, but that pressure had to be frequently re-applied to continue propagating the fracture which showed a tendency to heal itself with WBM. It is not uncommon to encounter this scenario in the field.

Several theories exist as to why this may be the case however general consensus is that there are three factors at play. Firstly, it must be understood that in order to propagate a fracture effectively, a certain level of hydrostatic pressure must be applied to the fracture tip to extend the fracture. With a WBM the fracture tip is somewhat protected by an external filter cake. This will be a deposit of solid particles such as barite or marble which are designed to bridge on the face of the borehole wall. However, an OBM will deposit an internal filter cake of emulsified brine droplets within the borehole wall. As the resultant filter cake is usually significantly thinner, and it is internal, less protection is afforded to the fracture tip. Secondly, conventional WBMs will allow a certain level of pore pressure transmission through formations. This allows some of the pressure to dissipate in the fracture before it reaches the fracture tip. With OBMs little or no pressure is transmitted through pores, therefore no such dissipation can occur. Finally, deformable solid particles such as LCM, mud additives or drill solids will deform and mould into a fracture more readily when carried in WBM than with OBM.

So not only do WBMs provide better pressure control in deepwater through lack of compressibility and less incremental ECD, but the extent to which this ECD can be pushed is generally higher than with OBM. In deepwater applications, where high bottom-hole pressures and high rig rates are involved, it's understandable that avoidance of losses is a critical requirement and any factor which may help extend the operating window between ECD and FBG is of great significance and benefit to the operator.

Barite Settlement

This is another area critical to pressure control where WBM has an advantage over OBM, the key factor being that WBMs have been proven to be far less prone to barite settlement than oil based equivalents.

The occurrence of barite settlement is often linked to drilling problems such as lost circulation, well control, stuck pipe and logging difficulties. The financial impact of barite sag on drilling costs, usually resulting from lost rig time due to circulating and conditioning the mud system, is not trivial. There are recorded incidences where recurring barite settlement problems have resulted in the loss of drilling projects.

Barite "sag" was once thought to occur predominantly under static wellbore conditions, however low shear rates under dynamic conditions are now recognized as greater contributors to inducing settlement.

Results from studies [7] have shown that the onset of dynamic barite sag in deviated wells occurs at shear rates below the lowest recordable speed of the conventional oilfield 6-speed viscometer. Therefore technology was developed to predict and prevent the occurrence of barite sag through viscometers which measure ultra-low shear rate viscosity modification.

While these modified viscometers have enabled reliable prediction and afforded some mitigation of the risks of dynamic settlement in the field, the fact remains that invert emulsions are far more prone to sag than WBMs. Several schools of thought exist as to why this might be the case. One possibility is that because OBMs are generally more viscous at surface than WBMs, there exists a temptation to reduce the viscosity which involves additions of base oil, emulsifiers and oil wetters, but minimizing additives such as the high grade organo-philic clays which are excellent for increasing low shear viscosity and for suspending barite. Another explanation is that fluid flow in a deviated wellbore is altered by the effects of drill-pipe eccentricity, typically resulting in low shear rates in the larger annuli, thus creating conditions conducive to barite sag particularly in highly deviated wells where OBMs are principally used.

This illustrates another area in which pressure control is likely to be more accurately achieved with WBM than with OBM, and in deepwater wells the down-sides of bore-hole failure through pressure effects, downhole losses or a well control problem can be very costly.

Gas Solubility

Formation gas is known to be soluble in oil and far less so in water based mud. O'Bryan et al [8] claim that natural gas solubility in oil based fluids could be anything from ten to one hundred times greater than solubility in water based fluids, making it very difficult to detect and deal with a kick in an oil based system in deepwater.

As these compressed gasses inevitably involve a huge change in volume with only a "small" change in pressure, the added complexity of gas solubility in oil becomes exponentially more relevant in deeper and deeper water. The understanding of gas solubility in synthetic or oil based systems plays a fundamental role in preventative well control and corrective actions in deepwater wells.

Many studies have been conducted [9-11] which analyzed gas solubility in various oils, emulsions and gas-liquid mixtures. Typically methane is used as a standard representation of formation gas, however actual formation gas may be a complex mixture, adding further complexity to the issue. For each specific fluid, or mixture of formation gas and liquid, a complex array of testing is required to determine bubble point, solubility, liquid density, volume factor of oil and volume factor of gas under downhole thermodynamic conditions.

It is clear that one way of improving kick detection in deepwater and avoiding these complexities without sacrificing performance would be to select a technically viable WBM.

Formation Evaluation – Logging

In many deepwater jobs, data collection is everything. The entire purpose behind drilling exploration wells is to collect and evaluate data with a view to future viability of the area concerned. While a drilling fluid is principally designed with the necessary attributes to drill the well, it is also critical that the fluid does not unnecessarily impede or interfere with data collection and quality.

Faced with this challenge, a HPWBM can become a very attractive alternative to oil based systems where neither drilling performance nor data collection can be compromised.

Historically, water based systems have been proven to allow superior quality data collection at rig-site than oil based equivalents, especially concerning high resolution electrical imaging, NMR data which may be affected by OBM surfactants changing wet-abilities in the flushed zone, and the ability to obtain uncontaminated hydrocarbon samples with wire-line formation testing tools – where with a water based mud only reservoir hydrocarbons are present.

Drilling Performance Attributes – HPWBM v's OBM

Much has been documented about the development and deployment of high performance water based muds as technically viable and environmentally sound alternatives to oil based systems. [12-17] The authors acknowledge that in terms of drilling attributes, invert emulsions remain the pinnacle performer. More so, OBMs are generally considered low maintenance given that most of the drilling performance benefits are derived from the continuous organic phase.

Water based systems are at a huge technical disadvantage in that the continuous phase is highly polar, of the same wet-ability as most troublesome formations, and without a pressure blocking membrane. Owing to this fundamental difference, all WBMs have to be skillfully designed and engineered to mitigate the effects of pressure transmission, swelling clays, bit balling and sticking tendency, if they are in any way going to emulate the drilling performance of OBM.

Shale is mechanically stabilized (given the right mud density) by means of a barrier or membrane which prevents pressure bleeding off into the formation. With an OBM this membrane is formed by the emulsion of brine droplets in oil sitting at the wellbore wall and also by an oil capillary entry pressure effect - an additional pressure required for an emulsion (oil wet) to be forced into the pores of a water wet formation. With a conventional WBM no such membrane is in place and pressure is prone to bleeding off into the formation, allowing the equalization of pressures and failure or sloughing in the near wellbore area.

A HPWBM has been developed which blocks pore pressure transmission by means of a shale sealing polymer (SSP) in combination with an aluminum resin complex (ARC) designed specifically to bridge the micro pores and micro fractures found in typical shale. As shown in Figure 6, it has also been repeatedly and consistently demonstrated that when run with a higher salinity (or lower water activity) than the connate water, pressure transmission is actually reversed from the formation to the wellbore in the same manner as with OBM.

In terms of ionic inhibition or chemical stabilization of clays, oil based systems will inevitably show little or no swelling physical swelling in laboratory or field tests given that the external phase is not polar and the internal phase is drawing water from the clay sample. With conventional water based mud a certain level of ion exchange is inevitable, where the native ionic composition on the reactive sites (basal planes) of the clay platelet is altered by means of invasion and replacement according to ionic replacement order. Generally, this will disrupt the electrostatic bond between clay platelets allowing them to swell and this causes all manner of problems while drilling, including stuck pipe, bit balling, increased ECD through narrowing annular clearance or increased mud viscosity – or both, swabbing, surging, losses and ultimately in some cases failure to meet the drilling objectives.

The HPWBM uses a unique, patented, poly-amine based clay suppressing agent (CSA) which is designed to contain ions which are high in replacement order. Not only does this provide a high level of electrostatic binding, but it is a more permanent effect than using simple brines such as KCl or NaCl for the same purpose. When combined with the pore blocking attributes of the SSP and ARC, this leads to superior mechanical and chemical inhibition of shale and clay with the HPWBM.

Solids removal efficiency is not a prevalent problem when drilling with OBM. Owing to the high levels of mechanical and chemical inhibition afforded by OBM, cuttings which have sat in an annulus for a considerable length of time can often be circulated up at a later date still in an apparently "fresh" condition. As long as the level of cuttings beds does not impede objectives, often hole cleaning efficiency is not high on the list of concerns.

With WBM, some degree of hydration and swelling is inevitable if cuttings are allowed to sit in hole and the problem will become more prevalent as cuttings residence time in hole increases.

The HPWBM uses a patented acrylamide based cuttings encapsulator (CE) which reacts with available sites on the surface of cuttings to physically encapsulate them, further preventing hydration and agglomeration in the annulus and assisting in solids removal at surface by minimizing cuttings surface area or maximizing cuttings size.

While the HPWBM offers a high degree of mechanical and chemical inhibition and encapsulation, emphasis must still be placed on optimizing annular hydraulics and adopting other best practices for cleaning the hole as would be necessary with any WBM.

Drill bits, bottom hole assemblies and drill-strings run in an OBM are oil wet, and as there is little or no tendency for water wet shale or clay cuttings to adhere to oil wet steel, the occurrence of bit balling or drill string accretion is uncommon with OBM. Understandably this leads to higher ROP.

A WBM must be designed to mitigate the effects of bit balling and accretion if it is to try to emulate oil based ROP. The HPWBM incorporates an anti balling agent (ABA), the development and deployment of which out-with the HPWBM is also well documented. Bland et al [18] discuss that changes to mud chemistry alone do not alleviate bit balling and products which seek to reduce agglomeration by altering the wet state of the metal surfaces and surface of the cuttings are much more likely to produce results. The ABA is such a product. It uses a proprietary blend of surfactants and organics to provide an oil wetting effect on steel and cuttings, mitigating balling and delivering ROP far superior to what had been achieved previously with conventional WBM.

HPWBM Deepwater Case Histories

The following deepwater case histories and offset information shows that the HPWBM truly raises the bar in terms of water based drilling performance. It emulates the drilling performance of OBM without the inherent down-sides of compressibility and the like in deepwater. The HPWBM provides the technically viable and environmentally sound solution sought after by clients and regulatory authorities alike.

Gulf of Mexico – Alaminos Canyon

HPWBM was used by a super-major operator on a deepwater well drilled in 4,931 ft of water in the Alaminos Canyon field in the Gulf of Mexico. The HPWBM was evaluated by the operator as a high performance water based alternative to synthetic based mud while drilling a 12¼" interval and building angle to 45°.

The 12¼" interval was drilled with HPWBM below the 13⅜" casing shoe starting at 8,721 ft (measured depth) using a rock bit.

The system performed extremely well with respect to shale and gumbo inhibition at high rates of penetration. The solids removal efficiency in the interval ranged from 80-82%. This was supported by MBT tests which showed an increase of only 4.0 ppb after drilling 2,000 ft of young, swelling clay as illustrated in Figure 7. Four linear motion shale shakers processed up to 1,250 gpm of flow over 145 mesh screens. The drill string was pulled out of hole at 9,593 ft MD to change the directional assembly and an inspection of the drill string, BHA and bit showed them to be generally free of accretion and bit balling.

A total of 2,543 ft of 12¼" was drilled with 957 ft drilled while sliding and 1,586 ft while rotary drilling. ROP generally varied from 20 to 200 ft/hr, averaging 88 ft/hr. Instantaneous ROPs were higher than 300 ft/hr in several cases. The average ROP when sliding was 85 ft/hr and average ROP was 94 ft/hr when rotary drilling. This equates to an overall average ROP of 88 ft/hr which is comparative to ROP achieved on offsets with SBM. Average ROP is illustrated in Figure 8. Flow line temperatures averaged just 54°F (12°C) and the total active circulating volume was in excess of 4,000 bbls. The well reached total measured depth of 11,257 ft (11,020 ft true vertical), with a 369 ft horizontal departure. There were none of the pressure control problems associated with SBM and no losses or other mud related hole problems. 9⅝" casing was run to bottom with no problems and all section drilling and completion objectives were achieved. An outline of basic well parameters and typical mud properties are given in Tables 3 and 4.

Dilution rates were low for a WBM at 0.31 bbls per foot, planned cost objective was met and this was competitive with SBM. More so, the set up, containment, disposal costs and environmental liability of running SBM were all eliminated as well as saving half a day in rig time by omitting the necessity for a full cased-hole clean up before running completion.

Brazil - Campos Basin (1)

The HPWBM was used by a major operator to drill the 12 ¼” interval of a deepwater well in Campos Basin, Offshore Brazil. Offset wells drilled in the area with conventional water based mud were plagued with problems such as gumbo attacks, bit balling and accretion.

Performance metrics were established during the pre well planning meetings to measure performance against competitive systems. These metrics included a requirement for an ROP of greater than 33 ft/hr (10 m/hr) and for a friction factor of 0.22 or less.

The HPWBM system performed extremely well with respect to shale and gumbo inhibition at high rates of penetration. Performance highlights included ROP averaging 66 ft/hr (20 m/hr), an average friction factor of 0.17, excellent wellbore stability and elimination of bit balling and accretion as illustrated in Figure 9. More so, there was no repeat the stuck pipe incidents encountered an offset wells.

Drilling costs were reduced owing to the excellent ROP which had doubled expectation as well as elimination of any requirement to set up, contain and dispose of any SBM or SBM drilled cuttings.

No mud related NPT was encountered and all section drilling and completion objectives were achieved. Well parameters and typical mud properties are given in Tables 5 and 6.

Brazil - Campos Basin (2)

In order to validate results from the first Brazilian well and to make a fairer assessment of HPWBM performance and expectations, a second deepwater HPWBM trial was undertaken by the customer on the same rig, in the same area, using the same performance metrics and planning procedure as before.

Results on the second well included similar performance with respect to shale/gumbo inhibition at high rates of penetration. ROP averaged 85 ft/hr (26 m/hr) and an average friction factor of 0.17 was achieved. Wellbore stability was excellent and bit balling and drill-string accretion was eliminated again.

Australia - North West Shelf

Objectives for this deepwater exploration well were to drill both the 12¼” and 8½” sections with the HPWBM, achieving drilling and completion targets while measuring drilling performance against conventional WBM and SBM offsets. Additionally there was a significant drive to use HPWBM owing to the environmental sensitivity of the area concerned.

As is often the case with deepwater exploratory drilling, pore pressures were unknown and information from the two offset wells and indications from the well were used to determine mud density. A narrow operating window existed between anticipated ECD and FBG and so accurate pressure control and ECD management was vital to avoid losses and unnecessary down-time.

There had also been significant bit balling problems and resultant low ROP encountered in the offset which had been drilled with conventional WBM.

Highlights of the well included the delivery of gauge hole in both sections, excellent ECD management and no downhole losses, a successful 9⅝” casing run, low dilution rates, excellent wellbore stability and ionic inhibition of clays, very stable mud properties (Table 7) and successful achievement of all drilling objectives.

Having drilled 5,689 ft, most of which was clay, the MBT rose from an initial value of 2.5 ppb to a final value of just 8.75 ppb with dilution rates as low as 0.18 bbl/ft.

As illustrated in Figure 10, over both sections the average ROP with HPWBM (including connections) was 41.7 ft/hr, this is well above the offset ROP with conventional WBM which was 26.2 ft/hr, well above the client’s own technical limit which was set at 32.8 ft/hr and nearing the 45.9 ft/hr achieved on the offset with SBM.

Turkey - Black Sea

An exploration well is ongoing in the Turkish sector of the Black Sea, in which the HPWBM was selected over SBM for use in the entire well (with the exception of riser-less sections).

Several challenges are presented by this well including the logistical challenges in drilling in a remote location as well as the technical challenges presented by a complete wild-cat well. It is worth noting that the closest “offset” well is several hundred miles away in the Caspian Sea and not really an offset well as most would understand.

Shore-side fluids infrastructure such as mud plant, bulk liquid / powder storage and warehousing had to be established specifically for the job and this was completed safely, without incident, to specification, on time schedule and within budget.

Also, owing to concerns over the presence of shallow gas when riser-less, the operator required contingency to pump weighted spud mud, so while local infrastructure was being erected, over 9,000 bbls of 17.0 ppg viscous spud mud was transferred from an existing service port in the UK. This spent over six weeks in transit and was delivered to the local port and directly to the rig without any barite settlement problem. More so, weighted spudding operations were carried out using a unique blending manifold without problem and casing was run successfully.

From this point on, a further five sections have now been drilled with the HPWBM with excellent results.

A particular challenge posed in more than one section is that there is a very narrow operating margin between ECD and FBG. In fact in some circumstances the well was being controlled not by mud density but by relying on the incremental pressure of ECD while employing strict ECD management practices so as not to break the hole down. Before trips, the MW was gradually increased to match the previous ECD so as to control the well when static.

Some seepage losses have occurred which appeared to be self curing and remedial treatments with cross-linking polymer LCM has been required in one section.

Had this scenario been confronted with SBM in hole, it is considered that pressure control would have been less accurate through compressibility, potential for sag when slow circulating and other factors, ECD would have been higher and FBG would have been lower. In light of this increased challenge, the likelihood is that significantly more time and expense would have been spent on remedial treatments for losses or in setting contingency casing/liner strings.

Despite these events, wellbore stability has been excellent throughout. 3D imaging logs are of top quality and consistently show gauge hole.

The mud has performed well in terms of clay suppression and encapsulation. The same mud has been carried forward from section to section and only minor dilution has been carried out where necessary. Mud properties are very stable, the MBT has never risen above 10 ppb and to date the HPWBM has been in hole over 150 days.

Commendations have been received concerning the quality of log data retrieval which has surpassed expectations. Given that data acquisition is the primary purpose of the well, this is a significant achievement.

Conclusions

- Deepwater wells present many challenges, usually in the form of high pressures, extended depths, temperature variance and a low or narrow operating margin between ECD and FBG.
- Oil based systems are recognized as technically superior systems to the vast majority of water based muds in terms of drilling performance. However, they are subject to the effects of compression and expansion under the influences of pressure and temperature.
- In some respects, water based systems are better adapted to aspects of deepwater drilling, especially concerning pressure control.
- Conventional water based muds are not always technically viable for challenging deepwater wells and a HPWBM has been developed and deployed which raises the bar in terms of water based drilling performance.
- The HPWBM has been used as an environmentally driven alternative to SBM on several occasions in challenging, deepwater wells with a high degree of success.

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Nomenclature

OBM = *Oil Based Mud*
SBM = *Synthetic Based Mud*
IO = *Isomerized Olefin*
FROBM = *Flat Rheology Oil Based Mud*
WBM = *Water Based Mud*
HPWBM = *High Performance Water Based Mud*
ft = *Feet*
bbl = *Barrel (US)*
gpm = *Gallons (US) per minute*
MW = *Mud Weight*
ppg = *Pounds per gallon*
ESD = *Equivalent Static Density*
ECD = *Equivalent Circulating Density*
FBG = *Formation Breakdown Gradient*
FPG = *Fracture Propagation Gradient*
ROP = *Rate of Penetration*
HSI = *Horsepower / Square Inch*
TFA = *Total Flow Area*
GPM = *Gallons per minute*
SSP = *Shale Sealing Polymer*
CSA = *Clay Suppressing Agent*
ARC = *Aluminum Resin Complex*
CE = *Cuttings Encapsulator*
ABA = *Anti Balling Agent*
LCM = *Lost Circulation Material*
MBT = *Methylene Blue Test*
NMR = *Nuclear Magnetic Resonance*

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Table 1:

Deepwater Well Example		
Water Depth (ft)	5,000 ft	
Casing Size (in)	9 5/8" (8.681" ID)	
Casing Depth (ft)	13,000 ft	
Open Hole Size (in)	8 ½"	
Hole Depth (ft)	14,000 ft	
Mud Type	SBM	HPWBM
Mud Density (ppg)	11.5	11.5
600/300 (@120°F)	94/59	60/40
200/100 RPM	38/29	31/20
6/3 RPM	13/11	8/7
Gels 10s/10m/30m	11/15/22	8/11/13

Table 2:

Mud Type	HPWBM	FROBM
Components	Brine	Base Oil
	Viscosifier	Brine
	Filtrate Control	Lime
	Shale Sealer	Emulsifier 1
	Clay Suppressor	Emulsifier 2
	Caustic Soda	F/Loss Control
	Alu-Resin	Clay 1
	Anti-Balling	Clay 2
	Weighting Agent	Modifier 1
	Encapsulator	Modifier 2
	-	Oil Wetter
	-	Weighting Agent
	-	Bridging Agent
Mud Properties after hot roll at 150°F		
Mud Density	10.0	10.0
600/300 (120°F)	37/26	104/71
200/100 RPM	20/14	55/37
6/3 RPM	6/4	15/13
Gels 10''/10'/30'	6/7/8	15/25/32
PV (cP)	11	33
YP (lb/100ft²)	15	38
Corr Solids (%v)	4.67	11.66

Table 3:

Alaminos Canyon - Deepwater Well Data	
Mud System	HPWBM
Water Depth	4,931 ft
Section TD (measured)	11,257 ft
Section TVD	11,057 ft
Max Mud Density	10.6 ppg
Average Flow-line Temp	54°F
Max Hole Angle	46°

Table 4:

Alaminos Canyon – Typical Properties	
Mud Density (ppg)	10.6
Plastic Viscosity (cP)	21
Yield Point (lb/100ft²)	16
API Fluid Loss (mls)	3.2
HTHP @ 250°F (mls)	9.2
6 / 3 RPM	7 / 5
10 min Gel	18
pH	11.2
Chlorides (mg/l)	123,000
MBT (ppb)	7.5

Table 5:

Campos Basin (1) – Deepwater Well Data	
Mud System	HPWBM
Water Depth	3,757 ft
Section TD (measured)	11,312 ft
Section TVD	10,230 ft
Max Mud Density	9.8 ppg
Maximum Angle	56°

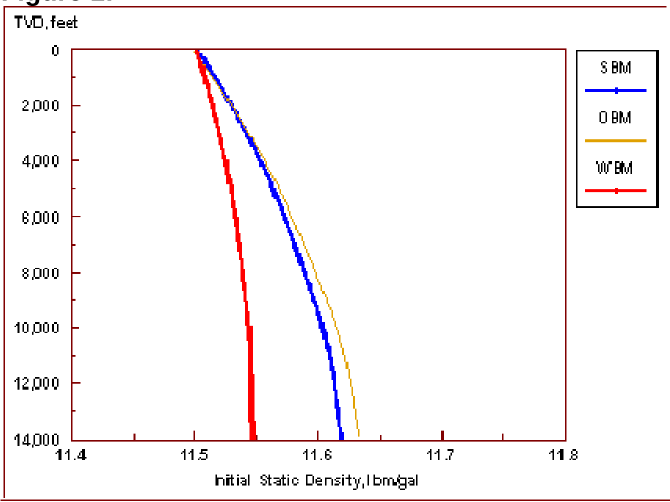
Table 6:

Campos Basin (1) – Typical Properties	
Mud Density (ppg)	9.8
Plastic Viscosity (cP)	16
Yield Point (lb/100ft²)	29
API Fluid Loss (mls)	3.5
Gels 10 sec / 10 min	9/15
pH	10.5
Chlorides (mg/l)	95,000

Table 7:

Australian NW Shelf – Typical Properties		
Hole Size	12¼"	8½"
Mud Density (ppg)	9.2	9.9
Plastic Viscosity (cP)	13	23
Yield Point (lb/100ft²)	17	30
6 RPM	6	8
API Fluid Loss (mls)	4.3	3.0
Chlorides (mg/l)	71,000	71,000
MBT (ppb)	4.6	8.6
pH	10.6	10.4

Figure 1:



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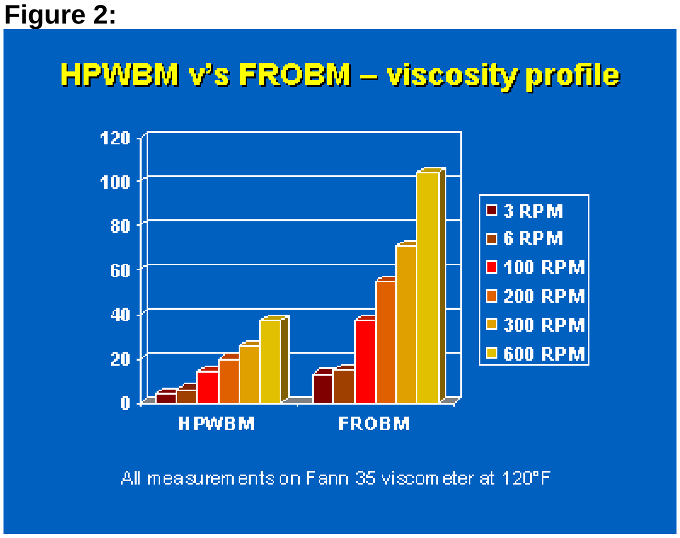


Figure 3:

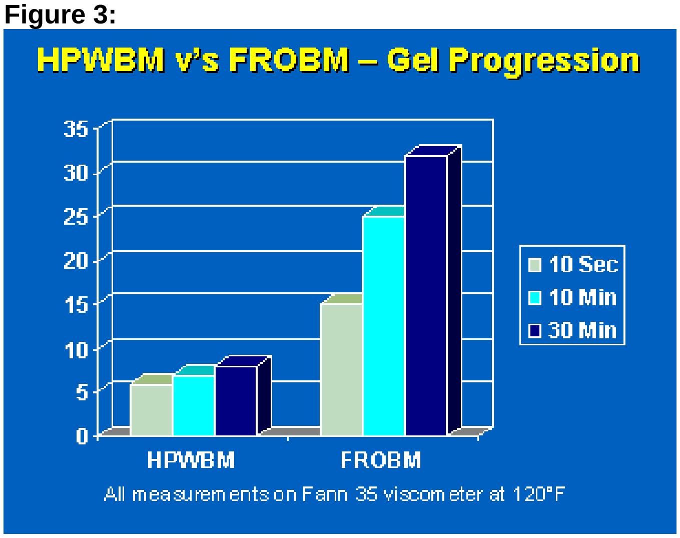
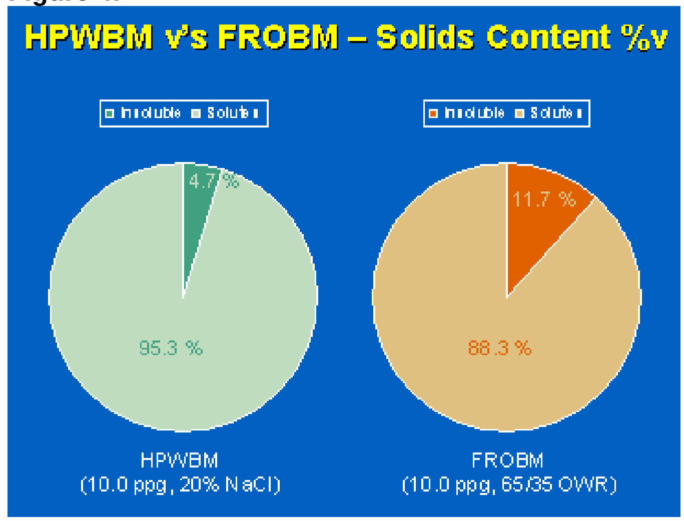


Figure 4:



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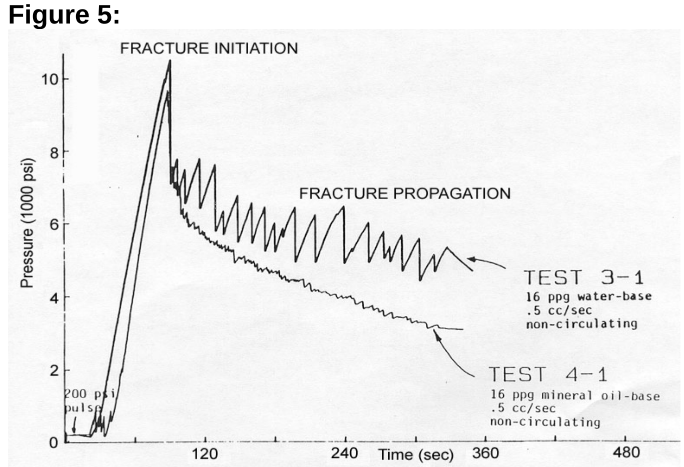

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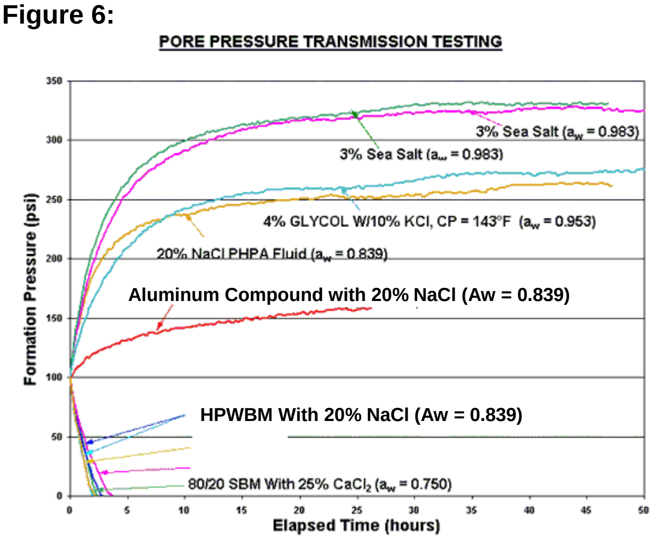

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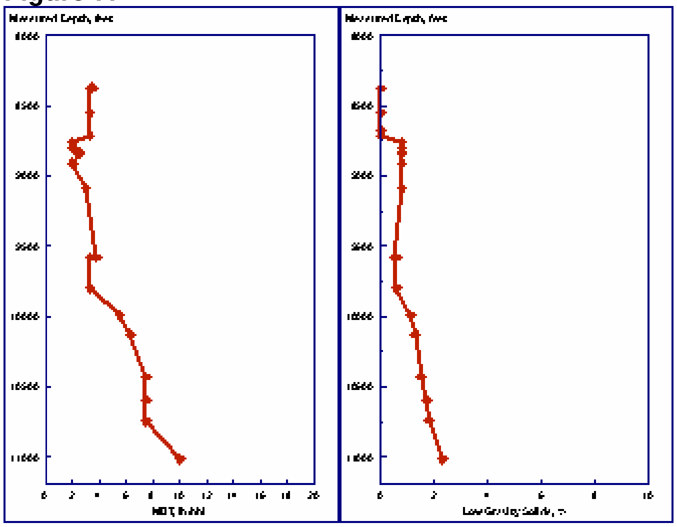

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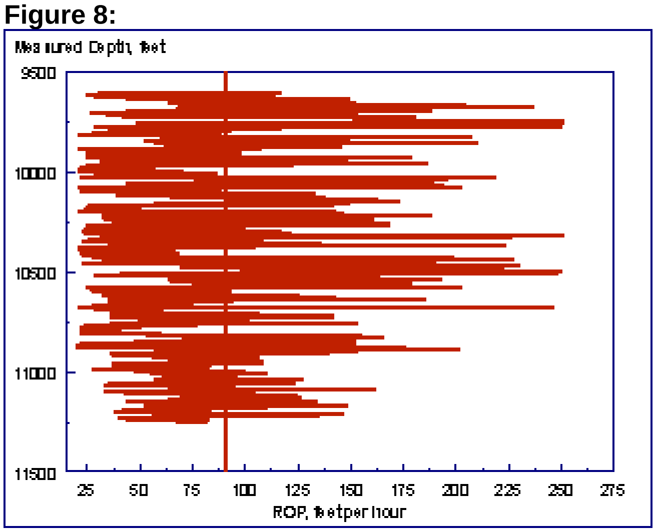

Figure 9:

Figure 10: