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Stringent Drill-in Fluid Design Results in Prolific Deepwater Horizontal Well– a BP Marlin Case Study

Brian A. Butler, TETRA Technologies, Inc.; Stuart W. Gosch, BP; Dale W. Bradford, BP*; Mike F. Adkins, TETRA Technologies, Inc.; Joe R. Murphy, TETRA Technologies, Inc.

* now with BHP Billiton

Abstract

A horizontal open hole gravel pack was the well configuration of choice for BP's Marlin A-4 development well. The drill-in fluid design was considered a critical factor influencing overall well and project success. A complex set of design criteria had to be met in order to drill, complete and produce the well efficiently.

The well's design phase proved successful and an optimal fluid was developed. The well was successfully drilled and completed, and no major problems were encountered in any aspect of the operation. Production results are considered outstanding, as the well produces at or above targeted rates. An open hole gravel pack was executed as designed, resulting in complete pack placement and a highly efficient completion. The investment in this comprehensive study is easily justified, as Well A-4 is considered one of BP's most successful wells in the Gulf of Mexico.

Introduction

BP's Marlin development is located in Viosca Knoll Blocks 871 & 915 in the eastern Gulf of Mexico in 3230 feet of water. Original field development plans called for the installation of a small tension leg platform (TLP) and the completion of five wells with surface trees. All wells were drilled, cased and suspended with a floater prior to arrival of the TLP. Upon installation of the TLP, the running of production risers as well as drill-in and completion operations would be conducted with a one-thousand horsepower platform rig.

Initial plans called for Well A-4 and three additional wells to be completed in the Main Pay Sand. A fifth well was targeted for a shallower oil sand. The Main Pay Sand is a Middle Miocene, deep sea, rich fan deposition, with moderate sorting and very limited cementation. Average gross thickness is 80-120 feet, with a typical net-to-gross ratio of 70-80 percent. Permeability, based on whole core analysis, was expected to be in the 800-1200 mD range, with isolated streaks as high as 3000 mD. However, pressure transient analyses from offset wells suggested a permeability in the 200-500 mD range. Original plans were for two wells to be cased hole frac pack completions near the crest of the gas cap, and two to be high-angle open hole gravel packs near the gas-oil contact.

Progress on the Marlin project halted after a casing collapse was experienced while producing the first well (a cased hole frac pack). Nearly a year was spent analyzing this failure and reassessing the field development plan. Ultimately, two subsea wells were added to the development scheme and the dry tree completions were redesigned. As a result, only one open hole gravel pack completion (Well A-4) and one cased hole frac pack remained as part of the Main Pay Sand, dry tree (TLP) portion of the project.

Given the large influence reservoir drill-in fluids can have on drilling, completion and, ultimately, on production success, a thorough design exercise is considered prudent. With the enhanced capability of modern drill-in fluids that are now available, this optimization process has become more complex. Given the importance of the subject well and the peculiarities involved in this deepwater project, a comprehensive design process for the drill-in fluid and well cleanup was undertaken. A number of the design parameters were driven by project economics, while others were a function of operational limitations. Rigorous testing resulted in what proved to be an optimal fluid. Field operations were considered very successful, as is well productivity.

Well A-4 Objectives

Well A-4 was originally planned to traverse the Main Pay Sand at a starting deviation of 80^{o}, then build angle to approximately horizontal. Initial plans called for an interval length of roughly 2500 feet. However, after geologic reinterpretation and inflow modeling work, it was decided that with an efficient completion, an interval length of roughy 800 feet would allow production targets to be met. It was determined that drilling additional interval would add cost and risk to the drilling and completion operations, but would not appreciably increase well productivity or recoverable reserves.

At the onset of the Well A-4 design, three major objectives were established. With the open hole configuration, all three objectives would be largely controlled by the performance of the drill-in fluid and subsequent cleanup success. The major objectives were as follows:

1. Accomplish an extremely stable wellbore to allow efficient placement of a long-duration, open hole gravel pack.
2. Installation of an efficient, high-rate well completion was dictated by project economics. This required thorough cleanup of the entire productive interval.
3. Achieve a durable, long-lived well, capable of producing all available reserves without the need for intervention.

Drill-in Fluid Design & Selection

For Well A-4 to be fully successful, the drill-in fluid would have to meet several important criteria. The fluid ultimately selected would have to demonstrate extremely good performance in the following areas:

- shale inhibition
- marine toxicity
- fluid rheology
- efficient filter cake cleanup

Additionally, the fluid would have to meet a 4/30 PCT (pressure crystallization temperature) requirement. Consequently, a robust test matrix was undertaken for the purpose of optimizing the drill-in fluid and well cleanup treatment. However, this exercise was complicated by the fact that adjustment of one property often had detrimental effects on other properties. The process was complicated further by a number of well uncertainties, including the fluid density that would be required during the drilling operation. Additionally, uncertainty involving the amount of shale that would be encountered added a great deal of complexity to the fluid design and selection. The fluid ultimately selected for the project was a PayZone® drilling fluid made from a mixed sodium-calcium base brine. This proved to be the best solution for this project, as it met or exceeded all of the prescribed performance criteria.

Fluid Crystallization (PCT). Inadvertent crystallization of salt from brine and the resultant problems are well known. Furthermore, this phenomenon is complicated in deepwater environments where fluids can be placed under substantial pressures at seabed conditions. Discovery of this phenomenon led to the development of clear fluids with PCT (pressure crystallization temperature) ratings, rather than traditional TCT (true crystallization temperature) ratings[1]. Since Well A-4 is located in over 3200 feet of water, and mud line temperature is 38°F, potential crystallization of brines at seabed conditions was a major concern.

Proper fluid design for deepwater applications includes projecting the maximum pressure that will be exerted on the fluid at the seafloor. This parameter for Well A-4 was set at 4000 psi. With an added safety factor 8^{o}F, all brine fluids used during the drill-in and completion operation were required to meet or exceed a 4/30 PCT specification (4000 psi / 30^{o}F).

Designing for PCT purposes had to be weighed against the marine toxicity and shale inhibition characteristics of the fluid. Due to uncertainties involving the fluid density that would be used, testing was begun at the lowest expected density. Testing was done on brines composed of NaBr, $CaBr_2$ and combinations of sodium and calcium salts. Densities were then increased at 0.5 ppg increments using dry calcium bromide, and these higher density brines were reevaluated. Various ratios of sodium and calcium were evaluated in an attempt to optimize the brine.

Whereas a sodium bromide system was known to possess favorable marine toxicity properties, it failed the 4/30 PCT requirement and was thus excluded from further consideration. Additionally, sodium bromide alone would not allow the maximum density of 13.0 ppg to be reached. A fluid comprised of calcium bromide only easily passed the crystallization criterion at all tested densities, but was excluded due to poor performance in shale inhibition. Additionally, it would not have met the desired toxicity rating. It therefore became necessary to focus on the mixed sodium-calcium brine systems.

In testing the mixed-salt systems, the inclusion of calcium had the desirable effect of lowering crystallization temperatures. Although a number of salt combinations were evaluated, none of those tested passed the 4/30 PCT criterion when weighted up to the maximum density required. The upper limit turned out to be a 12.8 ppg drill-in fluid density. Weighting up beyond that point would have to be done using calcium carbonate as the weighting agent, which was considered acceptable, but less desirable than using salt. Optimization exercises then centered on selecting the fluid that exhibited the best performance in the other areas studied.

Density. The final drilling fluid density that would be required was not finalized until shortly before project startup. Modeling work conducted by BP suggested that a density range of 12.0 to 13.0 ppg would be required. In this application, the fluid density was not governed by reservoir pore pressure (10.3 ppg EMW), but rather by borehole stability requirements. Ultimately, the decision was made to begin drilling with 12.0 ppg fluid, and weight up, as dictated by well behavior, to as high as 13.0 ppg. Therefore, with this as the basis, the fluid would have to be designed such that the other design criteria could be met at all densities in the stated range.

Given the density range established, it was necessary to examine the best ways to accomplish the density increases if the need arose. Three methods were examined, and each method was judged on the basis of its effect on fluid properties, cost effectiveness and logistical complexity. With the maximum density set at 13.0 ppg, a pure sodium bromide system was not possible. The three weighting agents considered were calcium carbonate, calcium bromide spike fluid and anhydrous calcium bromide.

Due to its undesirable impact on fluid rheology, weighting up with calcium carbonate was considered acceptable for only very minor increases ($\leq$0.2 ppg). Additionally, storage space limitations would not permit large density increases by this method.

Increasing density using calcium bromide spike fluid (14.2 ppg) could result in significant volume gains, and would thus require that a full complement of additives be used in the process. This, along with the fact that the resultant volume increase might be unmanageable, made this method somewhat unattractive. However, because additions of 14.2 ppg $CaBr_2$ could be made quickly and with minimal difficulty, this method was reserved for emergency weight-up purposes.

After evaluating each method, anhydrous calcium bromide became the clear choice as the best weight-up method for this project. It was determined to be most cost effective and would not require large quantities to be stored on location. Pilot testing revealed that there would be very little effect on the fluid's rheological properties, and volume increases would be minimal.

Shale Inhibition. With the uncertain geology, it was possible that the well path would intersect fairly long shale sections. As drilling reactive shale can be a major factor influencing the design and performance of brine-based fluids, it was decided to plan for this contingency. This required that a fluid with maximum inhibitive qualities be developed.

Good shale inhibition is obviously very important for drilling success. However, less obvious is the importance of this property for production optimization purposes. Poor inhibition can not only cause borehole stability problems, but can result in undue contamination of the drilling fluid with native (insoluble) drill solids. This contamination issue ultimately causes a dramatic reduction in filter cake solubility and degradability[2]. This in turn creates a situation where the filter cake and entrained solids become a serious production impairment mechanism that is difficult or impossible to treat out effectively[2,3].

A large amount of this study went toward developing the most inhibitive formulation possible, while still meeting the various other fluid requirements. Testing was conducted on shale taken from whole cores during the field's exploration phase. It was decided to use a shale dispersion test for the purpose of assessing inhibition. In this test, shale particle disintegration is measured after dynamic exposure to various test fluids. In order to improve test accuracy and better differentiate fluids, the base fluids only, rather than fully formulated muds were evaluated.

A total of 19 different variants of base fluid were tested, (see Table 1 & Fig.1). Sodium and calcium-based brines were tested, as well as several multi-salt combinations. As part of the test matrix, the various fluids were evaluated with and without inclusion of PayZone StrataFix™ (a glycol additive) and cesium formate, both considered potential shale stabilizing agents. Fresh water was used as a control in these tests. Not unexpected, the shale was very water sensitive, with the control sample yielding less than 5% recovery of the sample.

The best fluids yielded 85% to 95% recovery in the shale dispersion testing. Results in this range are considered very good, and fluids exhibiting this behavior in lab tests have proven very inhibitive in field use. Additionally, further improvement in this area can be expected when these brines are made into fully-formulated drilling fluids.

The most inhibitive systems tested contained both cesium formate and the glycol shale stabilizing additive. The combinations of sodium and calcium brines also gave very good results. A number of sodium-calcium ratios were evaluated, with no significant difference in shale recovery. The performance of the mixed-brine systems was most pronounced when the glycol additive was used.

In comparing brine compositions (Fig. 1), the sodium bromide system yielded similar results to the mixed brine systems, but was not considered for reasons covered above in previous sections. This result was somewhat unexpected given the improvement normally seen with calcium addition. The calcium bromide system yielded a very poor recovery of only ~55%. This poor result was also somewhat unexpected due to calcium bromide's widespread use in the Gulf of Mexico.

The addition of the glycol dramatically increased the fluids inhibitive qualities in shale dispersion testing (see Fig. 3). All fluids tested yielded higher recovery numbers when the glycol was used. Also, the product appeared to have a normalizing effect with regard to the inhibitive qualities of the various brines. Glycol concentrations of 1% to 6% by volume were evaluated, and product concentration was not a factor in the laboratory testing. This is attributed to lack of product depletion in the small scale tests. The glycol had no negative impact on fluid properties, and had the added benefit of enhancing fluid lubricity. For these reasons, the glycol was considered an important and necessary additive for this project.

As tested, cesium formate also appeared to be clearly beneficial in the shale dispersion testing (see Fig. 4). However, our evaluations were done at fairly high concentrations (~3-14% v/v) and it was eventually excluded due to complications involving cost and marine toxicity. As future applications allow, inclusion of cesium formate in drill-in fluids warrants further study.

Marine Toxicity. Space limitations on the tension leg platform made it impractical to capture the drill cuttings from the well. Because of this, a design parameter was established such that the ability to discharge cuttings and fluid would be maintained throughout the drilling operation. EPA compliance requires a minimum passing LC_{50} of 30,000 ppm using the established test protocols[2]. However, as insurance against a failing test, BP required that the drilling fluid exhibit an LC_{50} of 100,000 ppm or higher. As this was considered untypical for traditional brine-based fluids in this density range, a large amount of formulation work was required for this purpose.

Fluid optimization involved balancing the toxicity results against the numerous other aspects of the fluid. After a large number of iterations and comprehensive additive screening, the drill-in fluid ultimately selected for the well exhibited an LC_{50} of approximately 185,000 ppm. This was well above the minimum set by BP, and considered very high as compared to conventional calcium-based, low-solids fluids of this density.

Rheology. A great deal of planning work went into optimizing the rheology of the drilling fluid. Because frac data from an offset well indicated a 13.4 ppg EMW fracture gradient, maintaining an ECD below that point was considered critical. Given that this well was nearly horizontal, hole cleaning was obviously a major concern as well. This was made more difficult by the fact that the fluid would possibly require weighting up beyond the 12.0 ppg starting density.

To avoid possibly exceeding formation fracture pressure, a hard ceiling of 13.2 ppg ECD was imposed. As the flow rate used during the drilling operation is primarily dictated by the directional BHA, a large amount of fine tuning to the rheological properties was necessary. This became a delicate balancing act to ensure adequate hole cleaning, while assuring that the ECD limit would not be exceeded. Fine adjustments to fluid formulations were made and extensive hydraulics modeling was conducted.

The range of flow rates during drilling was estimated at a maximum of 300 gpm. Both Power Law and Herschel-Buckley models were used in hydraulics modeling and each gave considerably different results. The Herschel-Buckley Model consistently predicted higher friction pressures than did the Power Law Model. Due to very good historical matching between field PWD data and a Power Law Model, it was opted to use this for ECD predictions. In working through this process, the most suitable fluid formulation was devised. The results of hydraulics modeling indicated that for this particular well, target rheological properties were in the range of: a PV of 24; a YP of 24; a 6 RPM reading of 7-8 and a 3 RPM reading of 5-6.

Completion Fluid Design

Because wellbore stability is paramount to success with this well type, the completion/gravel pack fluid was designed to ensure that stability was not compromised. This is considered particularly important in completion intervals that contain exposed shale sections. To accomplish this, the completion fluid was designed to mimic the drill-in fluid as closely as possible. First, the completion fluid was density-matched to the drill-in fluid. Second, the brine was chemically-matched as closely as possible. And, because glycol proved to be a valuable additive in the drill-in fluid, it was also included in the completion/gravel pack fluid.

The close matching of these two fluids allowed the Well A-4 completion to be executed with no disruption of the wellbore. Because perfect wellbore integrity was maintained throughout the operation, the gravel pack was placed without incident and according to schedule.

Filter Cake Cleanup / Return Permeability

Three main criteria were established for clean up of the productive interval. The aim was to remove any production impairment mechanisms stemming from the drill-in process. These criteria were:

1. To contact any and all damage present, i.e., accomplish full heel-to-toe cleanup of the interval.
2. To accomplish efficient flowback at worst case (very low) inflow velocities.
3. Due to concerns with acidization, a non-acid cleanup process was considered a major advantage.

Breaker studies were conducted using a dynamic (stirred) modified HTHP fluid loss cell. A 750 mD ceramic disk was used as the filter media. To make the tests as realistic as possible, filter cakes were built dynamically using up to 30 ppb of Marlin shale as a contaminant. Filter cakes were aged a minimum of 16 hours at BHT (220°F) before commencing the breaker tests.

It order to best simulate the simultaneous cleanup and gravel pack operation, a large volume of PayZone A.C.T.™ breaker was used on the relatively small filter cake. After decanting the excess drill-in fluid, the cell was completely filled with breaker solution. The breaker was then brought up to temperature and pressure, and the stirring began. Fluid loss through the filter cake and disk was then measured over time. Several different breaker concentrations were evaluated before the desired break time was attained. The target break time for Well A-4 was set at 12 hours to allow ample time (with safety factors) for gravel pack placement.

A series of tests were conducted to assess fluid-fluid and fluid-rock compatibility. Various combinations of reservoir crude, drill-in fluid, gravel pack carrier fluid (with breaker) and acids (10% acetic and 7-1/2% HCl) were tested for sludging, emulsion and precipitation tendencies. The only source of concern was the gravel pack carrier fluid and HCl mixture, which yielded a low level of precipitation. This concern diminished when acid was excluded from consideration as a filter cake cleanup agent.

Core floods were done using both good and poor quality (low permeability) sections of core. Core plugs were injected with multiple pore volumes of the drill-in fluid filtrate, gravel pack carrier fluid, and completion brine, and return permeability measured. No significant permeability impairment was observed with any of the fluids tested.

Filter cake clean-up efficiency was measured by establishing baseline permeability through the core (with synthetic reservoir brine), building the drill-in fluid filter cake, injecting the gravel carrier fluid (containing breaker), installing the 20/40 proppant pack and back-flowing with the reference brine. The test sequence was repeated with the addition of acetic and HCl acid cleanup stages. Very low flow rates were used (~6 cc/min.) to simulate worst case flow-back conditions, minimizing any effect from fluid velocity. With this, the impact of the cleanup chemicals could be isolated. Core plugs were subsequently epoxied and thin sections cut at the core/proppant interface for the purpose of visual inspection. These inspections typically showed very minimal solids invasion of the proppant pack and good removal of the polymers. Regained permeability in this test sequence was as high as 60% with the use of the oxidative breaker alone, and 40% to 110% when combined with acids. With the particular well and test conditions, any result approaching 50% permeability regain was considered very adequate, especially if this would be achieved across the full completion interval. Acetic acid appeared to be marginally more effective than was HCl in this testing.

With the large variability seen in the acidization results and well known complications involved with successfully executing these treatments[3], it was decided to perform the cleanup operation with the oxidative breaker only. This method would also guarantee complete zonal coverage, because the breaker could be placed simultaneously with the gravel pack. An acid treatment would not be part of the initial completion operations. Acidization was viewed purely as a contingency treatment that could be conducted in remedial fashion if future needs dictated.

Drilling Operations

As part of the pre-drill program, a low angle (approx. 42°) pilot hole was drilled through the base of the Main Pay Sand to establish localized depth control of the productive zone. The well was then plugged back and sidetracked to the desired 80 degree hole angle and a 7-5/8 inch liner set. The liner shoe was positioned approximately 50 feet (~8 feet TVD) into the top of the pay sand. After installation of the TLP, the lateral section was drilled with a 6-1/2 inch bit and custom-designed PayZone drilling fluid.

As a result of a "right-scoping" exercise, the original well plan was revised to reduce the lateral length to approximately 800 feet, versus the originally planned 2500 feet. A bottom hole assembly designed to drop 1 degree per 100 feet was run, and approximately 806 feet (MD) of interval was drilled. Well deviation was approximately 70° at TD. TD was called at 13,390 feet MD after drilling roughly 100 feet of shale below the base of the sand. Of the 806-foot interval, 730 feet were completed, leaving the remainder as rathole below the completion setting. Detailed log analysis indicates that, of the completed interval, roughly 498 feet is considered productive reservoir.

Drilling operations went without incident. Hole behavior was considered excellent throughout the operation. To ensure that the hole was being cleaned adequately, back reaming trips to the casing shoe were planned at set intervals. However, on back-reaming short trips, only very slight increases in cuttings were seen in the returns. Also indicative of good hole cleaning was the fact that no noticeable increases in the downhole pressure, torque or drag were seen, which would have been indicative of cuttings buildup in the annulus.

Hydraulics modeling results compared very favorably with actual ECDs measured while drilling. As a PWD tool was run in the bottom hole assembly, actual downhole pressures could be regularly compared to those predicted via a numeric model (see Fig. 5). Throughout the drilling operation, actual ECDs were within 0.05 ppg of those predicted by the model.

During drilling operations, the amount of drill solids being entrained in the fluid was closely monitored. This was done at least once per tour via a gravimetric test to measure the acid-insoluble materials. As part of pre-job planning, the rig's solids control system was evaluated. With a standard complement of equipment available, a limit of 3% (by volume) acid-insolubles was established. Corrective actions were agreed upon in advance, in the event that the limit was reached. Although the drilled interval contained a fair amount of shale and dirty, poor quality sand, fluid cleanliness did not become an issue. With the optimized fluid, the level of acid-insoluble materials in the fluid reached a maximum level of 1.12%. This was considered an indicator of the fluid's inhibitive qualities (see Fig. 6).

After reaching TD, the drilling BHA was pulled and a hole opener was run back to bottom. The hole opener went smoothly to bottom without the need for circulation or rotation. With the hole opener at TD, a solids-free "slick pill" was spotted in the open hole and 500 feet into the 7-5/8-inch liner. The workstring was then raised and the cased section of the well displaced to completion brine.

Completion Operations

After displacing the well to clean completion fluid, a gravel pack assembly with 4 inch base pipe prepack screen was picked up and run to a depth of 13,314 feet, with the shoe positioned just below the bottom of the sand. The 0.012 gauge screen was 4.7 inches OD and prepacked with 20/40 ceramic proppant. Screens went smoothly to bottom without circulation or manipulation of the workstring.

A circulating (alpha-beta) gravel pack was then performed with 20/40 sand. The alpha wave was pumped at 2.0 bpm with a sand concentration of 1 ppg. During beta wave placement, the rate was gradually reduced to a low of 1.6 bpm by the end of the job. Extremely good return rates (>95%) were observed throughout the pumping of the alpha wave, with only slightly lower returns during the beta wave placement. Treating pressures gradually increased during the beta wave, and had increased by approximately 250 psi by the job's end.

The gravel pack went according to schedule, with just over 15,000 pounds of sand placed below the crossover tool. Based on the volume of sand placed and the pressure profiles as compared to those modeled, it is evident that complete packing was accomplished and an extremely gauge hole was achieved.

Simultaneous Cleanup and Gravel Pack

Prior to the Marlin project, the PayZone A.C.T. breaker system was shipped to well sites as a separate fluid system to be used as the carrier fluid in open hole gravel packing. Due to space limitations and logistical complexities on the Marlin project however, a concentrated form of the product was needed. A new product was ultimately developed that presented no serious handling or personnel exposure issues. The liquid concentrate was shipped to location in 25-barrel marine portable tanks.

The development of the new concentrate allowed the breaker to be easily added to the existing completion fluid on location. This fluid was in turn used to make up the gravel slurry and the job pumped as usual. This process proved very successful, and has since become standard practice for this type of operation.

No acid treatment was used to break the filter cake or to dissolve the calcium carbonate bridging solids. The level of native drill solids in the fluid was controlled during drilling operations, and proved non-problematic to the cleanup operation.

Production Results

The initial production target for this well was approximately 80-90 million scf per day. The A-4 completion was successful in meeting this target, even though the interval length was shortened to only ~800 feet. Ten months after first production, Well A-4 still produces approximately 87 million scf of gas and 9700 barrels of condensate per day, with only 40 barrels of water. Flowing tubing pressure is 1375 psig.

Early life, downhole pressure gauge data indicated total drawdown in the 650 to 750 psi range. Pressure transient analysis has been impacted by phase segregation and wellbore storage effects, and is thus far considered inconclusive. It is anticipated that additional efforts will be made to better understand the well's pressure transient behavior and assess whether or not any further stimulation can be justified.

Conclusions

Through the use of a comprehensive testing program, fluids considered optimal over a wide range of operating conditions can be developed. Close adherence to the parameters set forth in the design and engineering phases of Well A-4 led to successfully drilling, completing and producing the well. All phases of the operation went smoothly and all objectives for the well were met or exceeded. Productivity results are considered outstanding, as the subject well is one of BP's most successful wells in the Gulf of Mexico, and one of the company's highest net revenue generators.

With proper design, brine-based fluids can be made very inhibitive and, contrary to popular belief, are quite suitable for shaley environments. Efficient, open hole gravel packed completions are readily achievable in these environments, as evidenced by the subject well and a growing database of similar applications.

Acknowledgments

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Sample No.	NaBr	CaBr2	Blend A	Blend B	Blend C	Fresh Water	PayZone StrataFix	Cesium Formate
1	X							
2			X					
3				X				
4					X			
5						X		
6	X							X
7	X							X
8	X							X
9					X		X	
10					X		X	
11					X		X	
12	X						X	
13		X						
14		X					X	
15			X				X	
16			X				X	
17			X				X	
18r			X					
19r				X				
20r					X			
21r	X							
22					X		X	X
23					X		X	X
24					X		X	X
r = repeat test								

Table 1 : Fluid Combinations Evaluated

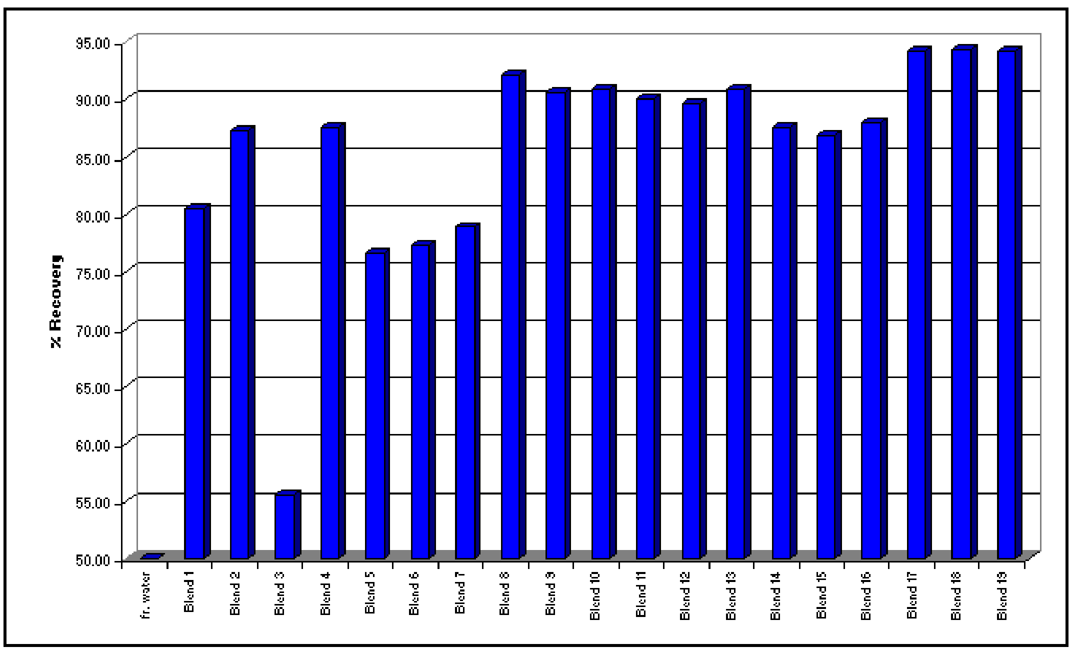

Figure 1: Shale Dispersion Testing—All Fluids

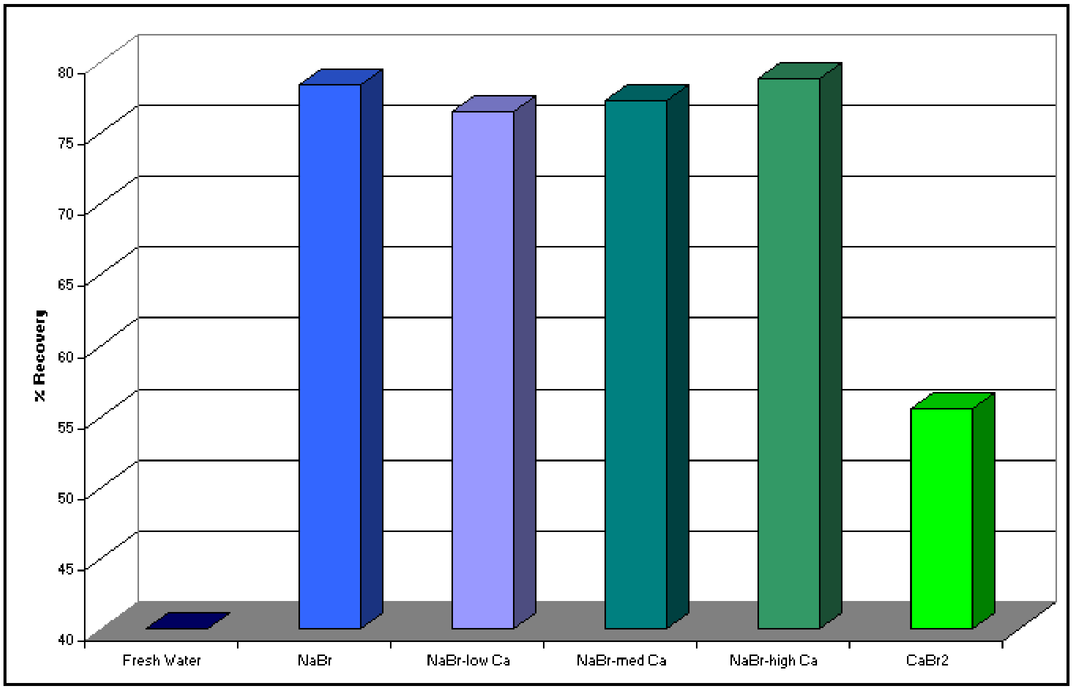

Figure 2: Effect of Brine Type on Shale Dispersion

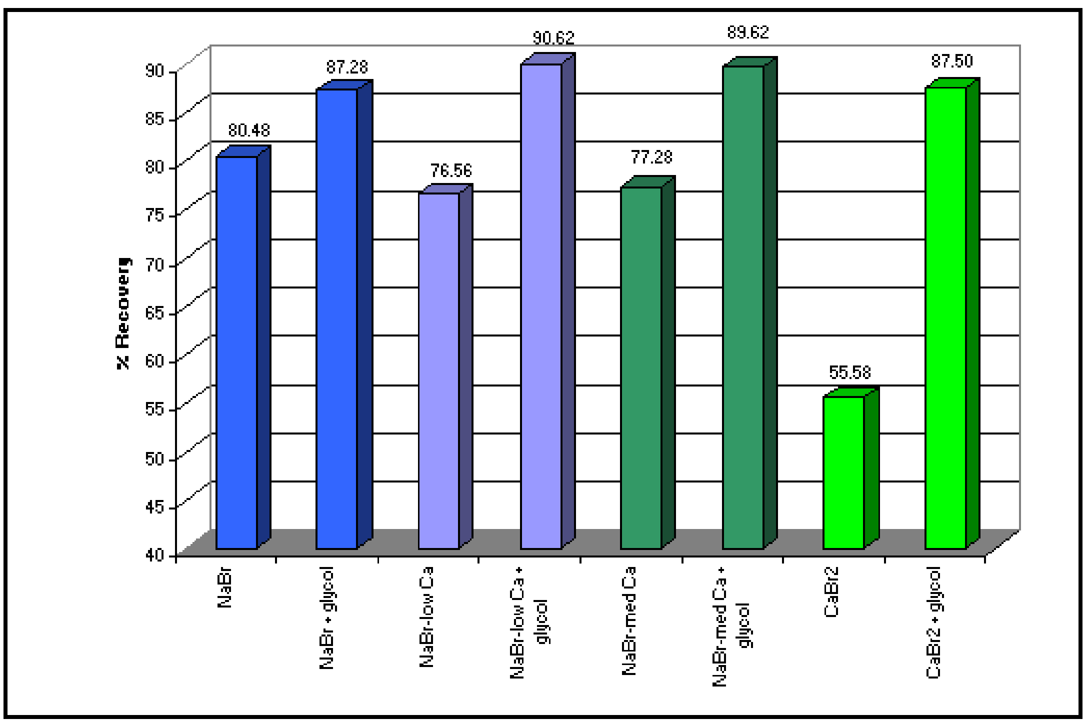

Figure 3: Effect of StrataFix Glycol on Shale Dispersion

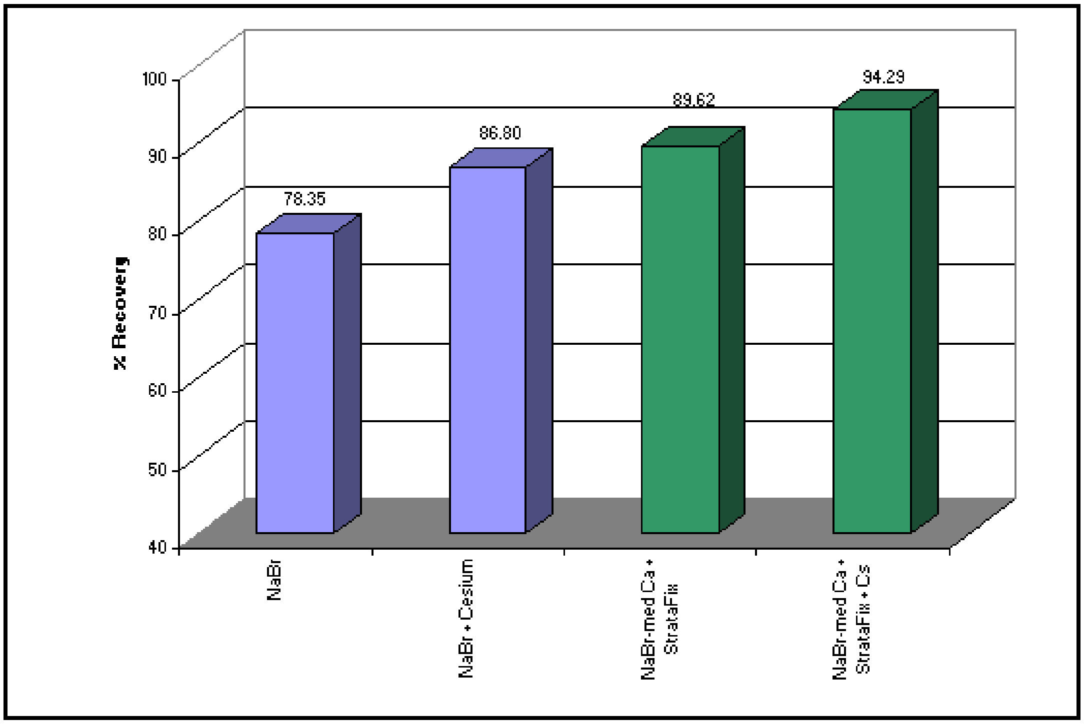

Figure 4: Effect of Cesium Formate on Shale Dispersion

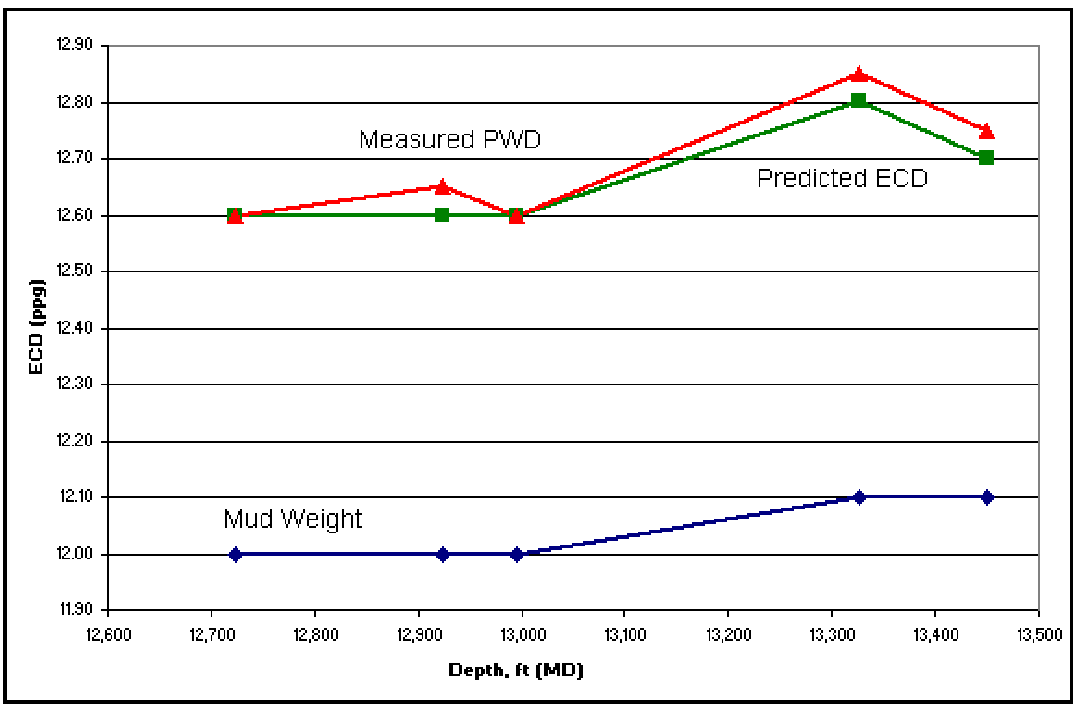

Figure 5: Equivalent Circulating Density vs. Depth

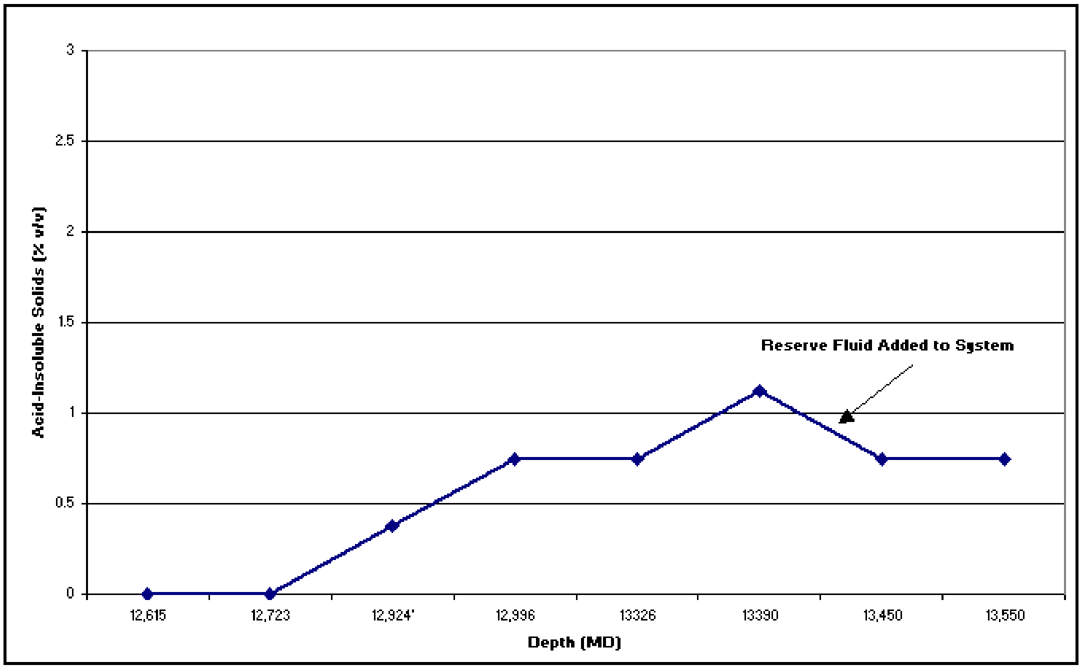

Figure 6: Entrained Acid-Insoluable Solids