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Successfully Controlling Fluid Losses in Troublesome Zones of Jurassic to Permian Age in Offshore United Arab Emirates Utilizing a Newly Optimized Crosslinked Borate Fluid Loss System

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Abstract

Two optimized polymer/borate/salt (PBS) fluid loss systems were recently implemented in two different ADNOC Sole Risk (ASR) wells in the Arabian Gulf while drilling different troublesome formations prone to losses. The first well was drilled through the fractured Khuff formation and the second well through porous Arabs and fractured Diyab/Jubaila groups, all primarily limestone. Use of the PBS systems enabled the rigs to regain circulation and successfully drill to the total planned depth.

These wells involved several different key drilling objectives including zonal isolation and obtaining logs. The ability to control losses at a partial rate allowed proceeding with the critical logging program and securing the first unimpeded logging suite in the area, including high quality imaging and pressure sampling as well as the avoidance of a liner run. The application of the PBS system in the second well allowed multiple troublesome formations to be drilled as one interval thus achieving successful isolation. The losses before and after for each well are contrasted with an offset well to illustrate the difficult downhole environment and the economic savings that were realized.

This paper also summarizes the recent optimization of the PBS system that enables extending the controlled range of set time from less than 2 hours to as many as 6 hours. In addition, newly implemented particle size grades are also discussed with respect to their application as well as this system's integrity compared to cement and common LCM.

Introduction

Controlling fluid loss while drilling the upper wellbores and/or the target reservoir is well documented in the literature. Excessive fluid loss and failure to control to manageable rates can subsequently lead to, among other things formation damage, well control issues, excessive NPT, cost overruns, and inability to run planned logging tools and casing (Samuel et al. 2003). In severe cases of lost circulation, especially in the upper wellbores, the only options, in lieu of LCM and fluid loss pills, include pumping cement, employing a floating mud cap (Davidson et al. 2000), employing underbalance drilling, or drilling ahead accepting losses. All of these options, which may well prove successful, typically include increased costs as well as NPT (Ferras, M, 2002).

The use of LCM to control losses is prevalent and judicious with many textures available (e.g., flakes, granular and fibers) as well as types, such as fiberglass, graphite, calcium carbonate, mica, nut shells, wood, rubber, swelling polymers and foam to name a few. Many of these LCM have been contrasted and compared using laboratory simulations (Loeppke 1991, Waldmann 2014, Wang 2011). A succinctly proposed classification of LCM which includes nanoparticles was summarized using physical and chemical properties as well as their application (Alsaba et al. 2014). One application of LCM is the continuous/controlled addition to a mud system as background material to enhance bridging and reduce the loss rate in known problematic zones (Sanders et al. 2003).

In lieu of LCM, other methods and systems include reverse gunk pills (Ryan et al. 2015), chemically activated crosslinking pills (Ferras et al. 2002), defluidizing pills (Scorsone et al. 2010), limiting drilling parameters to limit losses (Al-Hameedi et al. 2017), and potential use of formate brine and xanthan gum to create pseudoplastic fluids which can control fluid loss via relatively high viscosity that increases exponentially with increasing radial distance from the borehole (Howard et al. 2017).

Our literature investigations revealed nearly 2,000 publications which document products, systems, methods, laboratory simulations and/or case histories to resolve fluid losses. However, when searching whereby the keywords were confined to lost circulation, vugs, carbonate and fluid loss materials or systems with respect to problematic carbonates/limestones specific to prolific losses associated with drilling, less than 20 publications were identified. While these articulately document the history, methods/management, LCM, gel type, cement, fibers, resins, etc., only a few papers discuss applications for controlling and mitigating losses in fractured or vugular limestone and document field experiences (Davidson et al. 2000; Sanders et al. 2003; El-Hassan et al 2003; Mofunlewi et al. 2014; Rastogi et al. 2015; Urdaneta et al 2015).

The aforementioned literature searches demonstrate a palpable contrast between the myriad of LCM, fluid loss pills, laboratory simulations and methods versus documented learnings from successful case histories in problematic carbonate formations, especially when NPT and costs are mitigated. The following narrative documents a recently optimized fluid loss system and its successful application and learnings in two different problematic carbonate formations.

Polymer/Borate/Salt System

The polymer/borate/salt (PBS) system is a blend of sized borate mineral salts and polymers, formulated to produce a low-permeability filtercake (Powell et al. 1991). This formulation generates dual functionality that enables bridging of small fractures, voids, vugs, and pore networks while bonding to formation rock as well as the ability to amalgamate loose fragments and particles. The formulation also includes xanthan gum, cellulose, and pre-gelatinized starch. Gelation and rigidity develop from chemical crosslinking of the polymer blend by the borate salts. The degree of gelation depends on the interaction of a number of factors:

- pH
- Temperature
- Salt type and ratio
- Polymer ratio and concentration
- Time
- Buffer concentration
- Grind size
- Degree of beneficiation of the borate salts

Manipulation of these variables allows the PBS system to be customized and optimized to achieve desired objectives for specific applications, such as reducing the time required to fully crosslink once pumped, thus subsequently reducing rig time.

The borate mineral salts are multi-functional, serving as bridging material, weighting agents, and the source of crosslinking borate anions. The hydrous borate has a fibrous microstructure that consolidates and compacts under pressure, greatly enhancing sealing properties and high-pressure, high-temperature (HPHT) fluid-loss control. The unrefined borate salt is ground and screened to specific particle sizes which range from 0.02 to 20 µm (for extra fine grades) to as large as 8000 µm (for extra coarse grades). These particles promote bridging and sealing of fractures and high-permeability thief zones.

The borate mineral salts are sparingly soluble in water (and acid soluble), dissociating slowly to release calcium, sodium, and borate ions. As dissociation of the borate ions proceeds and the pH rises above 8, a portion of the borate is converted into an anionic crosslinking form (i.e. $B(OH)_4^-$), shown in **Fig. 1**, which then crosslinks the xanthan polymer. The rigidity of the initial hydrogen bond crosslink is strengthened and reactive temperature controlled as well as stabilized by the addition of salts and buffers. Gelation of the PBS system progressively develops within 6 hours, hardening over 24 hours to form a homogeneous ductile material. In contrast, the refined and highly soluble borate component promotes bonding to rock and amalgamation of loose formation material as the system cures.

Concurrent with the aforementioned bonding is bridging functionality; the dual-functionality of the PBS system being inherent in the design of the system. Fluid-loss optimization is predicated upon selecting a particle size which can effectively form bridges across the smaller fractures and vugs.

The rheology of the final slurry when displacing or spotting is characterized depending on the shear rate:

- pseudoplastic (i.e., shear-thinning) at high drillpipe shear rates
- highly thixotropic, and quickly gelling at annular shear rates
- viscoelastic at low or zero shear which reduces commingling (i.e., interface) with other drilling, completion or formation fluids.

Once a system is mixed, pumped, and spotted in the near wellbore, the slurry begins infilling and curing in a near-static to static environment as inherent fractures, voids and/or vugs are permeated. In this scenario, crosslinking that was initiated on the surface promotes viscoelastic properties in these non-sheared annuli spaces. Upon exiting the drillstring, the slurry transitions to a viscoelastic state which resists commingling, distortion and deformation thereby initiating bridging/bonding to the rockface and amalgamating loose fragments into the curing matrix.

Samples heat aged in sealed jars at 200°F (93°C) for six months, as well as samples kept sealed at room temperature for over three years, exhibited no significant/visual changes in consistency or visual evidence of syneresis. Curtailing syneresis enhances bonding to the matrix of formation rock as well as consolidating loose particles that range from fragments to pebbles to sand (**Figs. 2a** and **2b**).

The preferred method to assess the integrity of a PBS plug during and after curing (e.g. setting) is with the use of a penetrometer which determines resistance as unconfined compressive strength or relative hardness versus time. This instrument/technique measures the depth of penetration in tenths of millimeters (mm). A rubber stopper (1-in. by 1-in.) placed on the tip of an aluminum Koehler cone increases the surface area thus functioning to facilely differentiate the hardness/compactness of a selected plug during and after curing. The unconfined compressive strength as measured with this technique typically falls in the range of 6 to 21 psi (35 to 150 kPa) for laboratory plugs and is dependent on density, temperature, and time. These relatively low values explain, in part, the unproblematic drilling when removing a cured system/pill from a wellbore. For example a recently cured pill was removed using 300 gal/min, 60 rpm, 1300 psi and 0 to 5K-lb weight on bit (WOB) to drill approximately 213 ft. in one hour.

This technique also provides a relatively quick method to differentiate between selected PBS systems where the concentration of a component(s) or density is varied. Historical experience has demonstrated that a reading of 20 mm and less indicates that a plug is approximately 90 percent cured (internal standard). As such, this technique provides a means to assess the time required for the transition from a slurry to a solid.

For these types of systems/materials, such as those that solidify after static and/or dynamic aging, specific methods are available and used to assess and simulate their response to environments. To further, mechanical properties are measured/ assessed to characterize the response of materials to mechanical loads and deformation. These can be subdivided into elastic and strength properties. Well known examples of strength properties are tensile and shear, whereby strength can be assessed in unconfined or confined environments (Lavrov et al. 2016).

To assess the integrity of a cured PBS system/pill in a confined environment, a confined compressive strength test was performed in lieu of an unconfined test as a means to determine if elastic propensity predominates. The method employed is similar to ASTM C39. A PBS formulation, as utilized in the Upper Khuff formation in the Middle East (Al Habsi et al. 2017), was employed as field experience demonstrated success with stopping losses and a decreasing loss rate with increasing pump rate. This formulation was blended and poured into a 2 ¾-inch diameter by 4-inch length cylinder mold and then placed into a curing chamber. The curing chamber was heated to 275°F and approximately 1000 psi applied as confining pressure. The PBS slurry was statically aged for 4 hours. The curing chamber was then cooled to 190°F and the now solid PBS removed. This plug exhibited no visual cracks, voids or degradation due to static aging at this temperature (**Fig. 3**). This plug measured a relatively low 0.8 mm using the aforementioned penetrometer technique. Next, the plug was demolded and placed into the confined compressive strength vessel in a rock properties analyzer manufactured by GCTS Testing Systems. The plug was again statically aged for five hours at 275°F using 1000 psi confining. Next a force via a piston was applied to the top of the plug. The plug compressed/deformed approximately 0.75-inch resulting in 1025 psi at a confining pressure of 1000 psi. This value is relatively low when compared to other materials (**Table 1**), such as cements, however demonstrates more elastic tendency coinciding with thermal integrity under confining stress. This postulated elastic tendency may explain, in part, the reduction of losses in the aforementioned formation from 1-27 bbl/hr at 200 gal/min to zero at 400, 500 and 600 gal/min. While future analyses are planned to further ascertain elastic properties of cured PBS plugs, an analogy of the aforementioned response may equate to structural members that are subject primarily to transverse loads and negligible axial loads such as internal shear forces and bending moments in beams while sustaining integrity in structures (Varma).

The dissolution of a cured system/pill is readily accomplished with strong acid, such as 15% by weight HCl. The dissolution rate is enhanced with increased contact such as with larger surface area. The crosslink mechanism is reversible even as a cured plug when contacted by low-pH fluids, such as organic and inorganic acids, and with continued contact will soften and eventually re-liquefy. This reversible mechanism is enhanced by shear. This reversibility is most useful to reduce the viscosity of a relatively thick slurry, such as when mixing in a pit/tank. Thus, if a delay in the pumping operation occurs, the undesirable setting in the tank can be mitigated.

In addition, the PBS system is compatible with both water-based and non-aqueous drilling fluids as laboratory simulations demonstrated as great as 20 vol% of either type of mud will not mitigate the curing process.

Table 2 summarizes the family of PBS system products and their functionality. At a minimum, the system requires three primary products, all of which are packaged separately. Optional products are used to reverse the crosslink, alter the cure/set time, and extend thermal integrity.

Other applications include workover operations whereby the PBS system can be used to seal older perforated intervals and holes in casing and even block thief zones (Mokhtari and Ozbayoglu 2010).

Recent Improvements to the PBS System

In the last three years, several improvements have been integrated into the PBS system thereby expanding its functionality. These improvements include:

- Expansion of the particle size, ranging from less than 0.02 to 20 µm (for microfractures) and up to 8000 µm (for larger fractures) using an unrefined borate salt grade
- An optional unrefined alkaline aggregate to alter the set time from a maximum of 6 hours to achieving set in less than 1 hour with a typical set time of 2 hours
- Addition of a refined highly soluble borate component to promote bonding to the formation rock

The PBS system is now manufactured with a sparingly soluble borate salt that ranges from less than clay size to as large as 8 mm. Several conventional, solids-laden, crosslink systems use only one particle size range, up to a maximum of 100 µm. The smaller particle size provides the ability to penetrate deeper into tight formations, shale, gravel, or microfractures, all of which may be less permeable due to a number of causes. The larger particles provide effective bridging of relatively large fractures and voids. The ability to alter the particle-size range allows customization and optimization of the system for specific or troublesome applications. In addition, this flexible particle-size range (e.g., 20, 100 and 500-µm particle size) allows for spotting a PBS system through a bottomhole assembly (BHA) or bit. When a larger particle size (e.g., 2000 or 8000 µm) is required, a fluid-loss bypass sub can be run above the BHA to prevent plugging or pump with open-ended pipe.

The concentration of magnesium salt and unrefined alkaline aggregate components, whereby either or both are varied in combination with the PBS, enables variation and variation of the cure/set time. The concentration of these products also allows variation of the final density. The typical cure/set time of 2 hours minimizes rig time waiting after pumping or, in contrast, the pumping time can be extended as needed for longer/deeper spotting.

Fig. 4 shows a plot for selected PBS systems ranging from approximately 10.3+ to 12.5 lb/gal. Note the relationship between depth of the penetrometer (mm) and time (min) for three pairs of systems with equivalent densities where only the alkaline aggregate is varied. This example illustrates the ability to alter the set time from approximately 1½ hours to 5½ hours. The internal standard for cure/set, approximately 20 mm, is shown as a horizontal red line. All PBS systems are pre-tested and contrasted to this internal standard. The decreasing penetrometer depth or unconfined compressive strength increases rapidly for shorter cure/set time versus an asymptotic increase for relatively longer cure/set times.

The incorporation of a refined borate salt promotes bonding to formation rock and amalgamation of fragments especially when bridging is less probable. **Figures 2a** and **2b** illustrate the bonding and amalgamating mechanism in a laboratory simulation. A 10.7-lb/gal PBS system was mixed and added to a plastic container containing loose limestone fragments, pebbles and sand. The slurry was static aged, or cured, for four hours at ambient temperature. After this time, the plastic container was removed. Note that the loose material, even the finer sand, is amalgamated with the now cured PBS system (**Fig. 2b**).

PBS System versus Conventional Loss Circulation Materials

The dual functionality of the PBS system, bridging and bonding, is inherent in the system. The unrefined borate salts allow for a customized PSD to enhance bridging. The addition of the refined borate salt enhances bonding and integrity which potentially stops or reduces the loss rate when bridging is less effective such as the case lost circulation in fractured or vugular carbonates.

With respect to conventional LCM, typical grades and/or products do not inherently adhere or bond to a matrix or rock, nor do they fuse loose particles and fragments, as they only function to initiate bridging and/or reduce filtrate. **Table 3** shows a comparison of some of the common LCM. In some formations, the misapplication of common LCM may not effectively stop or reduce losses due to lack of sufficient particle size and/or particle size distribution (PSD) to bridge the larger fractures or vugs (Amer et al. 2017).

Some of the inherent problems with LCM fluid loss pills include: dilution, tool plugging, pressure transmission, and failure to adhere to formation wall without sustained positive pressure. For example, fluid loss pills that include LCM may experience dilution, especially during high loss rates, which further reduces their effectiveness due to non-optimal concentration, rheology, or placement. In addition, if used at relatively high concentration or particle size, these materials can plug the components in the BHA (Amer et al. 2017).

The bonding nature of the PBS system also serves to resist the transmission of surge and swab pressure changes to the formation. When an LCM is used in a pill and the filtercake is deposited, sustained positive pressure is necessary to maintain the residual filtercake. Swabbing, or loss of the fluid column, may eradicate the filtercake in the near wellbore as filtercakes do not effectively bond to the matrix/formation, but rather they rely on positive pressure differential to be held in place. The PBS system bonds with the formation face/matrix and it is thus more resistant to the changing pressure differentials during surge and swab operations.

Conventional solids-laden, crosslinked pills, depending on the mechanism whereby they are formulated, may not effectively adhere or bond to the matrix. Again, their common maximum particle size, 100 µm, may render these pills ineffective for bridging the larger fractures and voids. A study by Amer et al. (2017) ranked traditional crosslink pills and reported that their effectiveness is generally limited to plugging openings of 4 mm and less, i.e., narrow slots, not larger voids.

Geology, Reservoir and Lost Circulation Challenges

The two wells in these case histories, Well A and Well B, are located offshore UAE in the western Arabian Gulf (**Fig. 5**) as previously discussed in Al Habsi et al. (2017). Offset wells in both areas were plagued with fluid loss due to very porous, fractured formations. The trouble zones that required contingency planning for fluid loss in these case histories ranged in age from the Upper Jurassic through the Triassic to the Upper Permian. Their rock types included oolitic-peloidal, packstones, grainstones, mixed carbonate, terrigenous limestones, dolomites with anhydrite streaks, wackestones, and peloidal packstones (Alsharhan 1989). The drilling objectives included drilling through the Upper Khuff (Well A) and the porous Arabs and fractured Diyab/Jubaila groups/formations (Well B). These formations were identified as problematic and known for lost circulation.

Well A

Well A is an ASR appraisal well. More specifically, it is a Pre-Khuff future gas development well drilled to determine reserves from two reservoirs (**Fig. 6a**). These target intervals are known to be gas bearing. In summary, the Pre-Khuff needed to be logged, fracked and short-term tested to acquire data vital for a future development. Secondary objectives of this well include appraisal of the Upper and Lower Khuff formations with comprehensive data acquisition including modular formation dynamic tester (MDT) and downhole sampling to optimize the field development plan.

Bottomhole pressure (BHP) and temperature of Well A are approximately 8,797 psi and 345°F, respectively, at a total depth (TD) of approximately 17,138 ft MD / 16,290 ft TVD in the Berwath Formation (Carboniferous age before the Permian Khuff) (Schlumberger 1991).

Placing the liner for Well A included drilling an 8⅜-inch section from the Base Sudair to Basal Khuff Clastics (BKC) at approximately 16,657 ft MD with rotary BHA and MWD tool. This put the bottom of the 8⅜-in section approximately 20 ft into the BKC. As such, a 7-inch production liner could then be run and cemented to isolate the Khuff reservoir from Pre-Khuff reservoir.

Well B

Like Well A, Well B is an ASR appraisal well with the main objective to evaluate the target reservoir (**Fig. 6b)**. In summary, this well plan included logging, fracking and short-term testing to acquire data vital for a future development. BHP and temperature approximated 8,200 psi and 330°F, respectively, at a TD of approximately 15,840 ft MD in the lower formation.

The 12¼-inch section of Well B was drilled directionally in two stages, first from the Hith formation to approximately 11,185 ft MD / 10,759 ft TVD (~50 ft above the expected top of Gulailah formation). After running the required open and cased hole logs, the mud weight (MW) was increased to ~11.8 lb/gal and drilling continued to the planned TD at ~13,126 ft MD / 12,573 ft TVD (~50 ft above the expected top of Khuff formation). A 9⅝-inch long string with stage tool was run and cemented in place to isolate the Arabs, Diyab group, Araej, and Hamlah formations from the troublesome Gulailah/Sudair formations.

The following three sections detail the lost circulation experience for an offset, objectives and mitigation measures related to the anticipated lost circulation for Wells A and B.

Offset Wells – Lost Circulation Incidents

Offset wells that were drilled in the ASR area encountered lost circulation challenges and subsequently were unable to attain quality logs across the Upper and Lower Khuff due to the relatively high loss rates. As an example, one offset, Well C, endured the following lost circulation experiences:

- 44 days spent curing losses on the original 8⅜-in. hole
- Approximately 11,000 bbl of mud lost
- Approximately 3,000 bbl of LCM pills made
- A total of 46 LCM pills pumped
- 7 cement plugs pumped
- Mixture of different types of pills pumped ($CaCO_3$-based, bentonite-based, crosslinked)
- Drillpipe and annulus got plugged; BHA left in hole
- Cemented BHA in hole and sidetracked, sidetracked hole conducted under managed pressure drilling (MPD), still encountered losses, subsequently hole not logged
- Liner cemented 170 ft above planned depth

These issues are typical for the area and led to the detailed pre-planning measures developed for the two subject wells.

Well A - 8⅜-inch Section Objectives

The 8⅜-inch section of Well A posed a considerable lost circulation challenge which required pre-planning measures for incorporating LCM. The best way to visualize these challenges is via the illustration shown in **Fig. 7a** which identifies the potential formations, shaded in red, that are prone to losses as confirmed from all relevant offset data. To mitigate these risks, a loss circulation plan was devised (**Appendix I**). Note that a trigger of approximately 30 bbl/hr was established.

Considering the lack of existing data in the Upper /Lower Khuff, the objectives for Well A included acquiring several valuable logging suites including:

- FMI-SS-LS = Image log/Sonic scanner/Litho scanner
- HRLT-LDS-APS-HNGS = Resistivity, Neutron, Density, Spectral gamma
- CMR-XPT = Magnetic resonance and Pressure points
- SS-LDS-APS-HNGS = Sonic scanner, Neutron, Density, Spectral gamma
- MDT-GR = Reservoir fluid samples.

Well B - 12¼-inch Section Objectives

For Well B, the 12¼-inch section posed multiple challenges that required defined mitigation and contingency measures for lost circulation, especially across the Arabs and Diyab formations. The best way to expound these challenges is via the illustration shown in **Fig. 7b** highlighting the fracture clusters and naturally porous or permeable formations. The planned 12¼-inch section was undertaken in two stages, the first stage planned to stop drilling at the top of the Hamlah Formation with 10.9-lb/gal mud weight to ensure the running/attaining of critical logs and limiting the mud weight stress across the porous permeable Arabs.

Fig. 8 shows a log acquired from the LWD that was deployed during drilling that illustrates fracture clusters (blue lines) in the Arabs and Diyab formations which were realized to be the primary reason for mud losses and in turn the data was used to assist the drilling team with spotting the PBS systems.

The second stage of the 12¼-inch section planned for continued drilling through the Hamlah/Gulailah/Sudair and Upper Khuff formations whilst keeping the previous formations open. The risk at this stage was three-fold: loss circulation across the Arabs or Diyab groups, a high-pressure water flow from the Gulailah Formation, and/or shale issues from the Sudair Formation. To mitigate these risks, a loss circulation plan was again designed using the same trigger as Well A (**Appendix I**). If this stage was not stabilized, particularly for the losses, then section objectives would have been cut short and three contingency plans would be considered next:

1. 9⅝-inch liner x 10¾-inch tieback
2. 11¾-inch drilling liner
3. 11¾-inch expandable liner

Note that these contingency plans, if implemented, would prevent achieving the desired objectives of section TD and placing a primary 9⅝-inch casing long string with stage tool. All of these options had to be considered and equipment readily available based on the uncertainty of downhole conditions.

Laboratory Optimization of PBS Systems

Laboratory simulations were used to optimize the PBS systems to help achieve the drilling objectives for the subject wells. The reservoir pressures, temperatures, planned wellbore depth, and interval lengths/pressures dictated the following:

- Maximum 2-hr set time after spotting a system
- Formulating multiple densities for each section/hole size, ranging from 10.7 to 12.5 lb/gal, while still achieving the desired set time
- Maintaining the integrity of a cured/set system at the maximum anticipated temperature, approximately 152°C (305°F)
- Rheological targets for quality control in the field

For this assessment, only the PBS concentration and weighting agents were altered to achieve the desired 2-hr cure/set (**Table 4**). The 90% cure was achieved using 55 lb/bbl of either 500 or 2000-µm particle size of PBS, plus weighting agents that included calcium carbonate (75 to 155 lb/bbl) and barite (53 to 160 lb/bbl) to achieve the densities shown in **Table 5**. Barite was designated as the weighting agent as less overall material would be required on location when blending. For reference purposes, a 10.3-lb/gal system is considered unweighted.

To confirm thermal integrity for Well A, a 12.5-lb/gal PBS system was assessed at 305°F, the anticipated static BHT. This PBS system included 5 lb/bbl of an anhydrous salt, to mitigate oxidation reduction reactions which could result in free radical formation. This system was formulated and dynamically aged at 175°F for 45 minutes to simulate pumping in place (e.g. EOS) as this period was considered the worst-case scenario. After dynamic aging, the system was still pourable and was then static aged at 305°F for 2 hours. Again a penetrometer was used to determine the relative hardness. The result, 9 mm, exceeded the 20-mm internal standard and confirmed an acceptable cure/set after exposure to this temperature/time period.

Table 6 shows rheological targets for field PBS 500 and 2000 Systems and was provided to assist the mud engineer with quality control. These readings are recorded without the activator. After addition of the activator, crosslinking quickly initiates and readings are difficult to acquire with standard rheometers, such as a FANN 35, which cannot measure the nearly exponential viscosity increase that occurs. The activator is always added immediately before pumping a slurry. Note that even as the viscosity of the slurry increases after addition of the activator, the slurry will not fully crosslink if the pit is continuously agitated as shear mitigates the crosslinking process. This mechanism also applies when pumping the slurry downhole, thus allowing placement before it cure/sets.

In summary, PBS formulations were prepared for each section using the aforementioned results to formulate the required density for each section (**Table 5**). It should be noted that the two particle sizes selected (500 and 2000 µm) were predicated upon pumping and spotting the PBS 500 system thru the BHA/bit and the PBS 2000 system using a by-pass sub. The pumpable volumes were initially selected based on 500 ft of length for each section. However for the 8⅜-inch and 12¼-inch sections, this was amended to 700 ft, 825 ft and 1400 ft, respectively, to facilitate pumping only one system to stop losses.

Field Mixing and Placement Recommendations

As no special blending, mixing, or equipment is required for PBS systems, they were mixed in advance in the slugging pits and the activator was withheld until pumping was imminent. As the activator had not been added, only agitation was needed to maintain the PBS system. If the activator was added and operational delay ensued or the pumping operation was shut-down, each rig was provided with a component which would further delay set time in the event of unanticipated shut down of pumping. Standard mixing procedures for each PBS system were provided to each rig as one instruction sheet per formulation. In total, five PBS systems were mixed on-site for both wells with no problems reported.

The desired method for PBS placement was utilized, that being spotting the tail to the end of the string (EOS) while directly above the loss zone and then pulling into the casing shoe. While this system can be spotted using a hesitation squeeze, that method was not used. The PBS 500 system was pumped through the BHA/bit while the PBS 2000 system was pumped through the bypass sub.

Field Results

Summaries, as extracted from daily drilling reports, are summarized in **Appendix II** and detail the placement of the PBS systems and the losses before, during, and after curing. Of note is that the PBS system was spotted in both wells while the column of fluid was dynamic. In this scenario, the probability of success is diminished with respect to stopping or reducing the loss rate. Spotting pills during relatively high loss rates diminishes their effectiveness due to non-optimal concentration, non-optimal particle size distribution, reduction of viscosity, placement and/or when such pills cannot adhere to the formation A summary of Wells A and B, below, show successful application of the PBS system when the fluid column was dynamic.

Well A

1. Drilling ahead from 15,468 to 15,485 ft with reduced parameters
2. Fluid loss rate = 60 – 90 bbl/hr
3. Stop and perform a pump test
    a. 400 gal/min pump rate, 40 bbl/hr loss rate
    b. 500 gal/min pump rate, 170 bbl/hr loss rate
4. Check static loss rate after pump test, 25-35 bbl/hr and reducing
5. TIH to spot PBS system
6. Loss rate while spotting = 13 bbl/hr
7. Loss rate while curing = 10-12 bbl/hr
8. Perform a pump test after PBS system set/cure
    a. 200 gal/min, 27 bbl/hr and tapering

b. 400 gal/min pump rate, full returns
c. 500 gal/min pump rate, full returns
d. 600 gal/min pump rate, full returns

To further, when RIH, after spotting the PBS, at approximately 14,990 ft. the drillstring set down 10,000 psi and was unable to pass. Using this depth versus the TD, the volume of cured PBS in the wellbore approximated 31-bbl to 33-bbl leaving 207-bbl to 209-bbl in the formation. This signified an application whereby a crosslinked system cured/set in the wellbore.

In addition, the application of PBS 500/2000 systems on Well A aided improved resolution of the subsequent FMI log (**Fig. 9**) as the loss rate was relatively reduced while logging over the 3-day period. In addition, the 7-inch production liner was successfully run to isolate the Khuff reservoir from Pre-Khuff reservoir.

Well B

1. Drilling ahead from 11,114 – 11,165 ft
2. Observed dynamic loss rate of 25 bbl/hr
3. Lost returns while preparing a LCM pill
4. Pump 30-bbl LCM pill with 12.0-lb/gal mud
5. Reciprocate drillstring to fill back side without success
6. Fill backside with water
7. Mix PBS system while losing 60 bbl/hr
8. Spot two (2) 30-bbl LCM pills and after spotting and when pumping water out of hole experienced lost returns
9. Filling hole with salt water
10. Spot PBS system with 50 to 60-bbl/hr dynamic losses
11. Loss rate while PBS curing = 11 bbl/hr dropped to 3 bbl/hr
12. Perform pump test after cure period;
    a. 900 gal/min pump rate, full returns

Note that three PBS systems were spotted however the first two were spotted before assessing the LWD-generated FMI log. This log showed where the losses were occurring (**Fig. 8**). Once the correct depth was ascertained, the third PBS system was spotted and the losses stopped. In addition, the use of the PBS 500 systems facilitated, in part, the successful running and cementing of a 9⅝-inch long string to isolate the Arabs: Diyab group, Araej, Hamlah from the troublesome Gulailah/Sudair formations.

Results

A total of five PBS systems were pumped into Wells A and Well B to regain control, subsequently drilling operations proceeded with zero NPT as normalized to the offset (Well C). **Table 7** summarizes the maximum loss rates for both wells before and after application of the PBS systems. The dynamic loss rate dropped from a worst recorded rate of 170 bbl/hr to a stabilized rate of 2 bbl/hr while pumping 500 gal/min for Well A using PBS 500 / PBS 2000. Similarly, the dynamic loss rate for Well B dropped from 60 to 0 bbl/hr while pumping 600 gal/min using PBS 500.

Well A Results

The application of the PBS system in the 8⅜-inch interval stabilized the wellbore and facilitated achieving section objectives. Critical logs were all run and the FMI exhibited relatively higher quality resolution; these were obtained for the first time across the target intervals/formations and provided invaluable data for the sub-surface team. To quantify the success of meeting objectives and obtaining the log data, **cost savings were estimated at US$12 million** using the previous offset Well C. The non-productive time (NPT) was normalized to all identified contingencies as shown in **Table 8**.

Well B Results

The successful application of the PBS system to cure lost circulation in the 12¼-inch interval negated the need to utilize the contingency plans, thus allowing operations to continue. The following are approximate costs for each of the contingency plans.

1. 9⅝-inch x 10¾-inch tieback – US$1,000,000 plus 7 days to run
2. 11¾-inch drilling liner – US$1,000,000 plus 7 days to run
3. 11¾-inch expandable liner – US$1,000,000 plus 7 days to run

Cost savings are estimated as US$1,000,000 plus seven (7) days rig spread rate for a total of US$2.5 million. The savings on rig days alone for curing losses are in excess of 7 days and **greater than $1.5 million in savings**.

In both wells, successful implementation of the optimized PBS system helped operations to proceed without activating contingency plans and incurring additional NPT-related loss circulation.

Learnings

- Drilling and logging the Upper Khuff in Well A were feasible after applying two PBS systems as the static loss rate stabilized to 16-24 bbl/hr thus controlling losses within manageable rates to allow a 3-day logging operation to proceed completely.
- The application of the PBS systems proved to be effective at stopping or controlling losses in the highly fractured Upper Khuff formation at a static temperature of approximately 314°F (157°C) for 3 to 4 days.
- Application of the PBS systems in Well A resulted in the drillstring tagging the top of the residual PBS 2000 in the 8⅜-inch wellbore when RIH whereby an estimated 207 bbl remained in the formation. Subsequently, an approximate calculation of a volume ratio to seal the Upper Khuff could be applied on subsequent wells.
- Placement was a key factor in Well B as using LWD logs to identify fracture clusters resulted in successfully spotting and subsequently stopping losses in the Arabs and Diyab formations in Well B.

- The application of the PBS systems proved to be effective at stopping losses in Well B as prior, returns were lost at approximately 11,165 ft. and static losses of 14 bbl/hr were recorded.
- All PBS systems were successfully mixed and pumped thru the drillpipe bypass sub or EOS with no problems. No pre-mature setting was evident thus validating the laboratory assessments.
- Spotting a PBS system after drilling completely through a drill break proved successful for stopping and/or controlling losses.
- The application of the PBS systems realized, with respect to casing, cementing and logging operations in both wells, from zero to significantly reduced losses during these operations.
- Before application of the PBS systems; Well A exhibited dynamic losses of 170 bbl/hr and static losses of 25 bbl/hr. Well B exhibited lost returns and then experienced dynamic losses of 60 bbl/hr. In both wells, the PBS system was spotted with a dynamic fluid column.
- For both wells, increasing pump rate was concurrent with decreasing fluid loss, to zero, after spotting and curing for approximately 2 hours.

Acknowledgments

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Nomenclature

BHA = *Bottomhole Assembly*
BHP = *Bottomhole Pressure*
LCM = *Lost Circulation Material*
MD = *Measured Depth*
MW = *Mud Weight*
NPT = *Non-Productive Time*
PBS = *Poly Borate Salt*
POOH = *Pull Out Of Hole*
RIH = *Run in Hole*
TD = *Total Depth*
TIH = *Trip in Hole*

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Tables and Figures

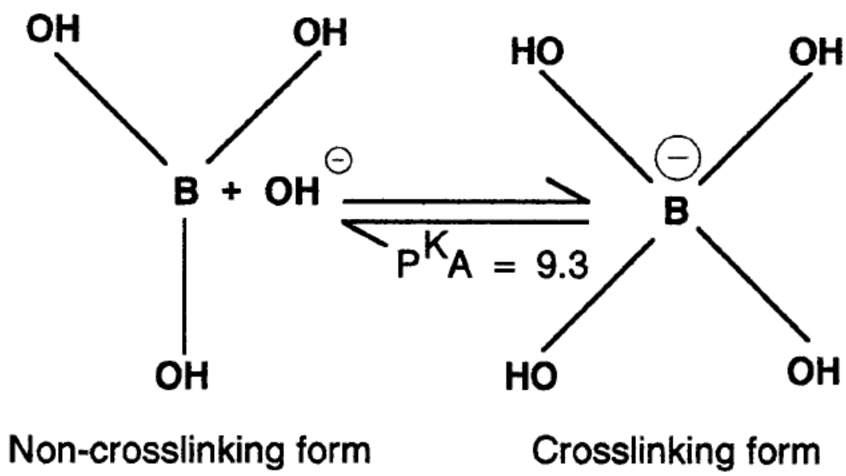


Fig. 1 – Crosslinking vs non-crosslink form of borate ion as controlled by pH (Powell et al. 1991).

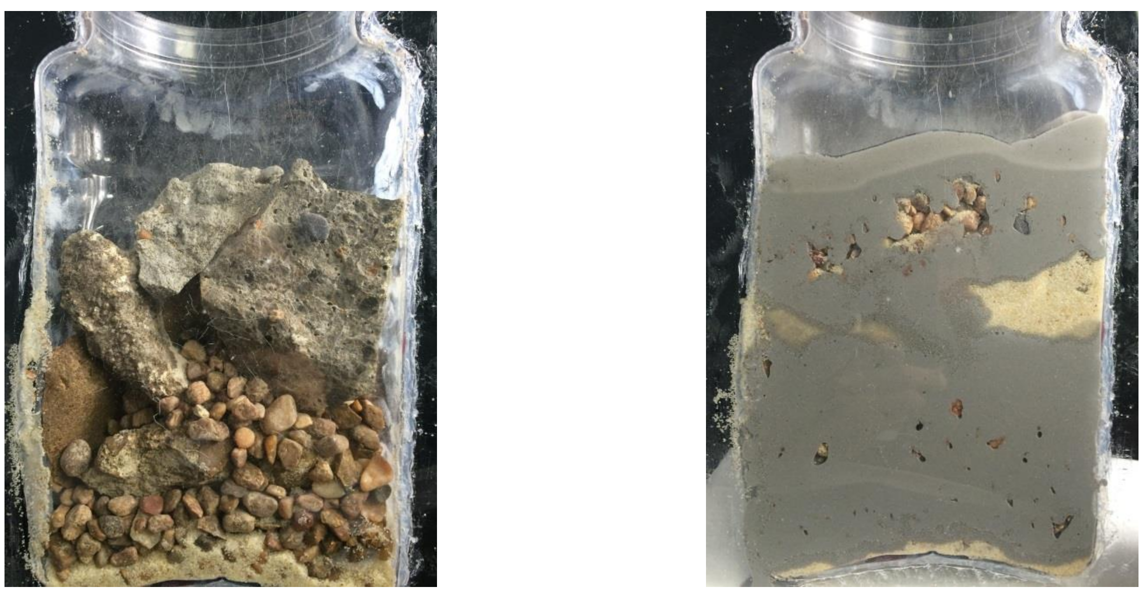


Fig. 2a – Simulation of a limestone formation with relatively large voids as well as loose fragments, pebbles and sand (left). A 10.7-lb/gal PBS system immediately after pouring into the plastic container (right).

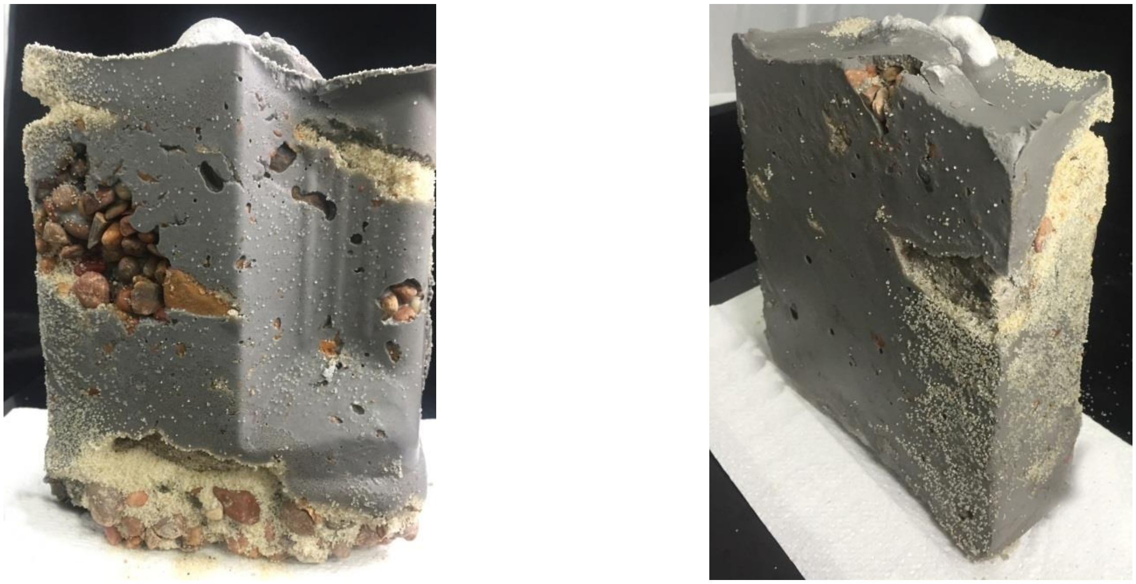


Fig. 2b – Front and back images showing the 10.7-lb/gal PBS system after static aging at ambient temperature for 4 hours followed by removal of the plastic container. Note the loose fragments and sand are amalgamated.

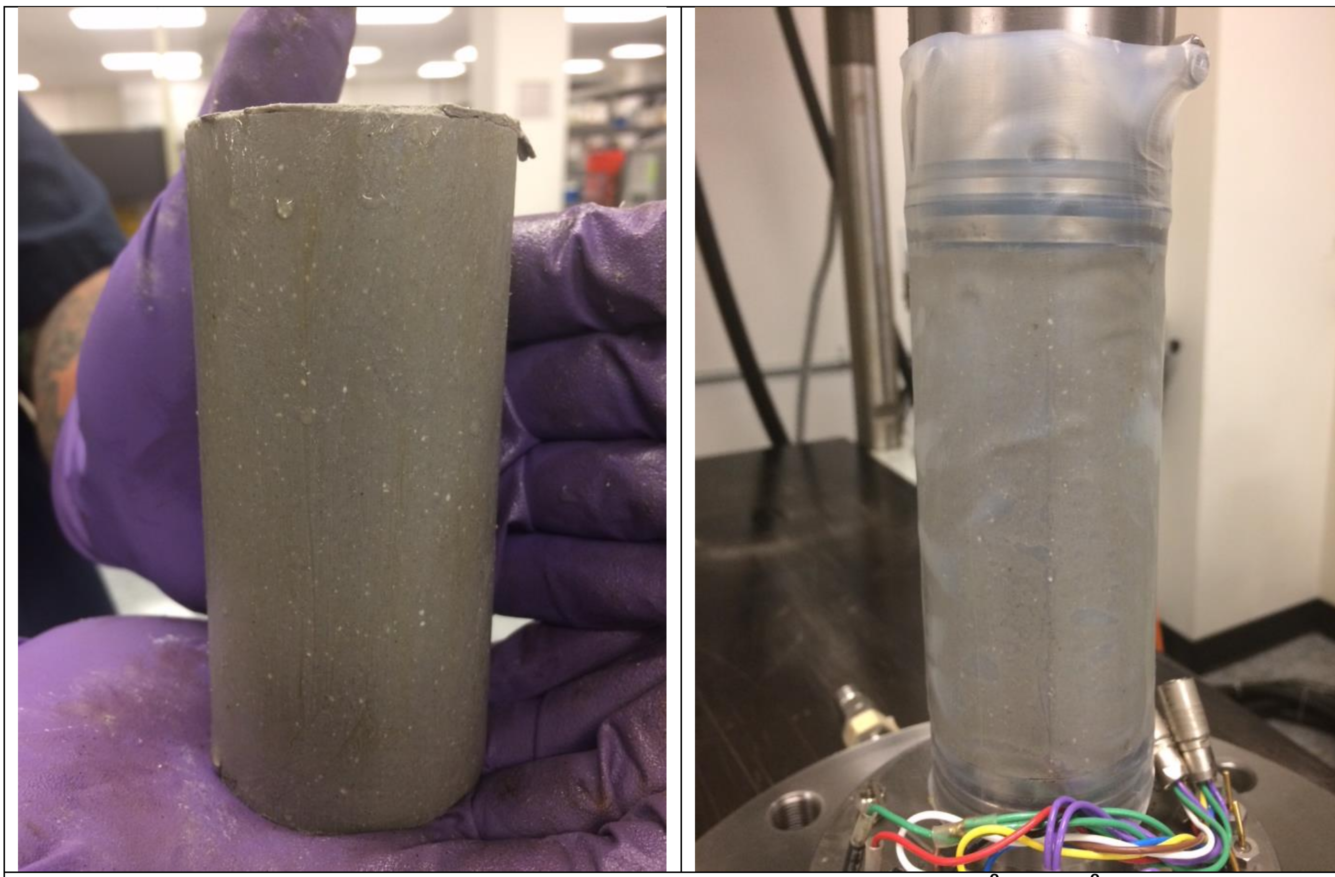


Fig. 3 – Digital images showing a 12.5-lb/gal PBS after static curing for 4 hours at 275°F to 290°F using 1000 psi confining pressure (left) and the same PBS plug demolded before placing into a compressive strength vessel (right). After curing and cooling the PBS plug on the left measured approximately 0.8 mm with a penetrometer.

Table 1 – Comparison of Confined Compressive Strengths	
Type Material	**Axial Stress (MPa)**
Class A Cement[1]	41.7
Tuff Rock, Yucca Mountain, Nevada[2]	39.6 – 439.7
PBS System – 12.5 lb./gal[3]	7.1
1. Samples aged for 14 days in water bath at 45°F. Average of three measurements (Cementing Solutions 2002)	
2. Confining pressures ranging from 0 to 10 MPa (Heiken 2006)	
3. 4 hrs aging at 275°F and 1000 psi confining (6.9 MPa)	

Table 2 – Components of PBS System	
Functionality	**Type**
Crosslink retarder and thinner	Primary
Crosslinking, fluid loss, viscosifying, bridging and anti-syneresis	Primary
Crosslink catalyst	Primary
Variation in set time from maximum 6 hours to less than 1 hour with typical 2 hours	Optional
Reverse crosslink	Optional
Thermal extender	Optional

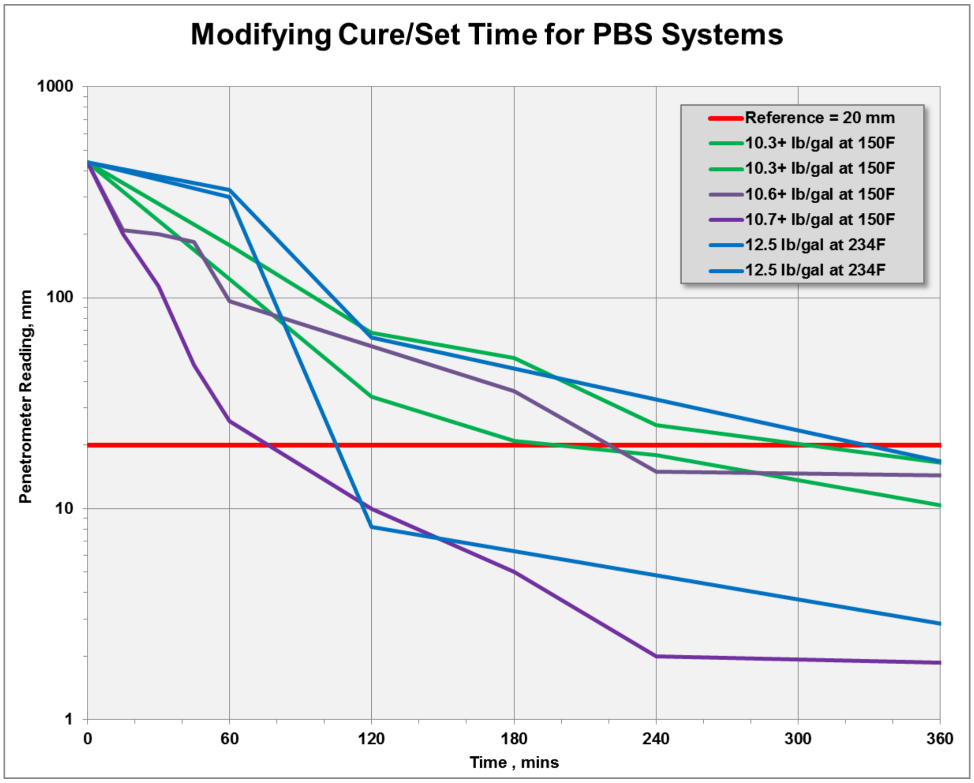


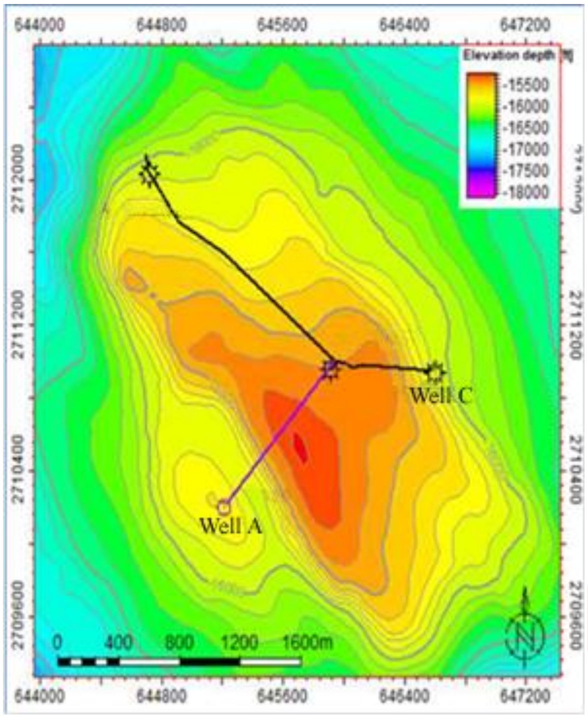
Fig. 4 – Plot showing selected PBS systems with density ranging from approximately 10.3+ lb/gal to 12.5 lb/gal. Note the relationship between depth of the penetrometer (mm) versus time (min.). For each of these PBS systems, only the alkaline aggregate component is varied while their density remains constant. The decreasing penetrometer depth or unconfined compressive strength increases rapidly for shorter cure/set time versus an asymptotic increase for relatively longer cure/set times. The red horizontal line is an internal standard for determining adequate set. These trends also show the transition from a slurry to a solid.

Table 3 – Summary of Common Lost Circulation Materials

Additive	Particle Size Range
Fibro Seal*	
Fine	7-13% is 28-100 mesh (650-150 µm)
Coarse	30-40% is 28-100 mesh (650-150 µm)
Mica (typical)	
Fine	1.0-30% is 14-100 mesh (1400-150 µm)
Medium	30-85% is 10-20 mesh (2000-850 µm)
Coarse	0.1-20% is 16-100 mesh (1180-150 µm)
Nut plug (typical)	400-2000 µm
Fine	400-500 µm
Medium	1200-1500 µm
Coarse	1600-2000 µm
G-Seal**	
Plus	300-500 µm
Plus Coarse	500-800 µm
M-I-X II**	
Fine	90% finer than 100 mesh (150 µm)
Medium	80% greater than 50 mesh (300 µm)
Coarse	80% is 8-100 mesh (2360-150 µm)
Polyswell	80-100 µm

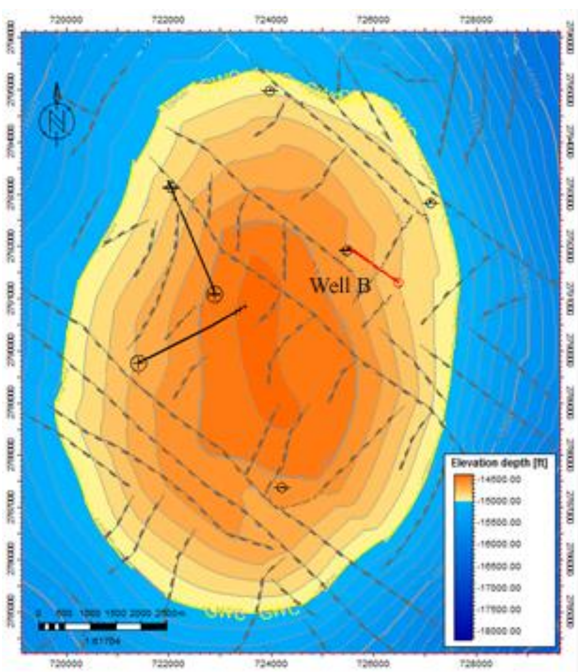
** Mark of PETROCHEM*
***Mark of M-I SWACO L.L.C. / Schlumberger*

Fig. 5 – Location of the ASR wells in the Arabian Gulf.



Hole Size	Formations
26"	Dammam
	Rus
	Umm Er Radhuma
	Simsima
	Fiqa
20"	Halul
	Laffan
	Mishrif
	Shilaif
	Mauddud
	Nahr Umr
	Thamama I
	Thamama IR
	Thamama II
	Thamama IIA
	Thamama IV
	Thamama V
	Thamama VI
	Hith
14½" x 16"	Arab A
	Arab B
	Arab C
	Arab D
	Diyab
	Upper Areaj
	Uweinat
	Lower Areaj
	Izhara
	Hamlah
12¼"	Gulailah
	Sudair
8⅜"	Upper Khuff
	Middle Khuff Anhydrite
	Lower Khuff
	Basal Khuff Clastics
6"	Unayzah-1
	Unayzah-2
	Unayzah-3
	TD

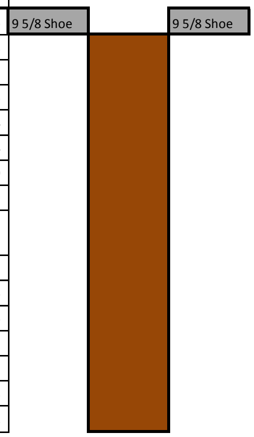
Fig. 6a – Well A location/structure contour map (left) and hole sections and corresponding formations drilled (right). The red outline shows hole section and formation where the PBS systems were applied. Note Well C is the referenced offset.



Section	Formations & Casing
26"	ASMARI
	DAMMAM
	RUS
	UER
	SIMSIMA
	FIQA
16"	HALUL
	LAFFAN
	MISHRIF
	SALBSHIL
	NAHRUMR
	THAMAMA I
	THAMAMA II
	THAMAMA III
	THAMAMA IV
	THAMAMA V
	THAMAMA VI
	HITH
12 ¼"	ARAB A
	ARAB B
	ARAB C
	ARAB D
	DIYAB
	UPPERARAEJ
	UWEINAT
	LOWERARAEJ
	IZHARA
	HAMLAH
	GULAILAH
	SUDAIR
8 ⅜"	KHUFF K1
	KHUFF K2
	KHUFF K3
	KHUFF K4
	KHUFF ANHYDRITE
	KHUFF K5
6"	KHUFF K6
	KHUFF K7
	TD

Fig. 6b – Well B location/ structure contour map (left) and hole sections and corresponding formations drilled (right). The red outline shows formations where the PBS systems were applied.

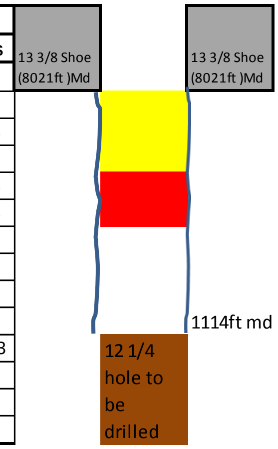
Formation/Marker	ACTUAL	
	ft MDBRT	ft TVDSS
Sudair	13747.0	-12786.6
Upper Khuff K1	14236.0	-13274.8
D1	14466.0	-13504.7
K2	14570.0	-13608.6
D2	14767.0	-13805.4
K3	14808.0	-13846.4
D3	15196.0	-14234.0
K4	15273.0	-14310.9
Khuff Middle Anhydrite	15560.0	-14597.7
Lower Khuff K5	15609.0	-14646.7
D5	15736.0	-14773.5
K6	15786.0	-14823.5
D6	15978.0	-15015.2
K7	16035.0	-15072.1
D7	16217.0	-15253.8
BKC	16238.0	-15274.8



Fracture Clusters
Open 8 3/8 Hole

Fig. 7a – Illustration of the anticipated troublesome formations, red-shaded, in the 8⅜-in. section of Well A with formation depths at: (i) measured depth below rotary table (MDBRT) and (ii) true vertical depth sub-sea (TVDSS).

Formation/Marker	ACTUAL	
	ft MDBRT	ft TVDSS
Hith	7996.0	-7567.1
Arab A	8190.0	-7751.9
Arab B	8286.0	-7843.4
Arab C	8342.0	-7896.8
Arab D	8473.0	-8020.4
Diyab / Jubailah	9076.0	-8594.4
Upper Areaj	9571.0	-9065.1
Uweinat	9835.0	-9315.9
Lower Areaj	10038.0	-9509.2
Izhara	10392.0	-9846.5
Hamlah	11008.0	-10431.3
Gulailah		
Sudair		
Upper Khuff K1		



Fracture Clusters
Natural Porous /Perm areas
Hole remaining to be drilled , requiring 12ppg Mud minimum

Fig. 7b – Illustration of the anticipated troublesome formations, red-shaded, in the 12¼-inch section of Well B with formation depths shown as measured depth below rotary table (MDBRT) and true vertical depth sub-sea (TVDSS).

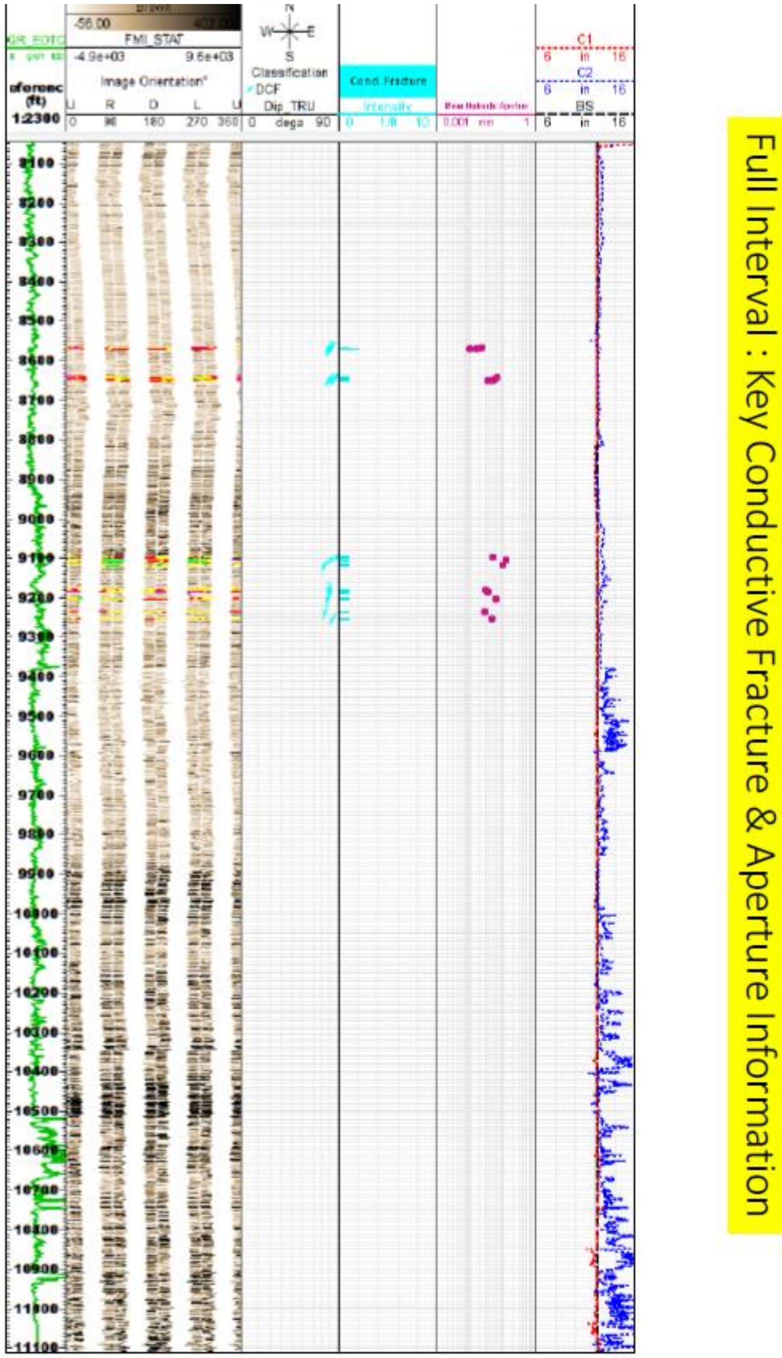


Fig. 8 – Fracture cluster identification using log sourced from LWD.
Blue ticks represent fracture clusters in the Arabs (upper) and Diyab (lower) and suspected loss zones.

Table 4 – Results of Testing to Assess Cure/Set Time for PBS Systems				
Density (lb/gal)	**10.7**	**11.0**	**11.2 – 12.5**	**12.0 – 12.5**
Wellbore Size (in.)	**26, 20, 16**	**12¼**	**8⅜ or 8½**	**6**
Temperature (°F)	**105 – 240**	**240 – 280**	**285 – 333**	**305 – 345**
90% Cure/Set Time (hr)	2	2	2	2
99-100% Cure/Set Time (hr)	4	4	4	4

Table 5 – Summary of PBS Systems for Each Planned Hole Size

PBS System (size in µm)	Pumpable Volume (bbl)	Hole Length* Relating to Pumpable Volume (ft)	Hole Size (in.)	Density		Weighting Material	Other Materials Required
				lb/gal	s.g.		
500	330	~500	26	10.7	1.28	$CaCO_3$	
500	330	~500	26	10.7	1.28	Barite	
2000	330	~500	26	10.7	1.28	Barite	
500	200	~500	20	10.7	1.28	$CaCO_3$	
500	200	~500	20	10.7	1.28	Barite	
2000	200	~500	20	10.7	1.28	Barite	
500	125	~500	16	10.7	1.28	$CaCO_3$	
500	125	~500	16	10.7	1.28	Barite	
2000	125	~500	16	10.7	1.28	Barite	
500	75	~500	12¼	11.0	1.32	Barite	Anhydrous salt
500	50	~700	8⅜ or 8½	11.2	1.34	Barite	Anhydrous salt
500	100	~1400	8⅜ or 8½	11.2	1.34	Barite	Anhydrous salt
2000	50	~700	8⅜ or 8½	11.2	1.34	Barite	Anhydrous salt
2000	100	~1400	8⅜ or 8½	11.2	1.34	Barite	Anhydrous salt
500	50	~700	8⅜ or 8½	12.5	1.50	Barite	Anhydrous salt
500	100	~1400	8⅜ or 8½	12.5	1.50	Barite	Anhydrous salt
500	20	~550	6	12.0	1.44	$CaCO_3$	Anhydrous salt
500	120	~825	8⅜ or 12¼	10.3	1.23	Unweighted	Anhydrous salt
2000	120	~825	8⅜ or 12¼	10.3	1.23	Unweighted	Anhydrous salt

Hole length without pipe in hole.

Table 6 - Rheological Targets for PBS 500 and 2000 Systems with No Activator*

Density (lb/gal)	10.7	11.0 – 11.2	12.5	12.0 – 12.5
Wellbore Size (in.)	26, 20, 16	12¼, 8⅜, 8½	8⅜ or 8½	6
600-rpm Dial Reading	70 – 80	70 – 80	95 – 110	125 – 140
300-rpm Dial Reading	45 – 60	45 – 60	65 – 80	95 – 110
200-rpm Dial Reading	40 – 50	40 – 50	55 – 65	75 – 85
100-rpm Dial Reading	30 – 40	30 – 40	40 – 50	55 – 70
6-rpm Dial Reading	18 – 25	12 – 18	15 – 25	20 – 25
3-rpm Dial Reading	11 – 17	10 – 15	12 – 20	17 – 23
PV (cP)	18 – 25	30 – 40	25 – 35	35 – 45
YP ($lb_f/100\ ft^2$)	30 – 35	20 – 30	35 – 45	55 – 70
Gel Strength, 10-sec/10-min ($lb_f/100\ ft^2$)	12 – 18 / 13 – 19	10 – 15 / 10 – 15	15 – 20 / 12 – 20	18 – 25 / 18 – 25
0.3-rpm Dial Reading	35K – 50K	35K – 50K	55K – 70K	75K – 90K

** All properties measured with a FANN 35 at temperatures ranging from 90 to 95°F and pH ranging from 7.5 to 8.0 (measured direct).*

Fig. 9 – Selected section from the FMI run in Well A, 8⅜-inch wellbore as run/processed after controlling losses.

Table 7 – PBS Systems Utilized on Well A and Well B

Well Name	PBS System (size)	Total Pills Pumped	Pill Volume (bbl)	Dynamic Loss Rate Worst Recorded (bbl/hr)	Dynamic Loss Rate Stabilized/Achieved (bbl/hr)
Well A	PBS 500 / PBS 2000	1 / 1	110 / 100	170 @ 500 gal/min	2 @ 500 gal/min
Well B	PBS 500	3	60 / 60 / 110	60 @ 600 gal/min	0 @ 600 gal/min

Table 8 – Summary of Cost Savings

	Rig Days Curing Losses	Volume Mud Lost bbls	Cement Plugs Pumped	BHA lost in Hole	Sidetrack
Well C	44 days = $11,000,000	11,000 = $330,000	7 = $70,000	1 = $500,000	1 = $2,000,000
Well A	7 days = $1,750,000	5,000 = $150,000	0 = $0	0 = $0	0 = $0
Cost Saving	**37 days = $9,250,000**	**$ 180,000**	**$70,000**	**$ 500,000**	**$2,000,000**

** based on cost estimates in USD for rig rate/LCM/cement plugs/BHA/Sidetrack.*

Appendix I – Lost Circulation Plans

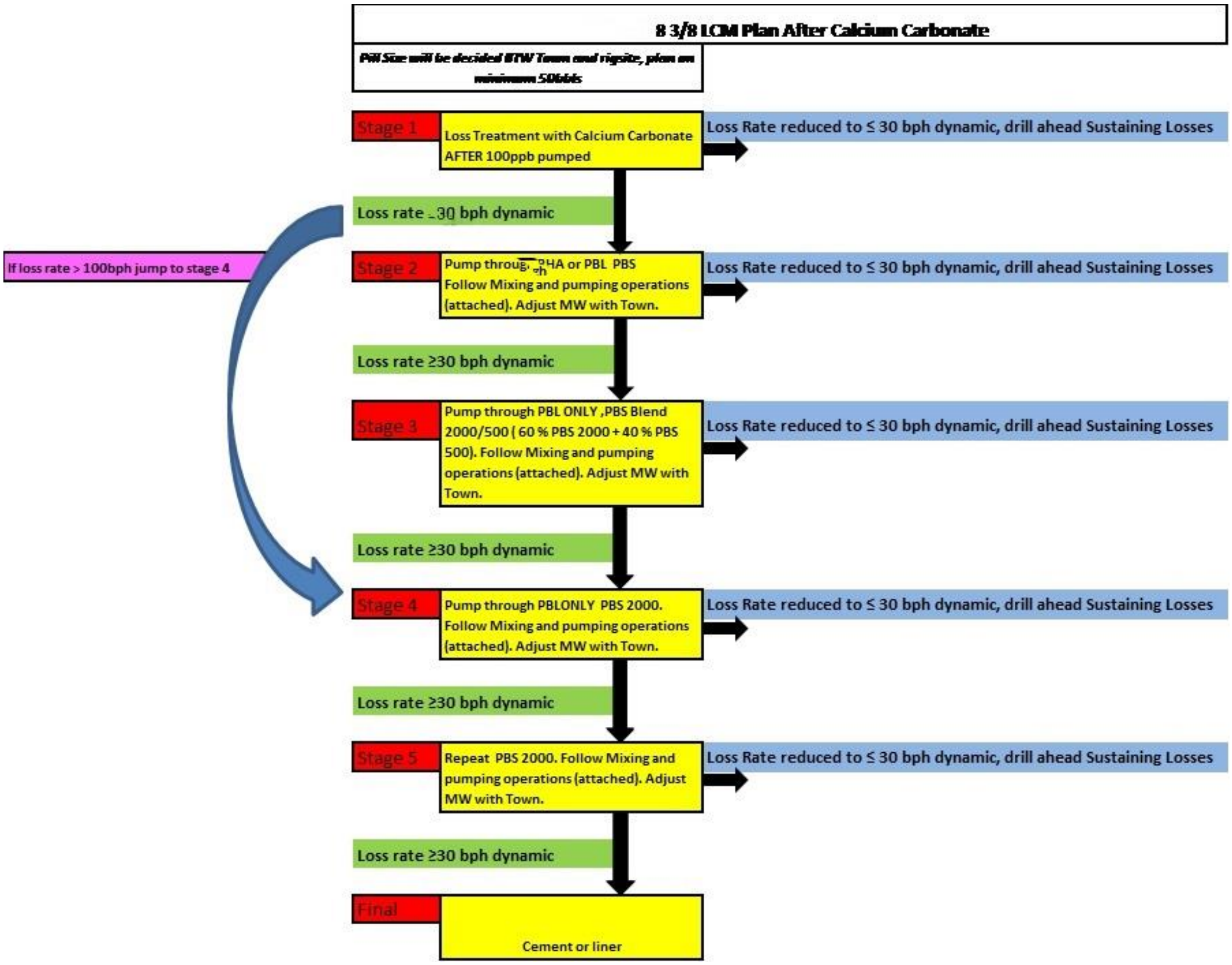


Fig. A-1 - Well A LCM Plan.

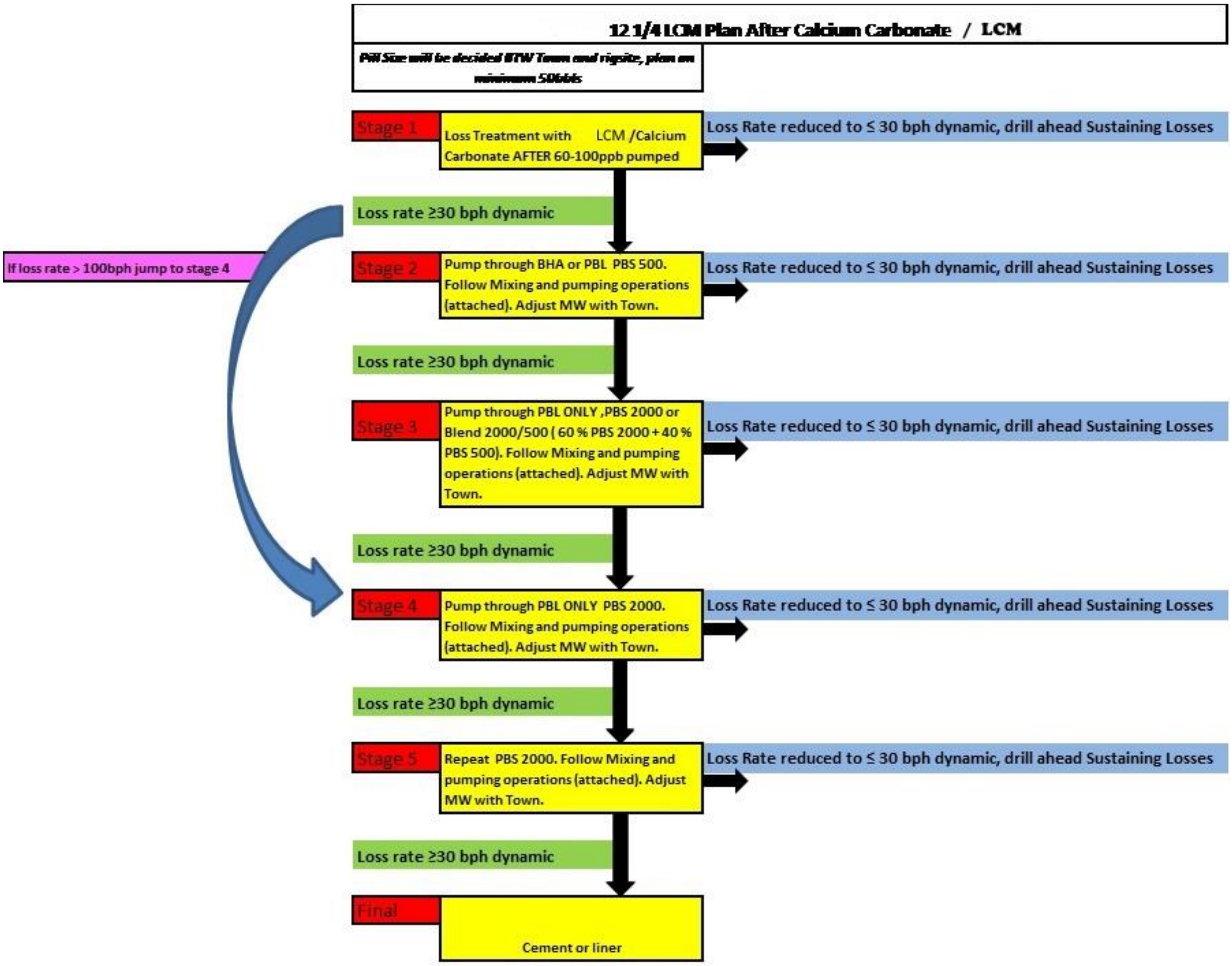


Fig. A-2 - Well B LCM Plan.

Appendix II – Well Summaries from the Daily Drilling Reports

Well A - 8⅜-inch Wellbore

1. The 8⅜-in. vertical section was drilled from the previous 9⅝-in. casing shoe at 14,150 to 14,360 ft with 11.3-lb/gal mud.
2. While drilling ahead, increased flow at surface was detected at 14,360 ft. The mud weight was increased to kill weight (12.8 lb/gal) and the well was controlled and confirmed static.
3. Drilled ahead, rate of penetration (ROP) suddenly increased (>100 ft/hr) and a loss of weight on bit (WOB) was observed while drilling at 14,735 ft in the Upper Khuff (K2). Severe losses were encountered at a rate of 108 bbl/hr.
4. A 50-bbl and 100-lb/bbl $CaCO_3$ LCM pill was pumped, reducing the loss rate to 42 bbl/hr at 400 gal/min.
5. Continued drilling with controlled parameters pumping $CaCO_3$ 100-lb/bbl LCM pills (30 to 75 barrels each) as needed. Losses were controlled at 15 to 22 bbl/hr at 450 gal/min however at 525 gal/min, loss rate >90 bbl/hr.
6. ROP increased >100 ft/hr and loss of WOB again observed at 15,155 ft until 15,201 ft. Loss rate was recorded as >144 bbl/hr.
7. Drilled with controlled parameters to 15,468 ft, loss rate controlled at 60 bbl/hr. Pumped 30-bbl, 100-lb/bbl $CaCO_3$ as well as 40-bbl, 25-lb/bbl LCM pills as needed, but losses increased from 60 to 200 bbl/hr.
8. A 30-bbl LCM pill was pumped to bottom and left to soak until well was confirmed static. Well was static with pumps off. Dynamic losses ranged from 60 to 90 bbl/hr and were again observed when circulating.
9. After confirmation of static loss rate, determined insufficient LCM pit volume to keep drilling with dynamic loss rate. Wiper trip to shoe while building LCM pit, conducted circulation test at shoe to establish loss rate. <u>Dynamic losses were 170 bbl/hr at 500 gal/min; static loss rate stabilized to 4 to 25 bbl/hr after dynamic test</u>.
10. **At this point it was decided to implement the PBS loss circulation system.**
11. PBS 500 system #1 (110-bbl) spotted at 15,465 ft through the bypass sub ports pumping at 400 gal/min.
12. Pulled-out string to 13,650 ft to allow the PBS to set.
13. Established circulation after setting time was completed and full returns were attained. The well was confirmed static. This was tested by circulation at 13,650 ft, 500 gal/min with full returns.
14. Pulled out BHA with static loss rate of 12 bbl/hr. Run in hole (RIH) to tag PBS and clean out. Static loss rate increased to 33 bbl/hr; dynamic loss rate was 12 bbl/hr at 400 gal/min.
15. Decision to pump PBS system (#2). Pumped 100-bbl PBS 2000 system. The top of the first PBS 500 was not tagged.
16. PBS 2000 system (#2) was allowed to set while pulling out BHA to surface and pick up cleanout BHA. <u>Dynamic loss rate at 500 gal/min was zero</u>. RIH with cleanout BHA; <u>static loss zero</u>.
17. RIH and tagged top of PBS 2000 at 14,990 ft (5-10K psi) and drilled out to 15,485 ft (bottom) without losses. Dynamic losses of 10 bbl/hr at 500 gal/min after pumping high viscosity pill to remove residual PBS debris.
18. BHA was pulled out of the hole and preceded with the wireline logging program.
19. Three logging runs were performed over three days with static losses stabilized at approximately 18 bbl/hr. As such, <u>uninterrupted logging was possible</u>. Log runs were as follows:
    - Log run #1: FMI-PPC-SS-PPC-LS-GR
    - Log run #2: APS-HRLA-HGNS-GR-PEX
    - Log run #3: CMR-XPT-GR

    An example of the FMI log (**Fig. 9**) confirmed improved resolution and subsequently revealed a more complete fracture network in the Upper Khuff
20. Ran cleanout BHA to bottom without issues. Dynamic losses were initially 25 bbl/hr at 350 gal/min and went to zero at 450 gal/min indicating PBS squeezing and expanding against formation, maintained 450 gal/min and well was static; zero losses in static condition. Pull out of hole (POOH).
21. Run drilling BHA to drill to next logging point, displaced well from 12.8 to 12.4-lb/gal mud (to reduce any barite settling possibilities) without losses.
22. Drilled with controlled parameters pumping basic LCM pills ($CaCO_3$ blends) as required to control losses (20 to 35 bbl/hr) until planned TD (16,278 ft in the Lower Khuff) was reached as new loss zones potentially opened/exposed.
23. Performed wiper trip and trip to surface with stable static losses of 4 to 15 bbl/hr.
24. Ran 2 more logs (CBL and MDT) with static loss rate stabilized at 10 bbl/hr.
25. The 7-in. liner was run to TD with static and dynamic loss rates of 2 bbl/hr at 500 gal/min.
26. Set liner and cemented without losses.

Well B – 12¼-inch Wellbore

1. 12¼-in. section drilled to logging depth of 11,114 ft MD (top of Hamlah Formation), MW maintained at 10.95 lb/gal to prevent Arabs Formation breaking down.
2. Critical logs secured before drilling Gulailah/Sudair Formations.
3. Hole was static and slick, POOH on elevators.

4. Run logging suites; no losses throughout 3 days of logging.
5. RIH slick and conduct formation integrity test (FIT) and increase MW to drill Gulailah/Sudair Formations. Mud weight of 12 lb/gal achieved.
6. Commenced drilling 51 ft into Hamlah Formation (11,114 to 11,165 ft) and observed >25 bbl/hr dynamic losses and then lost returns.
7. Pumped 30-bbl LCM pill (40-lb/bbl of $CaCO_3$+ LCM) and spot in open hole. POOH from 11,165 to 10,916 ft, attempt to fill annulus with 12-lb/gal mud without success; no fluid level seen. Decision made to fill backside with drill water.
8. Trip in hole (TIH) to 11,165 ft ; static losses are 60 bbl/hr.
9. At a depth of 11,165 ft; spot PBS 500 system #1 as 30-bbl $CaCO_3$ spacer followed by 60-bbl PBS 500.
10. POOH to 9,830 ft, spot PBS 500 system #2 as 30-bbl $CaCO_3$ spacer followed by 60-bbl PBS system thru drillstring.
11. POOH to shoe, mix another PBS system while monitoring losses. Static loss rate improving from 35 to 12 bbl/hr.
12. Consulted LWD log. RIH to 11,000 ft, spot PBS 500 system #3 as 50 bbl of 12-lb/gal mud, 30-bbl $CaCO_3$ spacer followed by 110-bbl PBS system thru drillstring.
13. POOH to shoe and monitor losses. Static loss rate was 48 bbl/hr after 15 minutes and dynamic losses 50 to 60 bbl/hr while pumping.
14. Wait on PBS system #3 to cure for 2.5 hours. Stage-up pumps to 600 gal/min; no losses. Drilled ahead to section TD.