Chair of Drilling Engineering and Well Completion

Master Thesis

Experimental Study on Effectiveness of Lost Circulation Materials to Mitigate Fluid Losses

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EIDESSTATTLICHE ERKLÄRUNG

Ich erkläre an Eides statt, dass ich die vorliegende Arbeit selbständig und ohne fremde Hilfe verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

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(20/06/2016) (Moamen Khafaga)

Abstract

Lost circulation has plagued the industry since the beginning of drilling. Severity of losses has been categorized based on the amount of barrels lost to the formation, i.e., Seepage, partial and total losses. This strategy doesn't help understand the underlying drive mechanisms for losses and doesn't provide enough data to propose a solution. The recently followed approach is focused on the lost-circulation mechanism based on the properties of the exposed formation: theses classifications are losses due to 1) Pore throats, 2) Induced or natural fractures, 3) Caverns.

Lost circulation not only causes the adverse effect of mud loss itself, it can also lead to severe additional issues, such as formation damage, stuck pipe, hole collapse and well control incidents. The current industry trend is moving towards drilling more low pressure zones or through depleted zones and lost circulation planning becoming vital to these projects.

Knowledge of the type and the expected amount of mud loss can assist engineers to select the most appropriate and effective solution pre-plan accordingly. Moreover, it provides criteria to evaluate the effectiveness of the applied lost circulation technique.

The objective of this thesis is to evaluate and compare the performance of different lost circulation materials (LCMs) to determine the effect of particle size distribution (PSD), concentration and type on their performance to provide more wellbore strength and mitigate loss circulation.

This thesis will first discuss the different lost circulation mechanisms and will explain the well strengthening practice with its different techniques adopted using LCMs and will point out the impact they have on the drilling process in order to reduce the chances of getting loss of circulation and consequently mitigate the non-productive time and overall cost.

The last part of this work is specified to present the successful results of a case study. The main objectives of presenting this case study to highlight the impact LCMs on alleviating and suppressing loss of circulation and to present the resultant cost savings achieved when applying LCMs in the mud systems as a solution to mitigate the losses.

Kurzfassung

Seit Beginn von Bohrtätigkeiten sind Zirkulationsverluste ein Problem für die Industrie. Die Schwere der Verluste wurde kategorisiert anhand der Menge an Barrels, die in die Formation verloren gehen, wie zum Beispiel teilweise oder vollständige Verluste. Diese Strategie hilft jedoch nicht, die zugrunde liegenden Gründe für die Verluste zu verstehen und liefert nicht genügend Daten für eine Lösung des Problems. Der zurzeit verfolgte Ansatz beruht auf den Mechanismen des Zirkulationsverlusts, basierend auf den Eigenschaften der jeweiligen Formation. Diese Klassifikationen beinhalten Verluste in 1) Porenräume 2) induzierte oder natürliche Brüchen 3) Höhle.

Zirkulationsverluste führen nicht nur zu den ungünstigen Effekten, hervorgerufen durch die Bohrflüssigkeitsverluste selbst, sondern können auch zu anderen gravierenden Problemen, wie Schäden an der Formation, feststecken des Bohrstranges, Bohrloch und den Verlust der Kontrolle über das Bohrloch führen. Der aktuelle Trend in der Industrie fokussiert sich mehr auf das Bohren in Niederdruckzonen, entweder in erschöpften Zonen oder vor der Küste und gerade für diese Projekte hat die Planung von Zirkulationsverlusten eine entscheidende Bedeutung.

Kenntnis über die Art- und Menge von Bohrschlammverlusten kann Ingenieuren helfen, die am besten geeignete und effektivste Lösung im Vorhinein zu wählen. Des Weiteren liefert sie Kriterien um die Wirksamkeit der verwendeten Zirkulationsverlustmethode zu evaluieren.

Das Ziel dieser Studie ist es, die Ergebnisse von verschiedenen LCMs zu evaluieren und zu vergleichen, um den Effekt der Partikelgrößenverteilung “PSD”, der Konzentration und ihre Fähigkeit dem Bohrloch mehr Festigkeit zu liefern, um die Zirkulationsverluste zu mindern, zu bestimmen.

Diese Diplomarbeit wird die verschiedenen Zirkulationsverlustsmechanismen erläutern, wird die Praxis der Stärkung des Bohrloches durch unterschiedlichen Techniken mit Hilfe von LCMs erklären und wird deren Auswirkung auf den Bohrvorgang durch eine reale Fallstudie aus dem Feld aufzeigen, um die Wahrscheinlichkeit von Zirkulationsverlusten zu reduzieren und infolge dessen die unproduktive Zeit und die Gesamtkosten zu reduzieren.

Im letzten Teil dieser Arbeit wird eine Fallstudie präsentiert, mit dem Ziel, die Auswirkung von LCMs auf die Verringerung von Zirkulationsverlusten aufzuzeigen. Der Fokus liegt auf dem Einsparungspotential, das sich ergibt, wenn LCMs im Spülungssystem verwendet werden, um Zirkulationsverlusten entgegen zu wirken.

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1 Introduction and Objectives

During a drilling operation a certain number of unexpected events continue to plague the performance and the progress of the entire drilling operations. One of these events is lost circulation which is considered to create significant loss of time and money. Moreover, if not handled properly it may cause or contribute to other problems such as kicks, formation damage and stuck pipe. Therefore, significant efforts have been invested into understanding the mechanisms behind lost circulation, developing and implementing new steps to mitigate or eliminate it.

In general, there are several adopted techniques used to handle loss of circulation problem for instance, placing a cement balance plug, running an extra isolating casing string, underbalance drilling, drilling ahead, or pumping sacrificial fluids through the thief zone. The selection of any of the aforementioned techniques is highly dependent on the existing well situation considering, characteristics of the loss zone, the depth, type of drilled well and the associated risk. Nevertheless, only two treatments methods exist, proactive “preventive” and corrective. In The proactive method [which is commonly referred to as Wellbore Strengthening (WS)], LCMs are always part of the drilling fluid system. Whereas, in the corrective method, LCMs are pumped separately.

Proactive or WS methods adopt the concept of usage of a pretreated mud to continuously be pumped in order to provide more wellbore strength when there’s no sufficient information about the upcoming to-be-drilled formation. This continuously applied method requires achieving a screen out effect sealing the already existing fractures tips to stop any further fractures propagation and the consequent resultant loss of circulation. In contrast, the corrective method is achieved by batch pumping. It’s a remedial treatment applied after the losses occur. That batch pumping is specified to the lose zone so it requires precise pills/squeezes spotting followed by a careful surface solid removal handling not to lose such valuable and expensive pumped materials.

A wide variety of pumped LCMs are used in both methods, either to seal[1] the fracture tip by self-dehydration (1) which is done in the proactive method or to bridge the fracture mouth as being done in the corrective method.

[1] **Bridging:** It’s a conventional LCM pill action to form a bridge of particles at the fracture mouth or to collect in the interstices of a permeable zone. A bridging agent must contain particles that are no smaller than ½ of the opening size to be bridged.

In a permeable zone each bridge will be required to support only a small fraction of the total pressure drop.

In a fracture, the bridge occurs at the rock face and is required to support the total pressure load.

Sealing: requires that rigid particles (approximately the same size as the fracture) be used as part of the blend

Since different types of LCMs exist, the selection of one or blend of some is not a trivial decision to make and should go through a complete process and planning to select the optimum fit to fix the problem. Thus, as an objective of this study is to evaluate and compare the performance of different LCMs used to determine which material to use and what the effect of size distribution, concentration and type has on their performance to mitigate the problem of lost circulation. The main focus point is on how the various LCMs additives behave with the different mud systems used (namely Oil Based Mud “OBM” and Water Based Mud “WBM”) (2) in order to demonstrate better understanding of LCMs implementation impact as a lost circulation problem solution and to what extent it can affect the whole drilling process timewise and moneywise.

2 Mud Loss Detection and Treatment

2.1 Method and Theory of Detecting Mud Losses

The most commonly used techniques to detect mud losses fall into two categories;

1. Monitoring the level of mud pits with acoustic or floating sensor but only with a small degree of accuracy taking in consideration only the pits surface level
2. Measuring the return mud flow rate using paddles set inside the flow line

This is known as the Conventional methods which provide a simple qualitative fluctuation in mud flow.

Nowadays, an advanced “Multi Phase” flowmeter works on the principle of converting mud flow rate out of the well into an analog signal which represents the volume rate of mud (liters/min). Moreover, it’s equipped with a gas chromatograph so it can measure and analyze the amount of gas in the mud return flow line. Additionally, using a special inserted tool sensitive to abrasion, it can estimate the percentage of presence of abrasive materials, i.e. sand, existing in the return flow.

Those measured volumes of liquid mud, associated gas and produced solids are set in patterns to be examined and analyzed. Providing the increase in resolution of mud flow measurements, it enables engineers to assess the flow quantitatively and be able to relate any mud flow anomalies with the presence of open hole fractures down hole (3).

As a matter of fact, the measuring action depends on the flow rate so the flowmeter performance is not affected by the changes in viscosity and density. That’s why; any existing anomalies in the flow patterns can be related and validated with the surface drilling parameter (i.e. torque). Since, open fractures are observed very often associated with increase in torque and gas indication. Thus, the flow anomalies provide crucial information for early kick or losses detection achieved by monitoring the changes of the mud flow rate in and out, respectively.

Currently through real time advanced delta flow curve (the difference between inflow and outflow volumes) it can be differentiated and distinguished between natural and induced fractures. It can detect and interpret the different formation fractures types with surface logging data and accordingly obtaining the kind of losses in terms of lost barrels and to which sort of lose mechanism it occurred, as shown in Figure 1. The delta flow method has an advantage over other used methods like for instance using a laser sensor to measure the mud level in mud pits which can lead to miss readings considering foamy muds and evaporations.

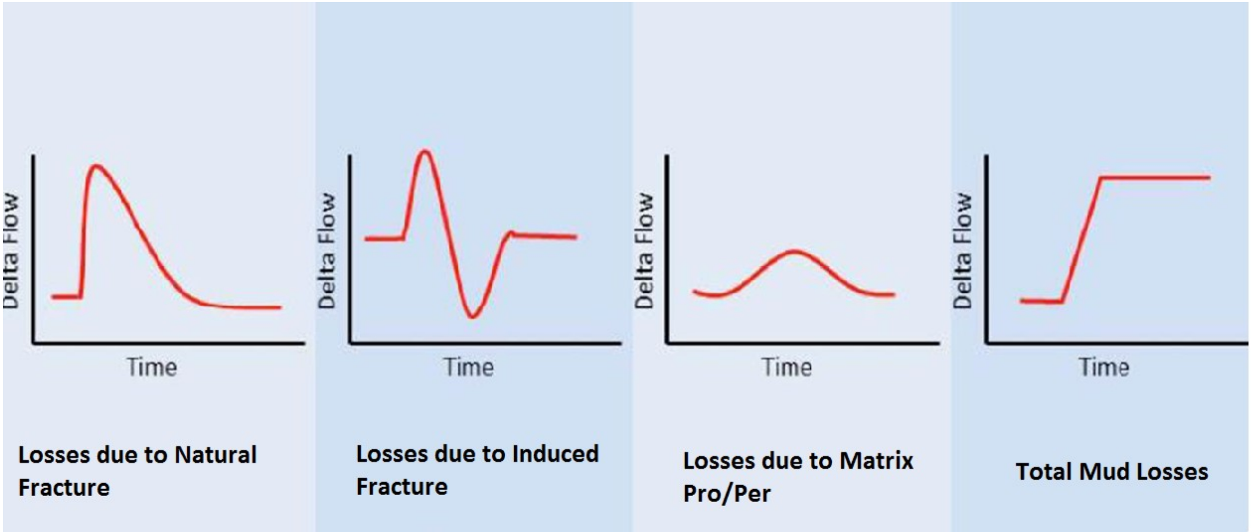


Figure 1. Fluid Losses Patterns Model (4)

In a natural fracture, initially the mud flows into the open fracture tends to concentrate mud solids within the fracture showing sudden increase in delta flow and decrease in flow out followed by a gradual decrease in mud losses because of damage in permeability due to fractures plugged with mud solids.

In the case of losses due to matrix permeability (i.e. porous formations or micro-fractured zones), mud losses gradually increase with penetration, and slowly decrease when the permeable zone finishes and plugging effects take place. In cavernous zones, mud losses start suddenly, at a high rate, with no return to the surface lines.

Through previous examples mud losses occur without any changing in drilling parameters such as weight on bit “WOB”, rate of penetration “ROP”, stand pipe pressure “SPP”, mud weight etc. However, in the case of induced hydraulic fractures variations in some drilling parameters are recorded, allowing these losses to be distinguished from natural ones. Generally, the mud lost in the induced fractures is given back after a short period of time.

Basically, there is a difference in fractures’ behaviors corresponding to the used mud systems. As a matter of fact, that all the treatments are applied through the mud systems, that made it a key factor to understand the different fractures’ behaviors prior to apply the treatment as being explained in the next section.

2.2 Fracturing Behaviors with Different Mud Systems

There's a difference in the fracturing behavior between OBMs and WBMs. Investigations (5) discovered that there is no difference in fracture-initiation pressure for different fluid types and formulation in intact borehole. Apparently, the only factor determining fracture initiation is the wellbore pressure to put the effective near-wellbore stress state in tension. Nonetheless, quite significant differences were observed for fracture propagation behavior, which was found to be highly depended on fluid type and formulation. In particular, higher density WBMs exhibit significantly higher fractures propagation resistance pressures than OBMs, thereby explaining the more-severe lost circulation problems observed with the former in the field, since it occurs at much higher pressures compared to the latter.

This difference is explained by considering fracture-tip screen-out behavior, as shown in Figure 2. When a fracture grows, rapid spurt loss into the new void space and the new fracture faces will occur in most WBMs, leading to a dehydrated plug of fluid-loss-control solids that seals and isolates the fracture tip from full hydraulic mud pressure. The fracture can now only grow if the mud pressure is significantly higher to break through the plug and communicate once again with the tip of the fracture. Every time the fracture grows, the process repeats as the following:

1. Spurt loss occurs
2. Tip sealing by plug
3. Breakthrough of the pressure to tip then fracture growth

Evidently, considerable resistance and inefficiency occurs when fractures grow in WBM, leading to elevated fracture-propagation pressures.

By contrast, OBMs and Synthetic Based Muds (SBMs), exhibit superior matrix fluid-loss control because of their ability to generate internal filter cakes with their inverted emulsions, as shown in Figure 2. This has made OBMs/SBMs the preferred systems to drill depleted formations intersected at high mud overbalance. But their superior ability to protect the drilling operations from bulk fluid loss to formation-matrix (thereby preventing differential sticking problems, since OBMs/SBMs form slimmer filter cakes internally) is in fact their limiting usage factor when it comes to fracture propagation. When a fracture goes in OBMs or SBMs, invert emulsion will quickly seal the newly created fracture faces with only limited spurt loss, but the process still allows full transmission of the hydraulic mud pressure to the tip of the fracture. This direct contact unhampered by the presence of filter cake in the WBM case ensures fracture propagation at a higher pressure than for OBM. As a result, drilling margin in the field will be lower using OBMs as compared with WBM, and important disadvantage of the former when drilling low margin wells.

Several low margin deep water wells were proven to be “un-drillable” with SBMs were successfully drilled to total depth (TD) by switching to WBM and gaining a larger workable drilling margin as a result.

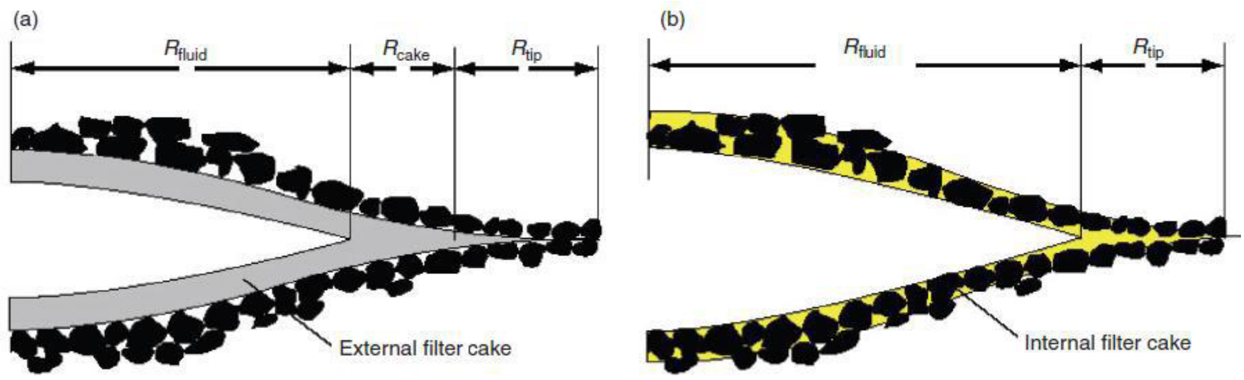


Figure 2. Fracturing Behaviors with Different Mud Systems (6)

Figure **2**.a. Fracture propagation in WBM, showing the buildup of an external filter cake that seals the fracture tip and prevents effective pressure communication, thereby interfering with the fracture extension.

Figure **2**.b. Fracture propagation in OBM/SBMs, allowing for full pressure communication to the fracture tip, thereby facilitating fracture extension at lower propagation pressure than for WBM.

2.3 Mitigating and Recovering Lost Circulation

As mentioned earlier, lost circulation causes serious problems money and time wise in order to have full return of circulation again, several practical steps have been developed by the drilling fluid companies. It is necessary, before going further into wellbore strengthening techniques to explain the essential pre-treatment steps, which are recommended and implemented by drilling fluid companies. The pre-treatment and the treatment steps collectively form the integrated solution. Figure 3 shows one of the proposed road map to achieve full return of circulation.

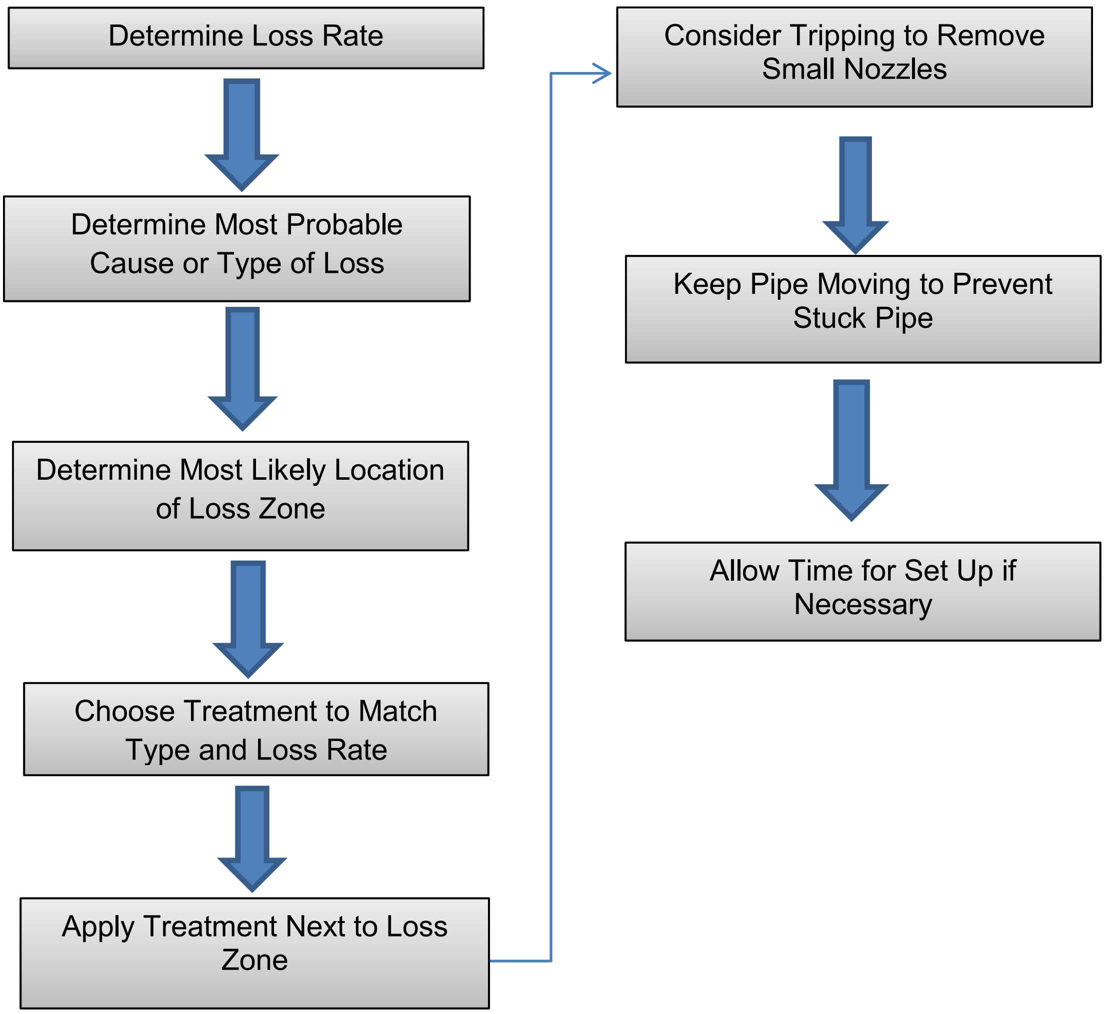


Figure 3. Road Map for Mitigating and Recovering Lost Circulation (7)

2.3.1 Practices Followed to Recover Lost Circulation

2.3.1.1 Seepage Loss (< 25 bbl/hr WBM or <10 bbl/hr OBM)

1. Reduce mud weight and ECD, if possible.
2. Mix fine LCM and drill ahead.
   - Mica, cellulose, nut shells, LCM blends.
   - If seepage loss continues, increase LCM particle size & quantity
   - It may be necessary to change shaker screens to coarser mesh and treat entire system with 20+lb/bbl fine LCM blend (fibers, flakes and granules)
3. Spot LCM pill, pull up and wait.
   - Pill should contain 25 – 50 lb/bbl Medium LCM blend
   - Wait 2 – 4 hours

2.3.1.2 Partial Losses (25 – 100 bbl/hr WBM or 10 – 30 bbl/hr OBM)

Mostly common in the natural Loss Zones.

1. Reduce mud weight & ECD, drill slower, reduce pump rates, lower rheology.
2. Mix LCM and drill ahead. Change shaker screens to coarser mesh and treat system with 15-25 lb/bbl fine LCM blend.
3. Spot LCM pill, pull up and wait.
   - Pill should contain 25 – 50 lb/bbl Medium LCM blend
   - 10 – 30 lb/bbl medium and coarse nutshell
   - 5 – 10 lb/bbl Fine Mica
   - 3 – 10 lb/bbl Fine cellulose

Wait 2 – 4 hours, if losses continue, spot larger volume viscous pill using larger particle size LCM.

2.4 Applying Treatment Methods

In order to put both proactive and corrective approach into practice pills and squeezes are being used as being illustrated below. It depends on to which type of formation losses occur, whether it’s a reservoir zone or non-reservoir zone. Then a selected pill, squeeze or blind of both to be used is decided. This step of applying the treatments only accounts for selecting a type/or several of types to be added to the mud system. Later on, the selection process proceeds with deciding the applied concentration and particles’ sizes.

- Conventional Pills
- High Fluid Loss Squeezes
- Crosslinked Polymer Slurries

2.4.1 Conventional Pills

It's characterized by:

Mixture of types and particle sizes is being used.

- Combination of fibers, flakes and granules
- 4 parts granular, 2 parts fiber, 1 part flake

When using a conventional pill, it may require up to 80 lb/bbl (in some practices) but generally 40 lb/bbl of properly sized LCM will stop losses to permeable or fracture zones. Volume of pill may vary from 20 – 100 bbl depending upon hole size and severity of losses. Also, has to be kept in mind Solids control program may need to be modified to maintain LCM in system and entire system treatments may be necessary to replace materials eroded from the loss zone.

2.4.2 High Fluid Loss Squeezes

This type of treatment is characterized as it loose water quickly and deposit a thick cake of residual solids in the loss zone. So, it's Useful in preventing the extension of natural fractures.

An important element to the success of the high fluid loss treatment is the de-fluidizing stage. The faster the rate, the quicker a sealing foundation will develop. The speed of de-fluidizing can help determine how effective the treatment will be; in essence, the faster the better. As the filtrate is squeezed into the formation and the consolidated matrix of solids increases in thickness, so does the resistance to differential pressure and mechanical force. Hence, its shear strength is considered important and thus it's a key consideration in the development of the high fluid loss material (8).

2.4.2.1 High Fluid Loss Shear Strength

There are differences between cement and squeeze treatments in the way they react under strain. Rigid materials, such as cement, which generally exhibit a high pressure resistance to compressive forces, but with comparatively low shear strength, will ultimately fracture under load if that load is great enough. Conversely, materials such as High-Fluid Loss, that are more compressible but with comparatively high shear strength values will be more cohesive. As the applied force is increased, the treatment becomes more of compacted plug, instead of fracturing like conventional cement. This resiliency gives this novel product an improved ability to withstand the mechanical stresses involved downhole in lost circulation.

2.4.2.2 High Fluid Loss Enhanced Field Placement

The rate of de-fluidizing may also dictate how deep in the fracture the seal forms, and how effective it is the seal (9). When dealing with losses in permeable formations, a drilling fluid may not only have an external cake on the face of the formation, it may also form a filter cake inside any fractures that may be present, inhibiting leak-off into the matrix. Hence, considering to placement should be given. Although, many de-fluidizing treatments can be spotted effectively without need of complicated spacer trains, a pretreatment stage, or perhaps a combined-treatment may offer some advantages, particularly when confronted with Non-Aqueous Fluids (NAF) based filter cake.

To demonstrate this, a series of laboratory experiments (10) were conducted on NAF-Based filter cakes at 200˚F to show the potential benefits of pretreatment for enhanced application of a de-fluidizing pill. For the tests, a 40 lb/bbl un-weighted NAF High-Fluid loss treatment was used, in combination with specially selected solvents and solvent/surfactant blends as a pretreatment. The initial filter cakes were produced under static conditions onto 40-µm aloxite[1] discs at 200 ˚F using low density, low toxicity mineral oil (LTMO)-based field mud (See Figure 4).

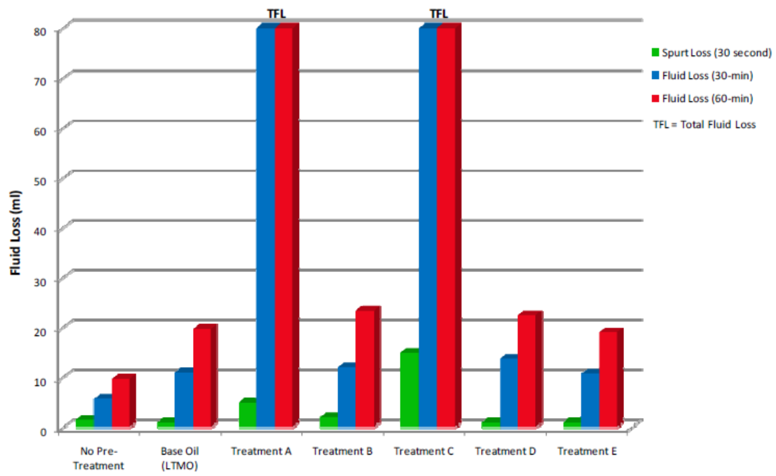


Figure 4. Enhanced Application of High Fluid Loss in NAF-Based Environment Using a Pretreatment Stage (11)

As can be seen from the results in Figure **4**, a selected pretreatment can positively impact the performance of the High-Fluid Loss. The simple base oil treatment does show some improvements in terms of increased overall fluid loss. However, its performance does not compare against those of the specialized treatment solutions. It is also interesting to see that the major benefits occur in the initial minutes of the pretreatment, with little, if any improvements in overall penetration rates over time.

[1] 40-µm mean pore throat size (mercury injection); known previously as 20-µm aloxite discs (to air).

2.4.3 Crosslinked Polymer Slurries

The slurry consists of a crosslinking polymer in composition in addition to bridging agents. It's used in controlling more severe cases of lost circulation as its plug cures to form a rigid gel. This plug can be formed in casing and/or open holes for fluid loss prevention due to excessive hydrostatic pressure.

2.4.3.1 Crosslinked Polymer Application

Set-up times of these slurries are controlled by the bottom hole temperature. For higher bottom hole temperatures, the use of RTR (Supplemental retarder) will be necessary. ACR (Accelerator) is available for cold water applications. It can be used in water or oil base drilling fluids.

Figure 5. Crosslinked polymer Plug (12)

2.5 Lost Circulation Materials (LCMs) Characterization

When lost-circulation zones are anticipated, preventive measures may include treating the mud with lost circulation materials (LCMs), which as indicated in Figure 6 are generally mixed with the drilling mud to seal loss zones as they are encountered. LCMs are commonly categorized as fibrous, flaked, or granular materials and area available in course, medium, and fine grades to seal low-to-moderate lost circulation zones. Conventional, relatively inexpensive LCMs include sized calcium carbonate, paper, cottonseed hulls, nutshells, mica, and cellophane.

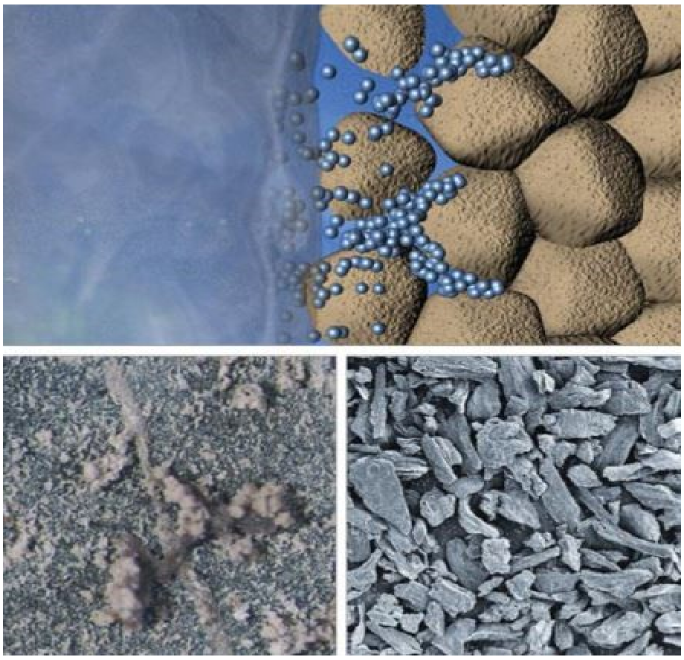


Figure 6. Lost Circulation Material (LCM) (13)

Conventional rock mechanics and hydraulic-fracture theory suggest that it is easier to prevent fracture propagation than it is to plug the fracture later to prevent fluid from re-entering. A LCM that can be carried into the well as part of drilling fluid, without adversely affecting its rheology or fluid-loss characteristics, facilitates the preventive treatment and can mitigate wellbore breathing (ballooning), seepage losses, and/or potential lost circulation when drilling depleted zones.

Mitigation methods for lost circulation focuses on healing the loss zone quickly, which has prompted the development of proprietary LCMs that conform to the fracture to seal off pores, regardless of changes in annular pressure.

2.5.1 Classification of Particles by Shape

Lost circulation materials are classified by shape as follows:

- Fibers
- Flakes
- Granular

2.5.1.1 Fibers:

- Long particles
- Easily deformable
- Absorb large amounts of water to increase viscosity
- Work most effectively in conjunction with granular and flake materials
- Used for seepage losses and as pretreatment in high permeability zones
- Generally used in pill form to correct lost returns and regain circulation

Short weak fibers:

- Rice
- Wood
- Peanut shells

Long sturdy fibers:

- Animal hair
- Nylon

Figure 7. Coarse Sized Fiber LCM (14)

2.5.1.2 Flakes:

- Thin particles with large planar surfaces
- Often effective by themselves
- Can be combines with fibers and granules for treating seepage losses
    i. Polyethylene plastic chips
    ii. Cottonseed hulls fall between the flake and fiber categories since the hull is flake-like and some fibers remain attached to it.

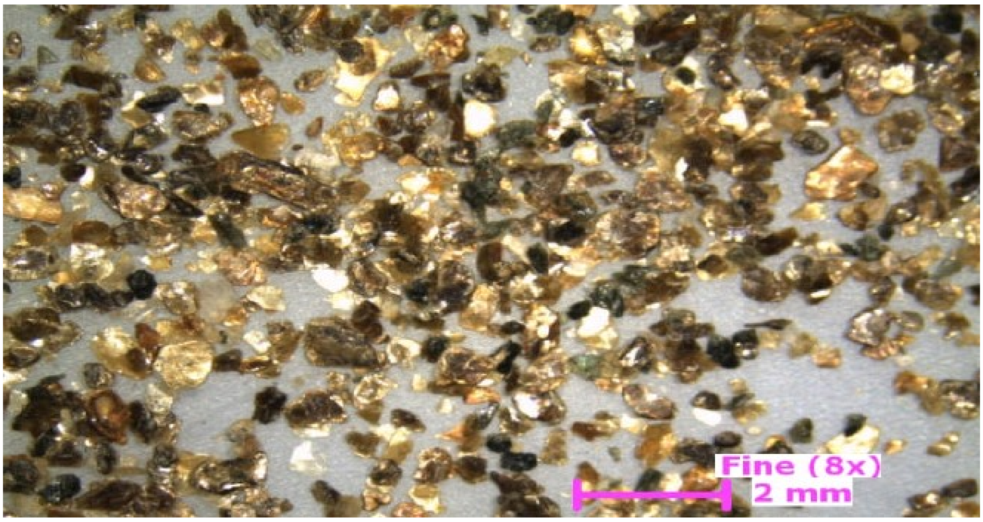


Figure 8. Fine Sized Flake LCM (14)

2.5.1.3 Granules:

- Roundish, rigid shaped particles used as the primary “bridging” agent in curing lost circulation
- Absorb less water than cellulose fibers and are a universally applicable LCM
    I. Graphite
    II. Calcium carbonate

Figure 9. Coarse Sized Granular LCM (14)

Experience in an area will determine the type and combination of materials to use. As there is no universal cure exists for all lost circulation situations. Blends of granular, flakes and fibers are most effective. These materials, if used properly, can seal pores of several millimeters and withstand pressures as high as 1000 psi.

2.5.2 Application of Nano Sized Particles as LCMs

2.5.2.1 Nano Particles (NP)

Particles used in drilling fluids with a size between 1-100 nm are called NPs (Nano particles). The application of NPs in the petroleum industry became significantly popular in different disciplines like: Wellbore strengthening, mud filtration control, wellbore stability and mitigation of pipe sticking. These very small particles can have access to the smallest pores and are also able to seal pore throats even in very-low permeability formation. Figure 10 illustrates the effect of NPs when they are combined with conventional LCM. When only LCM is added to the mud higher particles invasion occurs as a result of loose filter cake. NPs fill in the gaps between the bigger particles creating an effective seal and subsequently preventing particle invasion to the porous media. NPs are also believed to interact with clay particles participating at the initial stage of the filter cake formation creating a thin and very low permeability cake. Due to their ability to form thin, non-erodible and impermeable filter cake, NPs are considered a powerful additive in reducing mud filtration.

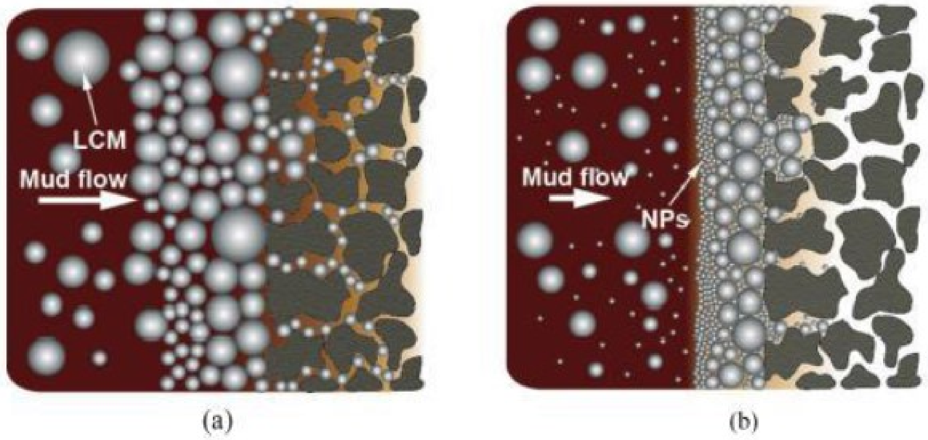


Figure 10. Mud Filtration Using (a) only Conventional LCM and (b) NPs and Conventional LCM (15)

The proposed method incorporates using Silicon nanoparticles in drilling mud composition to decrease the mud cake thickness.

The advantage of Silicon nanoparticles is that, there is formation of more continuous and integrated mud cake. Hence, by having an integrated (having low permeability and low porosity) mud cake, there is less volume of filtrate entering the formation and therefore mud cake thickness is less than in normal cases. The consistent particle size distribution provides better compaction medium with constrained flow of liquid from the drilling fluid. Furthermore, a thinner mud cake reduces the probability of stuck pipe. The addition of Silicon nanoparticles does not have much effect on the drilling fluid viscosity and other properties.

Silicon nanoparticles have thermal stability up to 2500 degree Fahrenheit. Moreover, the use of Silicon nanoparticles does not have side effects on the environment. These nanoparticles are generally immediately available in the required volumes. These require simple application techniques, consequently providing an appropriate solution to problems like stuck pipe and loss circulation while drilling.

The specific gravity of Silicon is 2.33. The atomic weight of Silicon is 28.086 and the atomic number is 14. The diameter of the Silicon particles ranges from 40-130 nanometers. The advantage of Silicon which has nanometer size particles causes to lessen the thickness of the mud cake and hence less amount of the drilling fluid to seep through it.

Using standard filter press the effect of Silicon nanoparticles on reduction of mud cake thickness at 100 psi pressure and 80˚F was as shown in Table 1 below.

Initial mud cake thickness [Inch]	Adding 3%[2] by volume if Silicon nanoparticle to mud [Inch]	Reduction in mud cake thickness [%]
6/32	4/32	34%

Table 1. Mud Cake Measurements of Silicon Nanoparticle

The effect of nanoparticles on mud viscosity and yield point was determined using standard rheometer[3] as shown in Table 2:

Mud Properties	Initial mud at 100˚F	Adding 3% by volume of Silicon nanoparticles to mud
PV, [cp]	28	26
YP, [100 lb/ft2]	5	4

Table 2. Rheological Properties of Silicon Nanoparticles

2.6 Calculating and Spotting a LCM Bridging Plug

2.6.1 Spotting Bridging Plugs in Offshore Operations

For many offshore drilling operations, it's considered a big challenge to precisely spot the correct volume of LCM and protect sensitive directional tools in the bottom hole assembly (BHA) as the daily rate of an offshore operation can easily reach millions dollars per day so precision is a must when dealing with such a time consuming problem. Thus, a loss-control deployment solution is needed to allow for LCM displacement in precise intervals of the loss sections and timely delivery of the materials into the well annulus.

2.6.1.1 Radio Frequency Identification (RFID) Circulation Sub

A circulation sub is a downhole tool that allows a higher circulation rate to be established by opening a pathway from the tool string into the annulus. A various circulation sub tools such as; a pulse-activation sub and a tool activated via a ball drop are solutions lacking. Pulse activation would take one hour or longer to deploy the pulse signal to the tool and required the driller to carefully monitor and maintain downhole pressure within a fairly tight window. Ball drop activated tools impose an inner diameter (ID) restriction on the tool string.

An alternative circulation sub tool was developed that activated via radio-frequency identification (RFID) technology (16). RFID uses radio frequency to transfer data and commands to the tool by pumping RFID tags from the surface and circulating them through the sub. The tags communicate

[2] As the results from the laboratories studies appear valid. However, further investigation is recommended when changing the Silicon nanoparticles concentration to be used on a wider scale.

[3] Fan viscometer was used to measure rheology.

open and close commands to the circulating valve through a signal received by a built-in antenna. The process of deploying a tag and actuating the valve occurs in a matter of minutes, thus allowing the driller to move LCM into the annulus and mitigate a lost circulation event more quickly than with pulse activation methods.

In addition, RFID activation does not impose any restrictions on the ID of the tool.

2.6.1.2 Temperature Activated, Rigid-Setting Fluid (RSF)

If these losses are not controlled in a timely manner during offshore drilling, it can significantly impact the economics of the drilling program as rig time increases. The RSF system has proven successful for curing severe dynamic and static losses by pumping treatments through the drill string (BHA) where no trip out required, because of its highly controllable fast-setting properties, which gives it a big advantage over the conventional use of LCMs and even in the most severe cases when cement plugs are used to stop the losses, as such treatments require pulling the drill pipe out of hole (POOH) and running with a cement stinger, resulting in significant additional cost to the drilling stage (17).

Description of the RSF System

The RSF system is a low-viscosity and temperature-activated with a controlled-right angle set, capable of quickly developing high compressive strength for the near wellbore water and gas shutoff and drilling applications. This system is engineered to remain a low-viscosity fluid during placement. It then sets rapidly at shrinkage during and after the setting process. It is resistant to H_2S and CO_2 degradation. Because of its particle size, the RSF system won't penetrate the matrix of the rock, even in highly permeable formations.

RSF Rapid Setting Properties

The RSF system has a right-angle set, which means the system transition from a liquid to a solid state in a matter of 5 to 10 min, depending on exposure temperature. Figure 11 displays a right-angle set transition time of less than 6 min. Opposed to conventional cement slurries; the RSF system has no static gel state, not allowing migration of fluids in liquid or gas states to pass through it during its transition stage. This is very important property for gas shutoff applications.

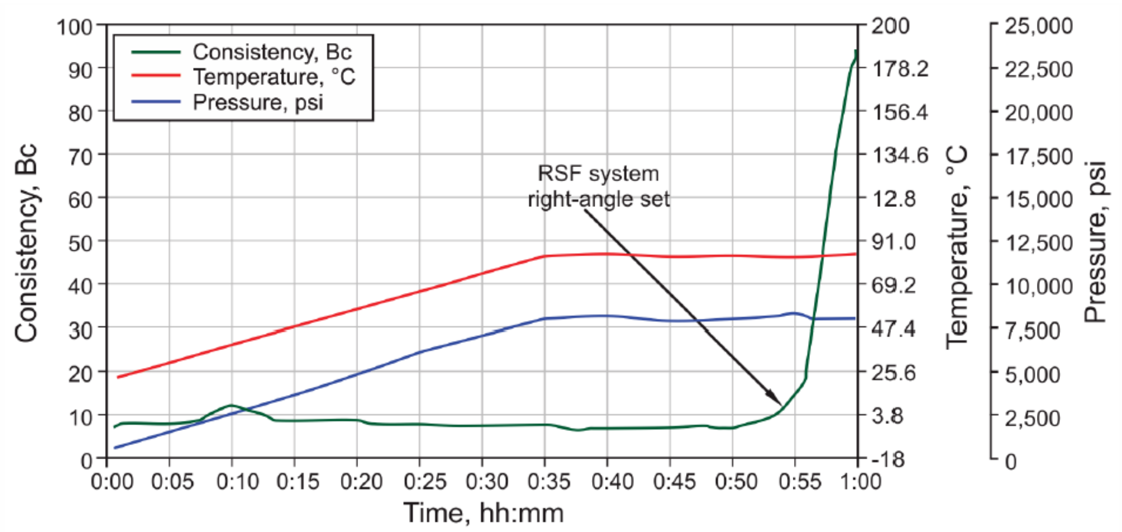


Figure 11. Typical Setting Curve for the RSF System Using a Chandler Consistometer (at 181˚F) (18)

Zero shrinkage

Opposed to conventional cement slurries the RSF system displays zero shrinkage during or after setting.

Controllable and Repeatable Activation to Temperature

The set time of the RSF system can be accurately engineered through the addition of a retarder chemical. In addition, the RSF undergoes an exothermic reaction during its transition period. As Illustrated by Figure 12. The relationship between set time and temperature is linear across the working range of the RSF. This linear relationship provides an element of predictability and reliability when considering the practical use of the RSF.

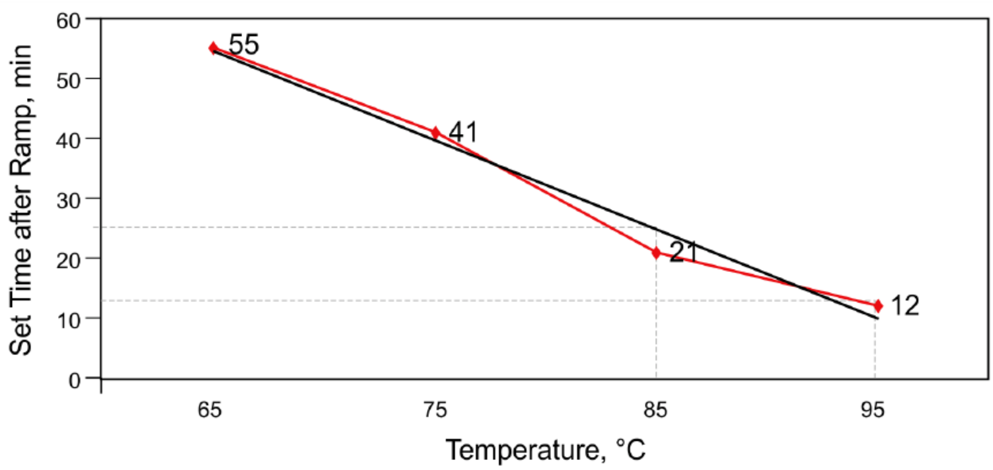


Figure 12. RSF Activation Time: Set Time vs Temperature (18)

Developing a High Level of Compressive Strength Tolerant to Contamination

After the RSF system reaches its right-angle set, it continues to develop compressive strength, reaching an ultimate compressive strength greater than 7000 psi within 24 hr. Standard cement lab equipment is used to measure compressive strength, as illustrated in Figure 13.This natural feature of the RSF is of particular benefit when considering small volume treatments and the unavoidable contamination that occurs at the lead and tail of the treatment during pumping and placement operations.

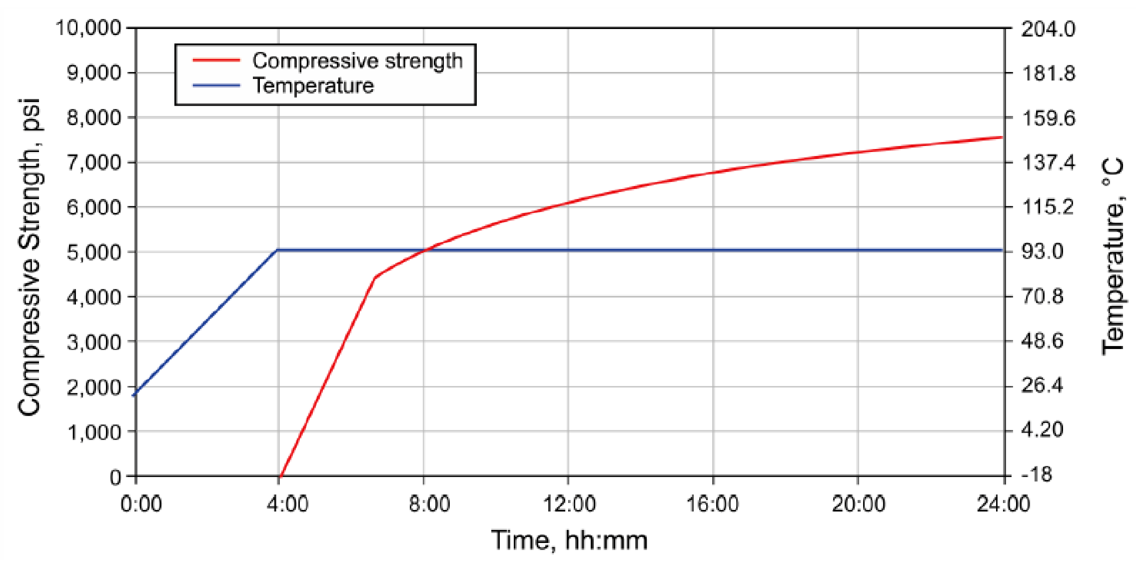


Figure 13. RSF System Rapid Development of Compressive Strength vs Time (18)

Non-invasive

The RSF system has an average particle size of 5 to 10 µm and the RSF system is categorized as non-invasive. As a consequence of its particle size, the application of the RSF as a water or gas sealant is limited to applications, such as: setting plugs behind or between liners and casing strings, sealing off perforation tunnels, or sealing leaking packers (19). The RSF can be removed from the wellbore and formation face by drilling or milling most of the set plug, followed by acid removal of the remaining skin at the formation face, typically with 15% HCL acid.

Field Application of the RSF System

The key to successful application of the RSF is a combination of correctly selected applications and, in particular diligent pre-job engineering. In many cases, the RSF is used specifically for the control it offers related to set time. For instance, when facing a severe lost-circulation problem while drilling, there is limited time for fluid to reach its set point before dropping into the loss zone and becoming ineffective. The challenge for the engineer designing the fluid treatment is to perform lab simulation of downhole temperature and loss rate condition to optimize the RSF set time.

Given the high correlation between set time and downhole temperature, which characterizes the RSF system, a successful intervention outcome is highly depended on establishing two key parameters:

1. The time necessary to pump the RSF in place by whatever placement method is selected.
2. The surface and downhole temperature profiles the RSF will be exposed to during the mixing and placement operation.

Major Field applications are:

- Sever circulation losses
- Eliminating flow of water or gas behind pipe in vertical and horizontal wellbores
- Sealing of fracture communication between injectors and producers
- Sealing casing leaks
- Remedial treatment of failed liner shoe

2.6.2 Placement Procedures of the Balanced Plug

A variety of situations may require a "LCM Bridging plug" be set. In order to calculate how many barrels of LCM pill are needed and how many strokes required displacing the pill, it's discussed below as follows: The upcoming set of equations do not determine "where" to set the balanced plug in the hole as there are several potential places to set the plug to alleviate lost circulation, for instance:

- Place the bit or open end of the drill string at the bottom of the loss zone. This will place the bottom of the plug in the hole at the bottom of the known loss zone and the pill will be pumped up the annulus to cover the loss zone.
- Place the bit or open end of the drill string at the top of the loss zone and spot the plug above the loss zone. This will allow the plug to move down into the loss zone and seal it off as the lost circulation pill invades the loss zone.

There are pros and cons for these and other theories. This discussion assumes the balanced plug will be set with the bit or open end drill pipe at the bottom of the lost zone. However, these calculations apply to any balanced plug.

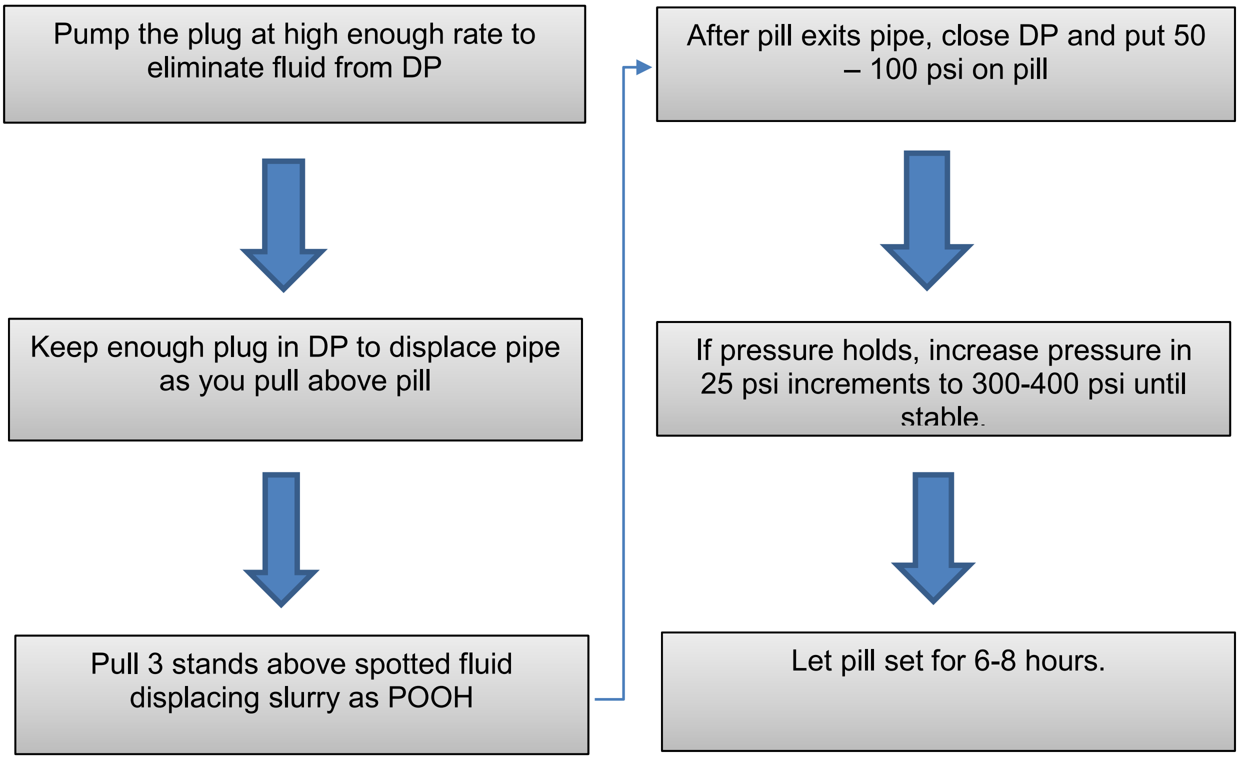


Figure 14. Placement Procedures of the Balanced Plug (20)

The following information will be required to perform these calculations:

- Depth – the depth of the bit or open end drill string, i.e., the bottom of the plug
- Bit size – inches
- Washout factor – expressed as a decimal – 25% washout would be 0.25
- Length of pill – feet
- Drill string data to include:
    - Outside diameter – inches
    - Inside diameter – inches
    - Drill string displacement – bbl/ft
- Pump output – bbl/stk

The following equations will be used for the calculations

- Hole capacity with washout factor – bbl/ft
- Annular capacity with washout factor – bbl/ft
- Drill string capacity – bbl/ft
- Pill length before drill string is pulled – feet
- Volume needed to displace pill – bbls
- Pump strokes needed to displace pill – strokes

2.2.1. Steps to Calculate the Balanced Plug

Step 1:

- Open hole capacity calculations:

$$OH_{\ Capacity}, bbl\ /\ ft\ =\ \frac{[\ ID_H\ x\ (1+WO)]^{\ 2}}{1029{,}4} \tag{1}$$

Step 2:

- Volume of desired pill without drill string:

$$V_{Pill}, bbls = OH\ Capacity\ x\ Desired\ length\ of\ pill \tag{2}$$

Step 3:

- Annular capacity calculations:

$$Annular\ capacity, bbl\ /\ ft\ =\ \frac{[\ ID_H\ x\ (1+WO)]^{\ 2} - OD_{DS}^2}{1029{,}4} \tag{3}$$

Step 4:

- Drill string capacity calculations:

$$DS_{\ capacity}, \text{bbl / ft} \quad = \quad \frac{ID_P^2}{1029.4} \tag{4}$$

Step 5:

- Pill length before drill string is pulled:

$$\text{L Pill with DS, ft} \quad = \frac{V_{Pill}, bbls}{Ann\ Cap,(\frac{bbl}{ft}) + DS_{Capacity},(\frac{bbl}{ft})} \tag{5}$$

Step 6:

- Barrels of mud needed to displace pill

$$\text{bbls to displace pill} = (\text{D}_{\text{Pill}} - \text{L}_{\text{Pill}} \text{ with DS}) \text{ x DS}_{\text{Capacity}} \tag{6}$$

Step 7:

- Pump strokes required to displace pill:

$$\text{Strokes} = \text{bbls to displace pill / PO}_{\text{BBL/STK}} \tag{7}$$

3 Wellbore Strengthening Principle and Mechanisms

According to the published work in the field of wellbore strengthening investigation, reopening pressures were observed to be higher in the presence of WBM as compared to OBM despite experiencing similar fracture breakdown pressure. This phenomenon was explained by the effect of the filter cake and amount of filtrate going into the formation. Analysis also reported that occurrence of peak shapes in the pressure behavior versus time when utilizing WBM. Researches believed that the screen out generated a complete fracture sealing requiring a higher pressure level in order to go through the current fracture tip. It was also stated that more unstable fracture propagation took place on low permeability formations due to the build-up of weaker filter cakes (21).

Before getting into more details explaining the different techniques of Wellbore strengthening, a good understanding to the hoop stress is a key element in comprehending the process as the wellbore strengthening technique never aims to change the mother rock stresses but it's only concern to make the near-wellbore walls withstand more pressures after applying the appropriate treatment. Thus, widens the safe mud pressure window.

3.1 Improving the Wellbore Strength by Managing the Hoop Stress

Hoop stress affects the strength of the wellbore to a great extent and in order to understand such effect, the hoop stress of the wellbore should be estimated subsequently as in the following order proposed by the numerical study presented (22):

a) Before fracture initiation "without crack"
b) After fracture initiation "with crack"
c) After bridging the fracture

Most important, the study of the Hoop Stress changes considering the pore pressure for the three cases mentioned previously.

3.1.1 Hoop Stress Distribution along the Wellbore Wall for Different Bridging Locations

Figure 15, summarizes hoop stress distribution for different bridging locations, with and without pore pressure. The numerical study was conducted using anisotropic stress state, where the maximum horizontal stress (S_{max}) was twice higher than the minimum horizontal stress (S_{max} = 2 S_{min}). Where, S_{min} is the Minimum horizontal stress of 3000 PSI. After bridging the fracture, hoop stress increases on the wellbore near the bridging location for both models. When bridging location is closest to the fracture mouth, hoop stress increase is greater. As bridging location is getting closer to the fracture tip, hoop stress on the wellbore wall less increases.

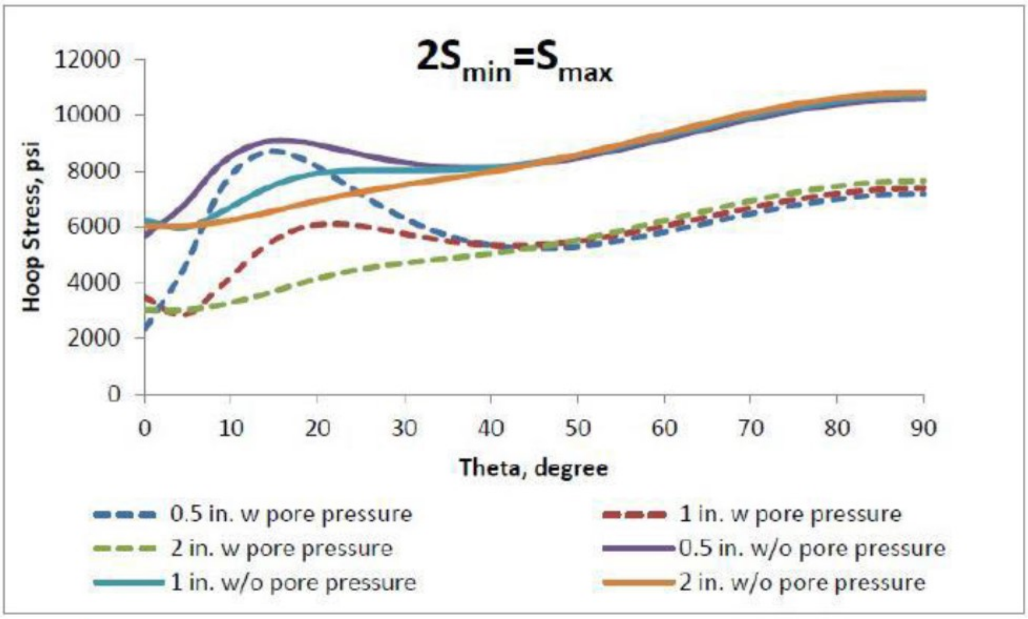


Figure 15. Hoop Stress Distribution along the Wellbore Wall for Different Bridging Locations (23)

From Figure 16, the hoop stress distribution trends are the same for both models with and without considering pore pressure. However, hoop stress in the pore pressure decreases significantly in the direction going away from the fracture direction, owning the initial pore pressure. After bridging the fracture, it is interesting to note that the increase in the hoop stress around the wellbore wall between the degrees of 0 and 30 in the pore pressure model is much greater than that in the no pore pressure model. Thus it is important to account for the pore fluid pressure in strengthening the wellbore.

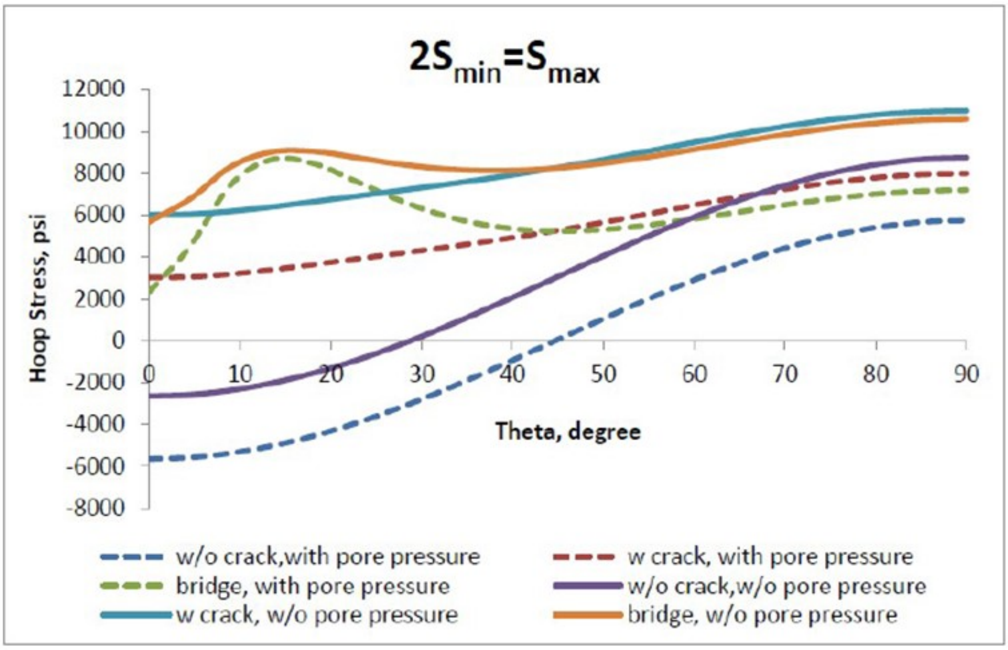


Figure 16. Hoop Stress Magnitude along the Wellbore Wall, with and without Pore Pressure Effect (23)

3.1.2 Hoop Stress Status before and after Bridging the Fracture

Stress contour profiles in the Figures 17 and 18, show hoop stress distribution in the wellbore model before and after plugging the fracture. The red color region represents tension and the blue represents compression.

Figure 17, shows that the maximum tension in the red region is at the fracture tip before bridging the fracture. After applying LCM Bridge close to the fracture mouth as shown in Figure 18, compression is highest in the bridging location, while the tension is widely distributed behind the bridging location.

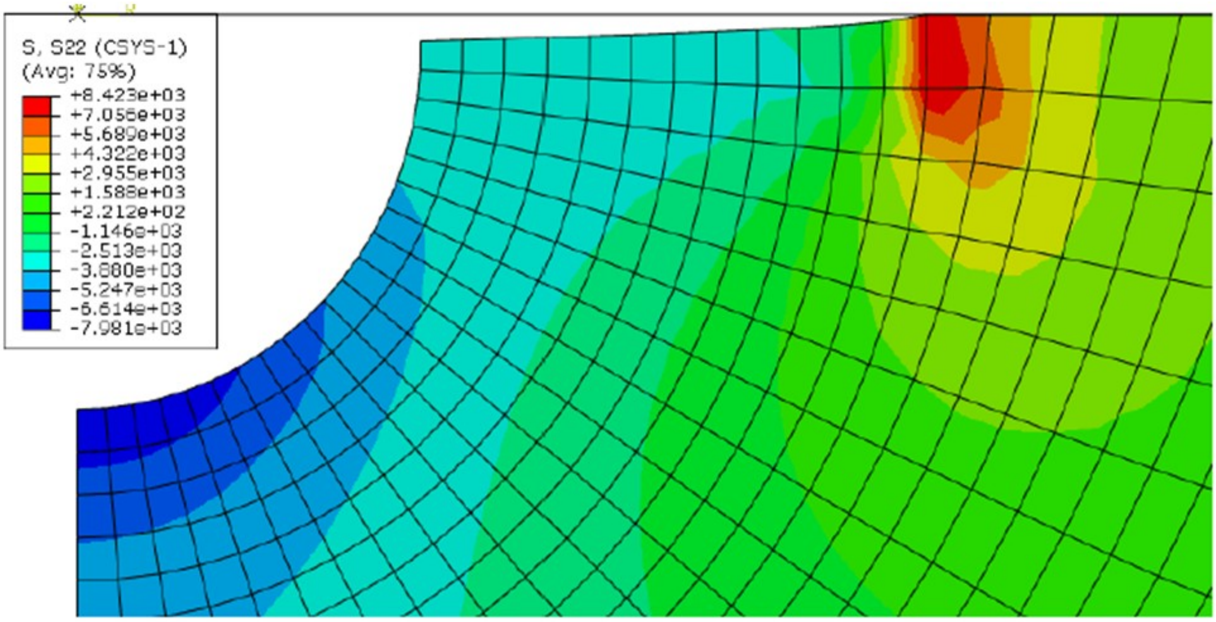


Figure 17. Hoop Stress Contour Profile in Pore Pressure Model before Applying Plugging (23)

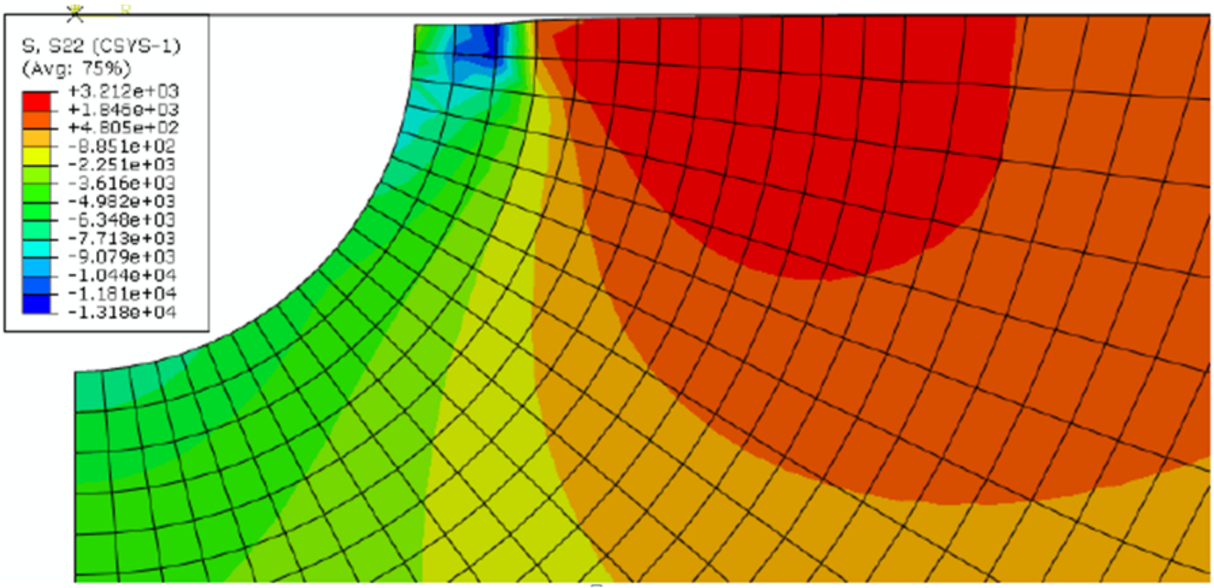


Figure 18. Hoop Stress Contour Profile in Pore Pressure Model after Applying Plugging (23)

3.2 Wellbore Strengthening Mechanisms

Currently, the drilling industry converges mainly on three wellbore strengthening mechanisms: Tip resistance by the development of immobile mass, Stress Caging theory and Fracture Propagation Resistance (FPR).

3.2.1 Tip Resistance by the Development of an Immobile Mass

This mechanism is established on the basis of prohibiting the pressure transmission to the fracture tip by blocking the tip using LCM. The fracture width plays a crucial role as it might be widening when additional pressure is applied in the wellbore and the blocking material is bypassed. When LCM is driven into the fracture, it is believed that an immobile mass can isolate the fracture tip due to the loss (mud filtrate) of its carrier fluid to the formation. Initially there is low resistance to flow into the fracture, however if resistance occurs the back pressure widens the fracture. This elastic growth of fracture width regulates the build-up pressure. Figure 19 shows the phenomenon.

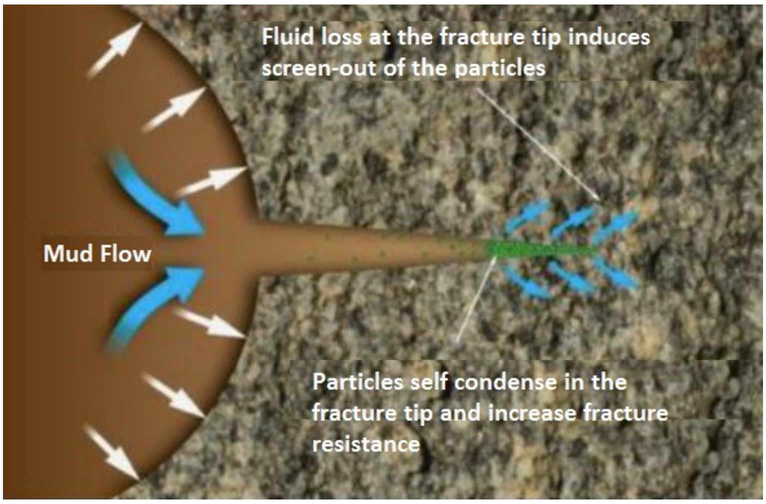


Figure 19. Tip Resistance by the Development of an Immobile Mass (24)

As the fracture is packed back to the wellbore, higher wellbore pressure values are required to continue the fracture extension, which causes wellbore strengthening. Difficulties in the creation of the immobile mass by particles are believed to occur in the very-low permeability formations as the mechanism requires some leak-off. Nevertheless, some material can invade induced and widened fractures in impermeable media.

3.2.1.1 Stress Caging

The Fundamental principal of the stress caging corresponds to the deposit of solids at or close to the fracture mouth to act as both proppant and seal isolation the fluid pressure. Considering a sufficiently permeable formation, the filtrate beyond the blockage will dissipate and pressure in the isolated part of the fracture will reach the same value of the pore pressure and, subsequently, the fracture will close. An increase in the hoop stress is generated when the fracture closes due to the blockage compression. Figure 20**Figure 20** shows the stress caging mechanism. Stress caging has also been reported to be the wellbore strengthening mechanism in shale formations. This approach is based on the transportation of bridging particles that could act as "cement" into the fracture. The solidification will avoid seepage and flow back towards the wellbore.

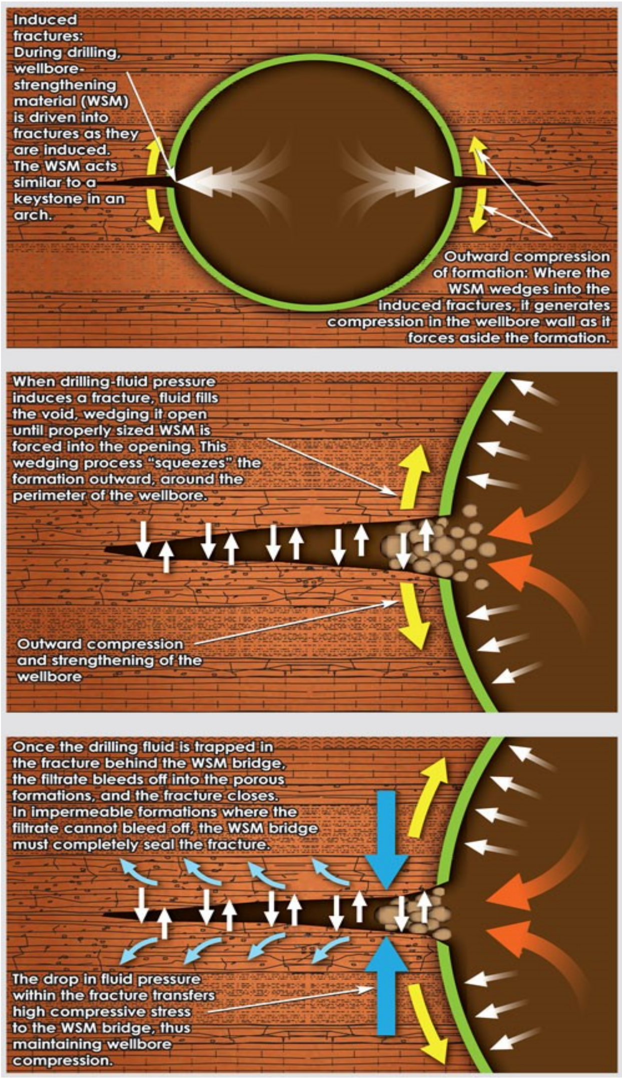


Figure 20. Stress Caging Mechanism (25)

3.2.1.2 Fracture Propagation Resistance (FPR)

FPR aims to increase just the fracture-propagation pressure by means of tip-isolation using specific particulate additives. This opposes the underlying theory behind the tip resistance and stress caging mechanisms that requires an increase in the fracture Initiation pressure (FIP). FPR raises argue that the stress caging or fracture tip resistance should increase the FIP. On other words, an extension of the linear part in the pressure versus time plot resulting from a LOT should be noticed. In contrast, if FPR was the wellbore strengthening mechanism, an increase in FIP should be observed before or after the treatment as illustrated in Figure 21.

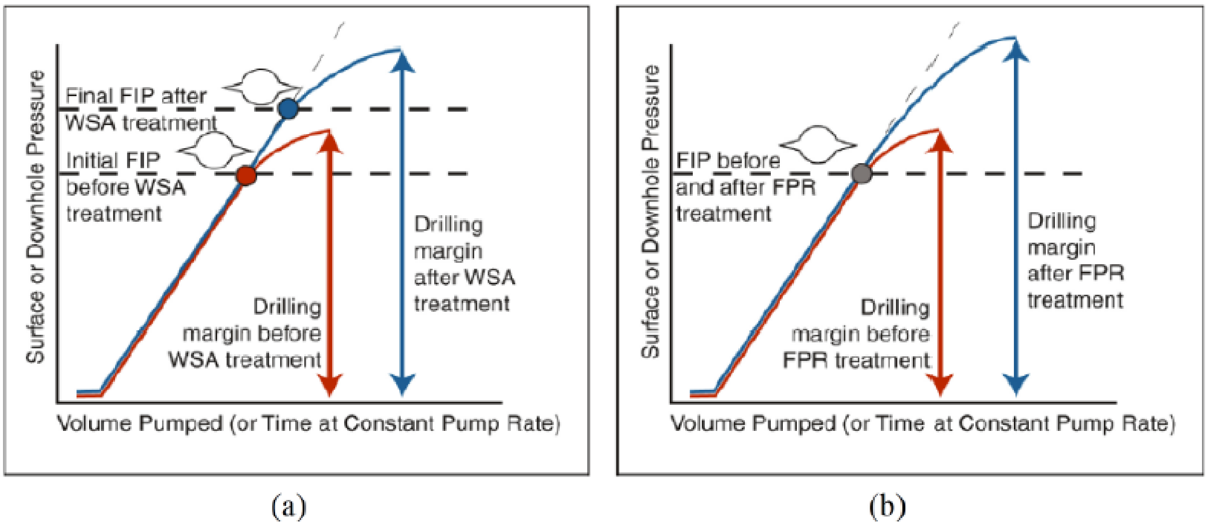


Figure 21. a) Idealized LOT Response that Indicates a Near Wellbore Stress Change that should Result from Stress Caging or Fracture Tip Resistance. (b) Idealized LOT Response after FPR (26)

This Figure, however, may be not explicated enough since mechanisms, tip resistance and stress caging, require the creation of fracture as a prerequisite. Results showed evidence that the FIP didn't increase after a wellbore strengthening treatment and therefore FPR was believed to be the predominant mechanism.

3.3 PSD Simulation to Optimize the Selection of Bridging Particles for Reservoir Drilling Fluids

Aside from minor adjustment of solids loading, the base brine, viscosifer and fluid-loss control additive in traditional reservoir drilling fluid, systems change a little from their original composition. However, the fourth primary component, the bridging particles, is used in a wide range of grades and sizes, depending on the anticipated extent of fluid invasion that must be thwarted. Thus, it's of high importance designing proper particle size distribution. On one hand, it's crucial to minimize the change in mud rheological properties and on the other hand it's the first step towards formulating a minimally invading, non-damaging fluid and optimum best fitting size to plug the existing fractures within the formation.

Abrams' rule (27) has been used for this purpose. This rule states that "the median particle size of the bridging material should be equal to or slightly greater than 1/3 the median pore size of the formation". It goes on to suggest the concentration of the bridging solids must be at least 5% by volume of the solids in the fluid. In terms of particles size this means, for example, those 50µ particles should be effective at sealing pores up to or around 150µ in diameter. However, Abrams' rule only addresses the size of particle required to initiate a bridge. The rule does not give optimum size or address an Ideal Packing Sequence (IPS) for minimizing fluid invasion and optimizing sealing.

3.3.1 Ideal Packing Theory (IPT)

Ideal packing can be defined as the full range of particle-size distribution required to effectively seal all voids, including those created by bridging agents. This subsequent layering of bridging agents results in a tighter and less invading filter cake.

The first step in the process of forming a seal is to define the "worst-case" possibility based on the largest dominate pore size of fracture width. While it is not the preferred method, known permeability of the formation can be used if pore size is not available. If a range of permeabilities is provided the largest value should be used as the aforementioned "worst-case". Median pore size (in microns) can be estimated from permeability by taking the square root of the permeability (in mDarcys). This pore size value is a rough guide to the average or median size of pores, known as the D_{50}. This value can be extrapolated to estimate the largest pore size.

IPT uses either pore sizing from formation analysis or permeability combined with PSD of the bridging materials to determine the IPS.

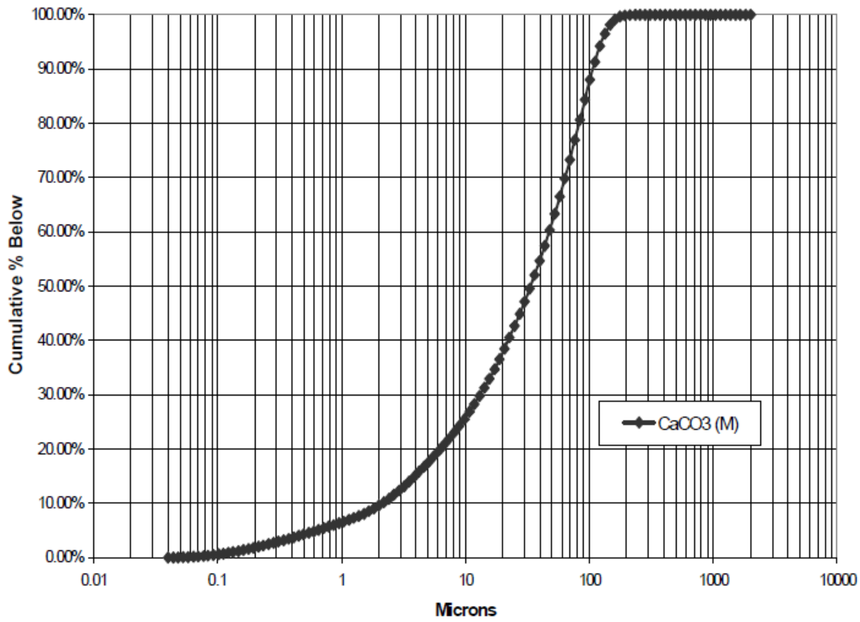


Figure 22. Conventional PSD Curve for Drilling Fluid Using Solid Bridging Material such as Calcium Carbonate (28)

Figure 22, shows a conventional PSD for solid bridging material, generally, the cumulative curve forms as S-shape when plotted on semi-log coordinates. The S-shaped curve merely indicates the range of particles present. It does not estimate the packing efficiency of the particles when they interact to form a filter cake. However, Kaeuffer (29) employed theories for particles to generate a simple IPT, known as the $D_{1/2}$ rule. This essentially a tool where by particle size data can be used to select the optimum particle size, which produces a cake with minimum void space. This rule states that ideal packing occurs when the percent of cumulative volume versus the $D_{1/2}$ forms a straight line relationship, where $D_{1/2}$ is square root of the particle diameter.

In reality, no single bridging agent exactly matches the optimum target line. However, by blending the different bridging agents, a more ideal formulation can be obtained for particular reservoir see Figure 23. To attain ideal packing, the PSD lie of the bridging material should be approximately the slope of this formation's optimum line. Preferably, the optimum blend line should remain slightly below (to the right of) the reservoir optimum target line. During the drilling process, natural attrition and the incorporation of drilled solids cause the blend line to shift upwards and to the left. This is normally treated in location by systematically adding the largest bridging particle, as stipulated in the formulation.

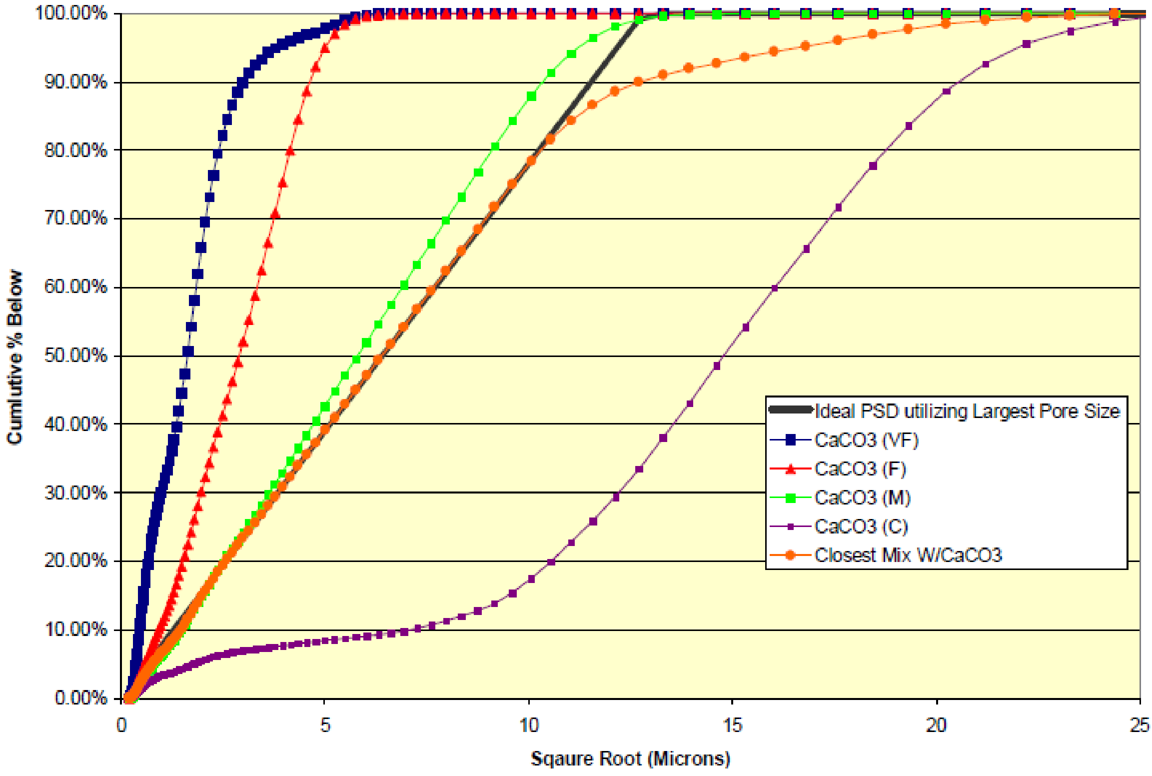


Figure 23. Best Mix of Particle Sizes with Calcium Carbonate to Seal 133-Micron Pore Size (30)

4 Drilling Fluids and LCM Compatibility with Reservoirs to Mitigate Formation Damage

The ground working mechanism of LCM when applied to fix a loss circulation problem is to seal the fractures in the formation by forming internal or external filter cake depending on the type of drilling fluid used. Afterwards comes the most important part, since the treatment is set and been effective to reduce and mitigate the losses, which is removing LCM to restore again the productive permeability of the formation allowing formation fluids to flow back again.

Formation damage is usually a result of the invasion of filtrate and solids during conventional overbalanced drilling and workover operations. In most cases, the damage is limited to the near-wellbore region and can reduce productivity because of decline in effective permeability. Permeability impairment from filtrate and solids invasion could be caused by a variety of damage mechanisms, such as blockage of pore throats by solids, reduction in relative permeability to hydrocarbons because of change in saturation, and phase blockage or clay swelling in the formation. The severity of the damage increases with the well complexity as the greater the depth the higher overbalanced and the longer the exposure of formations to drilling fluids (31).

Significant research has been done to understand, differentiate and alleviate the formation damage scenarios resulting from particle and fluid invasion. Migration of filter cake particles in to the near wellbore pores that leads to the formation of initial filter cake may result in irrevocable permeability impairment because of the difficulty associated in removing the internal filter cakes (32).

It is imperative to protect the interconnected producing flow paths of fractures and vugs. It is also worth considering that in the case of formations with high permeability and fractures, both particle and fluid invasion could take place resulting in more severe formation damage. The fine layer of internal residual solids is the prime culprit for the impairment of near wellbore flow potential.

Hence, in the formation with high permeability and large fractures it is always desirable to minimize, as far as possible, the invasion of both particles and fluids by plugging or bridging the formation pores or fractures. It is generally the combinations of LCMs rather than just one single type which give the best results in containing the mud losses. The optimal application consists of the combination of ground marble $CaCO_3$ (GM), unique resilient graphitic carbon and fibers with relatively large aspect ratios (33) as the best solution in arresting lost circulation.

4.1 Plug Permeability Test (PPT)

A specialized apparatus used in the particle-plugging test. The plug permeability apparatus (PPA)[1] (34) is used to determine the ability of particles in the drilling fluid to effectively bridge the pores in the filter medium and, therefore, the ability of the mud to reduce formation damage in the reservoir.

Customized PPT was conducted specifically for the case study mentioned later on. The tests objective and main purpose, on one hand, was to find the optimal mixture of LCM to minimize the fluid formation invasion and consequently the formation damage as much as possible. On the other hand, it provides a practical evidence for the previously mentioned theory of the necessity to decrease formation damage with used mud system and its additives to the lowest possible value.

Taking a closer look into the PPT results[2],it can be seen that using OBM without any additives of LCM resulted in higher invasion tendency represented by the highest filtrate value of 16 ml. that's why, using OBM program that way will most probably cause severe formation damage. Consequently, that result was not accepted and modifications on the OBM had to take place in order to decrease the formation damage to the lowest possible value. Thus, tests carried on with customized OBM introducing LCM combined with Nano-particles to enhance the plugging performance and decrease the fluid invasion.

Since, the customized OBM with medium LCM combination and NP showed the less tendency to cause fluid formation invasion it was used to plug the well at the 12 ¼ " hole section. As a result of precise LCM application significant savings were achieved in that hole section.

4.2 Remedial Treatments

The corner stone in the treatment is to be able to remove the plugging materials after fractures are plugged and losses have stopped. Biotechnology has incorporated in the development of improved damage removal systems. The polymer specific reactivity of the new systems provides environmentally safe polymer degradation without causing damage to the formation or tubular goods. Applying such systems is known as "Remedial Treatments".

Polymer specific systems have been developed for removal of damage caused by polymers such as cellulose and starch. The treatments can be applied over a wide range of downhole conditions to polymeric damage resulting from fracturing, gravel packing, or workover operations. Fracture

[1] Appendix A shows PPA
[2] Results are presented in the experiments chapter

conductivity and core flow evaluations have shown that multi-fold improvements in permeability and well productivity up to three-fold are achieved with the new systems.

Polymeric damage in many cases is due to insufficient degradation of drilling, completion, or stimulation fluids and the dynamically formed filter cake on the formation face (35).

A filter cake is a dense, practically insoluble concentration of polymer deposited on the fracture face. The presence of filter cake may impede flow, dramatically reducing the productivity of the well. The concentration of polysaccharides within a filter cake can range from about 10 to greater than 25 times the surface polysaccharide concentration of the treatment. The obvious goal, therefore, exists to reduce or remove the polymeric damage in order to obtain the optimum productivity.

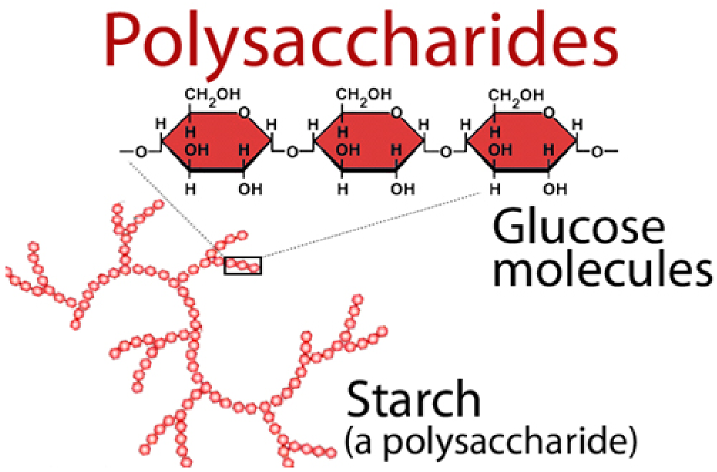


Figure 24. Polysaccharides (Polymeric Damage Material) (36)

4.2.1 Acid Soluble-non-Damaging-Material

1. Ground Marble Only

Particles like GM alone might be good enough in arresting fluid loss, but in the case if highly permeable formations or formations with large fractures or vugs, they often fail, particularly if a wide particle size distribution (PSD) is not maintained (See Table 3. Test Results on GM Only).

Test #	Combination	Conc. [lb/bbl]	Fluid Loss	Observations
1	GM 1200	60	No Control	No control could be mainly because of insufficient PSD

Table 3. Test Results on GM Only

There are many instances where the combination of GM and resilient graphitic carbon is reported to perform better due to the synergetic effect between the two. But in case of reservoir zones, operators usually tend to recommend the use of particles that minimize the formation damage which is usually equated to "Acid Soluble" materials. GM is, as for now, the most widely used as acid soluble-non-damaging-material in the reservoir zones.

2. Ground Material and Fiber Combinations

The combination of GM and fibers was not successful in arresting mud losses through the apparatus tapered slot.

The probable reason for this uncontrolled fluid loss may be the insufficient fiber length or insufficient concentration of fibers of that particular length to form a formidable plug along with the particles in the slot. On the other hand, the combination in which the fiber length was in the order greater than 2000 microns worked well at the concentration of 1.5 lb/bbl that resulted on complete 100% filling of the tapered slot with controlled mud losses. This may also be a further indication that a broad PSD is required for optimum plugging.

Test #	Combination	Conc. [lb/bbl]	Fluid Loss	Observations
1	GM 1200/PLA Fibers-1	60/1.5	No Control	
2	GM 1200/PLA Fibers-2	60/1.5	25 ml 28 ml	Slot 100% filled. very firm plug

Table 4. GM and Fibers Test Results

3. Drilling Fluid Hot Rolled at 225˚F with Particles and Fibers

When hot rolling the drilling fluids to 225˚F for a period of 16 hours then after cooling measuring the pH. It was found that pH dropped significantly compared to the base fluid after hot rolling.

Worth mentioning there was still no control on the fluid loss but at the temperature there were "no fiber" visually observed in the slot as it was partially filled with GM particles alone. This observation could indicate probable degradation of the fibers at/or around 250˚F.

Bottom line, combination of acid soluble-non-damaging materials like GM and fibers would be the best possible solution that can be used in the formations with high permeability and large fractures. Once the job of the LCM combination, to alleviate complete fluid loss, is achieved, fibers would degrade to release acid and which in turn could have the potential of dissolving some of the GM particles

4.2.2 Enzymatic Degradation

As mentioned in the previous section, acid soluble-non-damaging-materials are being used to remove damage in an effort to increase well productivity after the treatment to alleviate loss of circulation (37). These treatments are followed by remedial treatments which include either strong acids or oxidizing materials to affect polymer degradation and removal. While the conventional treatments have resulted in some marginal success, the non-specific chemical reactivity of the components has limited their widespread application. Some formations are acid sensitive. Formation damage can occur from incompatibility with undesirable acid reaction products, and acid contact can cause corrosion of tubular goods. These techniques are not directed to the polymers that caused the damage.

One remedial treatment employs fluoride ions and a combination of oxidative salts, including ammonium persulfate. Free fluoride ions can react with the metals in the tubing and calcium ions in the formation forming calcium fluoride, which precipitates in aqueous solutions and can damage the production zone. Another drawback is that oxidizers and acids may be consumed in the many different, competing reactions occurring downhole, reducing their availability for polymeric degradation.

4.2.2.1 Enzymes Advantages over Acid Soluble Materials

Unlike acidic or oxidative processes, the enzyme systems are environmentally friendly and non-reactive with anything other than the targeted polymer. Enzymes exhibit the unique ability of not changing their structures during the reactions they initiate. Enzymes are also known for their tendency to catalyze the initiating reactions at extraordinary rate "turnover number".

This unique property of "turnover number" indicates that when for instance, one of the selected enzymes has a turnover number of 1,100,000, it could turn over or cleave 1,100,000 linkages of substrate per minute. A great many more can be cleaved over the "life-span" of the protein. Conversely, one molecule of ammonium persulfate can only initiate two reactions.

4.2.2.2 Degradation Theory

The conventional enzyme degradants used in this industry are non-specific enzyme-substrate mixtures that randomly hydrolyze the base polymer. The random hydrolysis results in partial degradation of the polysaccharide into predominantly short-chain polysaccharides with minority concentrations of monosaccharides and disaccharides. The crosslinkable short-chain polysaccharides are relatively insoluble and, therefore, may cause significant permeability damage. This supports part of the "Lock and Key" principle of enzyme mechanisms. Once the lock (polymer linkage) has been changed (by non-specific enzymes or oxidizers), the less likely the key will open or cleave properly.

The developed systems utilize polymer specific enzymes, which only cleave specific linkages in the polymer structure, thereby degrading the polymer to non-reducing sugars, mostly monosaccharides and disaccharides.

Enzyme complexes have recently been developed to address cellulose-based, and starch-based residual polymer damage. Each particular polymer specific system was identified and optimized for its ability to hydrolyze specific linkages within the target polymer chain.

4.3 Field Application

The reaction of the treating fluid must be controlled so as to achieve maximum penetration and thus degrade as much of the damaging polymer as possible. If the reaction rate is too rapid, a leak off control problem may occur due to the near wellbore filter cake being degraded before sufficient penetration is achieved. Most treatments to date have been foamed to aid in diversion and penetration.

Field application of the new treatment was observed to more than double the production of a well which exhibited symptoms of polymeric damage after a hydraulic fracturing/LCMs treatments.

5 Experimental Study to Evaluate LCMs Performance

Conducted experiments in the laboratory, using High Pressure High Temperature -HPHT- filter press, were done using Bentonite Mud, Polymer Mud and OBM of different compositions. As shown below in table 5, The Bentonite Mud had mainly bentonite as a weighting agent. Polymer mud had potassium carbonate mainly for weighing in addition to citric acid for PH control especially for cementing jobs. OBM used was of 80/20 oil water ratio of diesel to water.

The objective of this study is to evaluate and compare the performance of different LCMs to determine the effect of Particle Size Distribution “PSD”, concentration and type on their performance to provide more wellbore strength and mitigate loss circulation of drilling fluids.

5.1 Experimental Set-up

A standard High Pressure High Temperature [HPHT] filter press was used to conduct the experiments. As shown on Figure 25 , the apparatus consists of a controlled press source (CO_2), regulators, a drilling fluid cell able to contain working pressures from 600 psi up to 1800 psi, a system for heating the cell, a pressurized collection cell able to maintain proper back pressure, in order to, prevent flashing or evaporation of the filtrate, and a suitable stand. The drilling fluid cell has a thermometer well, oil resistant gaskets, a support for filter medium and a valve on the filtrate delivery tube to control flow from the cell. Ceramic discs API 50 were used as filtration media.

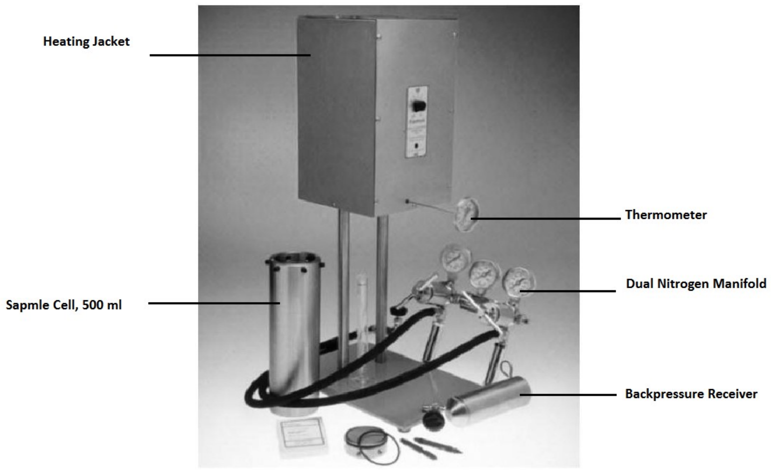


Figure 25. Main Components of High Pressure High Temperature Filter Press used to Conduct the Experiments

The technical specifications of the apparatus can be seen in Table 5.

Category		Specification
Maximum Temperature		500° F [260° C]
Maximum Pressure	Cell Pressure	1800 Psi [12.4 MPa]
	Back Pressure	750 Psi [5.17 MPa]
Cell Volume		500 ml
Receiver Volume		100 ml
Filtering Area		3.5 in^2 [22.58 cm^2]
Heating Capacity		800 watts
Pressure Connection		Nitrogen or Carbon Dioxide
Power Requirement		115/230 VAC, Frequency 50/60 Hz

Table 5. Technical Specifications of High Pressure High Temperature Filter Press

5.1.1 Tests Procedures

Tests were done according to API RP 13B-1, as follows:

1. Heating jacket should be heated to 6˚C (10˚F) above the desired temperature.
2. Drilling fluid sample is stirred in the high speed mixer for 10 min. Bottom valve of the drilling fluid sample cell should be closed when pouring the sample into the fluid cell, care should be taken not to fill closer than 1.5 cm (0.6 in) from top to allow for expansion, and then ceramic disc is installed.
3. The cell is completely assembled when both bottom and top valves are closed, then it should be placed in the heating jacket.
4. High pressure collection cell should be connected to the bottom valve and locked in place.
5. pressure regulated source should be connected to the top valve and collection cell, and locked in place.
6. Keeping the valves closed, top and bottom regulators have to be adjusted to (100 psi). Top valve then is opened to allow applying (100 psi) to the drilling fluid. Pressure should be maintained until the desired temperature is stabilized. The sample in the filter cell should never be heated for period exceeding a total of 1 hour.
7. When the sample reaches the selected test temperature, the pressure of the top pressure unit should be increased to (600 psi) and bottom valve should be opened to start filtration. Filtrate is collected for 30 minutes.
8. Correction of the filtrate volume to the filter area of 45.8 cm^2 (7.1 in^2) is done by doubling the filtrate volume recorded.

9. At the end of the test, top and bottom valves of the drilling fluid cell are closed and pressure is bled from the regulator.
10. Cell is removed from the heating jacket, first certain should be made that the bottom and top valves are tightly shut and the pressure is off the regulators. Using extreme care to save the ceramic disc, cell then is placed upright, valve is opened to bleed the pressure from the cell contents. Filter cake on the ceramic disc is washed with gentle stream of water.
11. Thickness of the filter cake should be measured and reported, to the nearest millimeter.

5.2 Fluid Description

Mud System	Base Fluid	Additives	Function
Bentonite	Water	Bentonite	Weight agent
Polymer Mud	Water	K_2CO_3	For Inhibition, weighting
		Flowzan	Viscosity agent
		Polypac UL	Fluid loss agent
		Citric Acid	pH control
OBM	Diesel/water	SULPHONATED ASPHALT	Shale Inhibitor
	OWR (80/20)	LIME	Alkalinity Control

Table 6. Drilling Fluid Systems Compositions

The different used mud systems were tested once as plain muds and once with the addition of Lost circulating materials (LCMs). As, plain muds didn't contain any additives in terms of LCMs on the contrary to the other mud groups which contained 5,10,15,20 lb/bbl of LCM, respectively.

5.2.1 Chemical and Physical Properties[1] of LCMs

Physical Properties

Hardness: MOHS 3

Specific Gravity (ISO 787/10): 2.7

PH in water solution (ISO 787/9): 9 ±0.5

Loss on ignition (ISO 32662): 43.8%

[1] Values stated for chemical and physical properties of LCMs used are average values as provided from MI-SWACO Company

	Type	Size range	Mean particle size	Oil absorption (ISO 787/5)	Tamed apparent density	Chemical Composition[2]
MI-KHART 40	Fine	0-160 µm	30	<10	1.4	**$CaCO_3$ 99.1%** **$MgCO_3$ 0.8%** **Fe_2O_3 0.03%**
MI-KHART 130	Medium	60-400 µm	140	<10	1.7	
MI-KHART 0.5-1.5	Granular	0.63-1.8 mm	N/A	N/A	N/A	

Table 7. Lost Circulation Materials Properties

The used LCMs fall into 3 main categories with respect to size, as follows:

- Fine this is in range of 0-160 µm.
- Medium this is in range of 60-400 µm.
- Granular this is in range of 0.63-1.8 mm.

[2] Chemical Composition is the same for all the LCM used

Parameter	Additives	Size	LCM Concentration [lb/bbl]	FLUID
Bentonite Mud	-	-	-	**1**
Bentonite Mud	MI-KHART 40	Fine	5	**2**
Bentonite Mud	MI-KHART 40	Fine	10	**3**
Bentonite Mud	MI-KHART 40	Fine	15	**4**
Bentonite Mud	MI-KHART 40	Fine	20	**5**
Bentonite Mud	MI-KHART 130	Medium	5	**6**
Bentonite Mud	MI-KHART 130	Medium	10	**7**
Bentonite Mud	MI-KHART 130	Medium	15	**8**
Bentonite Mud	MI-KHART 130	Medium	20	**9**
Bentonite Mud	MI-KHART 0.5-1.5	Granular	5	**10**
Bentonite Mud	MI-KHART 0.5-1.5	Granular	10	**11**
Bentonite Mud	MI-KHART 0.5-1.5	Granular	15	**12**
Bentonite Mud	MI-KHART 0.5-1.5	Granular	20	**13**
Polymer Mud	-	-	-	**14**
Polymer Mud	MI-KHART 40	Fine	5	**15**
Polymer Mud	MI-KHART 40	Fine	10	**16**
Polymer Mud	MI-KHART 40	Fine	15	**17**
Polymer Mud	MI-KHART 130	Medium	5	**18**
Polymer Mud	MI-KHART 130	Medium	10	**19**
Polymer Mud	MI-KHART 130	Medium	15	**20**
Polymer Mud	MI-KHART 0.5-1.5	Granular	5	**21**
Polymer Mud	MI-KHART 0.5-1.5	Granular	10	**22**
Polymer Mud	MI-KHART 0.5-1.5	Granular	15	**23**
OBM	-	-	-	**24**
OBM	MIL-Carb 25	Fine	5	**25**
OBM	MIL-Carb 150	Medium	5	**26**

Table 8. Fluid Packages of Tested Drilling Fluids

5.3 Rheology

The densities of the Bentonite Muds (fluids 1-13) are shown in Table 9:

Parameter	Unit	Fluid 1	Fluid 2	Fluid 3	Fluid 4	Fluid 5	Fluid 6	Fluid 7
Density (ρ)	[ppg]	8.95	9	9.08	9.1	9.13	9.02	9. 08

Parameter	Unit	Fluid 8	Fluid 9	Fluid 10	Fluid 11	Fluid 12	Fluid 13
Density (ρ)	[ppg]	9.05	9.08	9.02	9.08	9.1	9.12

Table 9. Bentonite Mud Densities

The densities of polymer Mud (Fluids 14-16) and OBM (Fluids 24-26) are shown in Table 10 and Table 11 respectively.

Parameter	Unit	Fluid 14	Fluid 15	Fluid 16	Fluid 17	Fluid 19	Fluid 18	Fluid 20
Density (ρ)	[ppg]	9.03	9.18	9.21	9.24	9.05	9.12	9.18

Parameter	Unit	Fluid 21	Fluid 22	Fluid 23
Density (ρ)	[ppg]	9.03	9.18	9.21

Table 10. Polymer Mud Densities

Parameter	Unit	Fluid 24	Fluid 25	Fluid 26
Density (ρ)	[ppg]	10.9	10.93	10.95

Table 11. OBM Densities

5.4 Viscometer Measurement

For rheology evaluation viscometer measurements according to **API RP 13B-1** have been conducted. Bingham model was applied to the Bentonite mud, Polymer mud and OBM to calculate plastic viscosity and yield point. Equations for Bingham model:

$$\boldsymbol{PV} = \theta_{600} - \theta_{300} \tag{8}$$

$$\boldsymbol{YP} = \theta_{600} - \boldsymbol{PV} \tag{9}$$

The gel strength was measured after 10 seconds and 10 minutes with viscometer at 3 RPM.

Parameter	Unit	Fluid 1	Fluid 2	Fluid 3	Fluid 6	Fluid 7	Fluid 10	Fluid 13
θ_{600}	[lbf/100ft^2]	9	10	11	8	9	8	9
θ_{300}	[lbf/100ft^2]	6	7	8	5	6	5	6
PV	[cP]	3	3	3	3	3	3	3
YP	[lbf/100ft^2]	3	4	5	2	3	2	3
GS (10 s)	[lbf/100ft^2]	3	4	4	3	4	3	3
GS (10 min)	[lbf/100ft^2]	5	5	6	4	5	5	5

Table 12. Viscometer Readings, Calculated Plastic Viscosity, Yield Point, Gel Strength of Fluids 1:13

Parameter	Unit	Fluid 14	Fluid 16	Fluid 18	Fluid 23
θ_{600}	[lbf/100ft^2]	27	75	62	76
θ_{300}	[lbf/100ft^2]	18	52	42	51
PV	[cP]	9	23	20	25
YP	[lbf/100ft^2]	9	29	22	26
GS (10 s)	[lbf/100ft^2]	4	9	6	9
GS (10 min)	[lbf/100ft^2]	5	11	8	11

Table 13. Viscometer Readings, Calculated Plastic Viscosity, Yield Point, Gel Strength of Fluids 14:23

Parameter	Unit	Fluid 24	Fluid 25	Fluid 26
θ_{600}	[lbf/100ft^2]	51	51	47
θ_{300}	[lbf/100ft^2]	28	29	25
PV	[cP]	23	22	22
YP	[lbf/100ft^2]	5	7	3
GS (10 s)	[lbf/100ft^2]	2	3	2
GS (10 min)	[lbf/100ft^2]	7	8	6

Table 14. Viscometer Readings, Calculated Plastic Viscosity, Yield Point, Gel Strength of Fluids 24:26

Bentonite muds showed only slight changes in the rheological properties – compared to the plain mud- when LCMs were added having all the parameters stayed within the same range of numbers more or less.

Polymer muds showed big differences in the rheological properties-in general-compared to the Bentonite mud. When LCMs were added to the polymer system viscometer readings, plastic viscosity, yield point and gel strength increased significantly.

The LCM with the fine size when had been added had major effect on all the parameters of the polymer system compared to the plain polymer fluid 14. Changing the concentration of the added fine sized LCM -from 5 lb/bbl to 10 lb/bbl- showed noticeable increase in the rheological parameters of the polymer fluids 16 and 18, respectively.

OBM showed rheological properties in-between Bentonite mud and Polymer mud, relatively. The Addition of LCMs to OBM did not change much the rheological properties compared to the plain mud.

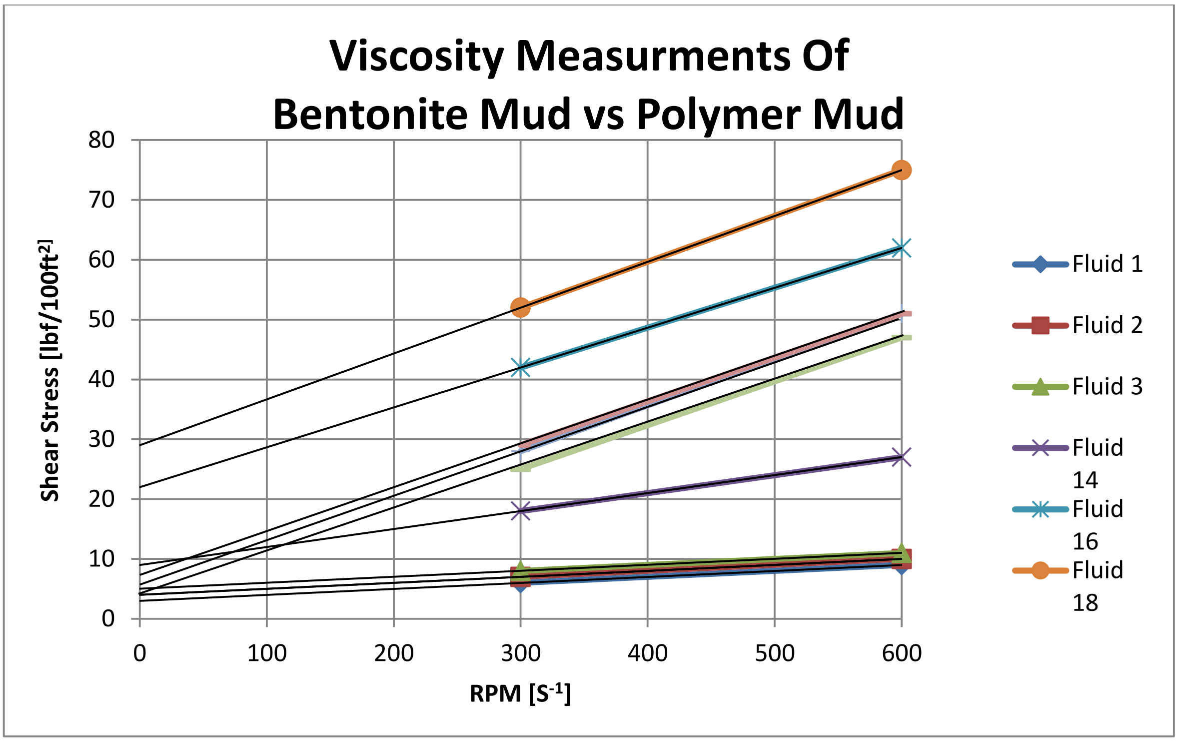


Figure 26. Viscosity Measurements of WBM and Polymer Mud with the Same Fine Sized LCM Added

A linear relation between shear rate (which corresponds to RPM) and the shear stress can be found for fluids 1, 2 and 3 representing Bentonite mud and Fluids 14, 16 and 18 representing the polymer system and fluids 24, 25 and 26 representing OBM. When all systems been treated with the same type, size and concentrations of lost circulation materials.

Generally, the polymer fluids 14, 16 and 18 showed higher shear stress readings than the Bentonite fluids of 1, 2 and 3 with OBM fluids of 24, 25 and 26 of values in between.

Fluid 18, which contains 10 lb/bbl fine sized LCM, showed the highest value of shear stress with 75 lbf/100 ft2 which demonstrate the effect of the fine sized chemicals on the rheological behavior of the polymer system. Meanwhile, the same added concentration of 10 lb/bbl fine sized LCM when used on the Bentonite mud showed the slightest change in behavior of the system which implies that it does not have much of effect on such a system. Fluid 26 of OBM, showed decreasing in rheological parameters with increasing the size of added materials at the same concentration.

5.5 High Pressure High Temperature -HPHT- Filter Press Laboratory Tests Operating Conditions

The selected operating conditions of pressure and temperature had been chosen with respect to certain factors:

1. **The fluid sample cell rubber gaskets**: test temperature should not exceed 150˚C in order not to ruin them and be able to use them several times instead of replacing them every couple of tests.
2. **Mud system used**: for polymer system, test temperature should not exceed 120˚C not to ruin the LCMs used and cause thermal degradation to it.
3. **Pressures**: selected to mimic down hole pressures and back-pressure was applied in order to keep evaporation of portion of the fluids during the heating period and also to suppress the evaporation of the filtrate to keep it in the liquid phase after the test.

Fluid	Target Temperature °C	Max Temp °C	Min Temp °C	Avg. Temp	Applied P. Psi	Back P. Psi
1	150	152	147	149.5	600	100
2	150	149	146	147.5	600	100
3	150	151	149	150	600	100
4	120	120.3	114	117.15	600	100
5	120	118	114	116	600	100
6	150	153	149	151	600	100
7	150	149	146	147.5	600	100
8	120	119	115.4	117.2	600	100
9	120	120.4	116	118.2	600	100
10	120	119.1	117.6	118.35	600	100
11	120	121.3	119.5	120.4	600	100
12	120	120.5	115	117.75	600	100
13	120	123	119.5	121.25	600	100
14	120	121	117	119	600	100
15	120	118	116	117	600	100
16	120	121	116	118.5	600	100
17	120	119	117	118	600	100
18	120	119	116	117.5	600	100
19	120	109	116	112.5	600	100
20	120	118	115	116.5	600	100
21	120	119	116	117.5	600	100
22	120	109	116	112.5	600	100
23	120	118	115	116.5	600	100
24	150	153	145	149	600	100
25	150	152	146	149	600	100
26	150	151	147	149	600	100

Table 15. Test Operating Conditions

Bentonite fluids' tests done at 150˚C and applied pressure from top of the fluid sample cell of 600 psi with back-pressure from the bottom of 100 psi. While, polymer and OBM muds' tests done at temperature of 120 ˚C and applied pressure from the top of the fluid sample cell and back-pressure from the bottom of 600 psi and 100 psi, respectively.

5.6 High Pressure High Temperature -HPHT- Filter Press Lab Results

FLUID	Mud System	Lost circ. materials(LCMs)	LCMs type	LCMs concentration [lb/bbl]	API HPHT Filtrate [ml]
1	BENTONITE MUD	Plain Mud	-	-	57.2
2		MI-KHART 40	FINE	5	49
3				10	33
4				15	23
5				20	25
6		MI-KHART 130	MEDIUM	5	37.2
7				10	28.2
8				15	17
9				20	12.4
10		MI-KHART 0.5-1.5	GRANULAR	5	51
11				10	46
12				15	42
13				20	38
14	POLYMER MUD	Plain Mud	-	-	16.2
15		MI-KHART 40	FINE	5	10.4
16				10	7.8
17				15	5.2
18		MI-KHART 130	MEDIUM	5	9
19				10	8
20				15	7
21		MI-KHART 0.5-1.5	GRANULAR	5	12.8
22				10	10.4
23				15	9.1
24	OBM	Plain Mud	-	-	3
25		MIL-CARB 25	Fine	5	0.2
26		MIL-CARB 150	Medium	5	1

Table 16. API HPHT Fluid Loss

Experiments had been conducted according to the **API RP 13B-1** / ISO 10414-1[3] at a differential pressure of 500 psi and temperature of (120-150) ˚C. The performance of LCM samples was determined based on the amount of total fluid loss after 30 min of filtration according to the API RP procedures. Table 16 shows all the results for the tested drilling fluid systems with different LCMs used.

[3] Followed testing procedures and safety measures are shown in Appendix A

5.7 Results and Discussion

As was mentioned earlier 3 types of LCM samples were tested in three types of drilling muds namely, Bentonite mud, polymer mud and OBM. Tests were performed to evaluate the effects of additive material type, additive concentration, additive size distribution and time on filtration process. The results are presented and discussed in the following.

5.7.1 Effect of LCM Material, Type and Concentration.

In order to provide a base for the effect of LCM additives on the filtration properties of the muds, HPHT filtration tests were conducted with plain muds. Results are shown in Figure 27.

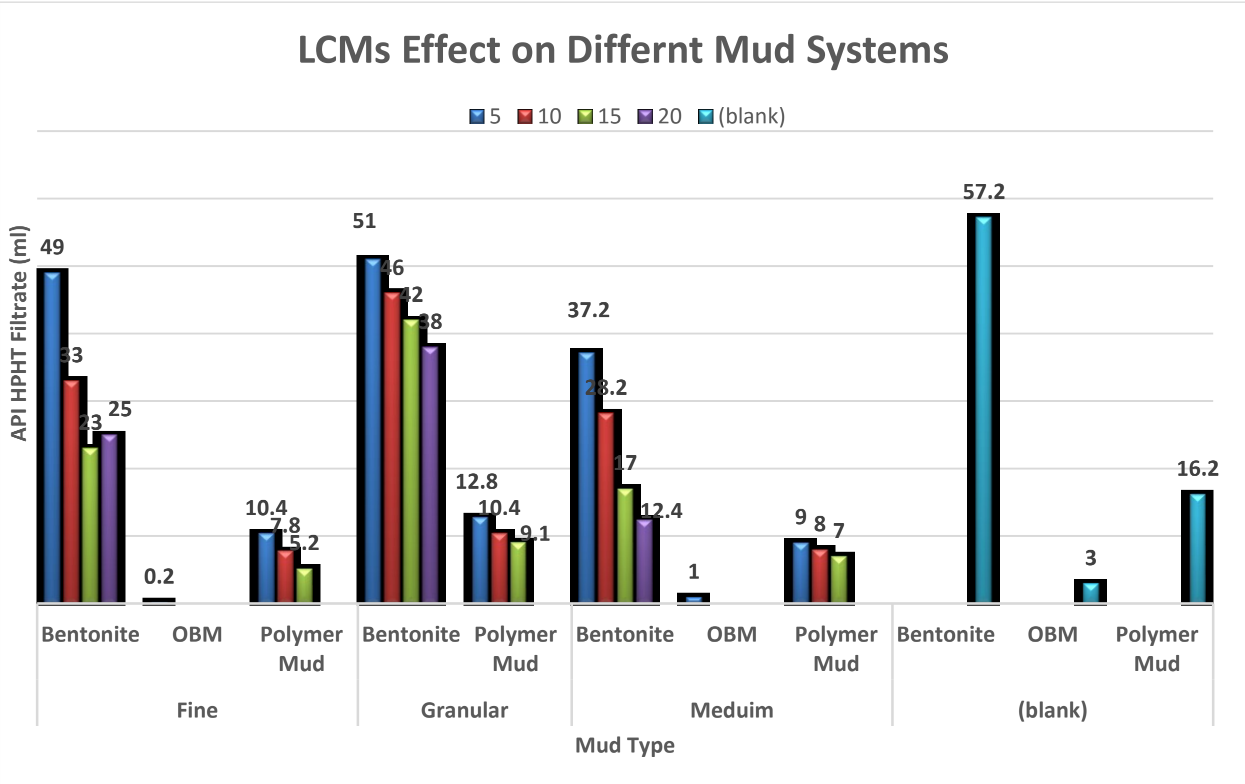


Figure 27. LCMs Effect on Different Mud Systems

As the figure shows the total filtrate is the highest for the Bentonite mud and the lowest for the OBM with the polymer system value in-between.

The addition of the additives in different concentrations has improved the filtration properties of the muds compared to the plain muds for all additives. Reduction in the total filtrate is significant. Over 65 % for the coarse size in Bentonite mud and over 60 % for the fine size in polymer mud. As Figure 27shows increasing the additives concentration from 5 lb/bbl to 20 lb/bbl has decreased the amount of total filtrate for all the systems.

5.7.2 Effect of LCM Size.

The effect of LCM size distribution was studied for the 3 additives used which were available in various sizes of fine, medium and coarse. It can be seen when comparing the mud systems to each other while using the same size of additives, that the fine sized LCM additive had the greatest effect in decreasing the total filtrate in the polymer system by far compared to the Bentonite mud. Taking a bigger look at the whole set of data, it can be seen also that this reduction in total filtrate using the fine sized LCM in polymer mud in the best performer.

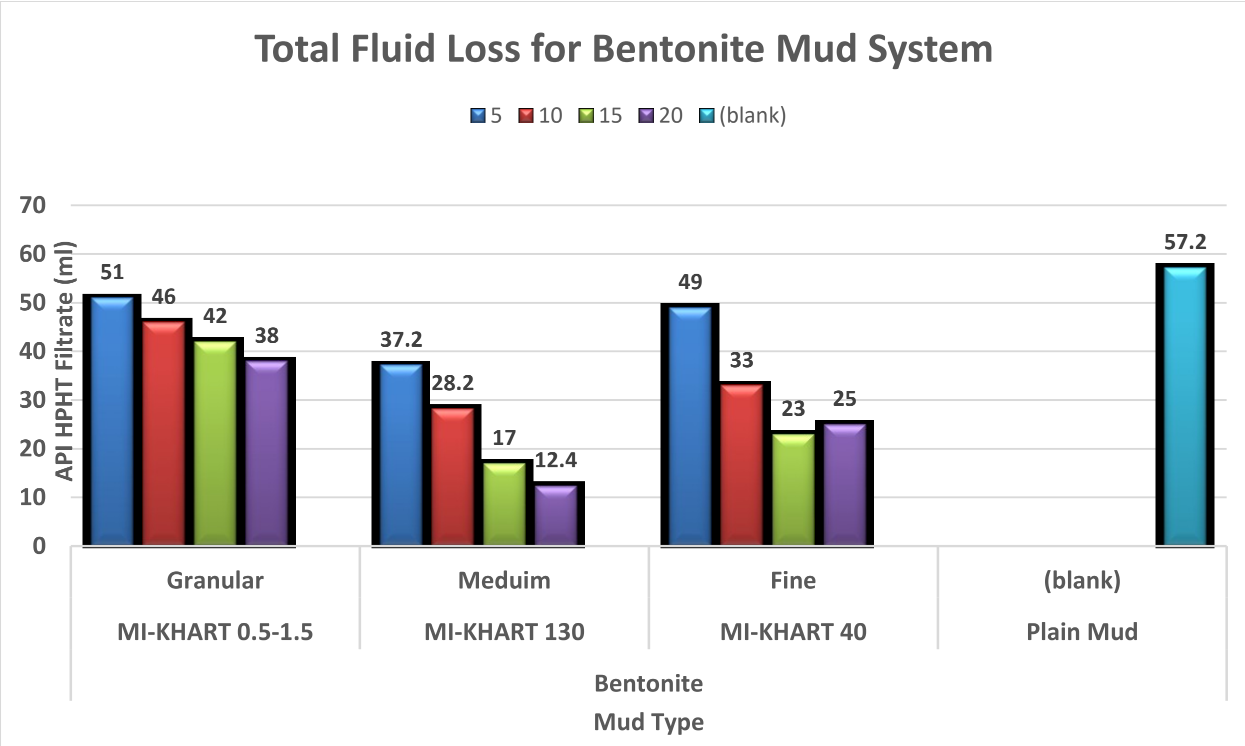


Figure 28. Total Fluid Loss for Bentonite System

With a closer look analyzing the Bentonite mud data-set shown in Figure 28 the total filtrate resulted from using the Fine size implies that this size is the first overall best performer for all mud systems in general and the Medium size is first best performer in the Bentonite mud system in specific.

The patterns of the fine and medium sized LCMs in Bentonite mud are close to each other in higher additives concentrations gives indication they perform about the same in such concentrations i.e., 10 and 15 lb/bbl. But at higher concentration as 20 lb/bbl the difference is obvious that the medium size can decrease the total filtrate. Hence, suppress the losses better than the fine size particles.

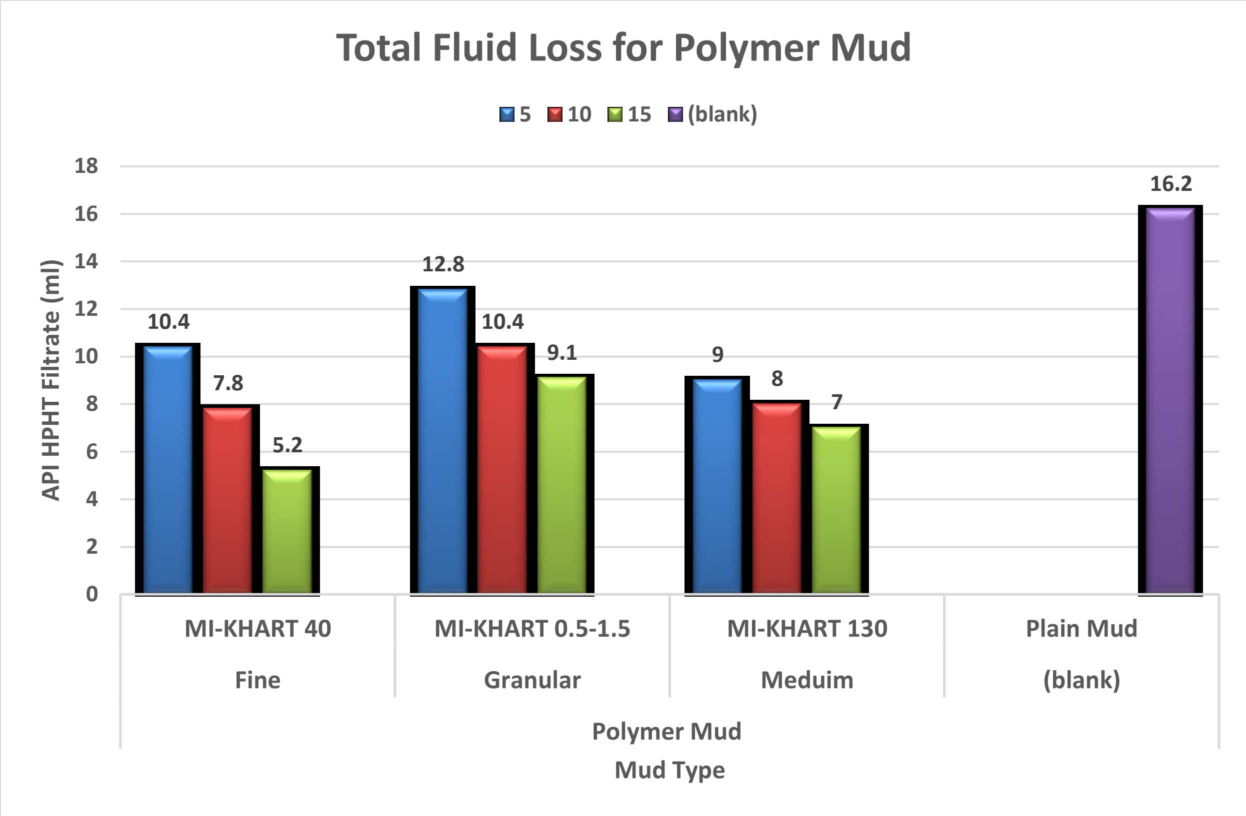


Figure 29. Total Fluid Loss for Polymer System

Compared to the plain mud the decrease in total filtrate with the addition of LCMs to the polymer system is significantly noticeable with the Fine sized particles, nevertheless the Medium size particles have a close performance over the whole range of concentrations of LCMs, but still at the higher concentrations i.e. 15 lb/bbl the Fine sized perform the best to decrease the amount of filtrate going into the formation.

In general, among the three mud system it can be clearly stated the OBM behavior with the LCM is the best in terms of suppressing the filtrate to the minimum amount it could be.

5.7.3 Effect of Pressure

The pressure used in evaluating lost-circulation materials affects the results in more than one way. Where the relationship between the particle size of the lost-circulation additive and the particle size of the bed on which it IS being tested is such that a stable seal can be formed, the effect of increased pressure is to cause a greater amount of mud to be lost before the seal is affected. That was observed during the heating periods of the tests when only 100 psi were applied on the mud samples then by increasing to the test pressure of 600 psi the amounts of filtrate increased, till the seal is formed on the ceramic disk.

One other effect has been noted in tests with polymer mud and coarse size LCM. If no seal can be obtained by rapidly raising the pressure to 600 psi, then reducing the pressure to some lower point where mud loss is slow and holding at this lower pressure for a while may produce a seal that will later hold the full 600 psi. The "Healing" effect may at times be useful in field application of LCM.

5.7.4 Effect of Time on Filtration

Going in a closer look to study the effect of time on the filtration process and the total filtrate the tests were conducted for 30 min as recommended by the API HPHT procedures and then were continued till 60 min, recording the amount of filtrate every 5 min to get better idea about the filtration rate and how much influence time has on it. Shown below in Figure 30 and Figure 31, the effect of time on filtration when using 15 and 20 lb/bbl LCMs in the Bentonite mud, respectively.

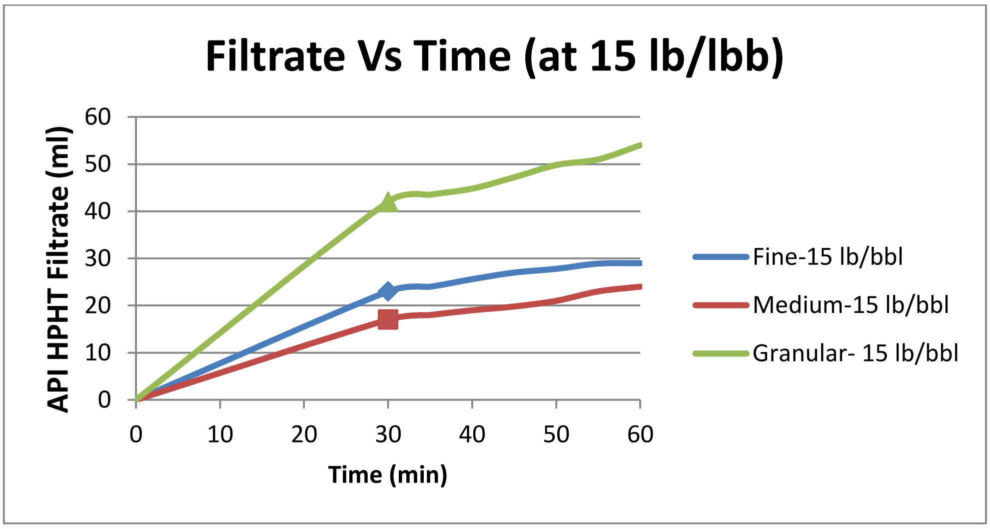


Figure 30. Time Effect on Filtration Using 15 lb/bbl LCMs

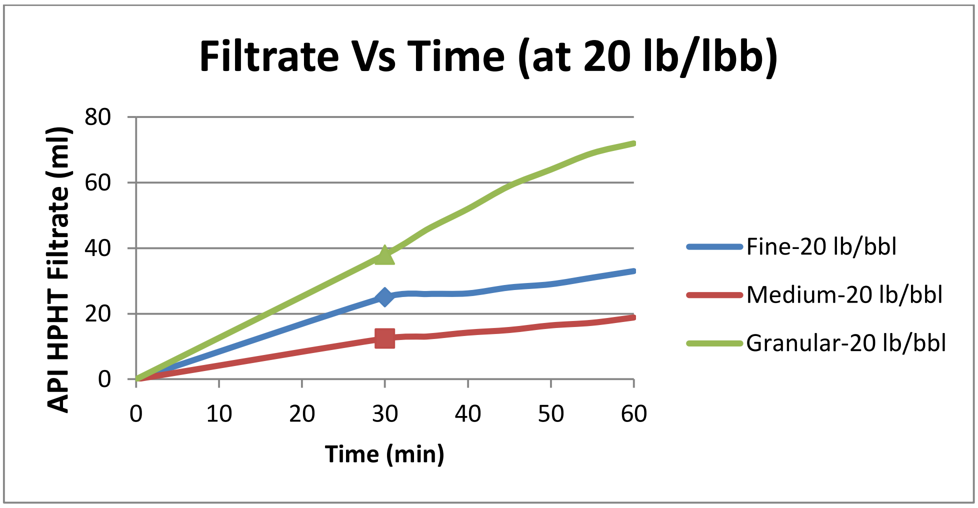


Figure 31. Time Effect on Filtration Using 20 lb/bbl LCMs

It can be seen from Figure 30 and Figure 31 that in general the total filtrate collected after 60 min is more than the 30 min collect. In general, filtration increases with time. But, most important is the filtration rate behavior as it decreases with time. That's a key factor for the LCMs applying technique in terms of setting time and for how long the process should wait-pill to soak into the formation- in order to get the best performance from the added material.

Granular sized particles have a quite interesting behavior to be noticed as it's the least decreased in rate compared to the fine and medium particles. Especially when 20 lb/bbl LCMs were used, the filtrate was doubled after 60 min which tells the rate of filtration remained the same and did not got affected with time. This behavior can be explained by taking careful look on the mud cake after the test and seeing how the LCMs particles were set by each other –having relatively big sizes- created channels in the cake itself led to the flow of the filtrate from the mud into the formation. So, a selection of a proper size of the particles to plug into the corresponding pores in the formation is a key factor in the treatment. That's why PSD simulation were conducted later on this study.

5.7.5 Effect of PPT for Minimizing Formation Damage

PPA resembles a high-pressure, high-temperature filtration cell that has been modified to operate upside down (to remove the effects of gravity) and to accept filter media of different permeabilities (porous ceramic disk). The medium is selected to match the permeability of the reservoir to be drilled. The filter medium is at the top so that sediment will not affect the filter cake. Pressure is applied hydraulically from below.

Tests were done on OBM once without any additives, only to measure how much tendency of invasion a plain OBM has to invade the formation. Afterwards, using mixture of LCM combined with Nano-Particles at different sizes of fine and medium, respectively.

The following table shows the tests results:

Mud System	LCM	LCM Type	LCM Concentration [lb/bbl]	PPT filtrate [ml]
OBM	-	-	-	16
Customized OBM	Mil-Carb 25 W/Nano-Particles	Fine W/Nano	5	10
Customized OBM	Mil-Carb 150 W/Nano-Particles	Medium W/Nano	5	6

Table 17. PPT Lab Results

The tests were done at 250 ˚F applying 3000 psi hydraulically at bottom of the test cell and 100 psi from top as a back pressure. Using a ceramic disk of 50 microns to mimic the formation permeability and working conditions of pressure and temperatures on South-East Kuwait.

Fine LCM at concentration of 5 lb/bbl combined with Nano-particles gave spurt losses of mud of 10 ml, while medium concentration combined with Nano-particles at the same concentration of 5 lb/bbl gave spurt losses of 6 ml.

Given the listed results, it shows the huge effect of using customized drilling fluids after testing it with PPA, since major change in the potential formation invasion resulted from adding the proper type/combination of types in the right concentration to the drilling fluid system.

5.7.6 Effect of PSD for Effective Bridging Selection

As mentioned in Chapter three in the third section, when performing PSD test the resulting size of the mixture of LCMs should at least fit on the straight part of the Kaeuffer curve" which represents the fractures size of the formation" or be shifted to the right side a little, meaning both the formation fractures and the mixed materials have at least the same particle size or the mixture size is slightly bigger. Conditioning that mixture minimum size requirement is important in cases of drilling considering the shearing action of the drilling bit as it grinds the mixed LCM resulting in smaller particles. This is better explained through the upcoming lab studies as in tables 18, 19 and 20. It shows the target size to plug the fractures in the formation and the corresponding median size of the particles as known of D90,50,10 which were generated by the simulator.

The laboratory experiments performed on OBM (Fluids 24, 25, 26), using PSD simulator, showed here were used to develop optimum PSD for bridging of wells Onshore South East Kuwait, as shown later on the case study, specifically in the 12 ¼ " section. PSD simulator was run to cover all the possible scenarios in respect to the subjected zone permeability in order to decide the best fit mixture size to plug the fractures in the formation.

Lab Study #1

OBM drilling fluids were designed for a 50 MD reservoir = 28 microns, running the simulator using Kaeuffer rule, it resulted in using 10 ppb of bridging materials to plug such formation by 90% (9 ppb) of fine LCM to 10% (1 ppb) granular material.

50 MD reservoir = 28 microns = 9 ppb fine LCM + 1 ppb Granular LCM (10)

D (Median Pore Size Probability)	90	50	10
Target for Kaeuffer rule	28.3	8.7	0.3
Result of Product mix	28.7	7.2	1.2
Variance	0	2	1

able 18. Particle Size Distribution Lab Study #1

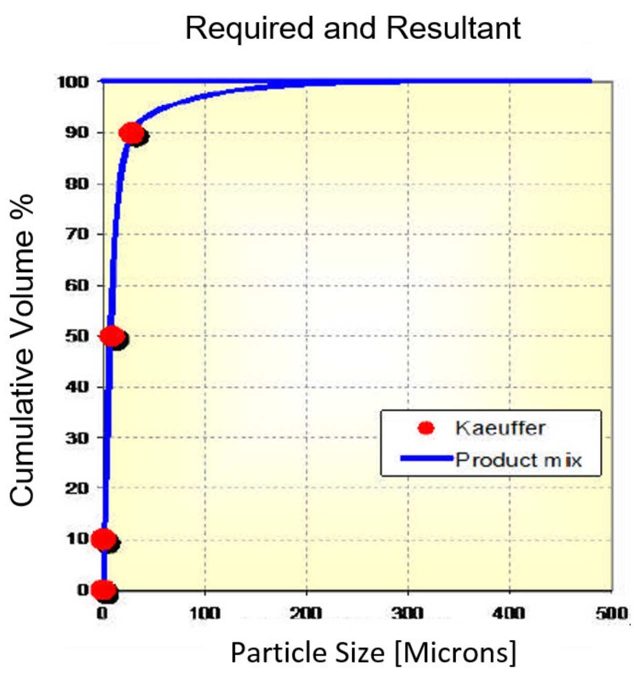


Figure 32. Permeability of 50 MD=28 microns

Lab Study #2

OBM drilling fluids were designed for a 250 MD reservoir= 63 microns, running the simulator using Kaeuffer rule, it resulted in using 15 ppb of bridging materials to plug such formation by 80% of fine LCM to 20% of medium LCM

250 MD reservoir= 63 microns = 12 ppb Fine LCM + 3 ppb Medium LCM

D (Median Pore Size Probability)	90	50	10
Target for Kaeuffer rule	63.3	19.5	0.8
Result of Product mix	62.8	18.3	1.3
Variance	1	11	1

Table 19. Particle Size Distribution Lab Study #2

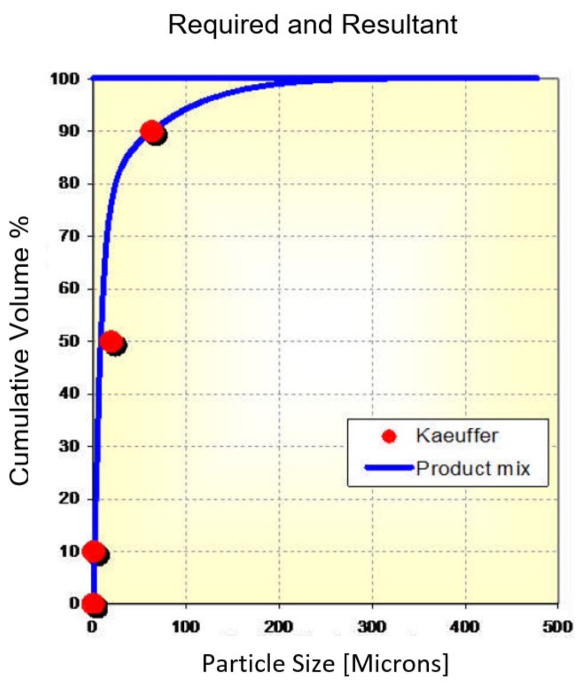


Figure 33. Permeability of 250 MD=63 microns

Lab Study #3

OBM drilling fluids were designed for a 1000 MD reservoir= 126 microns, running the simulator using Kaeuffer rule, it resulted in using 20 ppb of bridging materials to plug such formation by 20 % of fine LCM, 15% of Granular LCM and Medium.

1000 MD reservoir = 126 microns = 13 ppb Medium LCM + 3 ppb Granular LCM + 4 ppb Fine LCM

D (Median Pore Size Probability)	90	50	10
Target for Kaeuffer rule	126.5	39.1	1.6
Result of Product mix	113.4	37.4	3.3
Variance	13	1	2

Table 20. Particle Size Distribution Lab Study #3

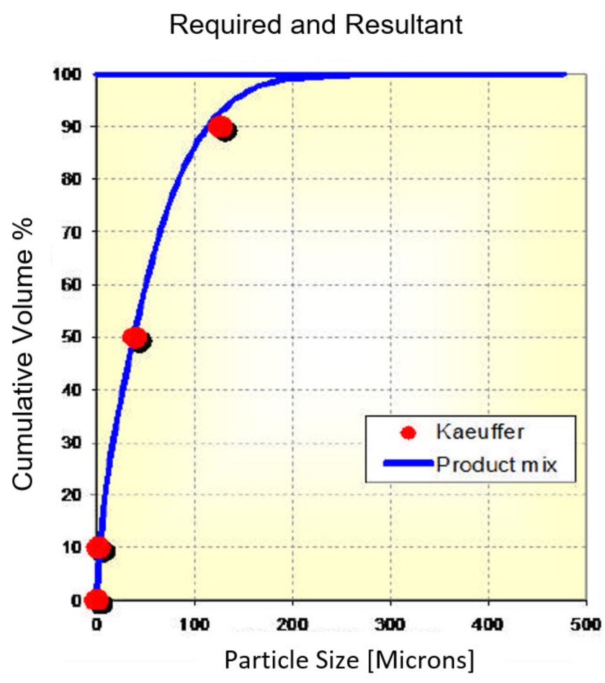


Figure 34. Permeability of 1000 MD=126 microns

The table below is based on numerous internal studies done by drilling fluid services company[4]. The table should only be used as a general guideline when more accurate data from core samples is not available.

Experienced losses rate with WBM BPH	Experienced losses rate with OBM BPH	Estimated Pore size diameter
0-10	0-5	31 microns
10-40	5-25	62 microns
40-55	25-35	123 microns
55-70	35-45	247 microns
70-145	45-95	370 microns
>145	>95	494 microns

Table 21. Losses Rates and Corresponding Estimated Pore Size Diameter

[4] The data acquired during internship with the company and authorized to public presentation

5.7.7 Trend Lines for Different Used Mud Systems

Based on the experimental study performed with three different LCM samples in three different types of mud systems using HPHT filter press with ceramic disk[5], the following conclusion may be stated (see Figure 35):

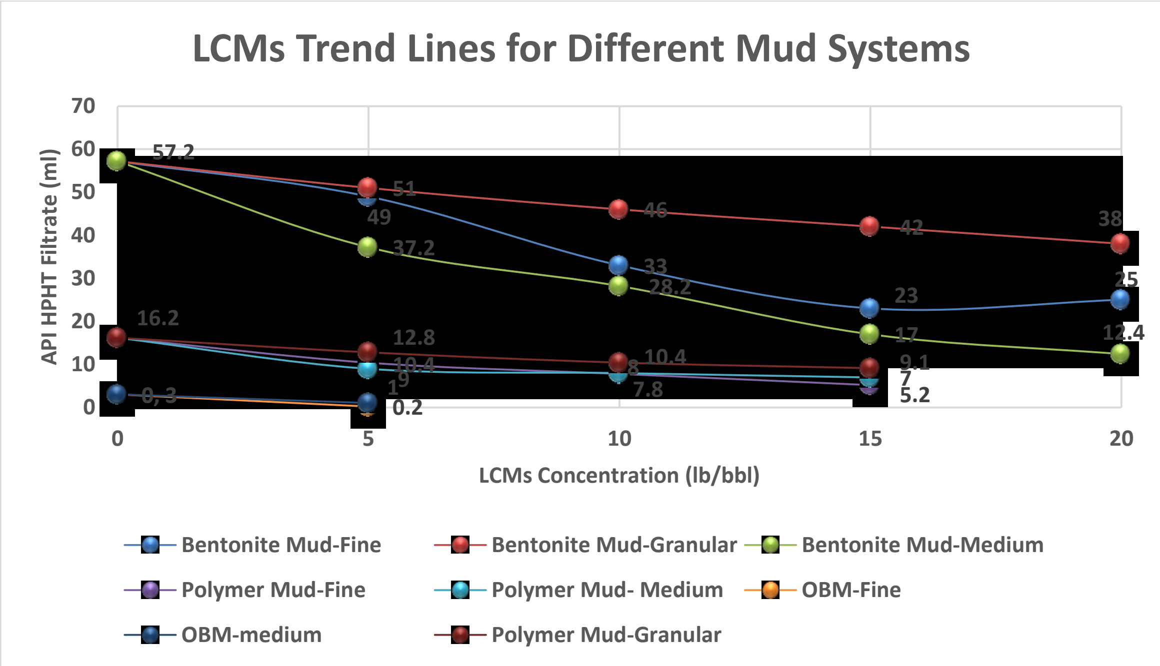


Figure 35. LCMs Trend Lines for Different Mud Systems

5.8 Experiments Summary

1. Generally, OBM with and without LCM additives, showed the lowest total filtrate loss, followed by the Polymer mud and then Bentonite mud, Respectively.
2. Addition of any concentration of LCM additives generally improved the filtration properties of all the muds, however the extent of the improvement depends on the mud type, LCMs type and size distribution.
3. Increasing LCMs concentration from 5 lb/bbl to 20 lb/bbl had an effect decreasing the amount of total filtrate volume for all mud systems. However, in Bentonite mud the optimum concentration was at 15 lb/bbl as increasing the concentration more than that amount resulted in increasing the filtrate.
4. Fine and medium sized LCM additives in Polymer mud perform about the same.
5. Effect of time on filtration rate is the least when using Granular sized LCMs.

[5] Fann ceramic filter Disc-Product Number 210540- was used with mean pore diameter of 56 microns new (Hg) and 35 microns old (air), Size of the disc is 2 ½ " Diameter and ¼ " thick

6. Filter cake had vital role in the filtration process. OBM and Bentonite mud when using fine and medium particles had somehow similar shape filter cakes with respect to consistency and thickness which resulted in steady decreasing behavior of the total filtrate with increasing LCM concentration. Unlike, Polymer mud when using granular particles which shaped lousy filtrate resulting in constant increase in total filtrate with relatively higher rate when increasing LCM concentration.
7. Effective bridging is most often obtained by using a blend of “sized” LCM.
8. Sized Calcium carbonate and degradable cellulose are effective in permeable reservoir formations requiring the use of non-damaging or acid soluble products.
9. Generally speaking, Abrams Rule (> than 5% solids should equal 1/3 the pore size) applies to matrix losses.
10. The particles needed to seal a fracture are equal to the fracture width.

6 Case Study

The main purpose of presenting the up following case study, is to highlight the significant resultant impact LCM successfully achieved when it is applied as a solution to combat loss circulation problem. This is illustrated through evaluation of the cost analysis, showing what total cost could have been without considering LCM application while only using conventional other methods i.e. placing cement plugs and comparing it to the actually cost of the well after applying LCM to stop the losses problem.

Well Background

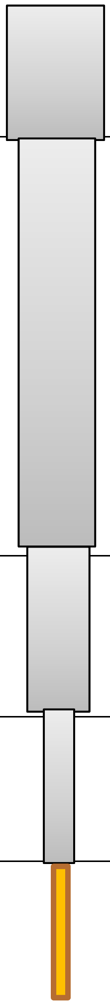
Hole Size [in]	Casing Size [in]	Casing Setting	Depth MD [Ft]	Depth TVD [Ft]	Drilling Fluid System	Drilling Fluid Weight [ppg]	Bottom Hole Temperature [˚F]	Max Inclination [Degree]
22	**18 5/8**		**271**	**271**	**Spud Mud**	**9.5-9.6**	**88.2**	**0**
16	**13 3/8**		**3664**	**3647**	**Gel Polymer Mud**	**8.7-9**	**128.4**	**13.9**
12 ¼	**9 5/8**		**5330**	**4995**	**OBM**	**10.5-10.8**	**144.4**	**51**
8 ½	**7**		**5930**	**5230**	**OBM**	**10.8-11**	**147.2**	**76.7**
6 1/8			**6931**	**5370**	**KCL polymer Mud**	**8.6-8.8**	**147.2**	**86.5**

Figure 36. Well Schematic

It was planned to drill a 6931 ft horizontal water disposal well, in 6.125” hole on well BG 1008 Onshore South East Kuwait-The Greater Burgan Field- Using Rig SP-137. Figure 36 shows the well schematic.

Challenges

- Manage high differential pressure (3500 Psi) across high porous permeable formation (eq. 9 ppg)
- Possibility of differential sticking due to high overbalance
- Possibility of induced losses due to week & depleted formations

Considering the above challenges and based on particle plugging lab testing performed under conditions resembling actual formations exposed, It was recommended to Use special LCMs in conjunction with SULPHONATED ASPHALT to overcome the mentioned challenges.

MIL CARB LCMS are specialized chemicals used for promoting wellbore stability as it reduces fluid invasion into the wellbore by sealing pore throats and micro-fractures at the borehole interface therefore increasing the hoop stress and making it withstand higher pressures.MIL CARBs also effective in reducing differential sticking because of its small particle size.

Desirable Benefits

- Improves formation integrity & wellbore strengthening
- Reduces filtrate invasion
- Easily dispersed in all types of Emulsion mud system
- Control of losses, specially within depleted formations and induced fractures because of high overbalanced.

6.1 Sections Synopsis Discussion

The following figures shows a comparison between the original well plan and the actual performed, considering all the unscheduled events happened during the job, in terms of Time vs. Depth, Depth vs. Cost and Cost vs. time[1].

Figure 37. Time vs. Depth (Actual/Planned)

[1] Appendix B shows necessary calculations of the each well interval

6.1.1 Drilling Operations, Problems and Technical Applied Solutions

The first phase drilled 22" reached a depth of 281' which is 10 ft deeper than planned target, it took 2 days for the job in general with 1 drilling day in specific as was planned. Hole after drilled was swept with 50 bbl HI-VIS pill and circulated to clean hole and POOH freely then casing and cement job was performed as instructed by Kuwait Oil Company (KOC) program.

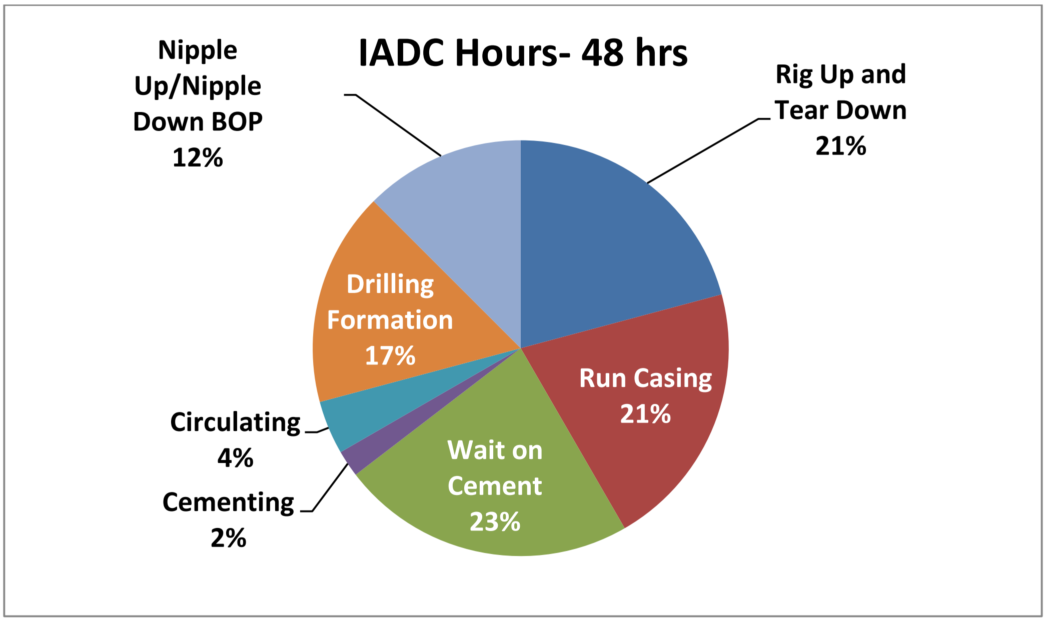


Figure 38. 22" Interval IADC Hours

The second phase drilled 16" reached a depth of 3679' which is 15 ft deeper than planned target depth. It took 8 days in total for the job with 7 days of drilling, longer by 1 day of the plan. Drilling 16" hole with gel mud of 8.6 ppg to 590', then partial loss of 60 bbl/hr was experienced but drilling hole to 2500' kick of point (KOP) was performed. Complete loss happened at depth of 3244', plan was to drill ahead using only lime treated water for 300 ft till TD 3680' and job is done in 7 days, but actual happened after the losses; was using lime treated mud and mud cap of 9.5 ppg, pumped 25 bbl HI-VIS every 45' drilled, pumped 15 bbl 9.5 ppg mud cap every 30 min. at TD pumped 100 HI-VIS, Wiper trip to 2500' run in hole (RIH) again to bottom pump 100 bbl and spot 200 bbl of fluid loss pill, POOH, run casing and perform Cement Job as instructed by KOC program. So that cost 1 more extra days to the plan.

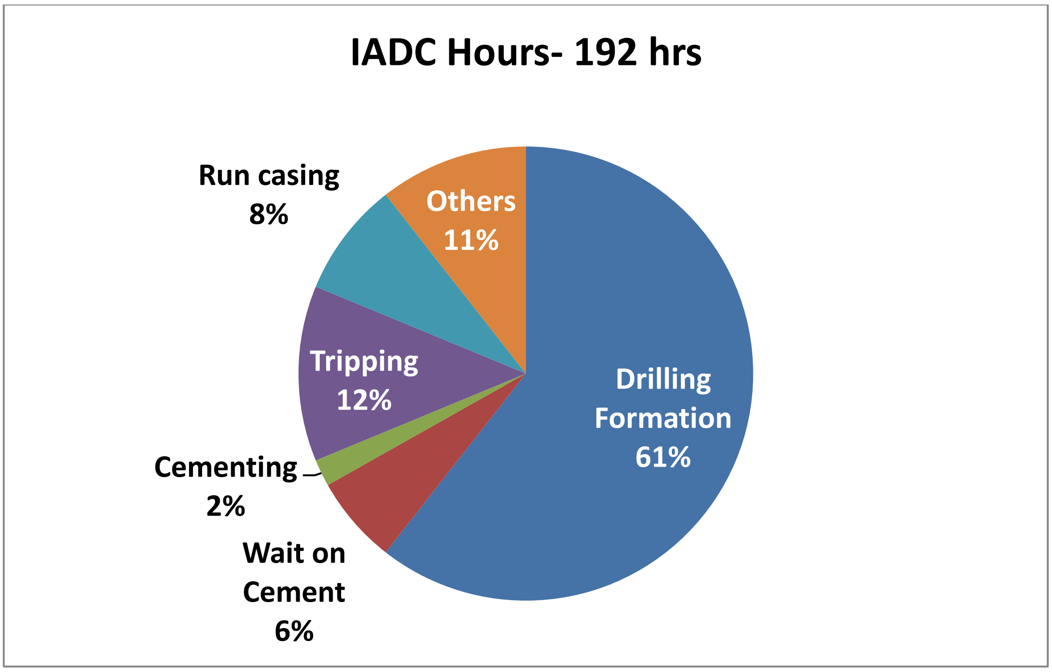


Figure 39. 16" Interval IADC hours

The third phase drilled 12 ¼" reached a depth of 5300' as was planned. It took 7 days in total for the job with 3 drilling days. The hole was drilled with OBM 10.6 ppg. 174 bbl of lost mud was experienced while drilling. Hole was drilled till 4331' where seepage loss of 8 BPH (bbl/hr) was observed. RIH to bottom and continue drilling to 4640', observed partial loss of 15 BPH. Continue drilling to 4955' with partial loss of 8 BPH. Pumped 25 bbl HI-VIS pill every 45 drilled ft. continue drilling ahead 12 ¼" hole with BHA directional to 5300 ft at TD.

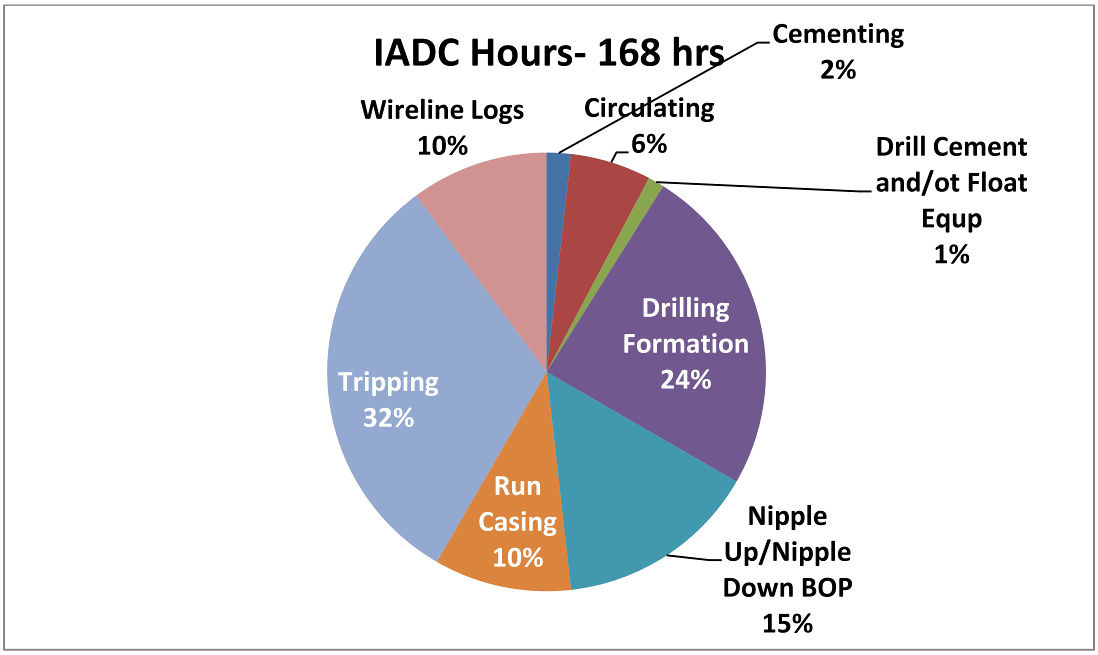


Figure 40. 12 ¼ "Interval IADC Hours

The fourth phase drilled 8.5" reached a depth of 6010' which is 80 ft deeper than planned target. The job took 19 days with 6 drilling days, less by one day than the plan of 19 days. The hole was drilled with OBM 10.6 ppg. Experienced sever loss of 3641 bbl due to caving and to the formation itself. Commencing and continuing drilling with no problems till depth of 6167' where no return in flow lines was observed (**Total loss**). POOH 8 ½ bit, mixed and pumped 120 bbl of LCM with 125 PPB of LCM. Observed no return. Pumped 50 bbl of 15.8 ppg as a **cement balance plug**. Observed no return. Mixed 120 bbl of LCM (**2nd pill**). Observed Return. Wait for LCM pill soak. RIH wash down to 6102 ft. Circulate and check dynamic losses, no losses. Circulate out all LCM pill with 100% return.

Make up 8 ½ bit and BHA then RIH to 5700 ft. Wash down to 6102 ft. observed total losses. Mixed 100 bbl of LCM (**3rd pill**). Displaced with 75 bbl OBM.POOH with 8.5" and BHA to surface. Circulate out all LCM pill with 500 GPM. After 30 min of circulation observed **total loss**. POOH to 5850 ft to perform **second cement plug** as per KOC program. Observed at the beginning of cement partial return. After 40 bbl of pumped cement, observed total loss. Mixed 100 bbl of LCM (**4th pill**). Displaced with 95 bbl OBM 10.6 ppg OBM observed no return. POOH with 8.5" Bit and BHA to surface.

RIH to 6167 ft. and rig up cement lines to perform a **third cement plug** as per KOC program. Observed return. Continue drilling to 5372 ft. Performed **fourth cement plug** as per KOC program. Displaced with 72 bbl OBM 10.6 ppg. Circulate hole clean, resumed drilling out cement from 5383 ft to 5397 ft. with 100% return at Inclination of 47.98 deg. continued drilling 8 ½" directional hole (side track) from 5397 ft to 5600 ft. **observed full return**. Spot 100 bbl of LCM. Wait on LCM for Socking. Circulate and check dynamic losses with different GPM. No problem. Continued drilling till **TD 6010 ft.**

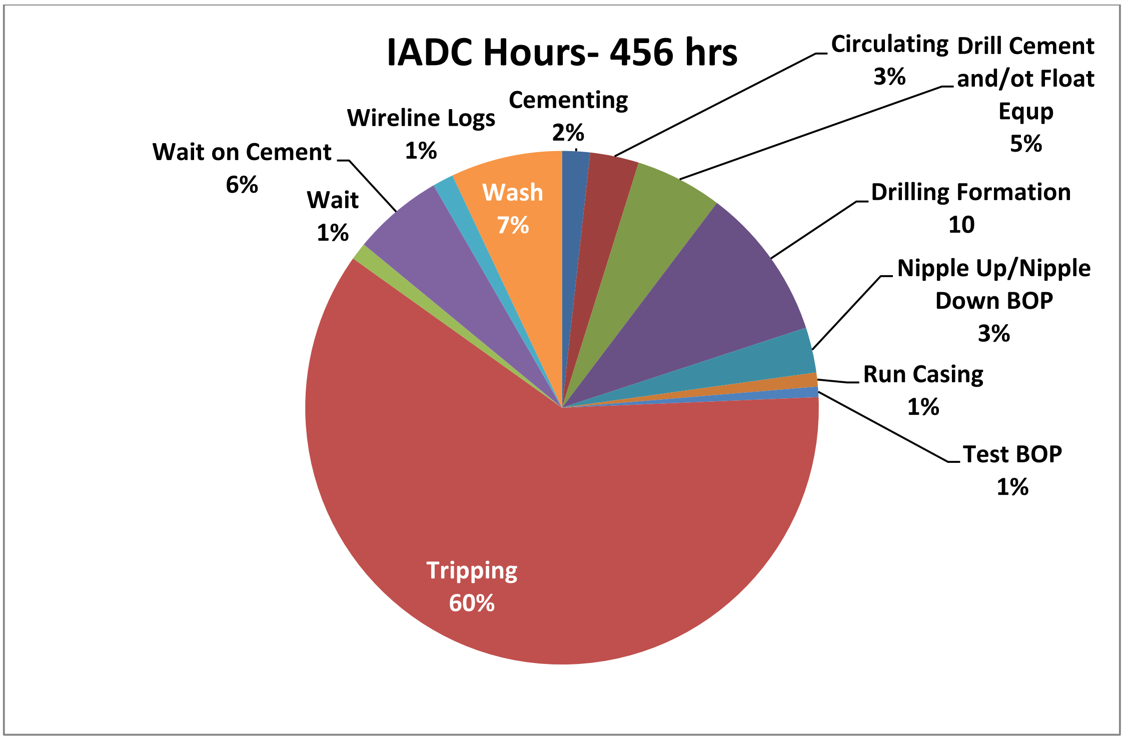


Figure 41. 8 ½ ″ Interval IADC Hours

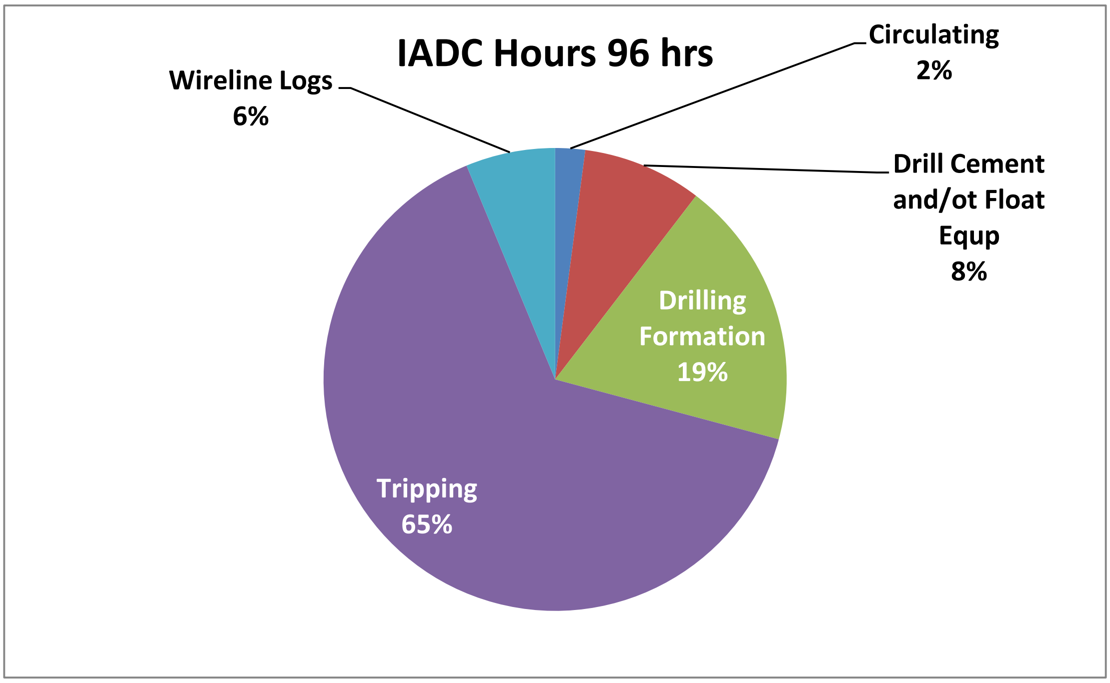


Figure 42. 6 1/8 ″ Interval IADC Hours

The fifth phase drilled 6 1/8″ reached 6361′ which is 570 ft shallower than the target depth. The job took 8 days with 7 drilling days less by 2 days than the plan. The hole was drilled using KCL polymer mud/ lime treated water. Drilling ahead was performed from 6015 ft to 6050 ft. with 100% return.

Drilling from 6050 ft to 6060 ft. **Observed total losses**. Switch lime treated water and continued blind drilling with water from 6060 ft to 6361 ft. Make up 7” Polish Mill. RIH to 5000 ft and dress off 7” liner with 200 GPM and torque 3700 ft-lb POOH Polish Mill. Lay down 5” DP single by single and 3 ½” DP. Well has reached its target depth.

6.2 Amounts of Mud Lost/Returned Analysis

The following figures show the amount of mud bbls planned to be mixed and compare it the actual amounts mixed given the well circumstances and events.

On the secondary Y-axis, can be read for each individual section the exact amounts lost Downhole/Surface Solid Removal Equipment (SRE) and the total amount Lost eventually.

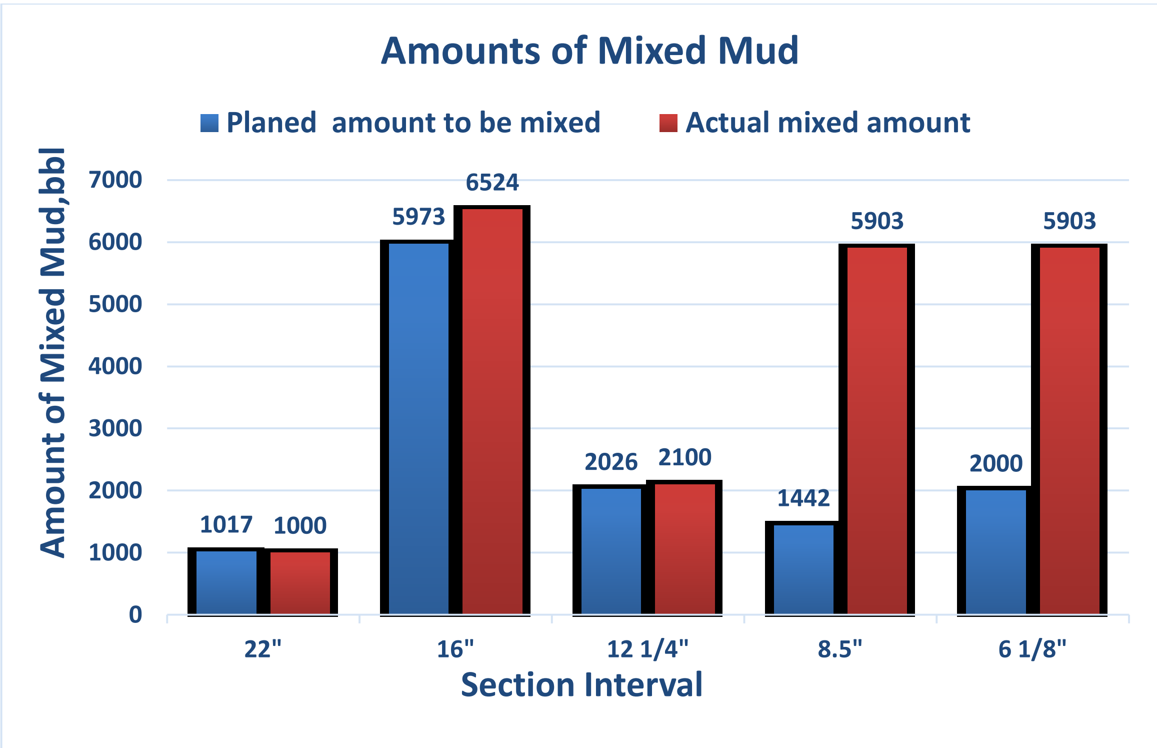


Figure 43. Amounts of Mixed Mud

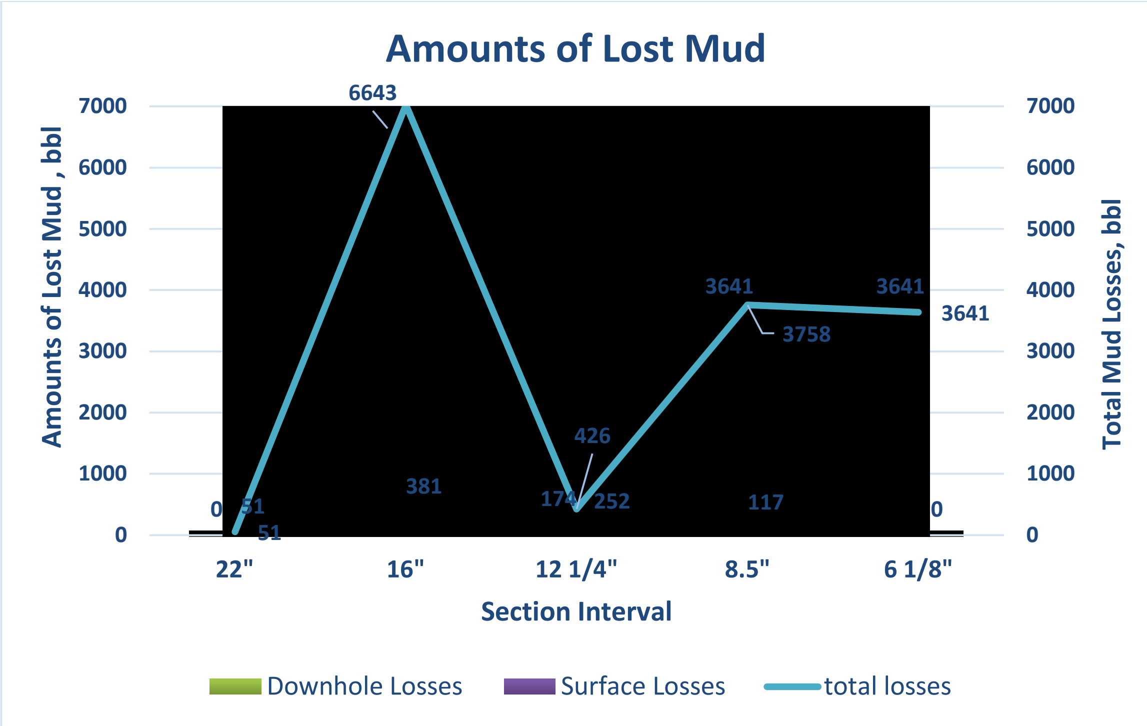


Figure 44. Amounts of Lost Mud

In the First section 22" interval, as shown in Figure 43 and Figure 44, there a slight difference in the amount of planed to-be-mixed mud to the actual mixed. Having 51 bbl lost at the surface to SRE with no downhole losses, only 500 bbl were disposed of the spud mud and the remaining 500 bbl were forwarded to be used in the next interval.

In the Second section 16" interval, as shown in Figure 43 and Figure 44, that section got complete loss of circulation while drilling with 6643 bbl lost down hole and 381 bbl lost to SRE and 7024 lost bbl in total for the section.

In the Third Section 12 ¼" interval, as shown in Figure 43 and Figure 44, there was 174 bbl lost of OBM to the formation downhole and 252 bbl to the SRE at the surface with 426 bbl lost in total.

In the Fourth Section 8 ½ " Interval, as shown in Figure 42 and Figure 43, while drilling total loss was experienced with 3641 bbl lost to the formation and 117 bbl lost to SRE at the surface. That section used almost 4 times the amount of planned mixed mud 5903 bbl instead of 1440 bbl. After section was drilled there were 1100 bbl of OBM back loaded to Mud plant.

In the Fifth Section 6 1/8" Interval, as shown in Figure 43 and Figure 44, total loss of circulation of 3641 bbl happened but during drilling a switch of mud system from KCL polymer mud to lime treated water with LCMs was done to alleviate the losses and Cont. drilling till TD.

Figures 44:47 show in 16" and 12 ¼" section intervals; the total amounts of mud added, the amounts of mud lost, the percentage of surface losses to down hole losses and total losses.

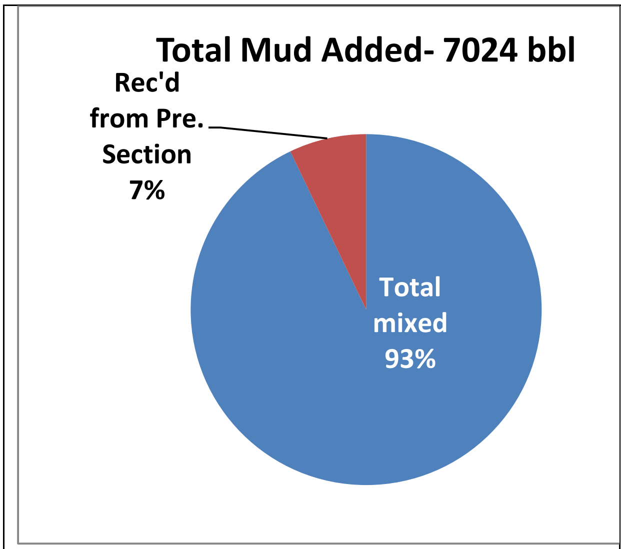


Figure 45. 16" Interval Total Mud added

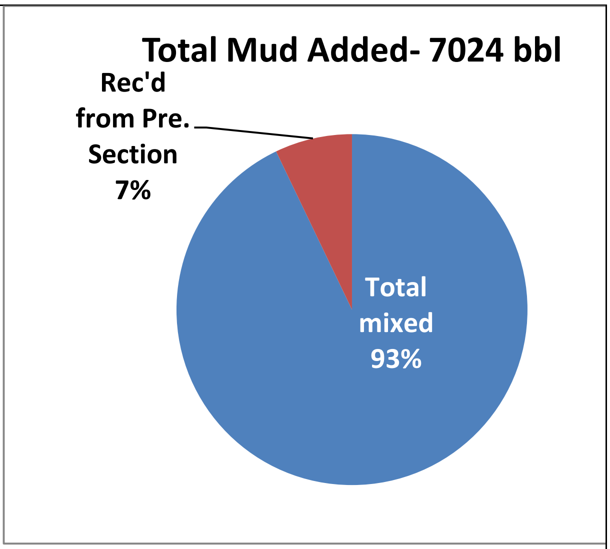


Figure 46. 16" Interval Total Mud Lost/ Returned

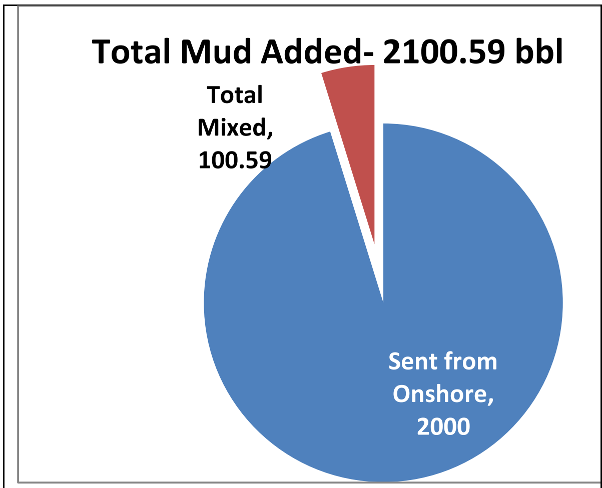


Figure 47. 12 ¼ " Interval Total Mud Added

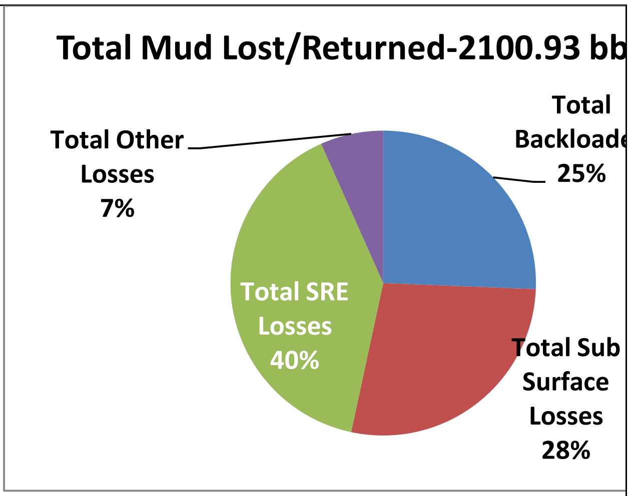


Figure 48. 12 ¼" Interval Total Mud Lost/Returned

6.3 Cost Analysis

The following figures show a close cost analysis of each interval drilled in terms of total interval planed cost, actual cost, LCMs % of the total cost and how much savings resulted from applying such treatment.

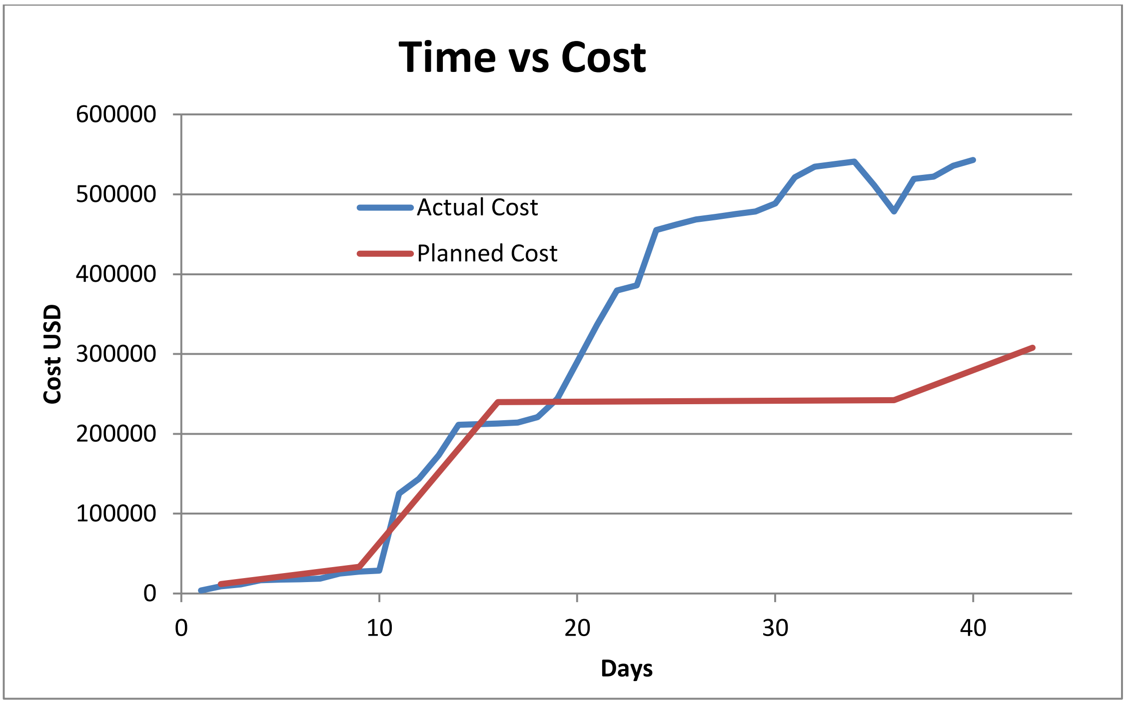


Figure 49. Time vs Cost

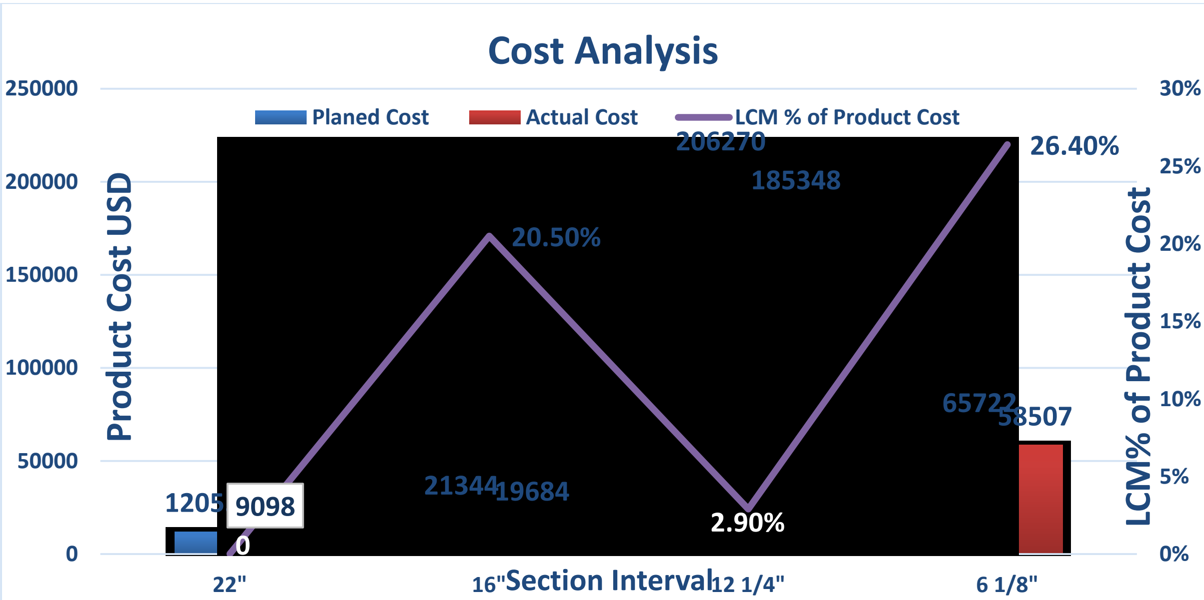


Figure 50. Well Cost Analysis

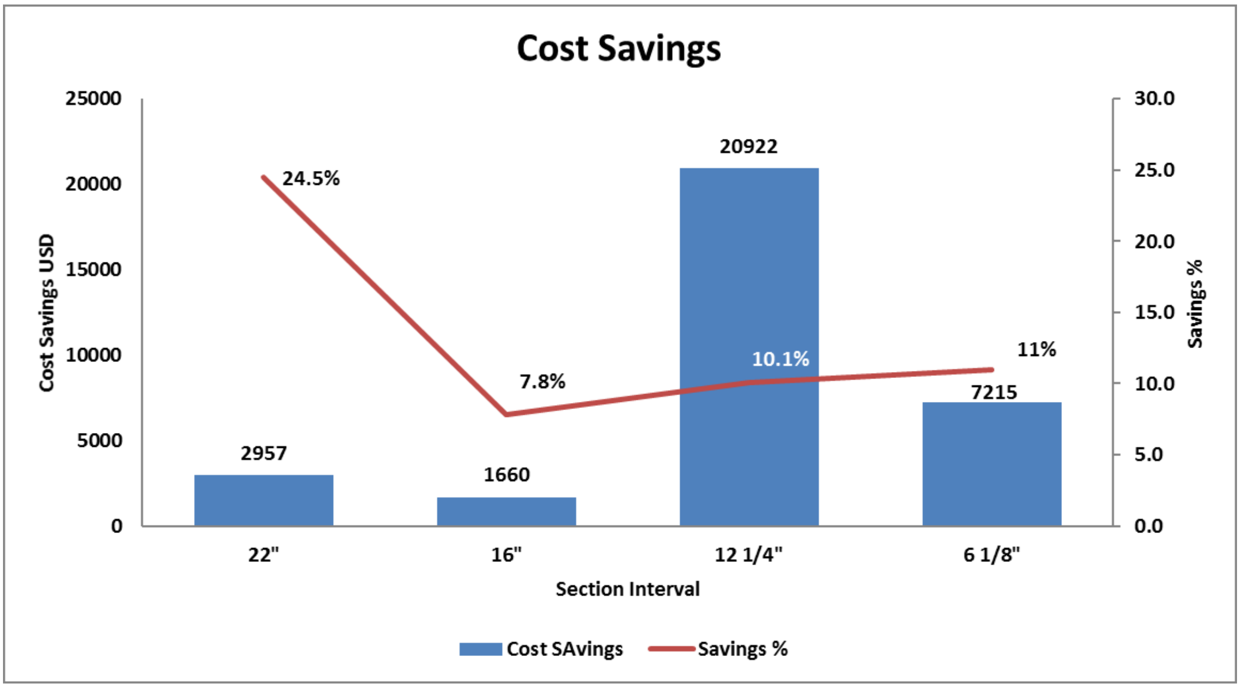


Figure 51. Cost Savings

As seen in Figure 50, the Blue and Red bars represent the planned and actual cost, respectively, read on the primary Y-axis. On the secondary Y-axis read the LCMs% of product cost, respectively.

In Figure 51 The blue bars represent the cost savings, read on the primary Y-axis. On the secondary Y-axis read the savings percentage.

The 22" hole interval had no LCMs used as it was a conductor section done only with Spud mud with little variations of added chemicals to the plan, resulted in **25% savings (3000$)** less than plan. That's due to using less amount of mud bbls, as hole dictated while drilling. Thus, when charged to KOC it cost less in total.

No LCMs were used in this section. All used materials were bulky for adding weight i.e. MIL-BAR and increasing the viscosity i.e. MIL-BEN.

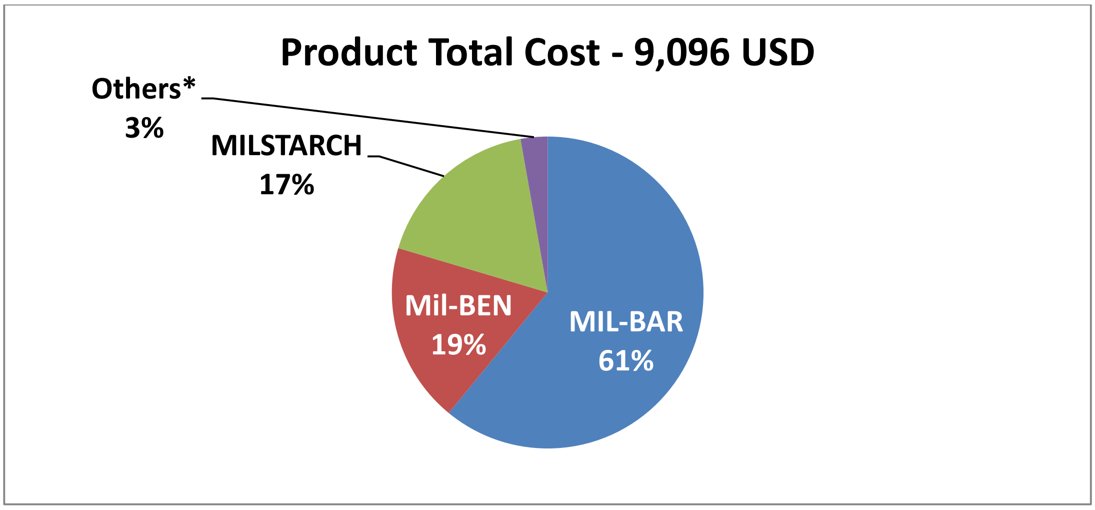


Figure 52. 22" Interval Total Product Cost

The 16" hole interval had complete loss of circulation and LCMs were used by a **20.5%** of the total product cost which is significant amount and resulted in **7.8% saving (1600$)** less than the original planned hole cost. Even though, the hole got complete loss but as it was already expected in the well plan, knowing the to-be-drilled formation so drilling fluids was prepared and bridging materials with LCMs were ready to be introduced to hole to plug the pores of the formation and suppress the losses, which actually happened and was even less in cost than planned.

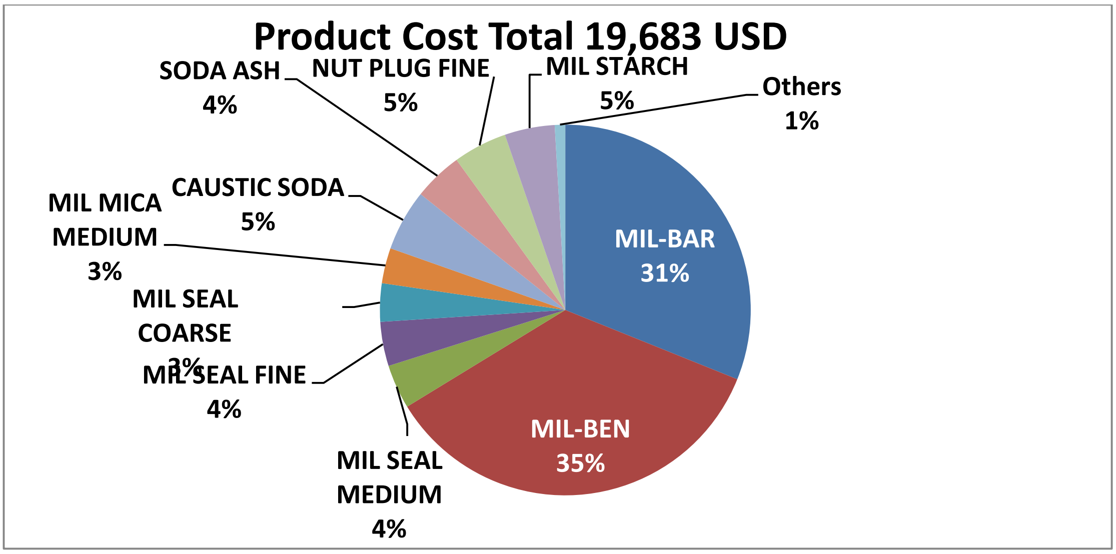


Figure 53. 16" Interval Total Product Cost

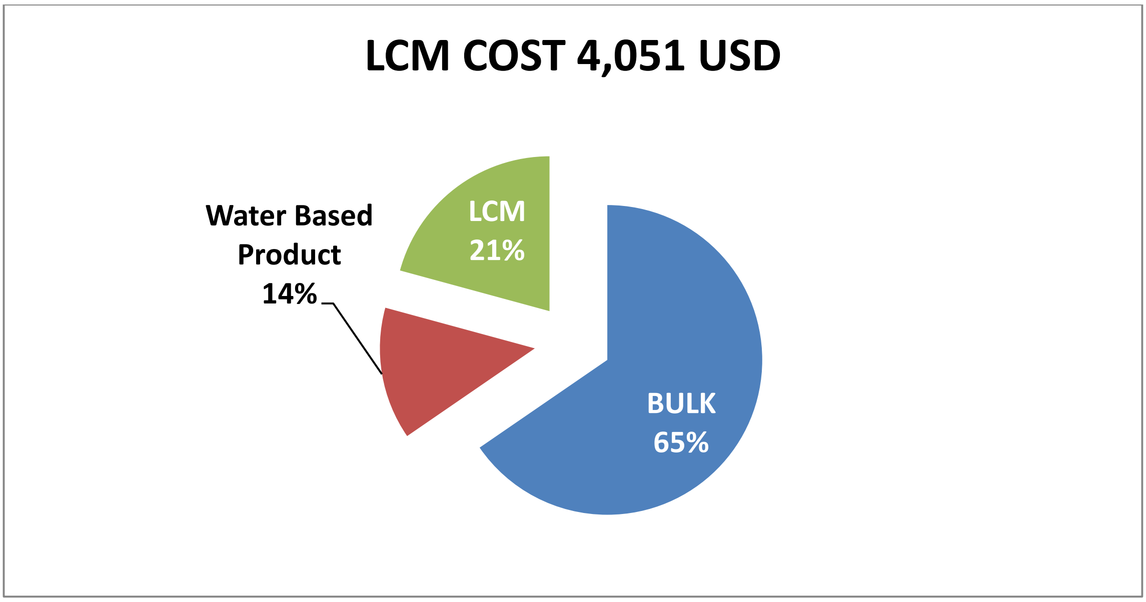


Figure 54. 16" Interval LCM Cost

The 12 ¼" hole interval shows a major impact of the treatment with LCMs when experiencing loss of circulation. The hole cost was less by **20,836 $** of the original planned cost. The main reason for such significant decrease in interval cost was due to the proper type selection companied with optimized **PPT** and **PSD** at the adjusted concentration of the selected treatment mixture. Since, in each hole, returned mud being examined for its contain of mud, drilled cuttings and drilled formations. Therefore, as the mud returned evaluation was done, PPT and PSD was performed to get better idea and better decision for the optimum mixture of LCMs to be used in the hole section. That did not do much with respect to time reduction of the drilling process because its more or less the same process, drilling, Pump HI-VIS pill wait soaking, run casing, cement and so on. But the highest impact was the reduction in cumulative cost for each interval due to the right selection of the proper size while introducing it at the right concentration.

As a matter of fact, being able to cut the cost short by **20,836$** due to the performance of couple of tests to analyze the returned mud contains and the to-be added mixture, is sensational in so many ways. It strongly emphasizes how effective that technique in terms of reducing the cost. Especially, as the total cost of LCM material itself compared to the total mud did not account to more than **2.9%.**

Precisely those two figures of **2.9%** material cost of the total mud system cost and **20,836$** savings which accounts to **10.1%** reduction in the original planed cost, show how combatant and effective that technique when applied. But, most important it should be applied after careful studies and analysis to both the drilled formation and the used mud.

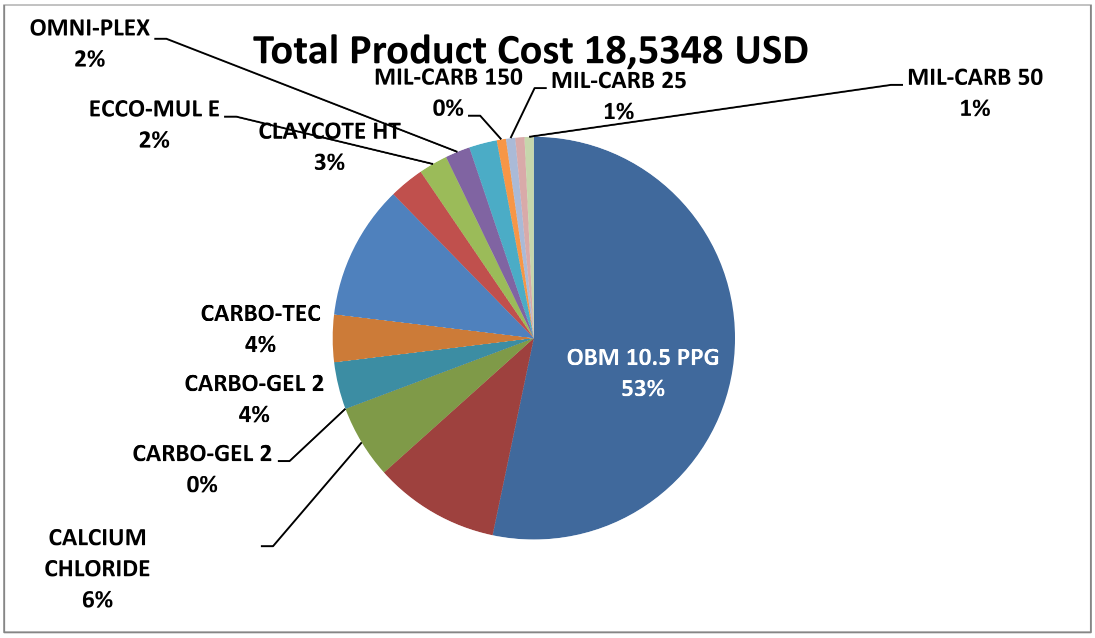


Figure 55. 12 ¼ " Interval Total Product Cost

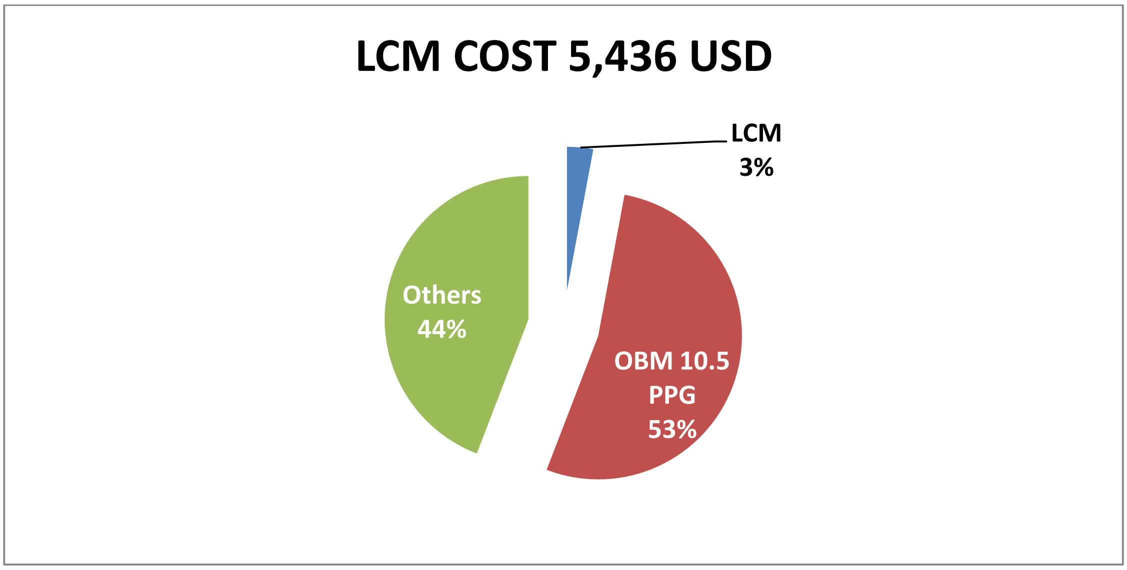


Figure 56. 12 ¼ " Interval LCM Cost

The 6 1/8" hole interval had total loss of circulation and LCMs treatment was applied with a **27%** of the total interval product cost and resulted in **11% savings (8,000$)** less than planned cost. Drilling mud was switched from KCL polymer mud to lime treated water with LCM. Once drilling reached the target formation, it stopped even at a depth less than the target but it was enough from the reservoir point of view for the water disposal well. Then 7" liner was run and well completed after.

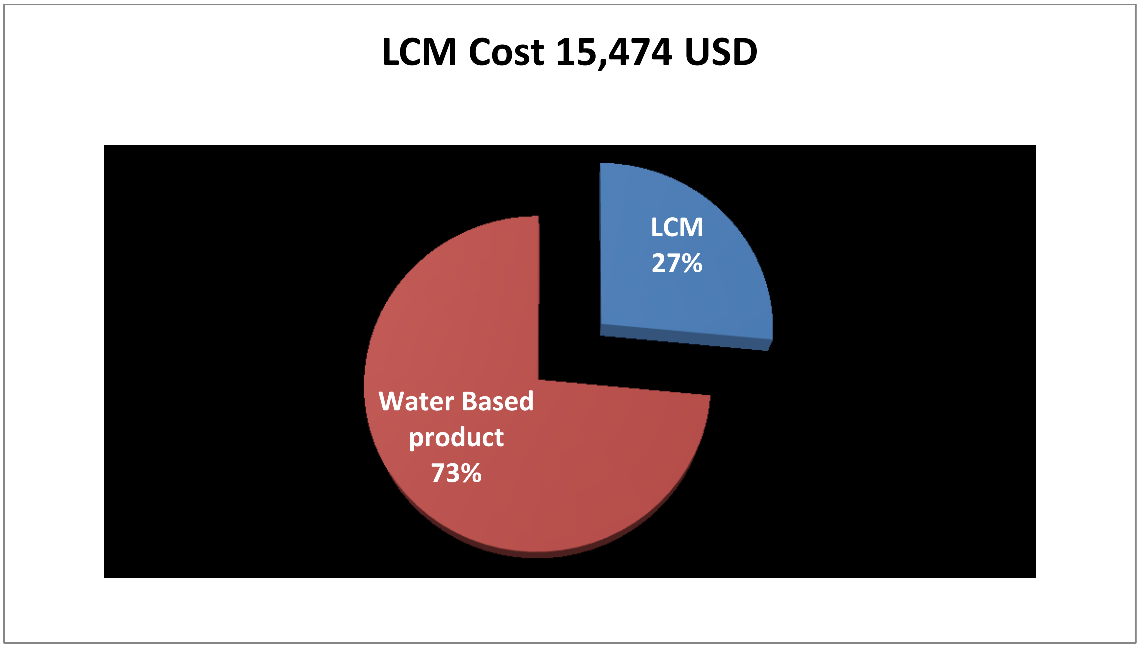


Figure 57. 6 1/8 ″ Interval LCM Cost

The following figure shows the total mud cost for the well and the LCM% of total cost.

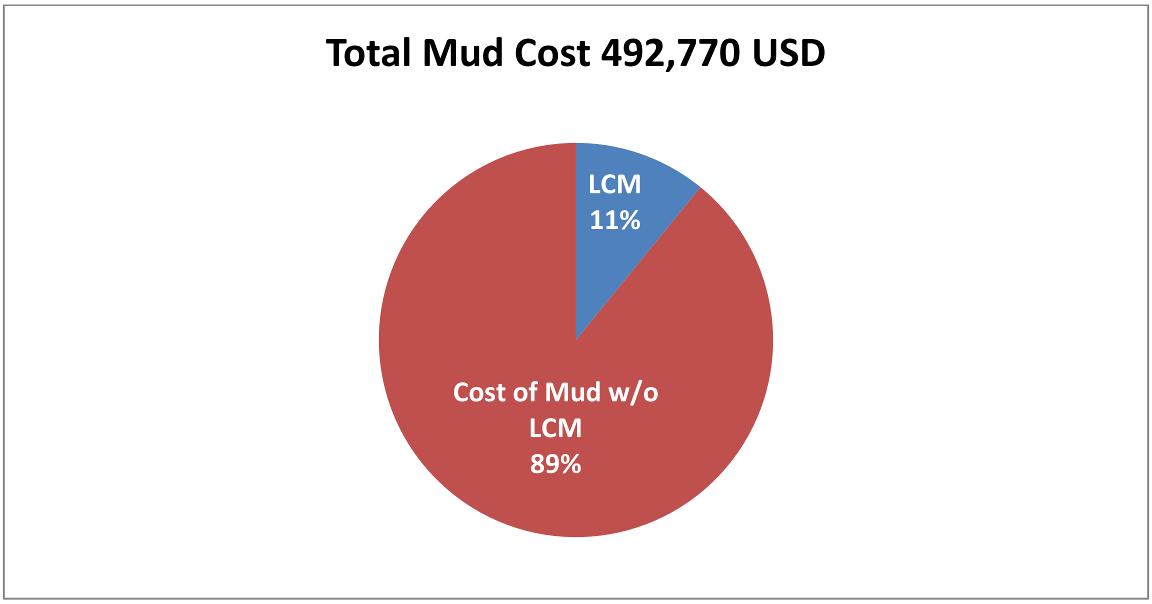


Figure 58. Well Total Mud Cost

Excluding the 8.5" hole interval, as it does not represent the scoop of this study being accompanied with other treatment i.e. cement plugs. The hole cost was higher by **200,881 $** of the original planned cost. That's due to the total loss of OBM drilling fluid experienced, which wasn't solved till four mixed spotted pills of highly expensive LCMs was placed with the need to perform three cement balance plugs meanwhile, nonetheless, there was loss in the cement slurry during the cement job, which add to the total cost. That's why, the interval ended up in a higher cost than planned. But, drilling the interval itself through the caverns at the formation losses would not have been possible unless the engineered LCMs and cement plugs were placed.

Worth mentioning remark on the 36th day, after the treatment with LCMs was done and circulation was restored back. The OBM used after interval drilling is completed has to be sent back to the mud plant for recycling and getting it ready for use again. This means that the company will use it again for the next job and it was already charged to KOC once, so as per contract KOC can charge the service company for the **back loaded mud**. This result in the drop in the cost curve on the 36th day by around **50,000 $** as back loaded mud.

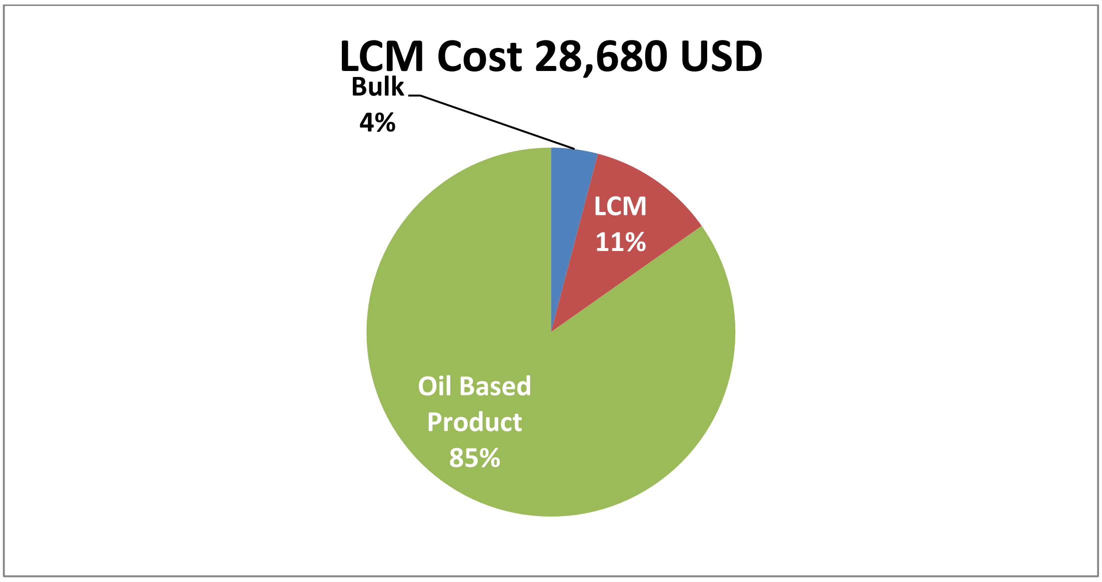


Figure 59. 8 ½ " Interval LCM Cost

Therefore, having LCM cost for the other 4 intervals and its saving impact to the job is as follows:

LCM% cost of the four sections of the total cost (excluding the 8 ½" hole) is **5.9 %** equals to **25,000$** and managed to save **30,000$** of the original cost plan. More over TD the well earlier by 3 days from the plan, which means in the bigger big for the total well cost saving 3 rig days that adds that least **100,000$** considering the daily rig rent rate. **Eventually, spending 25,000$ on LCM to be applied when facing lost circulation problem resulted in tremendous saving of almost 130,000$ with 3 days' rig rental time less.**

6.4 Results

The Well was drilled using customized OBM. The customized fluid proved its performance as listed below:

- The well was drilled using in some sections 11 ppg (3500 psi overbalanced) without any wellbore stability/ caving issues.
- Drill and set casing with minimal downtime.
- Good hole cleaning in the deviated and horizontal sections.
- Potential possibilities of getting stuck pipes were eliminated due to the fact of forming internal filter cakes when using OBM.
- Minimize downhole losses through losses strategy plan by always performing mud return analysis (**i.e. PSD and HPHT Filtration**) to take best fit necessary actions.
- Well reached TD by 3 days earlier than the original plan. resulting in savings of almost 100,000$ considering the rig rental cost.
- There was significant savings in the intervals costs' when LCMs were used to mitigate the lost circulation problem of about 30,000$.

Achieved goals

Goal relationship	**HSE**	**Performance**
Goal Description	Zero accidents, zero incidents, full compliance with HSE regulations	Achieved successfully
Goal relationship	**Technical Ops.**	**Performance**
Goal Description	Drill and set casing with minimal downtime. Achieve good leak-offs. Drill and log to TD.	Achieved successfully
Goal relationship	**Technical Ops.**	**Performance**
Goal Description	Minimize downhole losses	Through permeable zones of tayrat and ahamdi Managed with high efficiency

Table 22. Goals and Tracking

7 Conclusion and Recommendations

7.1 Conclusion

Based on the findings of this thesis the following conclusion can be drawn:

- The presented work explains in details the proactive and corrective methods used recently to deal with loss of circulation problems. The detailed case study illustrated has proven the high economic impact of using those methods on improving the drilling process with respect to decreasing the time needed to fix the problem and consequently the overall well cost.
- The lost circulation material selection and planning, as has been discussed in this work and been applied to mentioned the case study, is a process of exploring and assessing project specific lost circulation problems and links them to existing lost circulation products, systems and services. The process focuses on using existing resources to create project specific plans and solutions. The process consists of five key steps, as explained through this thesis:
    1. Collecting and analyzing all the available project and problem related data (i.e., offset well data including logs, recaps of previous wells as mentioned in the Case study)
    2. Identifying the loss mechanics (whether it's already existing or expected to occur)
    3. Selecting and deciding the best fit approach (proactive or corrective) to follow on order to fix the problem
    4. Identifying the best conventional lost circulation treatments, and recommending the contingency specialized treatments (i.e., cross-linking pills, conventional squeezes) through running lab tests and simulations including detailed operational procedures.
    5. Reporting results and comparing it to recaps and original plans to keep progress tracking, that's of high importance when it comes to the treatment evaluation. For instance, in the shown case study, the resultant impact of applying LCM treatment is highly tempting, in respect to the cost savings that were achieved time and money wise. To be more specific, saving around 130,000$ to spending only 25,000$ on LCM to be applied is absolutely sensational considering the down-cycle that the oil industry is suffering from nowadays.
- Based on the results of the conducted experiments, it can be stated that knowing the loss mechanism is a key factor in choosing an appropriate treatment. Given the fact that different mud systems behave in different ways when adding LCMs to them, OBM yields the least filtrate and the slimmest filter cake, while Bentonite mud gives the highest amount of filtrate and the thickest filter cake, whereas, polymer mud values are in-between.

- Most important about the corrective treatment with LCM is always to keep in mind it's a remedial treatment not a preventive one. No matter how effective such a method is, but it can't be applied for all the situations and the discussed case study gave a perfect example in showing that, specifically for the 8.5" interval section. While the interval took total losses, due to the development of caverns, even using four conventional pills of LCMs were not enough to stop the losses alone and three cement balance plugs were needed to fix the problem.

7.2 Recommendations

Using LCMs as treatment solution is recommended to be applied when at least one of the following conditions exists:

- Going through depleted zones or sand matrix (known for its low pore pressure and fracture pressure)
- Going through high permeable zone, knowing its permeability and performing Plug permeability test (PPT) prior to treatment is a must accompanied with PSD
- Overbalance drilling with the need of thin filter cake to avoid differential sticking problems (better to use customized OBM with LCM rather than WBM)
- Difficulties with running extra casings for zonal isolation
- Need to strengthen the wellbore by stress caging technique (better to use WBM as it forms thick filter cake assisting in strengthening and adding more stability to the near wellbore walls rather than OBM)

It is recommended to run series of tests prior to choosing the best fit mixture of LCMs to be applied with respect to optimum size, type and concentration. Here is the list of the essential tests:

- HPHT filter press test to measure the amount of filtrate given by the drilling fluid
- PSD simulator to judge the optimal sizes able to plug the fractures, considering and giving allowance to the shearing action of the drilling bit which turns the pumped LCM pill into smaller grains.
- Eventually the Plug Permeability Test (PPT) giving an indicator of the tendency of the drilling fluid to invade the formation as it's of much concern especially in a reservoir zone. It's strongly recommended and advised to try to keep the spurt losses that comes out of the PPT as low as possible. This means formation invasion is kept to minimum value.

8 Nomenclature

$OH_{Capacity}$	Open hole [bbl / ft]
ID_H	Hole Size [Inch]
WO	Washout [%]
V_{Pill}	Volume of pill [bbls]
OD_{DS}	Drill String Outside Diameter [Inch]
ID_H	Hole Size [Inch]
$DS_{capacity}$	Drill String Capacity [bbl / ft]
ID_P	Drill Pipe Inside Diameter [Inch]
L_{Pill}	Length of Pill [ft]
D_{Pill}	Depth to set Pill [ft]
$PO_{BBL/STK}$	Pump Output [bbl/stk]

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10 Appendix

10.1 Appendix A

10.1.1 High Temperature High Pressure-HPHT- Filter Press Test

Apparatus

HPHT Filter Press (see Figure 60) It consists of a controlled press source (CO_2 or Nitrogen), Regulators, a drilling-fluid cell able to contain working pressures from 4000 KPa to 8900 KPa (600 psi to 1300 psi), a system for heating the cell, a pressurized collection cell able to maintain proper back-pressure (see Tables 8 and 9) in order to prevent flashing or evaporation of the filtrate, and a suitable stand. The drilling-fluid cell has a thermometer well, oil-resistant gaskets, a support for filter medium and a valve on the filtrate delivery tube to control flow from the cell. It may be necessary to replace the gaskets frequently.

Caution—Nitrous oxide cartridges should not be used as pressure source for HPHT filtration. Under temperature and pressure, nitrous oxide can detonate in the presence of grease, oil or carbonaceous materials.

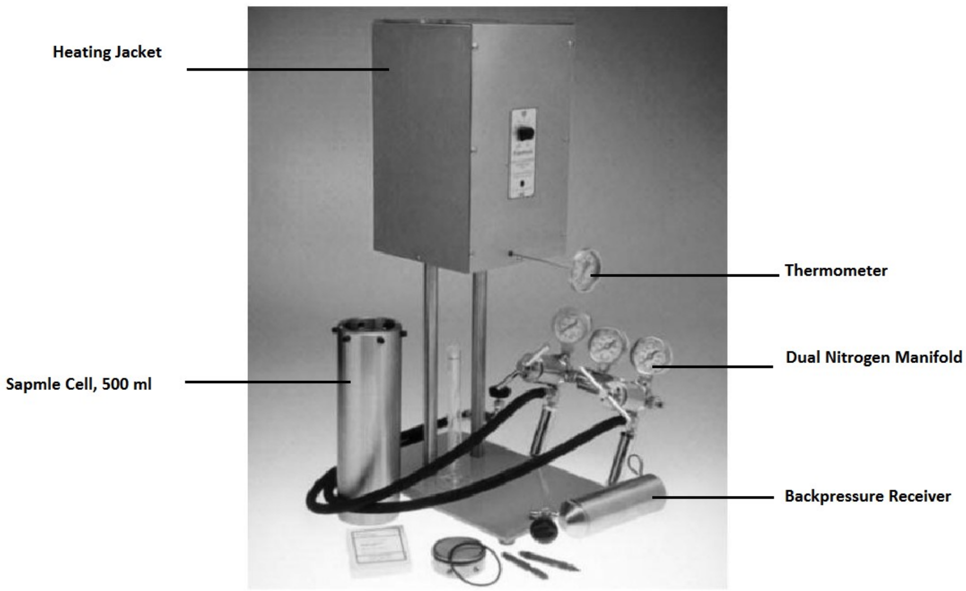

Figure 60. HPHT Filter Press, 500 ml

Temperature	< 200°F (93°C) No backpressure required.
	200° to 300°F (93°C -149°C) Backpressure at 100 psi (689 kPa).
	300° to 500°F (149°C- 260°C) for Backpressure see Table below.
Pressure	< 200°F (93°C), 500 psi (3447 kPa).
	200°F - 300°F (93°C - 149°C), 100 psi (689 kPa) during heating and 600 psi (4137 kPa) with 100 psi (689 kPa) backpressure during test.
Sample Preparation	Stir for 10 minutes with high speed mixer.
Expansion allowance	1/2 inches (12.7 mm), < 300°F (149°C).
	1-1/2 inches (38.1 mm), 300°F- 500°F (149°C - 260°C).
Sample Volume	500 ml cell: 455 - 470 ml, < 300°F (149°C).
	500 ml cell: 390 - 405 ml, 300°F - 500°F (149°C - 260°C).
Filter Medium	Hardened filter paper.
	Ceramic disks.
	For > 375°F (190°C), back the filter paper with a disc of glass fiber.
Time	Sample heating - less than 1 hour.
	Duration of test - 30 minutes.
Filtrate Collection	25 ml or 50 ml TC Graduated Cylinder [< 200°F (93°C)].
	Backpressure Receiver [300°F - 500°F (149°C- 260°C)] Bleed into graduated cylinder during and at end of test.

Table 23. HPHT Mud Test Outline

Temperature Range		Minimum Backpressure	
^{o}F	**^{o}C**	**Psi**	**kPa**
<200	<93	0	0
200-300	93-149	100	689
301-350	150-177	150	1034
351-375	178-190	200	1379
376-400	191-205	250	1724
401-425	206-218	350	2413
426-450	219-232	450	3103
451-475	233-246	550	3792
476-500	247-260	700	4826

Table 24. Recommended Backpressures for HPHT filter Press

Filter medium

The main feature of the HPHT filter press is the use of a porous ceramic disks[1] as a filtration medium. These are available in a wide range of porosities and permeabilities to match those properties of the formation much better than a filter paper can do.

- Timer, with at least a 30 min interval.
- Thermometer, with a range up to 260˚C (500˚F).
- Graduate cylinder, with a volume of 25 ml or 50 ml.
- High-speed mixer.

[1] Fann ceramic filter disc-Product Number 210540- was used with mean pore diameter of 56 microns new (Hg) and 35 microns old (air) , Size of the disc is 2 ½ ″ Diameter and ¼ ″ thick.

Procedure for Temperatures to 150˚C (300˚F)

1. Heating jacket should be heated to 6˚C (10˚F) above the desired temperature. Thermometer has to be placed in the well in the jacket to measure the temperature and the thermostat is adjusted to maintain the desired Temperature.
2. Using the high speed mixer to stir the drilling fluid sample for 10 min. Bottom valve of the drilling fluid sample cell should be closed when pouring the sample into the fluid cell, care should be taken not to fill closer than 1.5 cm (0.6 in) from top to allow for expansion, and then ceramic disc is installed.
3. The cell is completely assembled when both bottom and top valves are closed, then it should be placed in the heating jacket and the thermometer is transferred to the well in the drilling fluid cell.
4. High pressure collection cell should be connected to the bottom valve and lock in place
5. pressure regulated source should be connected to the top valve and collection cell, and lock in place.
6. Keeping the valves closed, top and bottom regulators have to be adjusted to 690 KPa (100 psi). Top valve then is opened to allow applying 690 KPa (100 psi) to the drilling fluid. Pressure should be maintained until the desired temperature is stabilized. The sample in the filter cell should never be heated for period exceeding a total of 1 h.
7. When the sample reaches the selected test temperature, the pressure of the top pressure unit should be increased to 4140 KPa (600 psi) and bottom valve should be opened to start filtration. Filtrate is collected for 30 min, maintain the selected temperature with ± 3˚C (± 5˚F). If back-pressure rises above 690 KPa (100 psi) during the test. Cautiously pressure is reduced by drawing off a portion of the filtrate. Total volume of collected, temperature, pressure and time are recorded.
8. Correction of the filtrate volume to the filter area of 45.8 cm2 (7.1 in2) is done by doubling the filtrate volume recorded.
9. At the end of the test, top and bottom valves of the drilling fluid cell are closed and pressure is bled from the regulator

Caution— **Pressure in the drilling fluid cell will still be approximately 4140 KPa (600 psi). to avoid possible serious injury, keep cell upright and cool to room temperature, then bleed pressure from cell before disassembling.**

10. Cell is removed from the heating jacket, first certain should be made that the bottom and top valves are tightly shut and the pressure is off the regulators. Using extreme care to save

the ceramic disc, cell then is placed upright, valve is opened to bleed the pressure from the cell contents. Drilling fluid is discarded, filter cake is retrieved. Filter cake on the ceramic disc is washed with gentle stream of water.

11. Thickness of the filter cake should be measured and reported, to the nearest millimeter.
12. Although cake descriptions are subjective, but notation as hard or soft, etc. may convey important information of the cake quality.

General Safety Precautions and Measures

Testing at high temperatures and pressures will call for added equipped precautions. Pressuring systems and filtrate receiving cells should be equipped with suitable safety relief valves. Heating jackets should be equipped with both an overheat safety fuse and thermostatic cut-off. Vapor pressure of the liquid phase of both water-base and oil-base fluids becomes an increasingly critical design factor as test temperatures are raised.

- Safe Pressurization

Nitrogen or carbon dioxide should always be used. The filter press should not be ever connected to compressed air, oxygen or other non-recommended gas. If nitrogen is used, it must be supplied in an approved nitrogen gas cylinder or the nitrogen supply system must be built into the laboratory. Nitrogen cylinders must be secured to meet safety standards. Carbon dioxide is normally supplied in small cartridges that contain about 900 psi (6206 kPa). They are primarily used for field operations. These cartridges must not be heated or exposed to fire. They can explode if overheated.

Pressure regulators have to be maintained in good condition. oil must not be used on pressure regulators. Leaking pressurization systems should be repaired or replaced. Gauges, fittings and hoses should be kept in good condition and leaks should be found and corrected. Periodically test the safety relief valves on the pressurization manifolds to verify they will relieve if excessive pressure should occur. These safety valves should never be plugged or bypassed.

- Safe Heating

Caution should be exercised by all personnel working with or working in the area where HPHT Filter Presses are in operation to avoid accidental injury caused by touching the heating jacket or cell assembly while these are hot. The heating jacket can operate at a temperature that will cause burns if touched. Safeguard the equipment after the test ends long enough for it to cool. It can still cause burns even after it has been turned off.

The practice of removing the cell and cooling it under water is very dangerous and is not recommended because the user could be severely burned if the cell is touched or accidentally dropped. Hot steam generated when the water hits the hot cell can cause severe burns.

Extreme caution should be used when handling a hot cell. A cell removal tool, shown in Figure 61, is available for handling the cell assembly and removing it from the heating jacket. Its use will reduce the chances of accidentally dropping the cell or being burned by it.

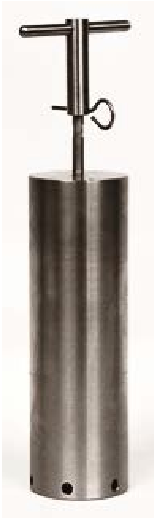

Figure 61. Cell Removal tool

- Safe Electrical Operation

Make sure the electrical source is fused and grounded. Power cable should be always disconnected before repairing the instrument.

10.1.2 Plug Permeability Apparatus (PPA)

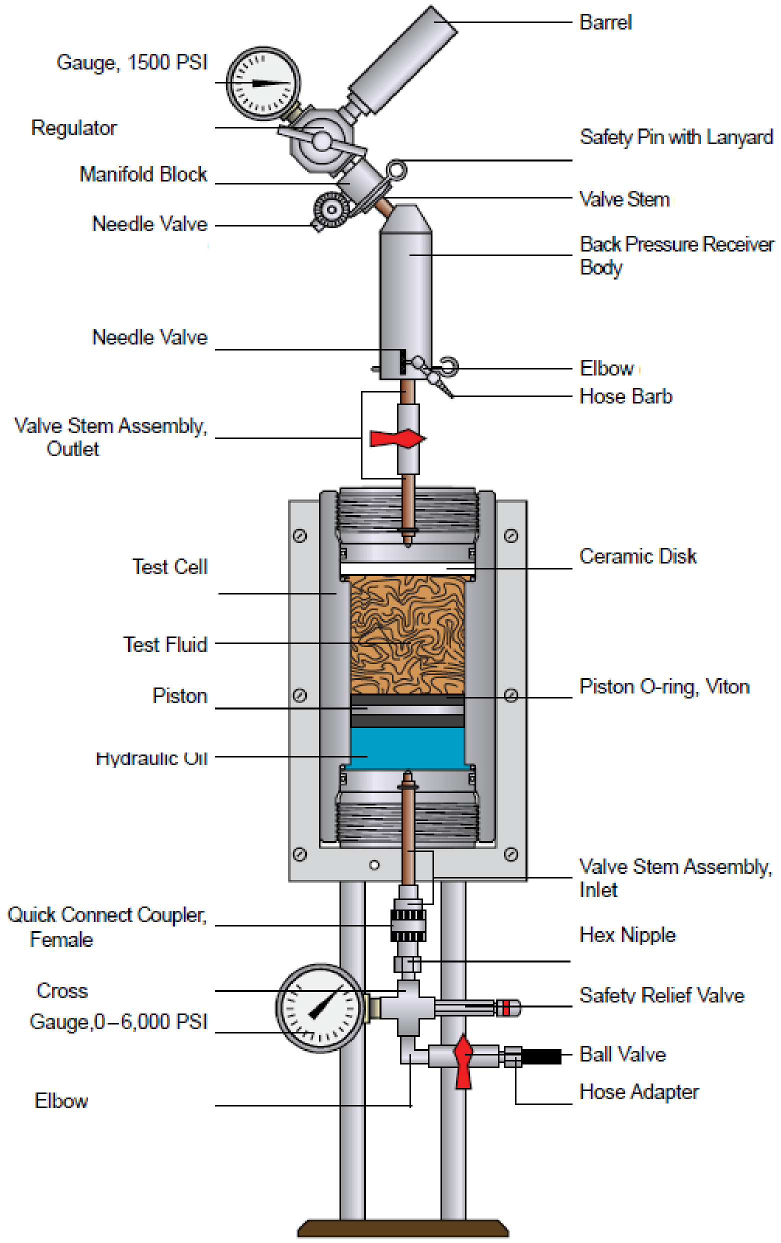

Figure 62. PPA

10.2 Appendix B

10.2.1 Case Study

Section 1: 22″ Interval

Major Frame

	Planned	Actual
Hole size – Casing size	22" / 18.625 "	22″ – 18 5/8″
Casing Depth (ft)	271' / 271'	281′ / 281′
Formations to be drilled	Kuwait and Dammam	Kuwait and Dammam
Maximum inclination/Dogleg	Vertical	0 deg
Mud System	Spud Mud	Spud Mud
Expected Problems	Hole cleaning , H2S gas & Total Loss of circulation	No problem

Table 25. 22″Interval Major Frame.

Volume and Cost Summary

	Planned	Actual
Drilling days / Total days	1 / 2 days	1 / 2 days
Unscheduled cost	0.0 USD	0.0 USD
Total cost excluding the unscheduled cost	12055 USD	9098 USD
Total volume Mixed	1017 bbl	1000 bbl
Formation losses bbl	0	0
Mud back loaded bbl	0	0
Mud transferred to next interval bbl	0	0
Min / Max mud weight	9.5 - 9.6 ppg	9.5 -9.6 ppg
Interval Cost/bbl	11.847 USD	9.24 USD
Interval Cost/ft	44 USD	32 USD
Interval Cost	12055 USD	9098 USD
Cumulative Cost	12055 USD	9098 USD

Table 26. 22″ Interval Volume and Cost Summary

Mud properties

	Planned	Actual
Mud weight ppg	9.5 - 9.6 or as hole dictates	9.5 - 9.6
Funnel Viscosity Sec/Qrt	Depends on 6 rpm (expected range 45 to 70)	44 - 45
PV C.P @ 120˚f	ALAP (expected range 10 to 15)	21
YP PPHSF @ 120˚f	Depends on 6 rpm (expected range 25 to 30)	20
Gels PPHSF @ 120˚f	8 - 14 / 12 - 20	10 - 15 / 6-8
6 RPM@ 120˚f	10 - 14 (Run mud rhelogy on 6 rpm)	10 / 6
API Fluid loss cc/30 min	< 10	9
Chlorides mg/l	Drill water salinity	800
MBT ppb	17.5 - 25	22
LGS % vol:	< 4%	0.56
Total Hardness mg/L	<200	200
pH	9.0- 9.5	10

Table 27. 22″ interval Mud properties

Chemicals and Concentration

Chemical Name	Function	Concentration
CAUSTIC SODA	Alkalinity control	0.5 – 1 ppb
SODA ASH	Calcium Remover	0.5 ppb or as needed for hardness
MIL BEN	Viscosifier and gelling agent	20 – 23 ppb
MIL BAR	Weighting agent	56 ppb (8.5ppg to 9.6ppg)
MIL-STARCH	Water loss reducer	2 - 3 ppb
NEWTHIN	Thinner	.02 gpb
SUPER SWEEP	High Sweeps	as needed for sweeps

Table 28. 22″ Interval Chemicals and Concentration

Volume and Cost Analysis

a- Planned

22″ phase Section						
Hole Geometry and casing Design			**Dilution factor calculation**		**Cost analysis comments**	
Open Hole size (inch)	22	146	Equip. Eff. %	85	Interval volume required	1017 bbls
Open Hole T.D (ft)	271		L.G.S %	6	Surface + casing	800 bbl
Open Hole Length (ft)	271		Est % hole washout	7	Open hole	146 bbl
Est % Hole washout	7		Est new open hole BPF	0.5383	Dilution volume	71 bbl
Est New Hole size (inch)	23.54		Dilution volume BPF	0.8	Net built Volume	217 bbl
Total Hole Volume (bbl)	146		Dilution volume	71	Interval cost	12055 USD
			Recovered pre. Sec.		Cumulative cost	12055 USD
			Imported		Interval cost/BBL	11.847 USD
			Surface Pits	800	Interval cost/Ft	44.484 USD
			Newly	217		
			Total	1017		

Table 29. 22″ Interval Planned Cost Analysis

b- Actual well analysis

Hole section summary

Days	2	
Top Depth	0	ft
Bottom Depth	281	ft
Length (Sum of daily drilled)	281	ft
Max TVD	281	ft
Max deviation	0	deg
Max Mud Weight	9.5	ppg
Bit Size	22	in
Actual Cost	9096.6	USD
Cost per day	4548.3	USD
Cost per ft	32.373	USD
Mud System	Spud mud	

Table 30. 22" Interval Actual Hole Summary

Section volume summary

22" PHASE #1			
Cumulative Section Additions- bbl		**Cumulative Section Losses- bbl**	
Starting Volume 0.00 bbl			
Weight material	31.51	Discharged	429
Water	940	Solids Removal Equip.	51
Additional products	28.37	Others Losses	20
Total volume added	999.88	Mud returned/total volume lost	500
			Ending Volume 499.88 bbl
Average Addition per Length		149.448 **USgal/ ft**	
Average Losses per Length		74.733 **USgal/ft**	
Average addition per day		499.94 **bbl**	
Average losses per day		250 **bbl**	
Bit Size		22 **in**	

Table 31. 22" Interval Actual Volume Summary

Section Product summary

22" Phase #1 Product Usage						
Product	**Unit Size**	**Received**	**Used Amt**	**Used Ib**	**On Hand**	**Cost USD**
Bulk						
MIL-BAR	1500 Kg	62	14	46297	84	N/A
MIL-BEN	1000 Kg	62	9	19842	53	N/A
Water Based Product						
CAUSTIC SODA	25 Kg	120	10	551	110	N/A
MILSTARCH	25 Kg	72	36	1984	36	N/A
NEW-THIN	5 USgal	16	2	108	14	N/A
SODA ASH	25 Kg	120	11	606	109	N/A
				Total Product Cost		**9096**
				Total Cost		**9096**

Table 32. 22" Interval Product Usage Cost

Section IADC Hours

22" PHASE #1	
IADC Activity	**Total Hours**
Cementing	1
Circulating	2
Drilling Formation	8
Nipple Up/Nipple Down BOP	6
Rig Up and Tear Down	10
Run Casing	10
Wait on Cement	11
Total IADC Hours	**48**

Table 33. 22" Interval IADC Hours

Section 2: 16″ Interval

Major Frame

	Planned	Actual
Hole size – Casing size	16" / 13.375 "	16″ – 13 3/8″
Casing Depth (ft)	3664' / 3647'	3679′ / 3652′
Formations to be drilled	RUS ,RADHUMA,TAYARAT,HARTHA,SADI, MUTRIBA and top of Ahmadi	RUS ,RADHUMA,TAYARAT,HARTHA,SADI, MUTRIBA and top of Ahmadi
Maximum inclination/Dogleg	16 deg	16 deg
Mud System	Gel Polymer Mud	Gel polymer mud / Mud cap
Expected Problems	Total Loss of circulation & Bit Balling	Complete loss

Table 34. 16″ Interval Major Frame

Mud properties

	Planned	Actual
Mud weight ppg	8.7 - 9.0 ppg or as hole dictates	8.6 - 8.8
Funnel Viscosity Sec/Qrt	Depends on 6 rpm (expected range 45 to 70)	36 – 40
PV C.P @ 120˚f	ALAP (expected range 6 to 8)	11-12
YP PPHSF @ 120˚f	Depends on 6 rpm (expected range 20 to 28)	10-19
Gels PPHSF @ 120˚f	8 - 12 / 12 - 17	8 / 11
6 RPM@ 120˚f	10 - 14 (Run mud rhelogy on 6 rpm)	8
API Fluid loss cc/30 min	5 - 10 before running casing	N/A
Chlorides mg/l	Drill water salinity	800
MBT ppb	15 – 20 & 10 - 15 before running casing	8-15
LGS % vol:	< 4%	2.790
Total Hardness mg/L	<200	200-450
pH	9.5 - 10	10

Table 35. 16″ Interval Mud Properties

Volume and Cost Summary

	Planned	Actual
Drilling days / Total days	7/8 days	7/8 days
Unscheduled cost	0.0 USD	0.0 USD
Total cost excluding the unscheduled cost	21344 USD	19684 USD
Total volume Mixed	5973 bbl	6524bbl
Formation losses	Total Loss Expected	6643 bbl
Mud back loaded bbl	0	0
Mud transferred to next interval bbl	0	0
Min / Max mud weight	8.7-9 ppg	8.6-8.8 ppg
Interval Cost/bbl	3.56 USD	2.97 USD
Interval Cost/ft	6.303 USD	5.79 USD
Interval Cost	21344 USD	19684 USD
Cumulative Cost	33400 USD	28780 USD

Table 36. 16" Interval Volume and Cost Summary

Volume and Cost Analysis

a- Planned

16'' PHASE Section						
Hole Geometry and casing Design			**Dilution factor calculation**		**Cost analysis comments**	
Last Casing OD	18 5/8		Equip. Eff. %	85	Interval volume required	5973 bbls
Last casing I.D	17.755	83	L.G.S %	4	Surface + casing	883 bbl
Last casing depth	271		Est % hole washout	6	Open hole	984 bbl
Open Hole size (inch)	16		Est new open hole BPF	0.2794	Dilution volume	71 bbl
Open Hole T.D (ft)	3664		Dilution volume BPF	1.5	Net Built Volume	5090 bbl
Open Hole Length (ft)	3393	948	Dilution volume	4142	Interval cost	21344 USD
Est % Hole washout	6		Recovered pre. Sec.		Cumulative cost	33400 USD
Est New Hole size (inch)	16.96		Imported		Interval cost/BBL	3.56 USD
Total Hole Volume (bbl)	1031		Surface Pits	800	Interval cost/Ft	6.3 USD
			Newly	5090		
			Total	5973		

Table 37. 16" Interval Planned Cost Analysis

b- Actual well analysis

Section volume summary

16" PHASE #2			
Cumulative Section Additions- bbl		**Cumulative Section Losses- bbl**	
Starting Volume 500 bbl			
		Downhole	6643
Weight material	36.01	Discharged	
Water	6334	Solids Removal Equip.	381
Additional products	153.95	Others Losses	
Total volume added	6523.96	Mud returned/total volume lost	7024
			Ending Volume -0.04 **bbl**
Average Addition per Length		80.638 **USgal/ ft**	
Average Losses per Length		86.818 **USgal/ft**	
Average addition per day		815.5 **bbl**	
Average losses per day		878 **bbl**	
Bit Size		16 **in**	

Table 38. 16" Interval Volume Summary

Section IADC Hours

16" PHASE #2	
IADC Activity	**Total Hours**
Cementing	4
Circulating	5
Drilling Formation	126
Nipple Up/Nipple Down BOP	1
Run Casing	17
Wait on Cement	13
Tripping	26
Total IADC Hours	**192**

Table 39. 16" Interval IADC Hours

Section Product summary

16" PHASE #2 Product Usage						
Product	**Unit Size**	**Received**	**Used Amt**	**Used lb**	**On Hand**	**Cost USD**
Bulk						
MIL-BAR	1500 Kg	30	16	52911	62	N/A
MIL-BEN	1000 Kg	21	38	83776	36	N/A
Water Based Product						
CAUSTIC SODA	25 Kg		39	2150	71	N/A
MILSTARCH	25 Kg	102	20	1102	118	N/A
SODA ASH	25 Kg		39	2150	70	N/A
LCM						
COTTON SEED	50 Lb	37	24	1200	13	N/A
MIL MICA MEDIUM	25 Kg	40	40	2205	40	N/A
MIL MICA COARSE	25 kg	32	26	1433	32	N/A
MIL SEAL FINE	25 Kg	40	30	1653	40	N/A
MIL SEAL MEDIUM	25 Kg	32	30	1653	62	N/A
NUT PLUG FINE	25 Kg	30	30	1653	30	N/A
OTHER						
MIL-LIME	30 kg		26	1720	149	N/A
				Total Product Cost		**19683**
				Total Cost		**19683**

Table 40. 16" Interval Product Usage Cost

Section 3: 12 ¼ ″ Interval

Major Frame

	Planned	Actual
Hole size – Casing size	12.25" / 9.625 "	12 ¼″ – 9 5/8″
Casing Depth (ft)	5300 ft 4995 ft	5300′/ 4945′
Formations to be drilled	Ahmadi, Wara, Mauddud,Burgan	Ahmadi, Wara, Mauddud, Burgan
Maximum inclination/Dogleg	51 deg	49 Deg
Mud System	CARBO-DRILL(OBM)	CARBO-DRILL(OBM)
Expected Problems	Loss of circulation	Loss of circulation

Table 41. 12 ¼ ″ Interval Major Frame

Volume and Cost Summary

	Planned	Actual
Drilling days / Total days	3 / 7 days	3 / 7 days
Unscheduled cost	0.0 USD	0.0 USD
Total cost excluding the unscheduled cost	206270 USD	185348 USD
Total volume Mixed	2026 bbl	2100.6 bbl
Formation losses bbl	Expected losses	174.77 bbl
Mud back loaded bbl	As could be possibly recovered	0
Mud transferred to next interval bbl	As could be possibly recovered	1614.64 bbl
Min / Max mud weight	10.5 - 10.8 ppg	10.6-10.7 ppg
Interval Cost/bbl	101.805 USD	55.23 USD
Interval Cost/ft	126 USD	114.32 USD
Interval Cost	206270 USD	185348 USD
Cumulative Cost	239670 USD	214130 USD

Table 42. 12 ¼ ″ Interval Volume and Cost Summary

Mud properties

	Planned	Actual
Mud weight ppg	10.5 - 10.8 ppg or as hole dictates	10.5-10.7
Funnel Viscosity Sec/Qrt	As required to meet the planned rheology	71-81
PV C.P @ 120˚f	ALAP (expected range 22 TO 30)	28-32
YP PPHSF @ 120˚f	Depends on 6 rpm (expected range 18 to 24)	16-22
Gels PPHSF @ 120˚f	6/9- 10/15	8/11- 9/14
6 RPM@ 120˚f	9-10	9/8
HTHP@250	< 3	2- 2.4
LGS % vol:	< 5	1.635
OWR	80/20	80/20
WPS($CACL_2$)[2]	< 220,000 PPM	200,000 ppm

Table 43. 12 ¼ " Interval Mud Properties

Chemicals and Concentration

Chemicals name	Function	Concentration
LIME	Alkalinity Control	5 ppb
MIL BAR	Weighting agent	200 ppb (11ppg)
ECCOMUL E	Primary Emulsifier	4 - 5 ppb
CARBO TEC	Supplementary Emulsifier	4 - 5 ppb
CARBOGEL II	Viscosifer	3- 4 ppb
CARBOTROL	Filtration Control	7 - 8 ppb
CLAYCOTE	Wetting Agent - Thinner	As Needed
MIL CARB 25/50/150	Pretreatment Bridging Blend	25-30 ppb
SULPHONATED ASPHALT	Shale Inhibitor	6-8 ppb
MIL CARB 400/ MIL CARB 450	High Density Sweeps	As Needed for Weighted Sweeps
OMNI-PLEX	LSYP Enhancer	1 ppb
CACL2 - 97%	Salinity	To maintain Water Activity = 0.8

Table 44. 12 ¼ " Interval Chemicals and Concentration

[2] The Water Phase Salinity (WPS) should be maintained at 220,000 ppm CaCl2. Monitor the integrity of the cuttings at the shale shakers. The cuttings should be firm and have integrity; moist or soft cuttings indicate that an increase in CaCl2 content is required.

Volume and Cost Analysis

a- Planned

12 ¼ "Phase Section						
Hole Geometry and casing Design			**Dilution factor calculation**		**Cost analysis comments**	
Last Casing OD	13 3/8	572	Equip. Eff. %	85	Interval volume required	2026 bbls
Last casing I.D	12.681		L.G.S %	5	Surface + casing	1372 bbl
Last casing depth	3664		Est % hole washout	4	Open hole	258 bbl
Open Hole size (inch)	12 1/4	258	Est new open hole BPF	0.1577	Dilution volume	396 bbl
Open Hole T.D (ft)	5300		Dilution volume BPF	0.4	Net Built Volume	654 bbl
Open Hole Length (ft)	1636		Dilution volume	396	Interval cost	206270 USD
Est % Hole washout	4		Recovered pre. Sec.		Cumulative cost	239670 USD
Est New Hole size (inch)	12.74		Imported		Interval cost/BBL	101.805 USD
Total Hole Volume (bbl)	830		Surface Pits	800	Interval cost/Ft	126 USD
			Newly	654		
			Total	2026		

Table 45. 12 ¼ " Interval Planned Cost Analysis

b- Actual well analysis

Hole section summary

Days	7	
Top Depth	3679	ft
Bottom Depth	5300	ft
Length (Sum of daily drilled)	1621	ft
Max TVD	4945	ft
Max deviation	49	deg
Max Mud Weight	10.7	ppg
Actual Cost	185348	USD
Cost per day	26478.2	USD
Cost per ft	114.34	USD
Mud System	OBM	

Table 46. 12 ¼ " Interval Actual Hole Summary

Section volume summary

12 ¼ " Phase #3			
Cumulative Section Additions- bbl		**Cumulative Section Losses- bbl**	
Starting Volume 0.00 bbl			
Mud added	2000	Downhole	174.77
Weight material	18.01	Trip Losses	42
Water		Solids Removal Equip.	252
Additional products	82.59	Other losses	17.51
Total volume added	2100.59	Mud returned	1614.64
		Total volume Lost/returned	2100.92
		Ending Volume	-0.33 bbl
Total mud Received		2000 bbl	
Average Addition per Length		2.606 **USgal/ ft**	
Average Losses per Length		12.599 **USgal/ft**	
Average addition per day		14.37 **bbl**	
Average losses per day		69.47 **bbl**	
Average Losses Per Volume oh Hole Drilled		4.27 **bbl**	
Bit Size		12 1/4 **in**	

Table 47. 12 ¼ " interval Actual Volume Summary

Section Product summary

12.25" Phase #3 Product Usage						
Product	**Unit Size**	**Received**	**Used Amt**	**Used lb**	**On Hand**	**Cost USD**
Bulk						
MIL-BAR	1500 Kg	30	11	36376	51	N/A
MIL-CARB 150	1000 Kg	5	4	8818	6	N/A
MIL-CARB 25	1000 Kg	7	4	8818	8	N/A
MIL-CARB 450	1000 Kg	7				N/A
MIL-CARB 5	1000 Kg	6	4	8818	7	N/A
MIL-CARB 50	1000 Kg	7	4	8818	8	N/A
Oil Based Product						
CALCIUM CHLORIDE	25 Kg		80	4409	160	N/A
CALCIUM CHLORIDE	1000 Kg	13	13	28660		N/A
CARBO-GEL 2	25 Kg	111	76	4189	185	N/A
CARBO-TEC	55 USgal	9	9	3917	16	N/A
CARBO-TROL	55 Lb	298	224	12320	254	N/A
CLAYCOTE HT	55 USgal	4	4	1702	12	N/A
ECCO-MUL E	55 USgal	10	6	2424	16	N/A
OBM 10.5 PPG	1 bbL	2000	2000	882000		N/A
OMNI-PLEX	55 USgal	1	3	1278		N/A
Other						
Sulphonated Asphalt						N/A
				Total Product Cost		185348
				Total Cost		185348

Table 48. 12 ¼ " Interval Product Usage Cost

Section IADC Hours

12.25" Phase #3	
IADC Activity	**Total Hours**
Cementing	3
Circulating	10
Drill Cement and/ot Float Equp	2
Drilling Formation	41
Nipple Up/Nipple Down BOP	25
Run Casing	17
Tripping	53
Wireline Logs	17
Total IADC Hours	**168**

Table 49. 12 ¼ " Interval IADC Hours

Section4: 8 ½ " Interval

Major Frame

	Planned	Actual
Hole size – Casing size	8.5" / 7"	8 .5" – 7.0"
Casing Depth (ft)	5930 ft / 4995 ft	6010'/ 5332'
Formations to be drilled	upper, middle & Lower burgan & Top Shauiba	upper and middle burgan
Maximum inclination/Dogleg	76 deg	60.5 deg
Mud System	CARBO-DRILL(OBM)	CARBO-DRILL(OBM)
Expected Problems	Cavings & Losses in Shauiba	Total Losses

Table 50. 8 ½ " Interval Major Frame

Volume and Cost Summary

	Planned	Actual
Drilling days / Total days	6 / 19 days	6 / 19 days
Unscheduled cost	0.0 USD	0.0 USD
Total cost excluding the unscheduled cost	69672 USD	270553 USD
Total volume Mixed	1442 bbl	5903.59 bbl
Formation losses bbl	Expected losses	3641.06 bbl
Mud back loaded bbl	1390 bbl	1100 bbl
Mud transferred to next interval bbl	As could be possibly recovered	0 bbl
Min / Max mud weight	10.5 - 10.8 ppg	10.6 ppg
Interval Cost/bbl	48.312 USD	45.837 USD
Interval Cost/ft	110.58 USD	N/A
Interval Cost	69672 USD	270553 USD
Cumulative Cost	309434 USD	484683 USD
Back Load Credit	67138.5 USD	50420 USD
Cumulative Cost After Backload Credit	242204 USD	434263 USD

Table 51. 8 ½ " Interval Cost Summary

Volume and Cost Analysis

a- Planned

8.5" Phase Section						
Hole Geometry and casing Design			Dilution factor calculation		Cost analysis comments	
Last Casing OD	9 5/8	390	Equip. Eff. %	85	Interval volume required	1442 bbls
Last casing I.D	8.7		L.G.S %	4	Surface + casing	1190 bbl
Last casing depth	5300		Est % hole washout	4	Open hole	48 bbl
Open Hole size (inch)	8 1/2	48	Est new open hole BPF	0.0759	Dilution volume	204 bbl
Open Hole T.D (ft)	5930		Dilution volume BPF	0.4	Net Built Volume	252 bbl
Open Hole Length (ft)	630		Dilution volume	204	Interval Cost	69672 USD

Est % Hole washout	**4**		**Recovered pre. Sec.**		**Cumulative Cost**	**309434 USD**
Est New Hole size (inch)	**8.84**		**Imported**		**Interval cost/BBL**	**48.312 USD**
Total Hole Volume (bbl)	**438**		**Surface Pits**	**800**	**Interval cost/Ft**	**110.58 USD**
			Newly	**252**	**Cumulative Cost After Backload Credit**	**242204 USD**
			Total	**1442**		

Table 52. 8 ½ " Interval Planned Cost Analysis

b- Actual well analysis

Section volume summary

8.5" Phase #4			
Cumulative Section Additions- bbl		**Cumulative Section Losses- bbl**	
Starting Volume 0.00 bbl			
Mud added	5414.64	Downhole	3641.06
Weight material	18.01	Left Behind Casing	575.20
Water		Solids Removal Equip.	117
Additional products	470.61	Evaporation	4
Total volume added	5903.25	Other losses	360.43
		Mud returned Total volume Lost/returned	1100 5903.59
			Ending Volume -0.34 bbl
Total mud Received		5414.64 bbl	
Average Addition per Length		23.670 **USgal/ ft**	
Average Losses per Length		232.7 **USgal/ft**	
Average addition per day		25.72 **bbl**	
Average losses per day		252.82 **bbl**	
Average Losses Per Volume oh Hole Drilled		152.03 **bbl**	
Bit Size		6 ¼- 8 ½ in	

Table 53. 8 ½ " Interval Actual Volume Summary

Section Product summary

8.5" Phase #4 Product Usage						
Product	**Unit Size**	**Received**	**Used Amt**	**Used Ib**	**On Hand**	**Cost USD**
Bulk						
MIL-BAR	1500 Kg		2	66139	31	N/A
MIL-CARB 25	1000 Kg	4	4	8818	8	N/A
MIL-CARB 450	1000 Kg		7	15432	5	N/A
MIL-CARB 5	1000 Kg	4	5	11023	6	N/A
MIL-CARB 50	1000 Kg	3	1	2205	10	N/A
Oil Based Product						
CALCIUM CHLORIDE	1000 Kg	18	18	39683		N/A
CARBO-GEL 2	25 Kg	30	65	3583	150	N/A
CARBO-TEC	55 USgal	12	18	7833	10	N/A
CARBO-TROL	55 Lb	226	370	20350	110	N/A
CLAYCOTE HT	55 USgal	8	3	1277	17	N/A
ECCO-MUL E	55 USgal	2	15	6059	3	N/A
OBM 10.5 PPG	1 bbL	2000	2000	882000		N/A
OMNI-PLEX	55 USgal	1	4	1704	6	N/A
OBM 10.6 (80/20)OWR	1 bbl	1800	1800	801360		N/A
OBM 10.6 (80/20)OWR B/L	1 bbl		1100	1100		**-54530**
Other						
Sulphonated Asphalt	25 Kg	90	198	10913	120	N/A
MIL-LIME	30 Kg	175	245	16204	140	N/A
LCM						
MIL-MICA COARSE	25Kg	492	332	18298	200	N/A
MIL MICA FINE	25Kg	96	17	937	97	N/A
MIL MICA MEDIUM	25Kg	400	242	13338	198	N/A
MIL SEAL COARSE	25Kg	260	202	11133	90	N/A
MIL SEAL FINE	25Kg		17	937	23	N/A
MIL SEAL MEDIUM	25Kg	257	281	15487	38	N/A
NUT PLUG COARSE	25Kg	120	60	3307	90	N/A
NUT PLUG FINE	25Kg	30	9	496	51	N/A

NUT PLUG MEDIUM	25Kg	148	88	4850	90	N/A
				Total Product Cost		**270,553**
				Total Cost		**270,553**

Table 54. 8 ½ " Interval product Usage Cost

Section IADC Hours

8.5" Phase #4	
IADC Activity	**Total Hours**
Cementing	8
Circulating	14
Drill Cement and/ot Float Equp	25
Drilling Formation	44
Nipple Up/Nipple Down BOP	13
Run Casing	4
Test BOP	3
Tripping	276
Wait	5
Wait on Cement	26
Wireline Logs	6
Wash	32
Total IADC Hours	**456**

Table 55. 8 ½ " Interval IADC Hours

Mud properties

	Planned	Actual
Mud weight ppg	10.8 - 11 ppg or as hole dictates	10.6-10.7
Funnel Viscosity Sec/Qrt	As required to meet the planned rheology	78-84
PV C.P @ 120˚f	ALAP (expected range 22 TO 30)	15-32
YP PPHSF @ 120˚f	Depends on 6 rpm (expected range 18 to 24)	18-24
Gels PPHSF @ 120˚f	6/9- 10/15	8/13- 9/14
6 RPM@ 120˚f	9-10	9/8
HTHP@250	< 3	2
LGS % vol:	< 5	0.392
OWR	80/20	80/20
WPS(CACL2)	< 220,000 PPM	200,000 ppm

Table 56. 8 ½ " Interval mud properties

Section 5: 6 1/8 " Interval

Major Frame

	Planned	Actual
Hole size – Casing size	6 1/8"	6.125"
Casing Depth (ft)	6931 ft / 5370 ft	6361.92'/ 5490'
Formations to be drilled	Shauiba	upper and middle burgan
Maximum inclination/Dogleg	86.5 deg	61.3 Deg
Mud System	KCL Polymer	KCL/POLYMER(WBM) / LIME WATER
Expected Problems	Shauiba Loss of circulation	Total Losses

Table 57. 6 1/8 " Interval Major Frame

Volume and Cost Summary

	Planned	Actual
Drilling days / Total days	7/8 days	7 / 8 days
Unscheduled cost	0.0 USD	0.0 USD
Total cost excluding the unscheduled cost	65722 USD	58507.5 USD
Total volume Mixed	2000 bbl	5903.59 bbl
Formation losses	Losses Expected	3641.06 bbl
Mud back loaded bbl	0	1100 bbl
Mud transferred to next interval bbl	0	0
Min / Max mud weight	8.6-8.8 ppg	8.3 / 8.7 ppg
Interval Cost/bbl	32.868 USD	45.837 USD
Interval Cost/ft	65.67 USD	166.7 USD
Interval Cost	65722 USD	58507.5 USD
Cumulative Cost	307927 USD	492770 USD

Table 58. 6 1/8 ″ Interval Volume and Cost Summary

Actual well analysis

Section volume summary

6.125" Phase #5			
Cumulative Section Additions- bbl		**Cumulative Section Losses- bbl**	
Starting Volume 0.00 bbl			
Mud added		Downhole	2354.71
Weight material	56.27	Left Behind Casing	
Water	2954.21	Solids Removal Equip.	
Additional products	106.84	Evaporation	
Total volume added	3117.33	Other losses	7.88
		Mud returned Total volume Lost/returned	2353.59
			Ending Volume 763.74 bbl
Total mud Received		bbl	
Average Addition per Length		373.013 **USgal/ ft**	
Average Losses per Length		281.626 **USgal/ft**	
Average addition per day		779.33 **bbl**	
Average losses per day		588.4 **bbl**	
Average Losses Per Volume oh Hole Drilled		183.99 **bbl**	
Bit Size		6 1/8 in	

Table 59. 6 1/8 " Interval Actual Volume Summary

Section Product summary

6.125" Phase #5 Product Usage						
Product	**Unit Size**	**Received**	**Used Amt**	**Used Ib**	**On Hand**	**Cost USD**
Bulk/LCM						
MIL-BAR	1500 Kg		25	82673	6	N/A
MIL CARB 25	1000 Kg		8	17637		N/A
MIL CARB 5	1000 Kg		6	13228		N/A
MIL CARB 50	1000 Kg		4	8818	6	N/A
Water Based Product						
CAUSTIC SODA	25 Kg		15	827	96	N/A
MILSTARCH	25 Kg		73	4023	105	N/A
CMC LV	25 Kg		52	2866	104	N/A

SODA ASH	25 Kg		20	1102	90	N/A
POTASSIUM CHORIDE	1000 Kg		10	22046	8	N/A
XANTHAN GUM	25Kg		66	3638	54	N/A
Other						
MIL LIME		70	20	1323	50	N/A
				Total Product Cost		**58,507**
				Total Cost		**58,507**

Table 60. 6 1/8 " Interval Product Usage Cost

Section IADC Hours

6.125" Phase #5	
IADC Activity	**Total Hours**
Circulating	2
Drill Cement and/ot Float Equp	8
Drilling Formation	18
Tripping	62
Wireline Logs	6
Total IADC Hours	**96**

Table 61. IADC Hours