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Design Considerations for High Performance Water-Based Muds

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Abstract

High performance water-based muds (HPWBM) are attractive alternatives to oil- and synthetic-based emulsion muds (OBM/SBM) from performance, cost and environmental perspectives. Conventional water-based muds (WBM) have failed to consistently meet key performance criteria obtained with emulsion systems in terms of shale and cuttings stability, rates-of-penetration, bit and stabilizer balling, torque and drag reduction and lower well costs.

A significant amount of laboratory work and field testing has been expended on closing the drilling performance gap between emulsion-based and water-based muds. The challenge of developing cost-effective HPWBM as viable alternatives for emulsion muds has presented itself to the drilling fluids industry for decades. Breakthroughs have only recently occurred using a systems-design approach to emulate the performance attributes inherent to emulsion systems in a new high performance water-based mud system.

Introduction

The primary drilling performance attributes of emulsion systems are: 1) shale stability, 2) gumbo and clay stability, 3) cuttings stability and solids removal efficiency, 4) high rates-of-penetration, 5) minimized bit balling and accretion, 6) torque and drag reduction and 7) minimized differential sticking. High performance water-based muds are assumed to possess these drilling performance attributes of invert-emulsion systems.

The term “HPWBM” is often wrongly defined and designers focus on a specific performance attribute rather than those of the entire system. For example, partially hydrolyzed polyacrylamide (PHPA) polymer is an excellent additive for cuttings encapsulation; however, PHPA does not address all of the drilling performance attributes of emulsion muds. The addition of an ROP enhancer to water-based mud may deliver drilling rates equivalent to those of an OBM/SBM; however, it is unlikely that it will deliver the overall drilling performance of emulsion muds.

The HPWBM described in this paper (PERFORMAX) is based on a systems-design approach, whereby state-of-the-art technology is combined in a HPWBM system that delivers drilling performance approaching that of emulsion muds.

Shale Stability

The term inhibition is a catch-all phrase to describe shale, clay/gumbo and cuttings stability. These mechanisms share little in common and one must consider each one separately in HPWBM design. The shale stability mechanism of emulsion systems truly sets it apart from WBM and presents the most significant challenge to designers of HPWBM. In this paper the stabilizing mechanisms for shale will be treated separately from those of reactive clays and gumbo.

The most important factor in maintaining shale stability is preventing pressure increases in the shale matrix.[1,2,3,4] Pore pressure increases, and differential pressure support decreases, when mud filtrate invades the shale. Wall support is lost with the reduction in differential pressure and the shale can then easily slough into the annulus. Shale (borehole) stability is achieved when pressure increases in the matrix is reduced and differential pressure support is maintained. The problem of pressure invasion is exacerbated by shales having low permeability, which slows the rate at which pressure can dissipate. This typically confines the added pressure in shale to the vicinity of the near-wellbore surface.

Pressure transmission in emulsion systems is managed by the generation of a semi-permeable membrane and the osmotic potential pressure difference between the shale and emulsion fluid. Sources of the semi-permeable (selective) membrane of OBM/SBM proposed in the literature include the oil film and emulsifiers/surfactants surrounding the emulsion.[2,4] Calcium chloride in the internal phase reduces water-phase activity and creates an osmotic pressure differential at the borehole wall. Additionally, pressure invasion in emulsion systems is suppressed by the capillary entry pressure that must be overcome in order to force oil into the water-wet pore throat.

Emulsion muds are the ultimate membrane-generating systems and provide superior drilling performance primarily because of their ability to reduce pressure transmission in shale. Preventing pressure invasion in shale using WBM is a formidable obstacle due to the technical difficulty of generating an efficient membrane while remaining cost-competitive with OBM/SBM. A significant technology gap in HPWBM occurs when the system cannot generate a membrane approaching that of OBM/SBM. The HPWBM described in this paper is designed to closely emulate the shale stabilizing mechanisms of an emulsion system by generating a selective membrane and creating an osmotic pressure difference between the mud and shale.

The mobility of solutes in shale determines membrane efficiency of drilling fluids. The shale essentially acts as a semi-permeable (selective) membrane because the clay-rich matrix hinders the movement of solutes. The shale matrix can be made more selective, thus further reducing the mobility of solutes, by decreasing shale permeability.[2,4]

A two-prong approach is used to generate the selective membrane in the HPWBM. This is done by reducing shale permeability using both mechanical and chemical means. A deformable sealing polymer, having an extremely small particle size, is used to mechanically bridge micro-fractures on the exterior of the shale matrix.[5] The polymer is stable and maintains its particle size distribution even in the presence of high salt concentrations. The particle size of the polymer is such that the polymers bridge fractures on the shale surface.[1] The deformable nature of the polymer allows it to mold itself along the fracture which improves bridging (plugging) efficiency. Aluminum chemistry is used to form an internal bridge via precipitation within the shale matrix.[6] The aluminum complex is soluble at the mud pH but precipitates as it enters the shale matrix due to a reduction in pH, reaction with multivalent cations, or a combination of both. A quantitative test procedure has been developed and is integrated into routine mud tests in order to determine the available concentration of the aluminum complex in the HPWBM.

Pore pressure transmission (PPT) tests were performed comparing the HPWBM to conventional WBM and SBM. Figure 1 shows the performance differences between these fluids in reducing pressure transmission in shale. The WBM in these tests contain 20% sodium chloride (NaCl) with a water-phase activity (A_w) of 0.84 and therefore all have equal osmotic pressure differentials. The SBM internal-phase contains 25% calcium chloride ($CaCl_2$) with an A_w of 0.75. The core is preserved Pierre II shale oriented parallel to the bedding planes with an A_w of 0.98. While all of the WBM shown have equal water-phase activities, their performance in reducing pressure transmission differs significantly due to the difference in the efficiencies of the membranes generated. An overview of the PPT testing procedures and methodology is provided in the Appendix.

In the PPT tests shown, the initial formation pressure is 100 psi while the borehole pressure is maintained throughout the test at 350 psi. This results in a 250 psi initial pressure differential across the shale core. The formation pressure reaches equilibrium and remains nearly-constant with time. This establishes an equilibrium differential pressure across the shale core generated by the selective membrane. The results presented in Figure 1 show a significant increase in the equilibrium differential pressure for the HPWBM over traditional WBM. The formation pressure with the HPWBM decreases with time, thus indicating the net flow of pore water from the shale into the HPWBM. This reduction in formation pressure, as compared to an increase in formation pressure for the traditional WBM, is attributed to the increased membrane efficiency of the HPWBM. The SBM results in Figure 1 show a reduction in formation pressure over time as pore water is displaced from the shale into the SBM. The HPWBM performance closely mirrors that of the SBM in PPT tests, as shown in Figure 1.

Clay Stability and Cuttings Encapsulation

Another area of 'inhibition' is the stabilization of reactive clays and gumbo encountered when drilling upper hole sections. The inability to suppress hydration and dispersion of reactive clays and gumbo leads to problems such as bit balling, accretion, poor solids removal efficiency, high dilution rates and problems managing rheological and filtration control properties. An effective and proven mechanism to suppress hydration and dispersion is cationic exchange at reactive sites on clays. The HPWBM uses a mixture of polyamine derivatives for suppressing the hydration and dispersion tendency of reactive clays and gumbo.[7] This technology is engineered such that excess polyamine is available to prevent clays and gumbo from hydrating and dispersing as they are drilled. This practice facilitates increased solids removal efficiency, allows for running fine screen sizes on shale shakers and reduces dilution rates and maintenance costs. A quantitative method has been developed to determine the excess concentration of the polyamine.[8]

Partially hydrolyzed polyacrylamide (PHPA) is used for cuttings encapsulation in the system. The combination of polyamine chemistry, to suppress hydration and dispersion, and PHPA, to encapsulate cuttings, has resulted in solids removal efficiency over 80% both onshore and offshore wells drilled with the HPWBM. This in turn has led to lower maintenance and dilution rates, and lower well costs.

ROP, Bit Balling and Accretion

Emulsion systems are the "mud-of-choice" in many drilling operations because of the economic benefits derived from achieving high rates-of-penetration in combination with PDC bits. PDC bits are typically used with emulsion systems because of extended bit life, increased footage and a reduction in the number of trips for changing bits. Additionally, the cutting mechanisms of PDC and rock bits differ significantly from one another.[9] Rock bits fracture the rock by concentrating the applied load at a point and crushing the rock. PDC bits, on the other hand, cut into the rock in a shear mode, with individual chips stacking on each other and forming "ribbon-like" cuttings.

Bit balling and ROP enhancement correlate strongly with cuttings size and cohesiveness. Anti-balling additives are used in water-based muds to preferentially "oil-wet" the bit and drill string, as well as to keep cuttings from adhering to one another. The most effective ROP enhancers are those formulated to create an "oil-like" film on metal and rock surfaces.[10,11] The term "oil" is used figuratively to describe the physical characteristics of the film rather than the actual chemical composition. The HPWBM contains an ROP enhancer which is designed to preferentially "oil-wet" metal and shale surfaces using environmentally approved base fluids and surfactants.

Torque and Drag Reduction

Friction factors for the HPWBM were derived using a torque and drag model in the Advantage System, INTEQ's proprietary engineering software.[12] Friction factors were calculated using drilling information such as depth, survey, well bore geometry, drill string, WOB, flow rate, hook load, block weight and off-bottom rotating (ROB) torque. The majority of this information was collected in real-time; however, off-bottom rotating torque was measured after picking up and rotating the string and then recording rotating torque. Friction factors for invert emulsion muds typically range from 0.16 to 0.57 and 0.21 to 0.67 for water-based muds (average of cased hole and open hole). Cased hole friction factors generally range from 0.15 to 0.25, whereas open hole factors range from 0.20 to 0.35.

Figure 2 presents friction factors of the HPWBM measured on a directional onshore well in the United States. Here, HPWBM friction factors ranged from 0.13 to 0.17, averaging 0.15. These friction factors values included both cased and open hole frictional forces. The accuracy of calculated friction factor values is evident when the values are nearly constant and reproducible with changing hole angle.

Minimized Differential Sticking

The particle size of the deformable sealing polymer is sufficiently small that it also serves as an excellent bridging agent for tightly consolidated, depleted sands. Well known lost circulation techniques such as bridging, gelling and cementing are commonly used to cure losses with varying degrees of success. These remedies to cure losses are diverse and can lead to a multitude of problems, such as differential sticking, difficulty logging and/or not being able to reach the well target depth. A new preventative approach, which utilizes the deformable sealing polymer of the HPWBM, has proven to be very successful in preventing differential sticking while drilling through highly depleted sands. This technology is discussed in more detail in paper AADE-04-DF-HO-27 presented at this conference.[13]

Environmental Acceptance

The HPWBM fully satisfies environmental requirements for use in the Gulf of Mexico and the UK-sector of the North Sea. The aluminum complex (MAX-PLEX) has been assigned a "gold" HQ value and approved for use in the UK sector of the North Sea. The deformable sealing polymer (MAX-SEAL) has received approval for a field test in the UK sector. All other additives in the HPWBM have prior approval from the UK regulatory authorities.

The table below summarizes bioassay results according to US and UK protocol.

US Bioassay	**PERFORMAX**
Mysidopsis bahia LC_{50}	762,600 ppm
UK Bioassay	**MAX-PLEX**
HQ Band	Gold
72-Hr EC_{50} *Skeletonema costatum*, mg/L	380
48-Hr LC_{50} *Acartia tonsa*, mg/L	484
96-Hr LC_{50} *Scophthalamus maximus*	>1000

Return Permeability

The HPWBM has been extensively tested in return permeability tests using a Hassler cell permeameter and Berea sandstone disks. The table below shows results from samples of the HPWBM taken from locations in the Gulf of Mexico and South Texas.

Sample Type	**Return Permeability, %**
HPWBM (Deepwater GoM)	92%
HPWBM (South Texas)	100%

Field Tests of the HPWBM System

The HPWBM was originally field tested on two shelf wells in the Gulf of Mexico. These field tests highlighted areas of improvement both in chemistry, product mix and applied engineering of the system. Afterwards, a field test program was implemented with the intent to test and evaluate the degree of success of engineering improvements, and to measure the overall performance of the system.

The conventional method of field testing drilling fluid systems is to test (relatively) small volumes of fluid in a controlled, laboratory environment and then to scale up to larger volumes required for a drilling operation. There is a significant difference between volumes, as well as the environment, in a laboratory setting compared to those in the "real world". Unknowns are inherent to field testing, and the unexpected usually happens despite our best efforts and planning. Therefore, it was decided to design and implement a field test process with emphasis on continual learning and improvements to the system. A process of testing the HPWBM, gathering data and gaining experience on increasingly difficult wells was implemented. Emphasis was placed on comparison to offset well data as performance metrics. Testing on onshore and offshore (shelf and deepwater) wells provided a broad knowledge and experience base.

BETA Test Facility

The HPWBM was field tested at the Baker Hughes Experimental Test Area (BETA) following initial field tests on shelf wells in the Gulf of Mexico. BETA presented the opportunity for field testing the HPWBM in a controlled drilling environment, with tremendous flexibility and state-of-the art data collection. BETA also allows for testing drilling fluids in combination with the latest technology in drilling systems and bits.

BETA is located on a 640 acre lease in northeastern Okmulgee County, 24 miles south of the City of Tulsa, Oklahoma. BETA is unique to the industry as it helps integrate a wide spectrum of drilling fluids, downhole tools and research efforts. The new facility bridges the gap between laboratory testing and commercial applications by providing a real-world testing environment and field conditions.[14]

Highlights of the location and equipment include a wide variety of geology within a relatively shallow depth, a carrier based drilling rig for quick moves between surface holes and specialized data collection equipment, both on the surface and downhole. The geology in and around the Tulsa, Oklahoma area is unique in that it offers a wide array of formation types. The combination of varied lithology and close proximity to a major city is why the location was picked for drilling research. The presence of oil, gas, coals, permeable sands, and unstable shales provide conditions that closely mimic oil field conditions.

Information access is the centerpiece of this facility. A sophisticated real time data acquisition system and a server based intranet website allow real-time and post analysis of data by any employee within the corporate computer firewall. This web-based system enables engineers to monitor virtually every variable and allows digital analysis of both time and frequency based data. Real-time data being collected includes depth, WOB, hookload, rate of penetration, rotary speed, torque, flow rate, pump pressure, axial vibration and torsional vibration.

The mud system is set up as a closed loop system capable of processing up to 700 gpm. The 480 bbl surface pit system is divided into two parts. The active mud system has a volume of 360 bbl, which is divided into six sections. The premix section has a volume of 120 bbl which is divided into two sections. The solids control equipment consists of two linear motion shale shakers, a centrifuge and mud cleaner.

Traditional rig data collection systems collect data on the order of one to several times per second. While this is acceptable for trending and plotting applications, it is not sufficient to perform dynamic analysis of signals as so often required for cutting-edge technologies. For this reason, the BETA system was designed to allow high-speed data collection and real-time frequency domain analysis. Drilling bits, downhole tools and other test equipment used in the tests at BETA are photographed in detail before and after testing using a professional grade digital camera. The rig is also equipped with two conventional video cameras, one mounted on the mud pits and the other showing a view of the rig floor. These cameras are linked to a computer video capture board that updates the BETA web site "real-time" video window every 10 seconds. The video can be viewed as part of the BETA website link or as a stand-alone view on the computer desktop. This means that any employee of Baker Hughes, whether located in Oklahoma, Texas, Scotland or any place with an internet connection can view and access current and archived test data from BETA.

The HPWBM was successfully field tested at BETA alongside a new MWD/LWD tool, rotary stearable assembly and PDC bits in the 8 ½" section after kicking off and building angle up to 40°. Resistivity measurements were made while drilling using LWD and afterwards were compared to similar measurements made using wireline logs. Highlights from this successful application include:

- Confirmation of engineering changes
- Controlled ROP at 85 – 115 feet/hour with PDC bits
- Compatibility with resistivity measurements
- Successful application using a freshwater HPWBM

South Texas

The HPWBM was used in South Texas to evaluate the system as an alternative to oil-based mud. Here, water-based muds have performed poorly in the 12 ¼" interval due to shale instability, with several days of operating time typically lost to reach TD and log the well. Because of pore pressure transmission effects mud weights required to drill, stabilize and log the interval using WBM are typically 1.0 – 1.5 lb/gal higher than OBM. Typical drilling problems encountered in this field with WBM include:

- Bit balling and accretion in upper portion of 12 ¼" interval
- Lost circulation in mid-interval formation
- High mud weights required to stabilize and log the interval from pressure transmission effects
- Wiper trips and lost rig time to log interval
- Severe hole stability and packing off
- Tight hole on trips
- Massive washout and hole enlargement
- Poor log quality

Wellbore instability problems with WBM typically lead to an average of 2-3 days of lost rig time during logging operations. The HPWBM was expected to reduce pore pressure transmission and allow the operator to successfully drill, stabilize and log the interval at a mud weight comparable to that of OBM. Unlike the OBM offset, the HPWBM was formulated using drill water and had a low salt content. This was done to eliminate the waste disposal costs associated with high chloride levels in systems such as OBM.

The well was displaced after drilling cement and testing the casing shoe with conventional spud mud. Afterwards, rates-of-penetration with the HPWBM ranged from 150 to 230 feet per hour in the upper portion of the interval (Figure 3). The rheological and filtration control properties were easily maintained using pre-mix and additional dilution was not required. The solids removal efficiency in the 12 ¼" interval ranged from 81 to 83%.

A planned trip was made after drilling the upper portion of the interval in order to inspect the bit and to ensure that the bottom-hole assembly (BHA) was clean of balling and accretion. This trip was made as a precautionary measure to ensure that the bit and BHA were in gauge, to minimize ECD, before drilling the mid-formation which is notorious for lost circulation problems. Figures 4 and 5 are photographs of the stabilizer and bit as they cleared the rotary table on this trip. The bottom-hole assembly (BHA), stabilizers and bit were generally clean with respect to balling and accretion.

The interval was drilled in record time and reached total depth with the lowest mud weight of any offsets, including oil-based mud (Figure 6). The interval drilled with HPWBM also had the highest average footage per day reported on daily reports (Figure 7). Figure 8 shows a comparison of average washout, from caliper logs, for the HPBM, OBM and one of the better WBM offsets. The degree of hole enlargement (washout) for the HPWBM was comparable to that of the OBM offset and significantly lower than a representative WBM offset. Highlights from this onshore application in South Texas include:

- Highest average footage per day compared to WBM & OBM offset wells
- Record low mud weight at TD compared to offset wells
- Reached logging objectives on 1st attempt
- Excellent log quality
- Eliminated lost rig time associated with logging operations and WBM
- Near-gauge hole diameter as shown by comparison to OBM and WBM caliper logs
- Eliminated shale instability problems associated with WBM in this field
- Eliminated waste management costs and liability associated with OBM
- Cost competitive with OBM

Gulf of Mexico Deepwater

The HPWBM, formulated with 20% sodium chloride, was recently used on a deepwater well in the Gulf of Mexico. The system performed well in drilling the 12 ¼" interval at a maximum angle of 45° by stabilizing reactive clays and gumbo at high rates-of-penetration. Solids removal efficiency ranged from 80 - 82% and four linear motion shakers were used to process up to 1250 gallons per minute of flow rate.

A total of 2,543 feet of 12 ¼" hole was drilled, with 957 feet (38%) drilled while sliding and 1,586 feet (62%) while rotary drilling. Rates of penetration generally varied from 20 to 200 feet/hour with instantaneous ROP above 300 feet/hour using a rock bit (Figure 9). The average ROP when sliding was 85 feet/hour, while the average ROP when rotary drilling was 94 feet/hour.

Environmental testing (96 hour LC_{50}) was done on the initial mud volume prepared at the liquid mud plant, as well as the field mud at the conclusion of the interval. Bioassay (LC_{50}) results were well above the minimum required for discharge (30,000 ppm), ranging from 225,000 ppm (mud plant) to > 500,000 ppm for the field sample (Figure 10).

Friction factors were calculated, using the torque and drag model in the Advantage System, while drilling and building angle to 45°, and compared favorably with values obtained for SBM offsets. Friction factors for the HPWBM in this well averaged 0.3 and are presented in Figure 11.

Return permeability testing showed the low potential of the HPWBM for formation damage, with results >92% return permeability. Flow line temperatures averaged 54°F (12°C) and the total active circulating volume was approximately 4000 bbls. Figure 12 shows a photograph of the HPWBM (20% NaCl) in surface pits.

Highlights from this successful application of the HPWBM in deepwater include:

- Penetration rates averaging 88 feet/hour while sliding and rotary drilling with a rock bit
- Good wellbore and cuttings inhibition resulting in solids removal efficiency above 80%

- HPWBM was highly lubricious and exhibited friction factors comparable to SBM offsets
- Drilled interval and ran casing without problems
- Eliminated rig setup for SBM
- Saved half a day in rig-time in clean up before completions compared to SBM
- Elimination of environmental risks and wastes associated with SBM
- Cost competitive with SBM

Conclusions

- A new HPWBM, designed to emulate the performance characteristics of OBM/SBM, has been developed.
- The system has been successfully field tested both onshore and offshore (shelf and deepwater) wells and proven to be performance and cost competitive with OBM/SBM.
- The HPWBM has eliminated the environmental risks and costs associated with waste management of OBM/SBM.
- The system is environmentally friendly and has been approved for use in the US Gulf of Mexico and UK-sector of the North Sea.
- The system cleans up easily prior to completions and has proven to be non-damaging to producing formations.

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Nomenclature

HPWBM = high performance water-based mud
WBM = water-based mud
OBM = oil-based mud
SBM = synthetic-based mud
BHA = bottom-hole assembly
PDC = polycrystalline diamond cutters
ECD = equivalent circulation density
ROP = drilling rate of penetration
TD = total depth
TVD = true vertical depth
ROB = rotating off-bottom
WOB = weight on bit
PSI = pressure, pounds/inch²
BETA = Baker Hughes Experimental Test Area
MWD = measurement while drilling
LWD = logging while drilling
A_w *= water-phase activity*
PPT = pore pressure transmission

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APPENDIX

Pore Pressure Transmission Testing

Pore pressure transmission (PPT) testing measures the formation pore pressure increase from filtrate invasion in very low permeability formations such as shale. In highly permeable formations the pressure rise from filtrate flow is rapidly dissipated in the formation volume and pore pressure is not affected. However in very low permeability formations, the pressure increase from filtrate invasion declines very slowly and the pore pressure continues to increase with additional filtrate flow. This pore pressure increase reduces the effective over balance pressure. Overbalance pressure decline is exaggerated by wall fractures from drilling. These fractures increase near - well bore permeability resulting in rapid pressure increase inside the wall. Reduced overbalance tends to destabilize the well bore and promote sloughing as demonstrated in the following figures.

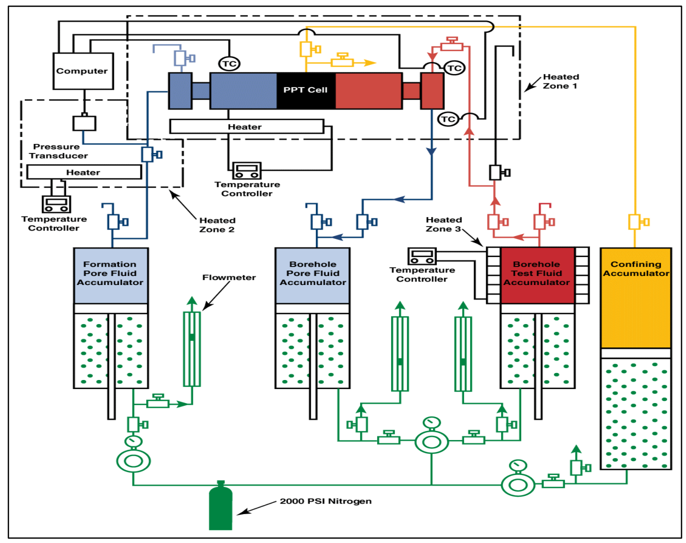
Equipment

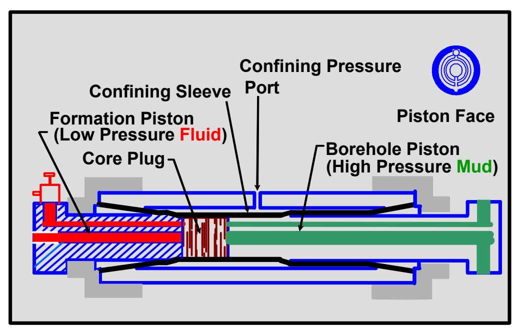
The PPT test is performed on a custom designed and constructed pore pressure transmission device. This device is based on a modified Hassler cell (1500 psi rating). A preserved Pierre II shale plug measuring 1 inch in diameter x 0.9 inch length is placed between two pistons and the circumference of the shale and pistons sealed with a rubber sleeve. The plug is oriented with the bedding planes in the parallel or high permeability direction.

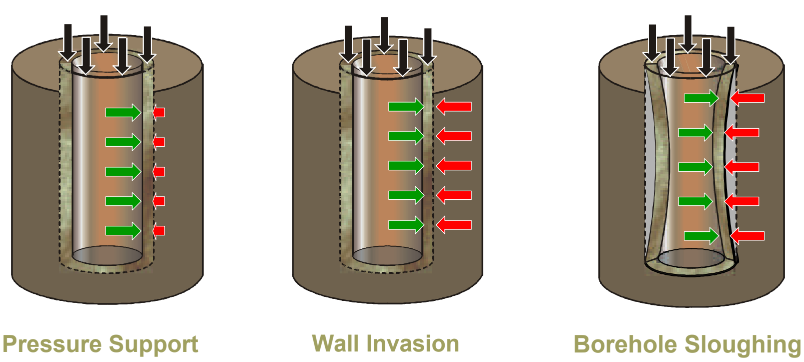
Drilling fluid is displaced through the upstream piston (borehole side) at 350 psi and synthetic pore fluid is pressured at 100 psi on the downstream or formation side. As mud filtrate enters the borehole end of the plug, the connate water in the shale is displaced into the formation piston. This invading fluid compresses the water inside the piston and causes the pressure within the core to rise. The pressure increase due to invading fluid is measured as formation pressure increase. Since water has low compressibility, minute liquid invasion into the core causes a large pressure increase. This makes the cell sufficiently sensitive to measure formation pressure increases in shale which have near zero permeability. During the test the pressure is automatically logged and plotted vs. time.

The low pressure side of the core (formation side) is fitted with a 1 liter, 2000 psi stainless steel accumulator to provide back pressure. The high pressure side of the core is connected to two similar accumulators, one for pore fluid, and one for the test fluid. The pressure in each accumulator is controlled with a manual regulator fed by a 2200 psi nitrogen bottle.

A schematic of the overall apparatus is shown below. The cell is enclosed in an insulated chamber and the temperature maintained with a 200 watt heater. The heater is controlled with a Dwyer temperature controller driving a Control Concepts phase angle SCR control unit. Temperature control is accurate to +/-0.09°F [+/-0.05°C]. The pressures are monitored with Validyne transducers. Data is collected via a computerized data acquisition system.







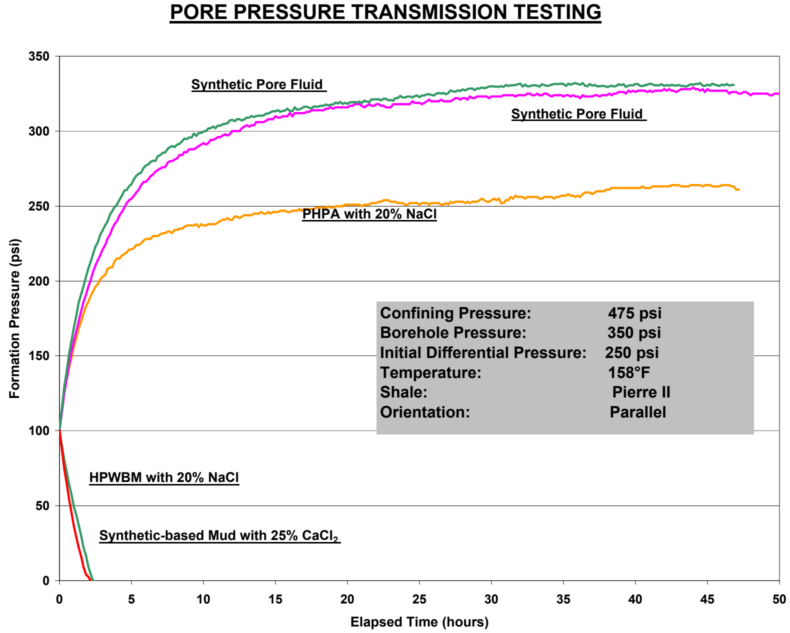


Figure 1 – PPT Tests comparing WBM, SBM and the HPWBM

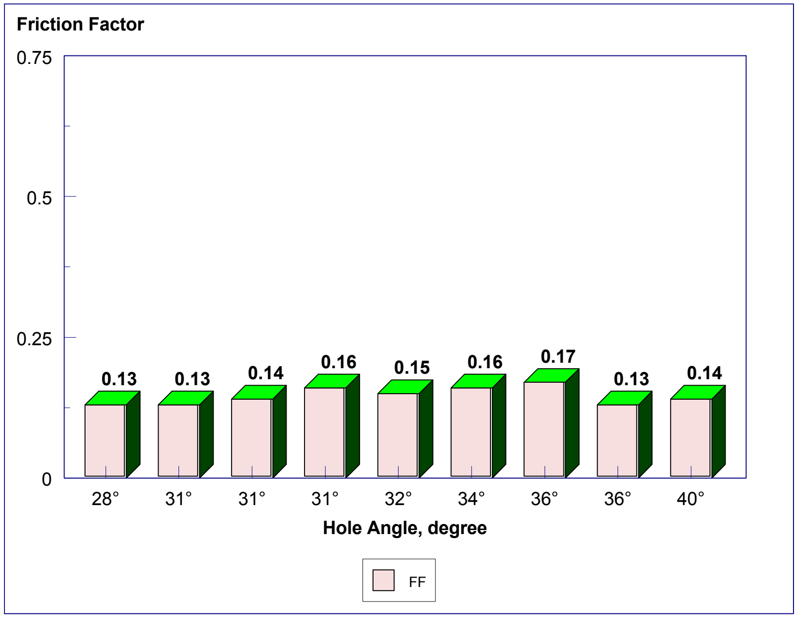


Figure 2 – Friction factors for HPWBM from onshore well

Figure 3 –Cuttings over 145 mesh screens and 175 feet/hour ROP- South Texas

Figure 4 – Stabilizers during trip with freshwater HPWBM in South Texas

Figure 5 – PDC bit during trip with freshwater HPWBM in South Texas

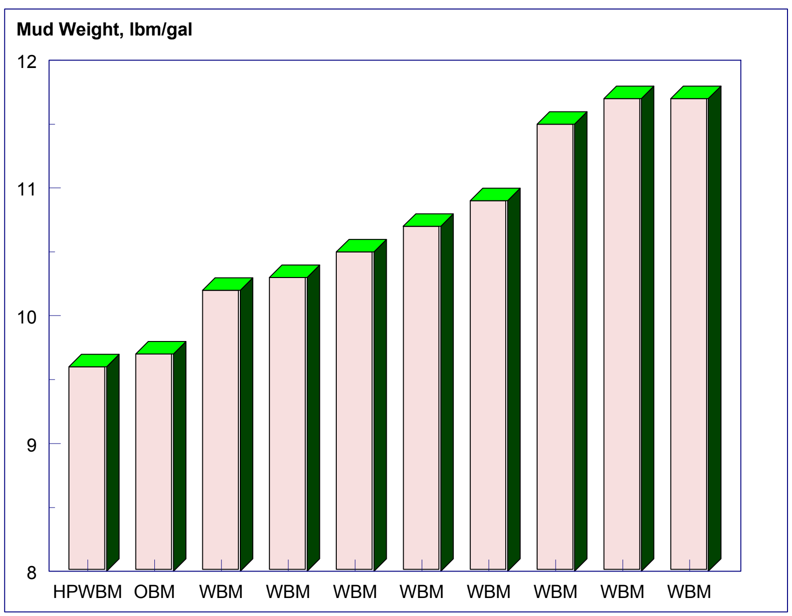


Figure 6 –Maximum mud weight at TD of 12 ¼" interval on South Texas well

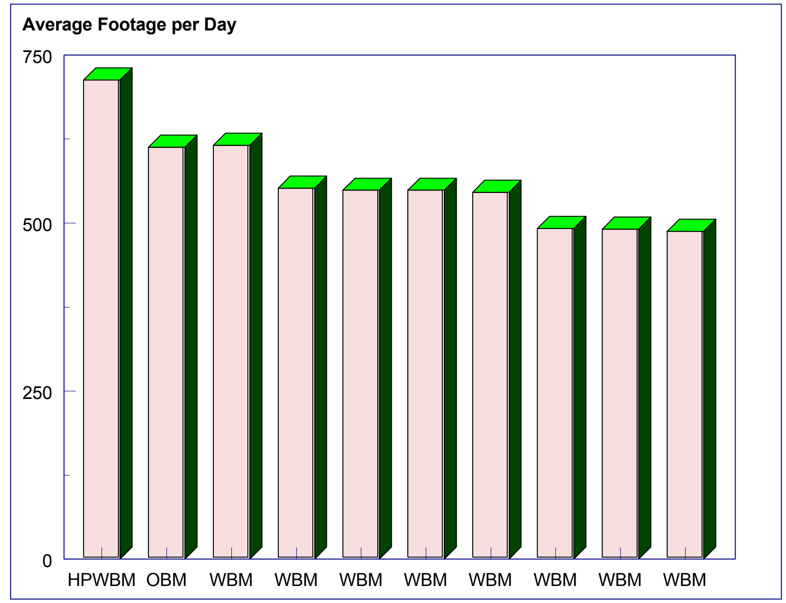


Figure 7 – Average footage per day in 12 ¼" interval on South Texas well

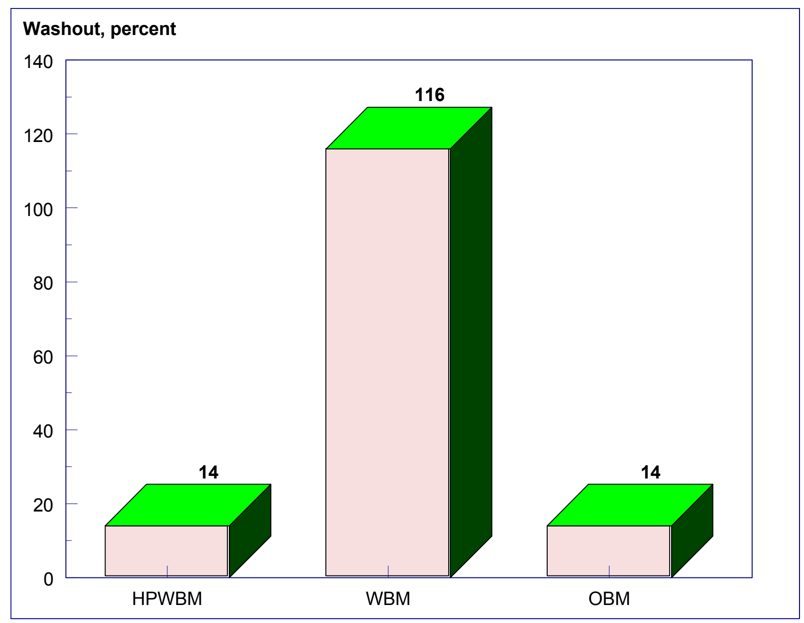


Figure 8 –Hole enlargement comparison in 12 ¼" interval on South Texas well

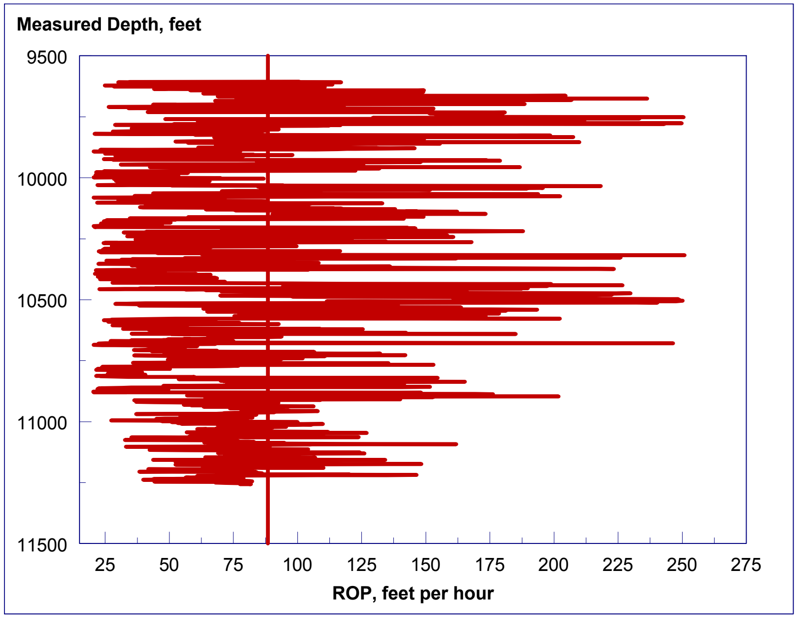


Figure 9 –Rates-of-penetration in 12 ¼” interval of GoM deepwater well

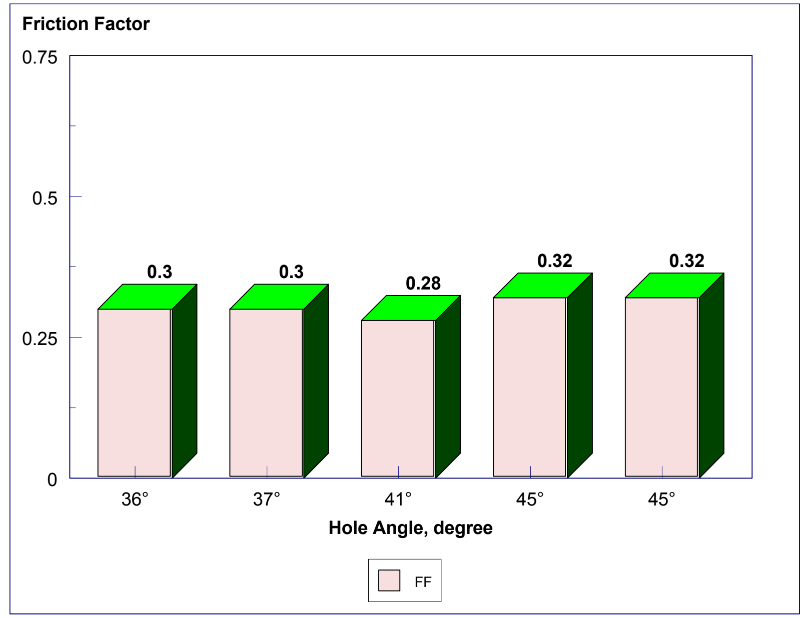


Figure 11 – Friction factors for HPWBM from GoM deepwater well

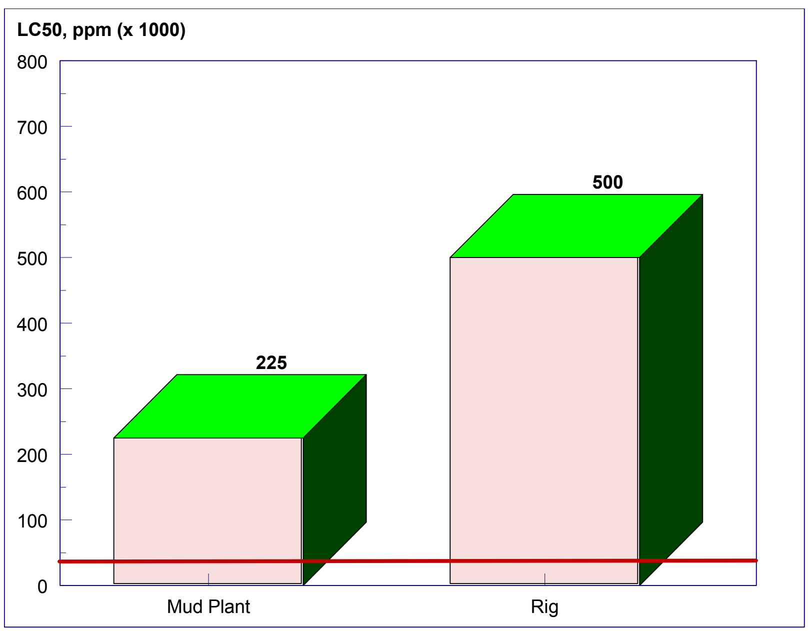


Figure 10 – US LC_{50} values of HPWBM from GoM deepwater well

Figure 12 – HPWBM (20 % NaCl) in surface pits