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Drilling on the Coast of Tabasco Mexico: Battling Wellbore Instability in a Narrow Pressure Window

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Abstract

A novel sealing package was designed to provide wellbore stability when drilling through abnormally high and low pressured zones. This sealing package is an engineered combination of carbon-based bridging agents and a micronized sealing polymer. Major challenges for an operator drilling in a field off the coast of Tabasco, Mexico included fluid loss while running casing and cementing as well as differential sticking. Applying the proprietary bridging and sealing package in these sections minimized mud losses and enabled successful casing placement without incidence of differential sticking. An offset comparison in the same field between three wells that used conventional LCM and then three wells that used the bridging and sealing package resulted in an average reduction from 8,596 to 3,069 barrels of lost oil based fluid.

Another field, also off the coast of Tabasco, Mexico exhibits a complex pressure profile that requires drilling with a narrow pressure window and wellbore stability challenges. Issues common in this field are water influx, gas kicks and high mud losses. The bridging and sealing package was utilized while drilling the section with the greatest incidence of high mud loss and differential sticking, at a measured depth between 3269 to 4614 meters. This section had a narrow fracture gradient with an overbalance of 1800 psi for the last 200 meters of the section. Casing was run and cemented with no sticking and minimal mud loss at the target depth.

Introduction

Wellbore stability is one of the most important factors today when drilling safe, smart, economical wells. Before the oil slump of the mid-eighties the problem was mostly ignored by operators and service companies. During that period, both the advancement of drilling technologies including horizontal wells, ERDs, reentries and multilateral wells as well as aggressive cost saving strategies brandished a whole new focus for R&D programs to find ways to maintain a stable wellbore[5]. As a result, well planning and design is uniquely focused on drilling and stimulating deviated and horizontal wellbores characterized by complex geological formations with layers of reactive or brittle shales, sections with abnormally pressured zones and tectonically active areas[4].

Wellbore Stability

Borehole instability issues result in what drillers commonly refer to as ‘tight hole’ or ‘stuck pipe’ incidents which can arise from a number of different but related root causes. The average cost of stability problems is approximately 5-10% of the total cost of exploration and production of a well due to lost time and occasionally lost equipment. In the case of deep water drilling, the comparatively high cost and complexity of drilling operations demands an emphasis on avoiding lost time events due to wellbore instability[2].

Evaluation of stability of a formation is problematic for well planning for a number of reasons when trying to predict a rock’s response to mechanical loading. The drill bit may be thousands of feet away and coring samples are rarely taken above the reservoir for rock mechanics testing due to high cost and lost time from sampling. There may be large variations in formation stresses such as depleted sandstone, non-depleted shale layers and faults all in the same well which are not systematically measured. There are a number of mechanisms that contribute to the onset of instability including drilling chemistry and density, redistribution of stresses, temperature changes. No matter how complex a model is for characterizing the stresses in a formation, complete accuracy cannot be achieved due to these special issues for evaluating potential for instability. But current models and field experience have led to guiding principles based on ideal assumptions that limit the risk of stuck pipe incidents[2].

Stresses, pore pressure and rock strength are widely regarded as the major factors governing wellbore stability and is the basis for a good approach to mechanical modeling[5]. The Mohr diagram is useful for characterizing stability based on these three major factors. In the model, rock strength is represented by a straight line (the Mohr Coulomb line) with two material constants, cohesion and friction angle. Mechanical state is represented by a circle (the Mohr circle) on the x axis, the size and position of which is determined by stress, mud pressure and pore pressure. The higher the stress, the larger the circle, the higher the mud pressure the smaller the circle. The position of the circle on the x axis is determined by pore pressure, where a higher pore pressure shifts the center of the circle closer to the Mohr Coulomb line.

Conditions resulting in the circle boundary tangenting the line indicate high risk for borehole instability[5]. The risk of mechanical hole collapse with respect to borehole stability is especially high when the formation strength is low, when the failure angle is low (55° or lower) and the pore pressure is high. These conditions are regularly found in shale formations, which make the situation especially problematic in shale layers located directly above the reservoir[2]. Mud composition and chemistry play a unique role in remedying unstable conditions resulting from high pore pressure, low fracture gradients and reactive shales.

Under/Over Balance

The terms overbalanced and underbalanced drilling are used to describe conditions where the mud column pressure is higher or lower than the pore pressure in the formation respectively. Hard limestones and sandstones can support underbalanced drilling without caving due to their inherently high cohesion strength, whereas shales with comparatively low or complete lack of cohesion strength would not. Shales drilled in underbalanced conditions are prone to large spalling shale fragments sloughing into the wellbore which are difficult to remove and further increase hole gauge[5]. Drilling underbalanced in a formation with high cohesion strength can be done to increase rate of penetration significantly, however in the case of high permeability formations the risk of a kick is heightened. In any formation, regardless of cohesion strength, stability is reduced in underbalanced conditions. Drilling overbalanced is preferred for stability; however the upper limit is then guided by the formation fracture gradient[4].

Pressure Window

The traditional method of increasing mud weight alone to remedy wellbore instability phenomena is not always the best option. Microfractures are commonly found in brittle shale layers and increasing mud weight could instead lead to other issues such as lost mud[6]. Low permeability shales are susceptible to slow losses from pore pressure transmission which over time lead to a reduction in pressure differential between the formation and wellbore. If the section is not cased in time, wellbore instabilities arising would be similar to the caving and sloughing issues found when drilling underbalanced.

In drilling a well, mud density (as well as equivalent circulating density) must be kept great enough to control formation fluids, but not so high as to induce a fracture. The safe mud weight window is hence defined as the pressure between the pressure at which a kick might occur and the pressure at which drilling fluid losses will be initiated[4]. In normally pressured zones, a sufficient margin of safety ensures an increased pressure window. However, in geo-pressured zones, the window between the fracture gradient and pore pressure will narrow significantly as the geo-pressuring increases. In highly geo-pressured formations, an additional margin of safety may be provided by the tensile strength of the rock. However, if natural fractures are present or the tensile strength is low it becomes extremely important to minimize circulating pressures and transient pressures in the annulus under these circumstances[1]. It is also possible to utilize certain specializes drilling fluid products in these areas to assist in stability control. The ability to predict formation and fracture pressures becomes important when planning mud weight, mud composition, equivalent circulating density and casing programs to minimize stability risks[1].

Failure types and prevention

The major ways that stuck pipe and tight hole impact the cost of drilling are from lost time due to the consequent need to ream or sidetrack while drilling. Wellbore instability may also contribute to other problems later in the drilling process. Wireline logs are difficult to read in sections where instabilities have occurred because log interpretation is based on the assumption of a gauge wellbore with a known diameter. Irregular borehole shape also leads to uncertainty when calculating the required cement volume for casing operations[2]. The main causes of tight hole/stuck pipe are hole collapse, Insufficient hole cleaning, differential sticking and deviation from ideal trajectory[2]. On the other end of the hole stability spectrum, lost circulation is encountered when a significant amount of fluid is lost to the formation due to induced fracture (by exceeding the fracture gradient) or losing mud to an existing fracture. Some of these failure mechanisms are outlined in more depth in the following sections.

Differential Sticking

Differential sticking is the only likely reason for stuck pipe in a permeable reservoir rock. When differentially stuck, the drilling tool is secured to the borehole wall as a result of a high differential pressure between the well and the formation and an overly thick filter cake[2]. The mechanism of differential sticking described briefly is as follows. A portion of the drill string lies against the low side of a deviated hole. With rotation of the bottom hole assembly, lubrication from a thin film of mud ensures even pressure on all sides of the pipe. When rotation is stopped, the portion of the pipe in contact with the filter cake is isolated from the mud column and the differential pressure between the top and bottom of the pipe causes drag when an attempt is made to pull the pipe. If the resulting drag exceeds the pulling power of the rig, the pipe is differentially stuck[1]. Sticking may occur at any point along the drillstring that bears against a permeable formation with a filter cake. The chances of sticking are greater in the presence of a thick filter cake, as the contact area is greatly increased when the drillstring is embedded in a thick, porous surface layer[1]. Drilling high angle holes from offshore platforms creates an increased occurrence of the tendency for differential sticking. In these circumstances, the weight of the collar against the wellbore and the erosion of rock beneath the collars may both be high enough to prevent the formation of a conventional filter cake. Coupled with an insufficient annular velocity, enough to transfer solid material out of the hole, a bed of cuttings will accumulated underneath the collars and become incorporated into the filter cake. The resulting conditions lead to the increased tendency for incidents of differential sticking[1].

Minimizing differential sticking incidents can be achieved by choosing different collar types and lengths, but also by optimizing drilling fluid components and properties. Pull out force has been shown to increase with high differential pressure, contact area, filter cake thickness and coefficient of friction. Differential pressure may be kept low by keeping the mud density as low as possible, the lower limit is dictated by the pore pressure and collapse gradient. Oil-based muds are preferred due to the inherently low coefficient of friction as compared to water based muds, although there are formidable water based products that work to minimize coefficients of friction. To minimize contact area and cake thickness, cake permeability should be kept low and drill solids should be rigorously reduced by means of desilting[1]. Drilling fluid additives that work by bridging and then effectively sealing the formation and filter cake by means of submicron deformable particles are critical for this process as will be described in later sections.

Hole Collapse

Hole collapse happens when the near-wellbore formation fails mechanically either by shear failure or tensile failure. Hole collapse can either result in an increased or decreased wellbore size depending on the nature of the failure. Increased borehole size results from the shear failure of brittle shale when a loss of pressure differential at the near-wellbore formation causes caving or spalling of shale fragments. A decrease in borehole size occurs in weak, plastic shales, sandstones, and salt or chalk formations. The reduction in hole size has been traditionally attributed to the swelling of reactive clays in contact with drilling fluid. Lack of sufficient pressure in the wellbore for while drilling in soft, plastic shale can result in a deformation of the wellbore and reduce hole size. This circumstance may require repeated reaming and could potentially lead to lost drill pipe, bit balling, and solids accumulation[2]. When shale spalling occurs in brittle shales from drilling below the pore pressure gradient, the free rock surface generated from this circumstance is exposed to the exact same conditions and thus the effect is not self-stabilizing. Drilling underbalanced is also risky since, in permeable zones a kick could result from the lack of hydrostatic pressure balance[2]. Traditionally the best method of preventing hole collapse is to increase mud weight[2].

Exceeding fracture gradient

In order to minimize influx of fluids, it is considered necessary to keep the mud weight above the pore pressure gradient. In order to prevent the loss of mud into fractures, the optimal approach is to keep mud weight or equivalent circulating density below the fracture gradient[2]. The fracture gradient is the pressure required to induce fractures in a rock at a given depth. A fracture is induced when the difference between the mud column pressure and the formation pore pressure exceeds both the tensile strength of the formation and the compressive stresses surrounding the borehole[1]. Significantly fracturing the wellbore leads to lost circulation which is problematic because drilling fluid is expensive and there is a limit to the amount available on the rig. Mud loss can also lead to temporary pressure drop in the well and may lead to a kick or blowout event. In some cases fractures may initiate but stress conditions may not lead to fracture growth. In previously unfractured wells, significant mud losses may not occur until the formation is stressed to the point of fracture growth[2]. Fracture growth commences when the pressure exceeds the minimum principle stress, plus an additional term depending on the conditions for fracture growth at the tip of the fracture. This additional term is decided based on operational experience in the field[2]. Usually a fracture is induced just below the casing shoe where the difference between fracture pressure and mud pressure is the greatest. This is especially common when the mud density is raised to control a kick in the lower part of the hole and the fracture pressure gradient is exceeded higher in the hole at the shoe. In this case, a common approach is to strengthen the wellbore by pumping pills of lost circulation materials downhole thereby filling the fractures with material that will widen the fracture and increase hoop stress in the formation[1]. When a natural fracture is encountered, it is possible to determine the size of the fracture by closely correlating mud loss and rheology data over time during circulation[3]. In this case, the optimal lost circulation material package may be designed based on particle size distribution and strength of material.

Formation Types and Associated Stresses

In terms of strength, rock can be roughly classified into two categories; high cohesion strength (hard limestones, sandstones) and low to zero cohesion strength (shales) [5]. During drilling, the strength of a rock relative to the near-wellbore stresses will remain mechanically stable or undergo permanent deformation. Predicting wellbore stability from a mechanical perspective requires rock strength parameters (cohesion), in situ stress, geometry and orientation of the borehole, and shear failure of the rock. The key parameters of rock strength include unconfined compressive strength, tensile strength, cohesion and the coefficient of internal friction. Core samples from the formation are generally used to characterize these aspects of the rock along with empirical correlations based on log data[4]. Many reservoirs are characterized by anisotropic rock fabric which is important when considering rock strength in relation to orientation of the wellbore. In general, rock strengths measured parallel and perpendicular to the bedding planes in anisotropic material are stronger than orientations in between. In deviated, unconventional wells it becomes very likely to intersect the formation at many angles relative to bedding planes and thus rock strength is significantly reduced. This leads to an increased incidence of fractures induced at the near wellbore[4]. In situ stresses are represented by three principle stresses; vertical stress which is the overburden stress from gravitational loading from overlying rock, minimum horizontal stress and maximum horizontal stress which are important in anisotropic rock fabric. Exceeding the minimal horizontal stress has a direct influence on fracture initiation and propagation[4]. Minimum horizontal stress can be determined by pumping fluid into a formation to induce a fracture and observing the pressure at which the fracture closes. The closure pressure is equal to the minimum horizontal stress[4]. The stable range of horizontal stresses is narrowed significantly as angle of inclination increases, particularly from 30° to 60°. In anisotropic rock fabric, the stable range of horizontal stresses is reduced significantly and the chance of fracture initiation and growth becomes high[2].

Pore Pressure Transmission and Shale

Any mechanism that increases the pore pressure in the well vicinity will result in a decrease in stability. Two main processes modify pore pressure, hydraulic force from overbalanced conditions and chemical gradient which is guided by salinity differences between formation and wellbore[5]. Fluid movement from well to rock, whether driven by hydraulic or chemical force has a tendency to increase pore pressure in the near-wellbore region. Pore pressure is therefore the main driving force of instability and the ability of a mud to mitigate flow conditions at the face of the wellbore becomes a key factor in fluid design. In overbalanced conditions when hydraulic force exerts pressure and causes fluid flow towards the formation, a good drilling fluid will create a hydraulic barrier on the formation face and utilize proper salinity to ensure osmotic drive in the reverse direction[5].

Shales act as a semi-permeable membrane and depending on the chemical activity (salinity) difference between formation fluid and wellbore fluid, osmotic water flow occurs from the fluid with higher water activity to the fluid with lower water activity[5]. Oil based muds are preferred to water based muds due to the reduced tendency to leak fluid into low permeable formations and the water phase of these muds are kept at sufficiently low water activity to further drive osmotic flow from formation to wellbore[5]. Oil based muds also act as a semi-permeable membrane by preventing ions associated with salts from moving between the water phase of the mud and the formation[2]. Adding salt to the drilling fluid so that the water activity is lower than the formation water sets up an osmotic potential that will tend to drive water out of the shale and effectively reduces pore pressure, enhancing stability. It is well established that shale surface allows the passing of not only water but also salt ions into the bedding planes and thus must be regarded as a 'leaky' semi-permeable membrane. Due to the 'leaky' nature of the shale surface, the pore pressure transmission reduction by means of osmotic gradient alone is a temporary effect[2]. Eventually water activity between formation fluid and the drilling fluid reaches a state of equilibrium and the pore pressure infiltration is directed by hydraulic force. Adding submicron deformable drilling fluid additives that prefer to disperse in the water phase of and at the boundary of invert emulsion droplets may further increase the efficiency of the semi-permeable membrane at the face of the shale formation and prevent delayed equilibrium in water activity level.

For permeable formations such as sandstone, creating impermeable conditions at the face of the wellbore by means of a thin efficient filter cake is necessary to stabilize the well[2]. Both permeable and impermeable conditions benefit from the use of deformable sealing materials that reduce permeability further and by increasing efficiency of the semi-permeable membrane established at the wellbore, thereby directing osmotic flow from formation to wellbore.

Product Mechanism

The term 'lost circulation materials' covers a wide range of product variations all with the aim of curing lost circulation from natural and induced fractures, highly permeable formations, and vugular zones. We can broadly classify these products into 4 categories[1]:

1.] Fibrous materials – low rigidity materials that are forced into large openings (cotton fiber, wood fiber, paper pulp sawdust, etc.);

2.] Flaky materials – flat materials that lie against openings and are strong enough to resist mud pressure (shredded cellophane, crystalline flake graphite, mica flakes, plastic laminate, wood chips etc.);

3.] Granular materials – High strength and rigidity materials with a range of particle sizes that can be optimized to fill fractures of different size and high porosity formations (ground nutshells, expanded shale, course calcium carbonate, petroleum coke, graphite etc.)

4.] Slurries with increased strength after placement – pumped downhole in pill form and either squeezed in place or left to set to form a thick impermeable plug (hydraulic cement, diesel oil-bentonite mixes, high fluid loss squeeze pills, etc.)

Lost circulation materials are used to heal fractures created during mud loss situations by bridging, plugging and or sealing the point of interest. Particles can be used in a preventative manner, by including material in the active fluid system while drilling. Care should be taken to ensure that materials are not larger than the openings found in shaker screens otherwise they will be 'screened out' and effectively wasted. The purpose is to arrest drilling induced fractures at an early stage before significant losses will occur. Correctly sized particles used in a preventative manner should bridge the fracture opening thereby reducing fluid loss to the fracture and preventing fracture growth[2].

Modeling can be used to show, in an ideal scenario that in the case of LCM's such as asphaltitic materials that work to seal induced fractures can significantly open the safe pressure window by allowing higher fluid column pressures with minimal losses[6]. It is proposed in this paper that an ideal combination of LCM's that work specifically to bridge induced fractures with hard particles and fill the intra-particular spaces between solids with a micronized deformable material to form a highly efficient seal in the case of induced fractures. The presence of submicron deformable material alone also works to increase the efficiency of the leaky semi-permeable membrane characteristic of shale and prevents the latent pore pressure equilibrium leading to hole collapse. The ideal combination of LCM's thus opens the available pressure window by limiting mud loss by induced fracturing and also limiting hole collapse from formation pore pressure increase by slow fluid injection.

Optimized Bridging and Sealing System

The optimized bridging and sealing system (OBSS) consists of a combination of highly resilient carbon based additives with a deformable, micronized sealing polymer. This combination of materials has been shown to effectively bridge and seal induced fractures when drilling and/or circulating across complex geo-pressured zones and through the curve when used in oil based mud. A 20x microscopic image of the blended product is shown in Figure 1.

Figure 2 shows the particle size distribution of the micronized deformable polymer component of the blend. Particles in this size range work to effectively seal the intra-particular spaces found in a filter cake in both water based and oil based muds. Particles in this size range are also able to increase the efficiency of the semi-permeable membrane which is characteristic of the shale surface which assists osmotic drive of formation fluid towards the wellbore. This feature is described more in the next section. Figure 3 shows the particle size distribution of the optimized bridging and sealing system. With the wide distribution of resilient particles found in this blend combined with the submicron deformable particles, this LCM is able to compact within the tips of induced fractures, create a sealed filter cake, and halt further propagation of fractures.

Figure 4 shows a comparison of particle plugging test (PPT) results between a standard oil based mud and the same fluid with the addition of 10ppb of the optimized bridging and sealing system. The test was run with 2000 psi differential pressure on a 150µ disc at 325°F. A reduction in overall fluid loss is clearly seen in the fluid containing the optimized bridging and sealing system compared to the base fluid. Figure 5 shows the same test results, but emphasizes the fluid loss data within the first 5 minutes of testing. In this initial part of the test, the development of a primary filter cake can be observed as the point where the rate of fluid loss makes a step change. The fluid loss measured at this point is referred to as a ‘spurt loss’ and it is valuable for the spurt loss to be as low as possible. A low spurt loss value indicates that a thin, efficient filter cake has formed quickly and will be better at mitigating pore pressure loss and mitigate incidences of differential sticking.

Micronized Deformable Polymer

Shale with its very small pore throats on its own can be defined as a ‘leaky’ semi-permeable membrane, which does provide some osmotic fluid flow from low to high ionic concentrations. This explains the benefit of adding 20%NaCl to a mud without any other additives to achieve some wellbore stability. Oil based muds are excellent at acting as a barrier to the transfer of fluid into the pores of shale due to their hydrophobic nature and can even allow formation water to flow osmotically towards the borehole with the brine found in the internal phase of the mud. The functionality of the micronized deformable polymer component is thought to increase the efficiency of the semi-permeable membrane created by the face of the shale formation.

Formation of Internal Filter Cake

As stated previously, differential sticking typically occurs when high contact forces caused by low formation pressures, high wellbore pressures or both, are exerted over a sufficiently large area of the drillstring. The bottomhole assembly is held in the cake by a difference of pressures between the hydrostatic pressure of the mud and the pore pressure around the surface of the wellbore. When a low permeability internal cake is formed, the pressure differential between the hydrostatic pressure of the mud and the external filter cake is reduced. The differential pressure between the mud column and formation is preserved which is necessary to prevent spalling shale or hole collapse. Due to the fine size and viscoelastic nature of the particles, the micronized deformable polymer has the ability to create a low permeability internal filter cake which helps to reduce the incidence of differential sticking.

The ability of the micronized deformable polymer to form an internal filter cake has been proven in a laboratory setting. In the study, two 30 minute dynamic filtration tests are done on low porosity ceramic discs (3-20µ), one with a standard water based mud and the same mud with deformable polymer included. Fluid loss values are plotted over square root time to observe the nature of the filter cake. In a dynamic fluid loss test, a filter cake builds initially and is relatively static in thickness over the course of the 30 minute test. In the base fluid, as expected, filtration values over square root time are increased linearly after the initial external filter cake forms. In the fluid containing submicron deformable polymer however, filtrations over square root time deviate from linearity and the rate of filtrate decreases over time. This is an indication that an internal filter cake is being built within the disc as particles are being deposited over time thus slowing the filtration rate. Based on the assumption of the formation of an internal filter cake, using measured fluid loss values, and a modification of Darcy’s Law test results using deformable submicron polymer in a fluid can be compared to base results to calculate pressure differences between at the interface between the fluid and filter cake, the interface between the filter cake and ceramic disk and the back pressured face of the filtercake. Figure 6 and Figure 7 show that samples containing submicron deformable particles maintain a high pressure differential at the interface between the disc and filtercake but there is a reduced pressure drop within the filter cake when compare to the base fluid. This is an ideal scenario for mitigating the incidence of differential sticking during drilling.

Return Permeability Consideration

Minimal return permeability testing has been completed to date but initial results show promise of a high fraction of production after exposure to deformable polymer when used in water based mud. No field issues have been reported to date.

Case Studies

The optimized bridging and sealing system was successfully applied in several wells off the coast of Tabasco Mexico to control high mud losses in narrow pressure windows due to complex geo-pressured zones which are commonly drilled close to the fracture gradient.

Field A

For wells drilled in Field A, incidences of significant amounts of drilling fluids lost to the formation are high. Due to complex geo-pressures and consequently narrow pressure windows, the wells require seven sections to arrive to the reservoir. The 17 1/2” section between 2100 and 3250m of depth is characterized by light and dark gray shale which ranges from medium to hard softness with some sandy, slightly calcareous parts. Intra-formational, normal faults are also present in this section. The details of the 14 ½ x 17 ½ sections that will be reviewed in this paper are outlined in Table 1.

Agreeing with simulations, the mud window allows us to drill without lost circulation due to induced fracturing (see Figure 8 and Table 2). Here, the equivalent circulating density (ECD) is close to the fracture gradient at the 16 in. shoe, but at the bottom of the section the ECD remains below the fracture gradient.

If the mud window depended only on pore pressure and fracture pressure, then the mud window would be considerably wider, but taking collapse pressure into consideration, the window is drastically reduced. It is very important in this section to introduce the casing as deep as possible in order to get the best leakoff test (LOT) for the next section. This is done best by drilling with wellbore pressures as close as possible to the fracture gradient. Figure 9 shows that increased flow rate cleans the open hole and it gives a reduction in ECD due to improved cuttings removal.

When the casing is introduced, the geometry in the annular space is reduced when compared to drilling due to the diameter difference between the drillstring and casing. When running the 13 5/8” casing, the ECD is above the fracture gradient along the drilled section, even when casing is introduced slowly (see Figure 10). Table 3 shows ECD results compared with geo-pressures in the section.

Circulating when the casing is placed at bottom, the ECD is above the fracture gradient even for lower flow rates (see Figure 11, Figure 12 and Table 4).

Due the size of the well, the amount of fluid lost while casing is introduced and cemented is close to 1350 m^3 on average.

When drilling fluid is lost by induced fracturing of the formation while casing is introduced (as in this case) the stress cage concept is used to mitigate further losses. Engineers in this field used pills of the optimized bridging and sealing system both while drilling and before running casing. This method has worked to drastically minimize the fluid loss in this section. Figure 13 shows the evolution of reinforcement methods used in the 17 ½” open hole section and the associated fluid loss with those methods. From the figure, it can be seen that using the optimized bridging and sealing system in place of the next best LCM material resulted in a 25% reduction in fluid loss.

The optimized bridging and sealing system concentration has been changed after every application, which has decreased the fluid loss further by 61% compared to the results in the first use of the product. The results showcase the ability of the optimized bridging and sealing system to control fluid loss from induced fractures.

Field B

Field B is characterized by complex geo-pressures and the risk of water influx, especially in the 14 ¾” open hole section where pore pressures are very high. This section isolates the high pressure zone, which makes it very important to place the shoe correctly to safely secure the next section. Due to the potential for water influx, it is necessary to drill with maximum mud weight. This, coupled with drilling parameters, allows us to maintain an ECD which is closer to the fracture pressure. The details of the 14 ¾” open hole section are outlined in Table 5.

Agreeing with simulations, the mud window forces engineers to drill as close to the fracture pressure as possible through the section (see Figure 14 and Table 6). It is possible to drill with an ECD below the fracture gradient by controlling the rate of penetration (ROP) and choosing the best flow rate to properly clean the well.

In this section, the upper and lower bounds of the mud window are limited to pore pressure and fracture pressure only. The flow rate and ROP were chosen to drill with an ECD close to the fracture gradient. Figure 15 shows the expected ECD plotted over flow rate.

When the casing is introduced, the geometry in the annular space is less than while drilling. Running 11 3/4” liner, we get an ECD which is greater than the fracture gradient, even for slow introduction of liner (see Figure 16). Table 7 shows ECD results compared to geo-pressures in this section.

Circulating when the casing is placed at bottom, the ECD results are inside mud window even for flow rates close to 300 gallons per minute (GPM). However, the open well has been fractured while during introduction of the liner, and consequently there is a fluid loss (a total fluid loss at times) even for low flow rates (see Figure 17, Figure 18 and Table 8).

Due the size of the well, the amount of fluid lost while casing is introduced and cemented is greater than 1000 m3. Lost circulation is due to fracturing of the formation while the liner is being introduced. Engineers in this field used pills of the optimized bridging and sealing system to reinforce the open hole due the narrow mud window. This goal has been achieved by using LCM in the active system. Using a highly concentrated pill of the optimized bridging and sealing system used previous to running the liner ensures that enough of the LCM will remain in the active system to mitigate further wellbore instability problems.

The results at Field B showcase the effectiveness of the optimized bridging and sealing system to reinforce the formation and minimize lost circulation events. Table 9 shows the difference in fluid loss events between this LCM system vs competitive materials. Use of the optimized bridging and sealing system in place of the next best competitive material resulted in a 49% reduction in fluid loss while drilling, running casing and cementing in this field.

Conclusions

The optimized bridging and sealing system was successfully applied in several wells in two fields off the coast of Tabasco Mexico that have previously experienced high rates of fluid losses due to the narrow pressure windows caused by complex geo-pressured zones.

- The first field, Field A, experienced losses averaging 8596 barrels of oil based fluid over three wells when using traditional LCM bridging packages which was reduced to 3,069 bbls per well when deploying the novel engineered bridging and sealing package.
- In the second field, Field B, the formation between 3269 and 4614 meters is characterized by complex geo-pressures.
- This section has an omnipresent risk of water influx which is minimized by running a high ECD close to the fracture gradient.
- When introducing the 11 3/4” liner, with associated reduction in annular volume, even low flow rates have previously caused the wellbore to fracture causing high rates of fluid loss with overbalanced pressures of up to 1800psi.
- By introducing high concentrations of the new optimized bridging and sealing system prior to running the liner ensured that potential instability issues were mitigated.
- Casing was run and cemented with no sticking and minimal mud loss at the target depth.

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Nomenclature

Define symbols used in the text here unless they are explained in the body of the text. Use units where appropriate.

BHA = *Bottomhole assembly*
ECD =*Equivalent Circulating Density*
LCM =*Lost Circulation Materials*
WBM =*Water Based Mud*
OBM =*Oil Based Mud*
GPM =*Gallons Per Minute*
PPB =*Pounds Per Barrel*
LB/BBL =*Pounds Per Barrel*
BBL =*Barrels*
ROP =*Rate of Penetration*
PPT =*Particle Plugging Test*
LOT =*Leakoff Test*
PSI =*Pounds Per Square Inch*
PSID =*Pounds Per Square Inch Differential*
OBSS =*Optimized Bridging and Sealing System*

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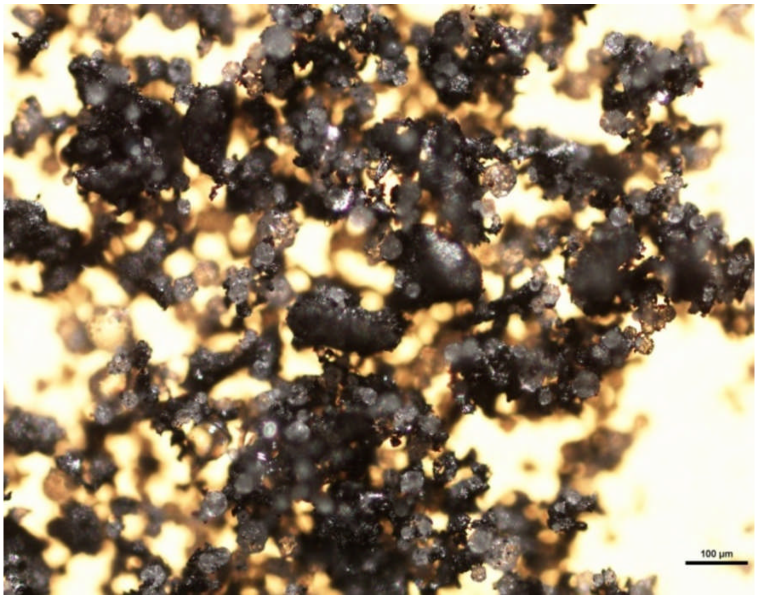

Figure 1: 20X Microscopic image of Optimized Bridging and Sealing Blend

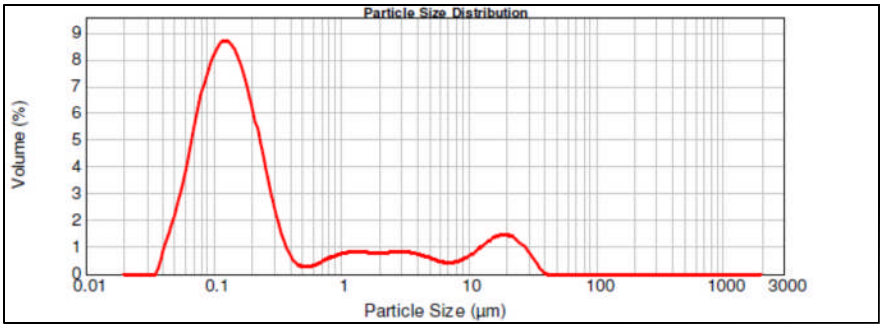

Figure 2: Particle size distribution of Micronized Deformable Polymer dispersed in deionized water

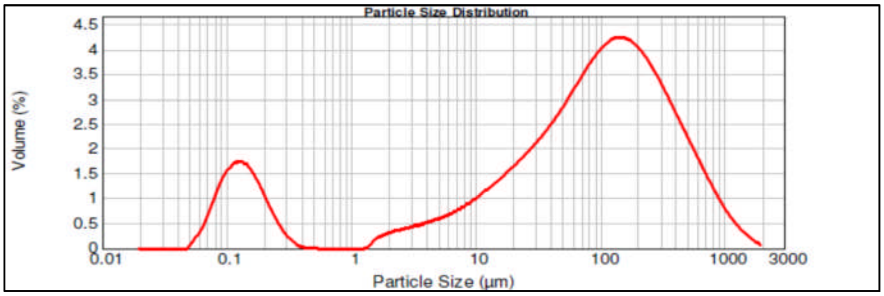

Figure 3: Particle size distribution of Optimized Bridging and Sealing System dispersed in deionized water

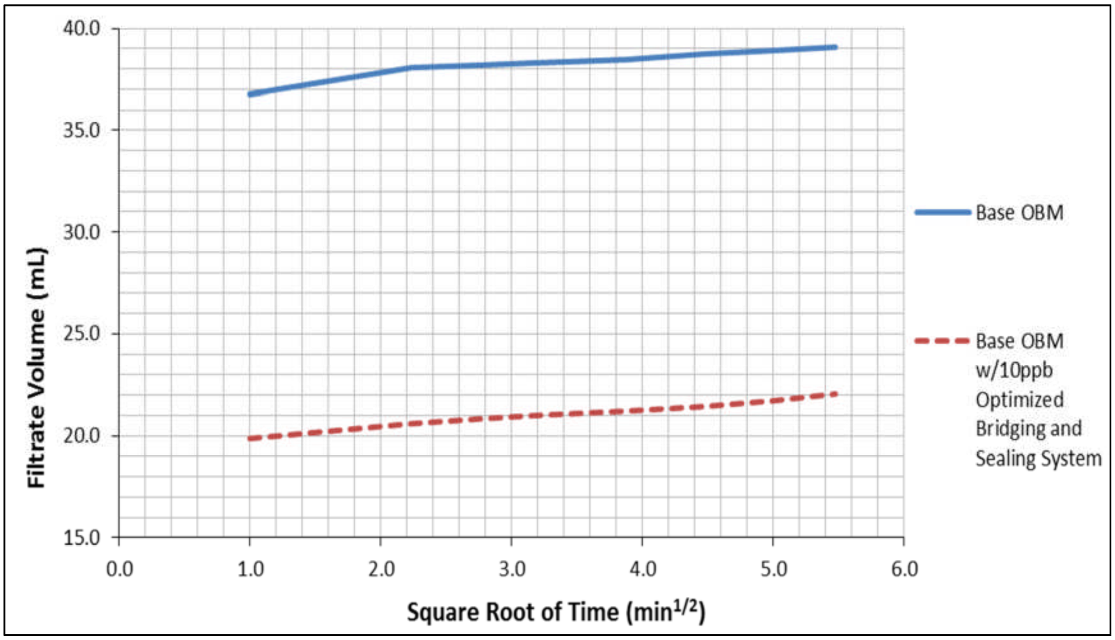

Figure 4: Particle plugging test (PPT) results showing the filtrate amount vs. the square root of time for a base OBM compared to the fluid with 10ppb of Optimized Bridging and Sealing System. Results obtained using 2000 psi differential pressure and a 150µ ceramic disc at 325°F after hot rolling both fluids for 16 hrs at 325°F.

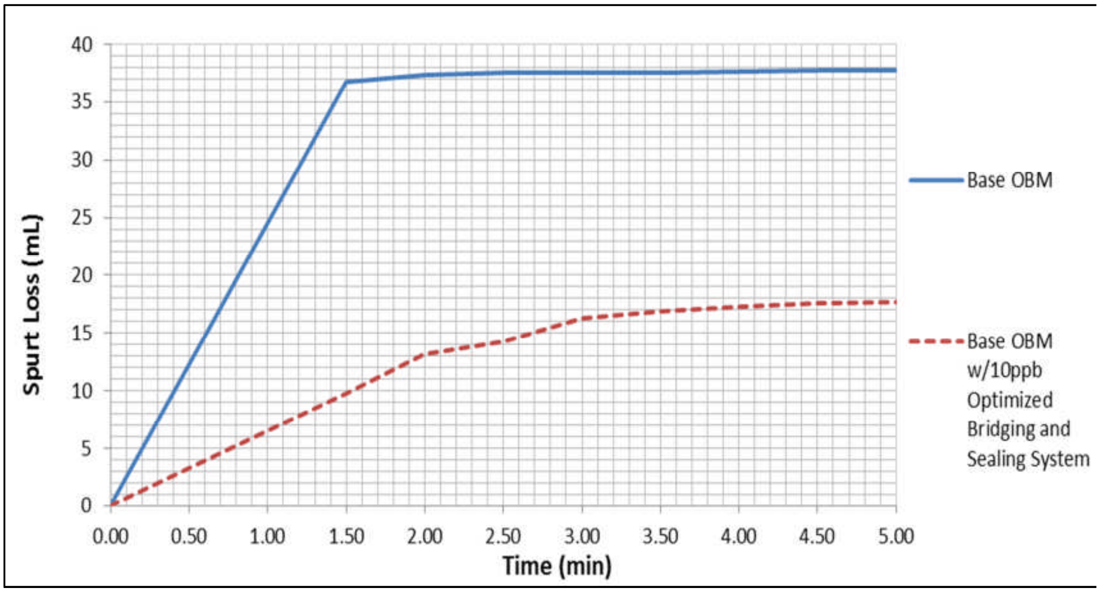

Figure 5: Particle plugging test (PPT) results showing an emphasis initial fluid loss values over time for a base OBM compared to the fluid with 10ppb of Optimized Bridging and Sealing System. It is during this time where a clear change in the rate of fluid loss increase indicates the building of a filter cake. Results obtained using 2000 psi differential pressure and a 150µ ceramic disc at 325°F after hot rolling both fluids for 16 hrs at 325°F.

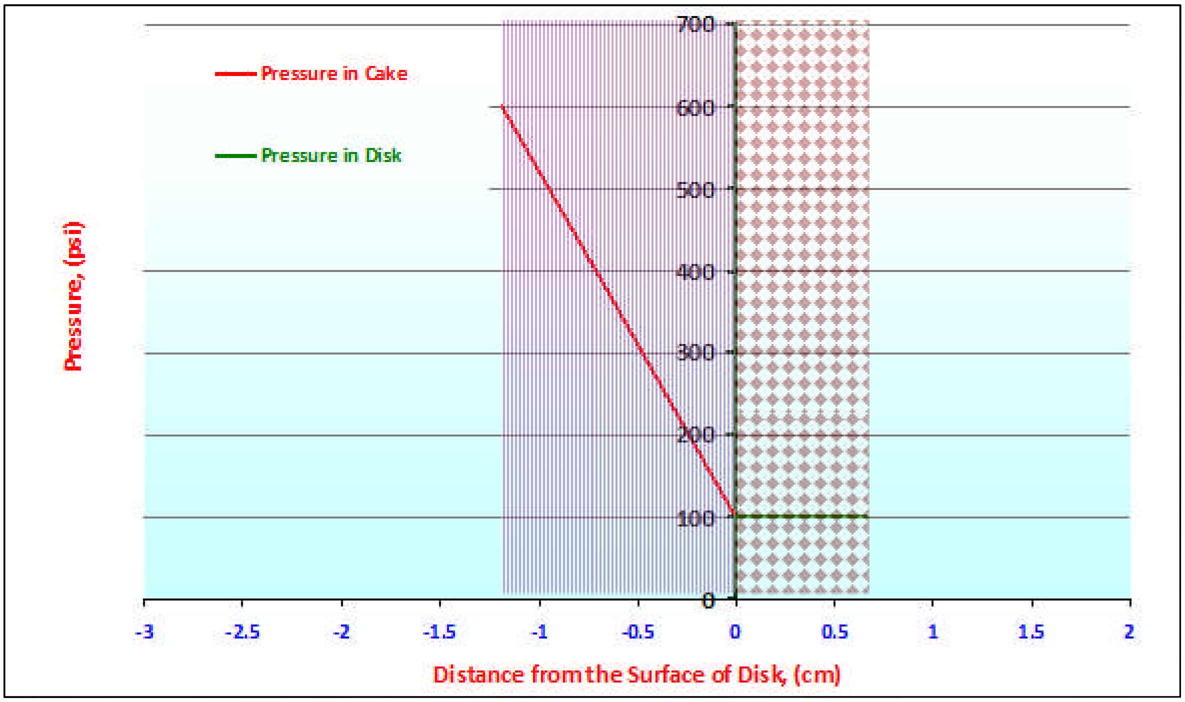

Figure 6: Calculated pressure profiles for a base fluid (WBM) after 60 minute dynamic fluid loss testing at 250°F on a 3µ disc

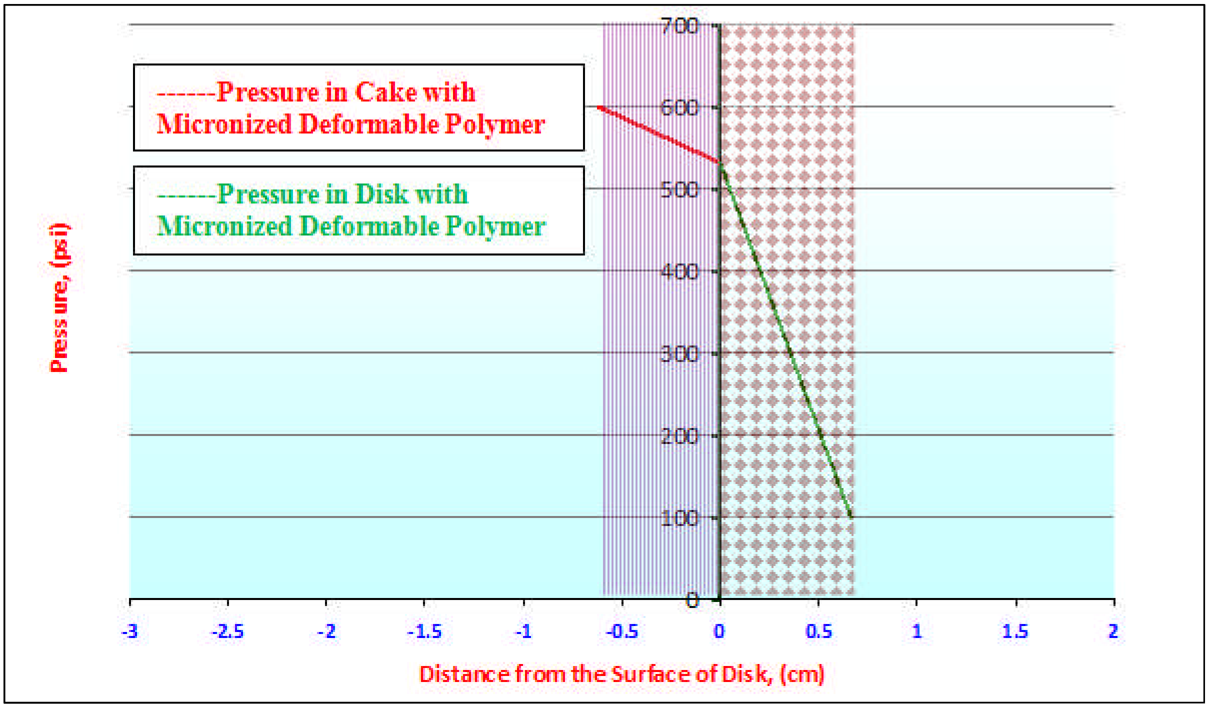

Figure 7: Calculated pressure profiles for a base fluid (WBM) with 10ppb of an Optimized Bridging and Sealing System after 60 minute dynamic fluid loss testing at 250°F on a 3μ disc

Table 1: : 14 1/2" x 17 1/2" section data for Field A

Shoe, in	16
Shoe, m	2100
End section, m	3250
Open hole, in	17 ½
Casing, in	13 5/8
Min. Pore, gr/cc	1.277
Max. Pore, gr/cc	1.6
Min. Collapse, gr/cc	1.33
Max. Collapse, gr/cc	1.78
Min. fracture, gr/cc	1.88
Max. fracture, gr/cc	2.04
Angle	0
Drilling Fluid	Oil based mud
Mud weight, gr/cc	1.75 - 1.83

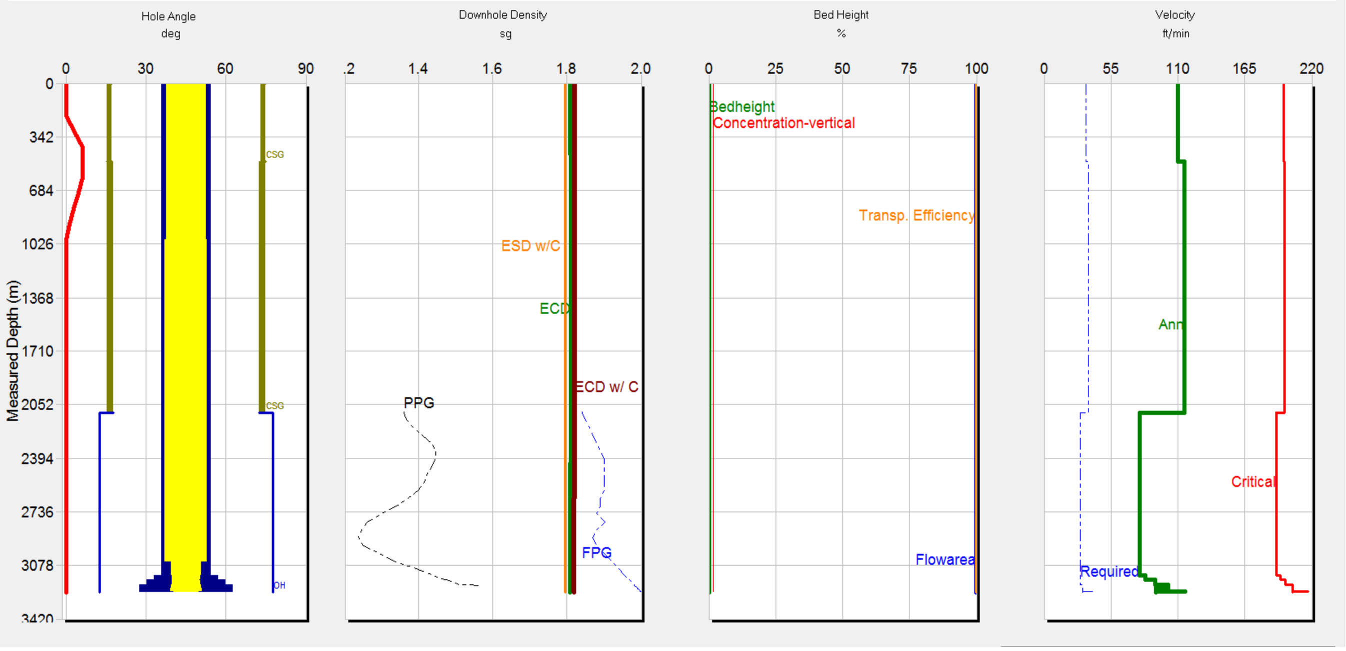

Figure 8: Drilling hydraulics and hole cleaning

Table 2: Drilling hydraulics results

TD m	Pore gr/cc	Collapse gr/cc	ECD, gr/cc without cuttings	ECD, gr/cc with cuttings	Fracture gr/cc
Shoe	1.4	1.46	1.86	1.87	1.88
Bottom	1.6	1.76	1.86	1.88	2.04

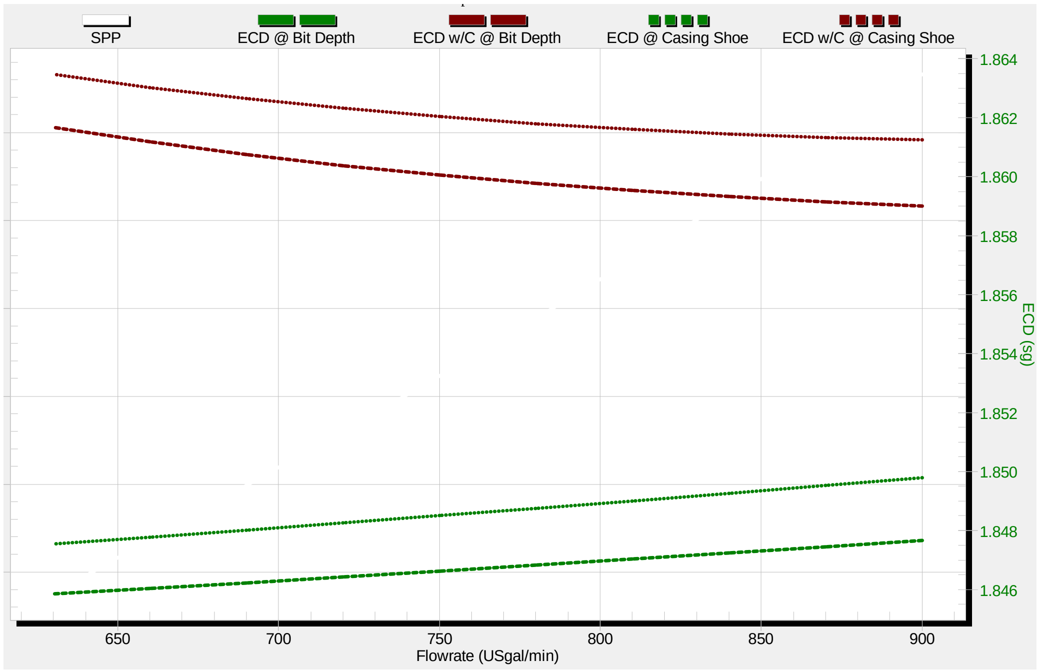

Figure 9: ECD as a function of flow rate

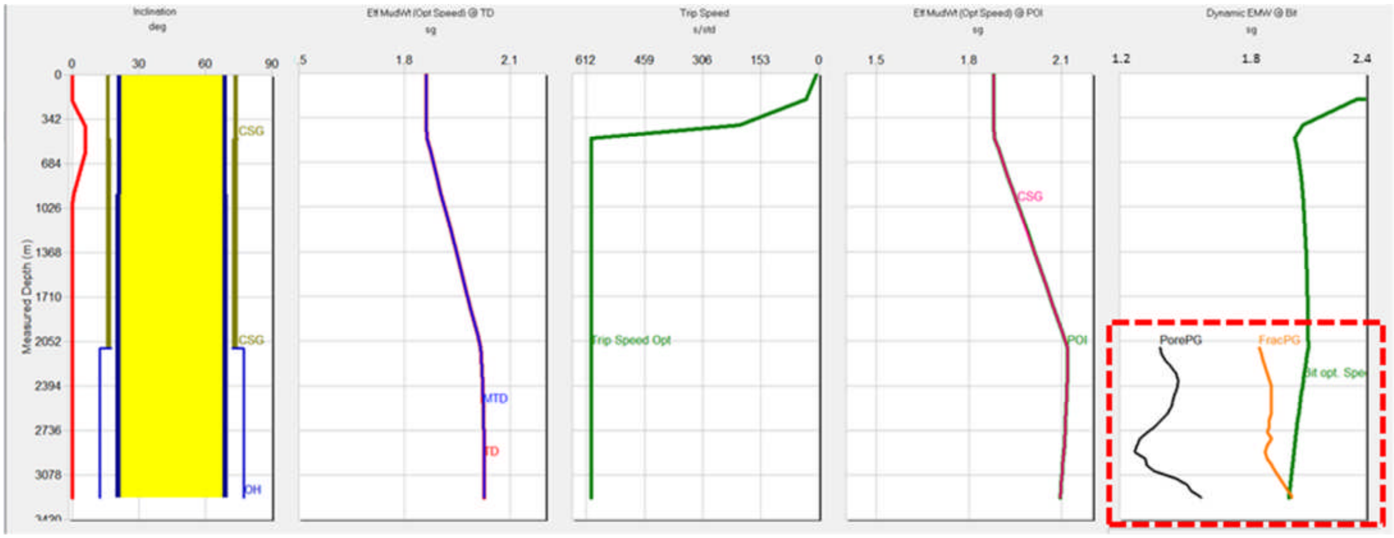

Figure 10: ECD while running 13 5/8" casing

Table 3: Hydraulics while running 13 5/8" casing

MD m	Pore gr/cc	Collapse gr/cc	ECD gr/cc	Fracture gr/cc
Shoe	1.4	1.46	2.12	1.88
TD	1.6	1.76	2.03	2.04

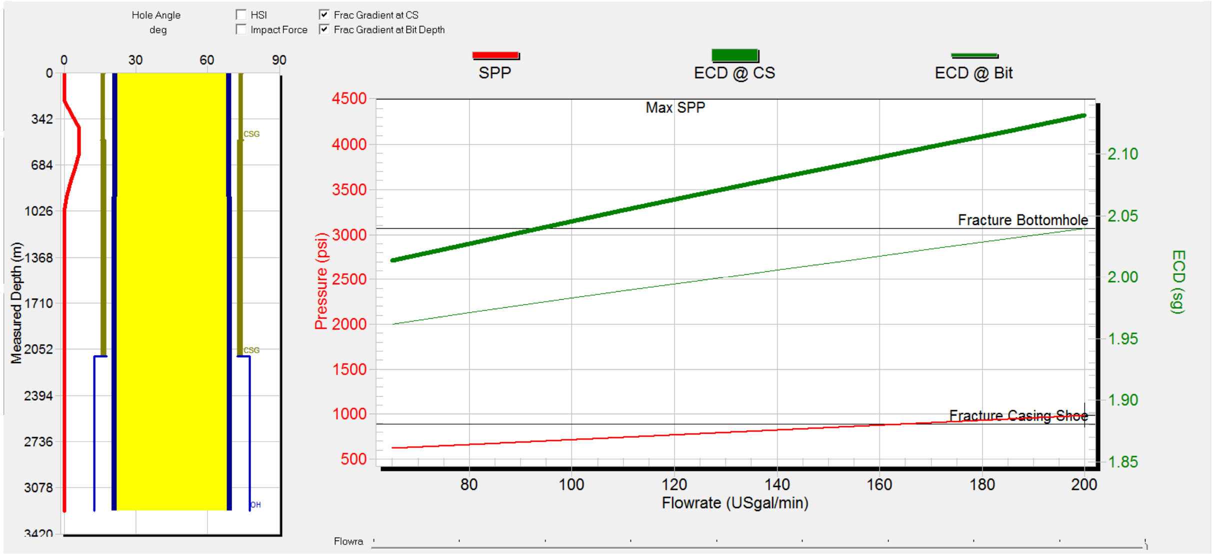
☐ HSI
☐ Impact Force
☑ Frac Gradient at CS
☑ Frac Gradient at Bit Depth

Figure 11: Circulating ECD while running 13 5/8" casing at bottom

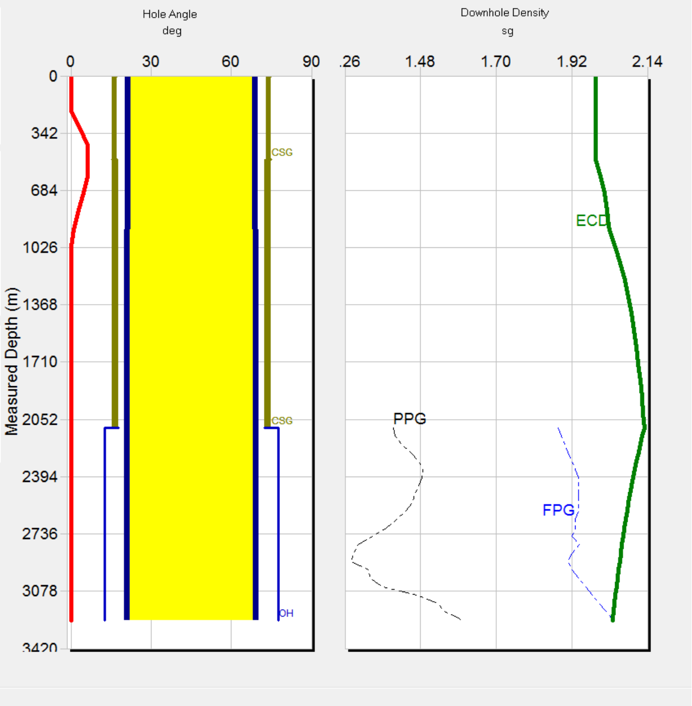

Figure 12: Circulating ECD at 200 GPM with 13 5/8" casing at bottom

Table 4: Circulating ECD at 200 GPM with 13 5/8" casing at bottom

MD m	Pore gr/cc	Collapse gr/cc	ECD gr/cc	Fracture gr/cc
Shoe	1.4	1.46	2.13	1.88
Bottom	1.6	1.76	2.04	2.04

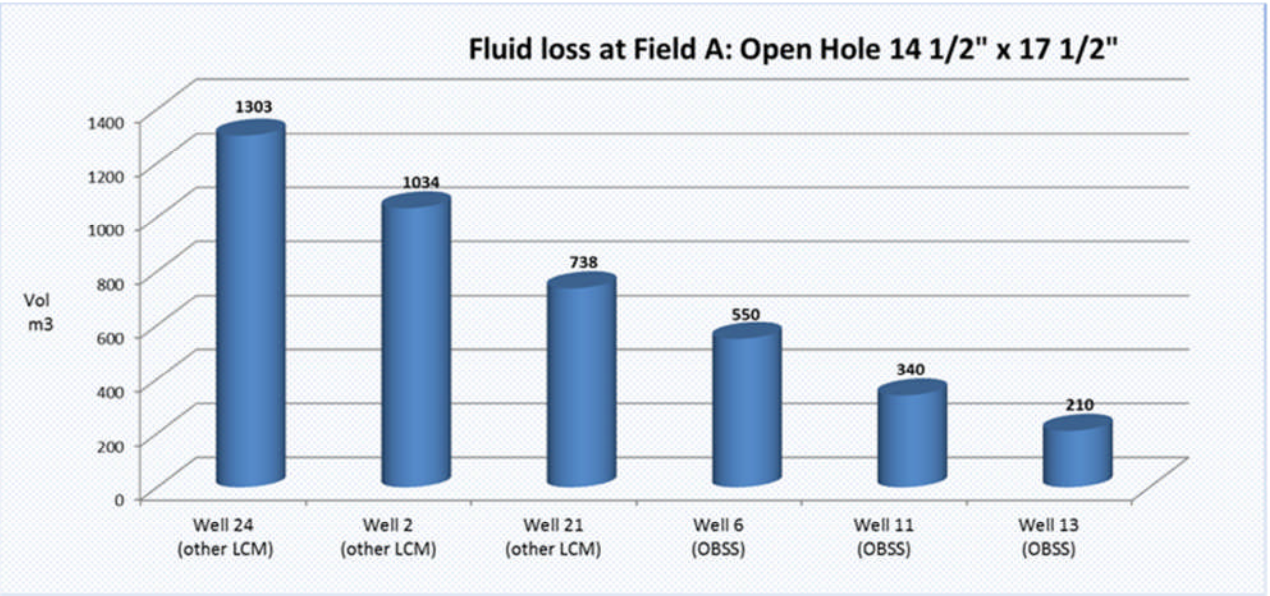

Figure 13: Evolution of LCM reinforcement used in Field A ***Note: The acronym OBSS stands for Optimized Bridging and Sealing System***

Table 5: 12 1/2" x 14 3/4" section data

Shoe, in	13 5/8”
Shoe, m	3269
End section, m	4614
Open hole, in	14 ¾”
Casing, in	11 ¾”
Min. Pore, gr/cc	1.71
Max. Pore, gr/cc	2.03
Min. Collapse, gr/cc	ND
Max. Collapse, gr/cc	ND
Min. fracture, gr/cc	2.094
Max. fracture, gr/cc	2.141
Angle	30
Drilling Fluid	Oil based mud
Mud window	2.04 – 2.09
Mud weight	2.05
ROP, m/h	10
gpm	780

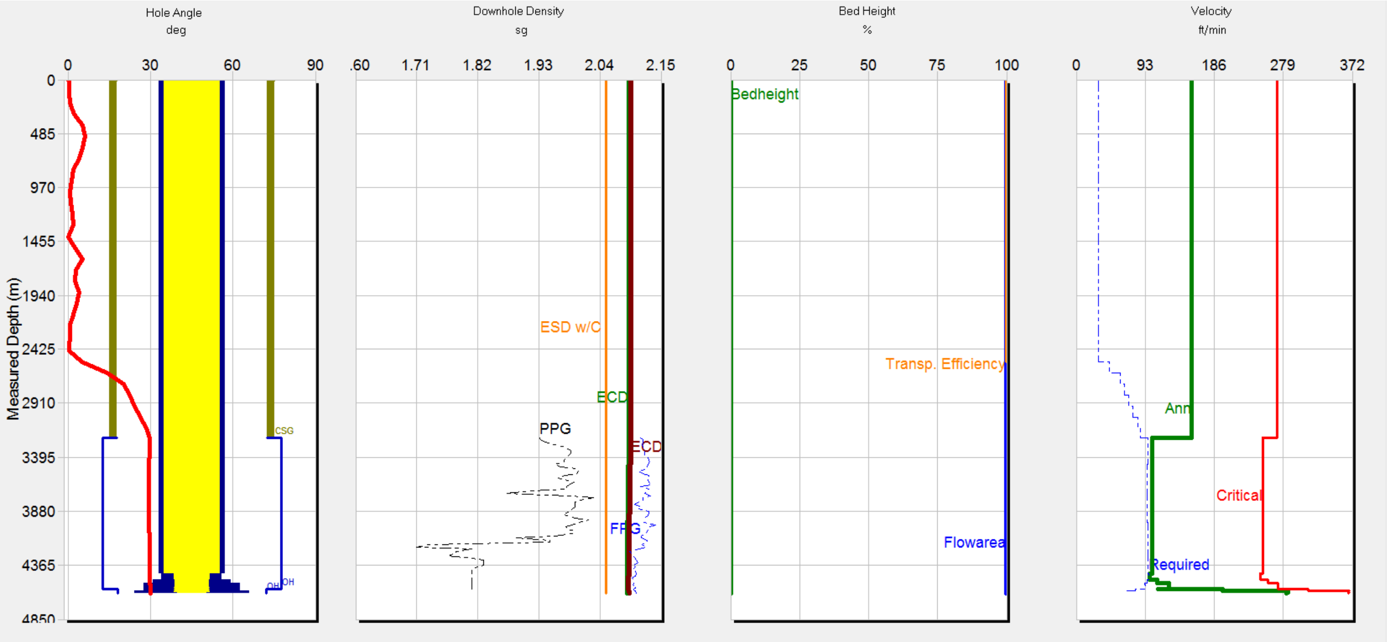

Figure 14: Drilling hydraulics and hole cleaning

Table 6: Drilling hydraulics results

MD m	Pore gr/cc	Collapse gr/cc	ECD, gr/cc without cuttings	ECD, gr/cc with cuttings	Fracture gr/cc
Shoe	1.93	NA	2.085	2.096	2.113
Bottom	1.81	NA	2.080	2.092	2.106

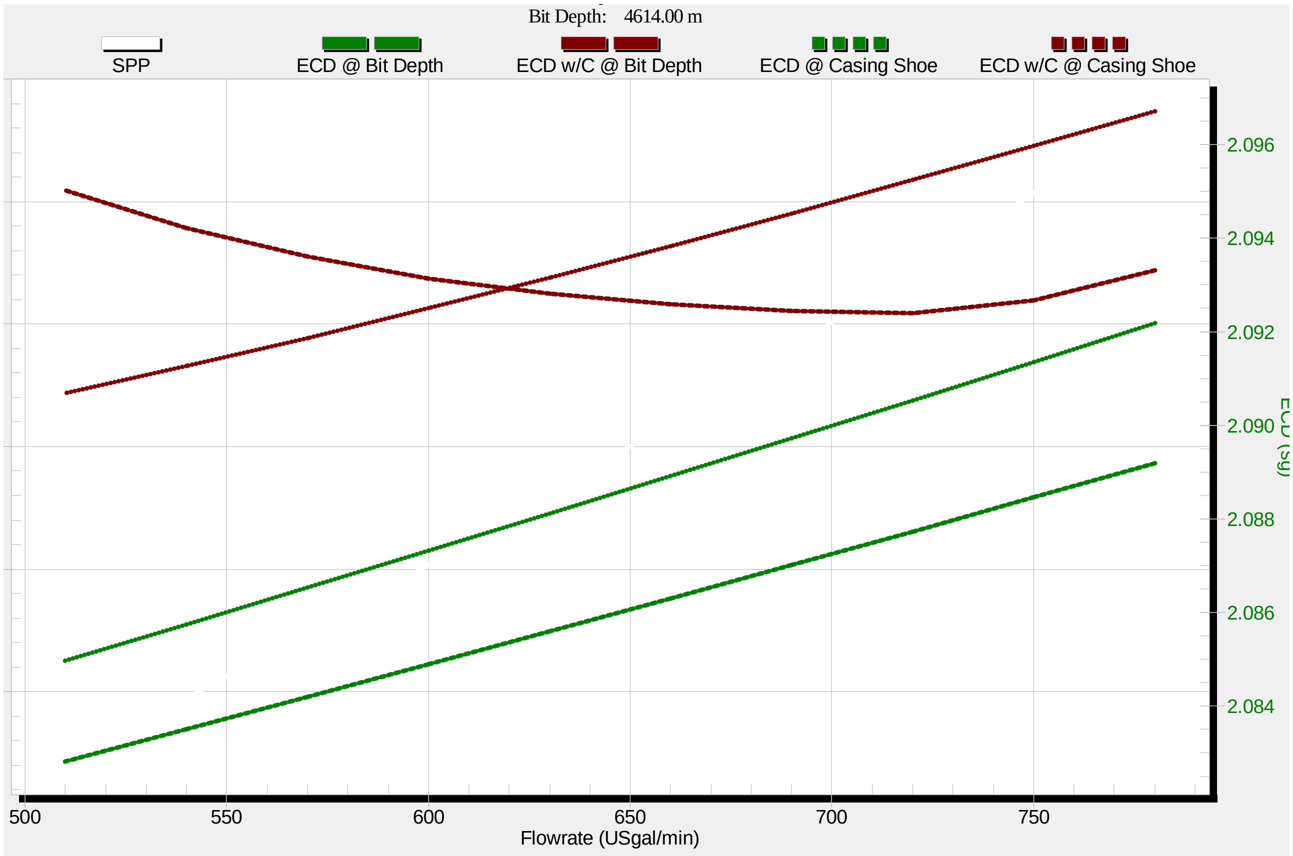

Figure 15: ECD as a function of flow rate

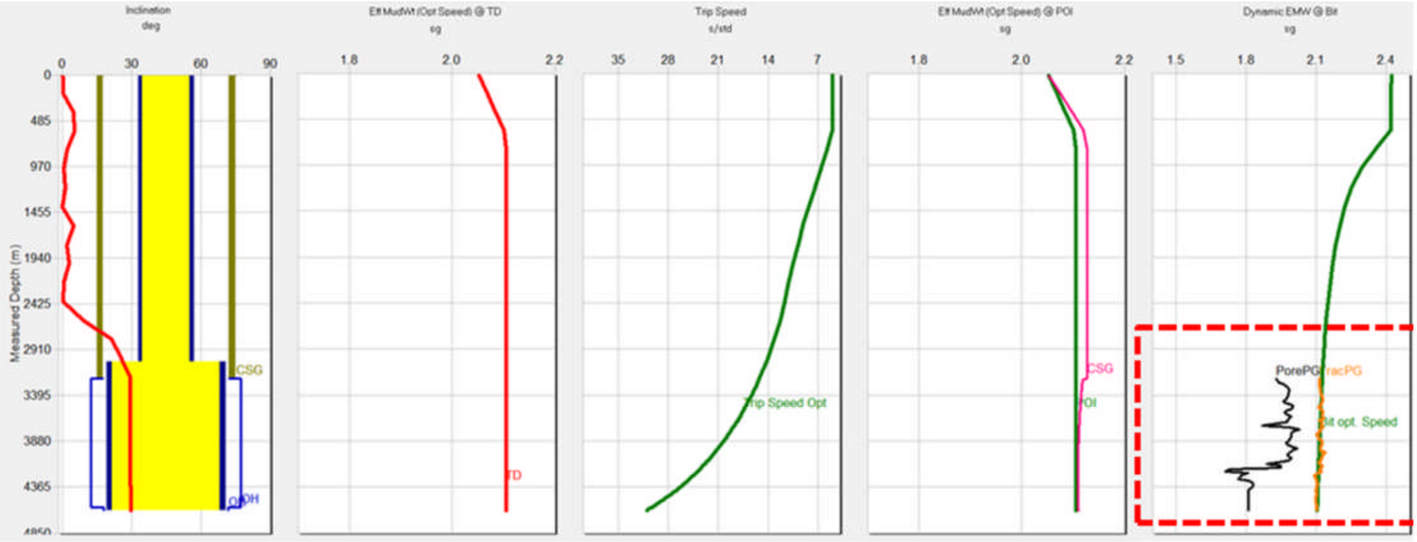

Figure 16: ECD while running 11 3/4" liner

Table 7: ECD while running 11 3/4" liner

MD m	Pore gr/cc	Collapse gr/cc	ECD gr/cc	Fracture gr/cc
Shoe	1.93	NA	2.13	2.113
Bottom	1.91	NA	2.106	2.106

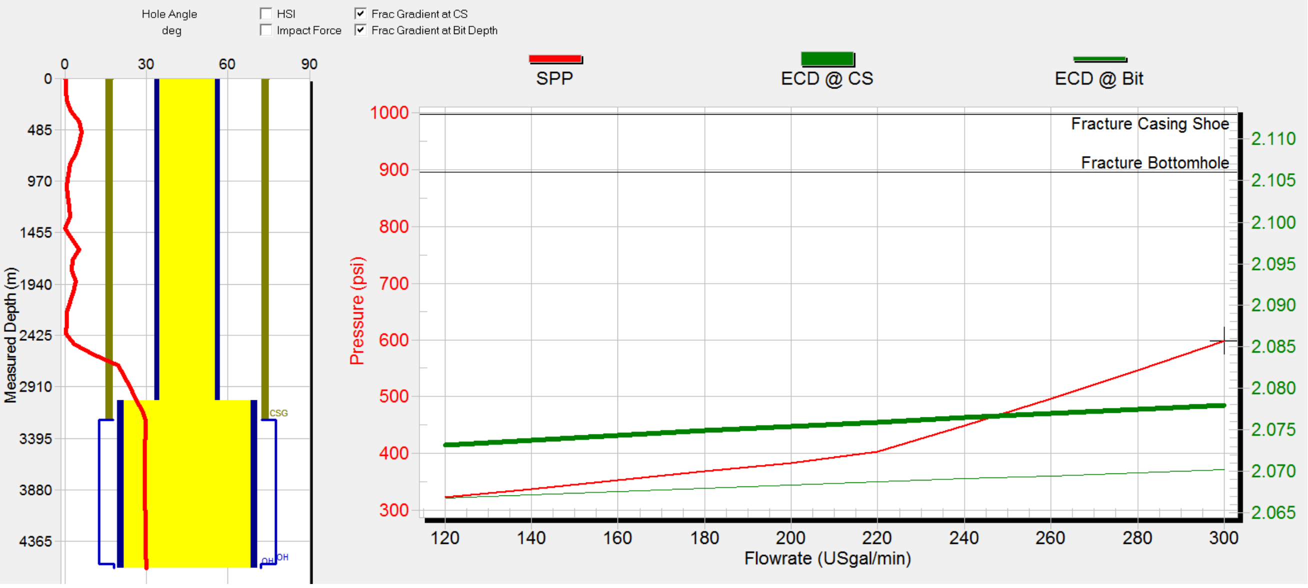

Figure 17: ECD and pressure results while circulating with 11 3/4" liner at bottom

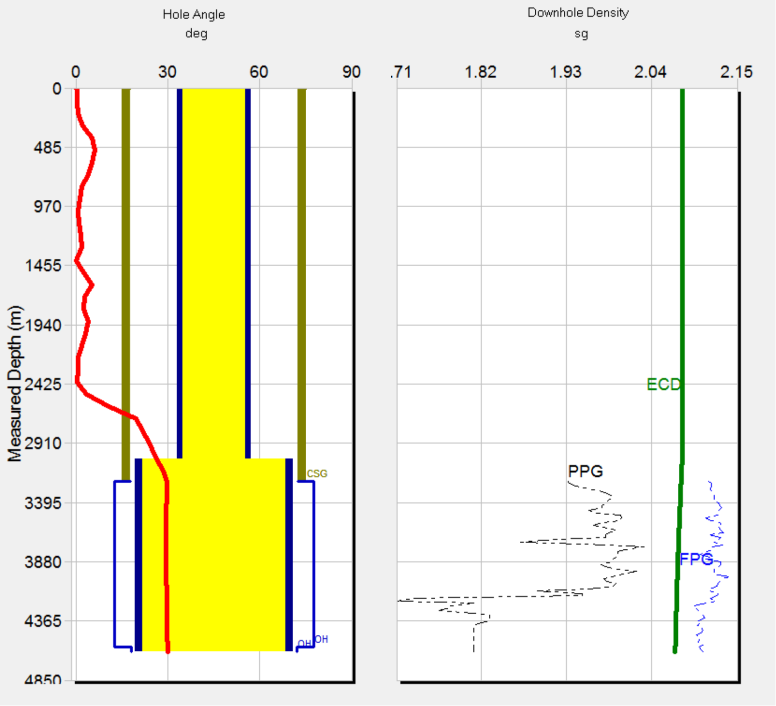

Figure 18: Results along the open hole while circulating at 300 GPM with 11 3/4" liner at bottom

Table 8: Circulating ECD at 200 GPM with 11 3/4" liner at bottom

MD m	Pore gr/cc	Collapse gr/cc	ECD gr/cc	Fracture gr/cc
Shoe	1.93	NA	2.079	2.113
Bottom.	1.91	NA	2.070	2.106

Table 9: Fluid loss in wells using Optimized Bridging System vs. other LCM packages

Cia Fluids	Well	Section drilled, m	Well OD, in	Fluid lost, m3						
				Drilling	Run Casing	Cement	Well Control	Trip	Circ.	Total
Optimized Bridging and Sealing System	Field B1	3269-4655	12 1/4 x 14 3/4	0	115	127				242
Competitor 1	Field B2	3064 – 4164	12 1/4 x 14 3/4	44	237.2	197.3				479
Competitor 2	Field B3	3125 – 4365	12 1/4 x 14 3/4	9	358	182	512	345	326	1732