

Consistent Successful Delivery of High-Pressure High-Temperature Extended Reach Wells Through Non-Aqueous Drilling Fluids Strategy Optimization

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Abstract

In south Mexico there is an ongoing campaign of drilling and completion to develop a strategic onshore field with high-pressure high-temperature (HPHT) extended-reach drilling (ERD) conditions averaging 8,200 m (26,896 ft) of measured depth (MD), reaching bottomhole static temperatures up to 180°C (356°F). The main objective from the client's side is to continue the strategy of accelerated development of newly discovered limestone reservoirs. In this paper we describe the fluid strategy and the solutions that were implemented during a field development that so far has encompassed more than 18 wells.

Based on a long-term presence in the region and extended offset well analysis, certain best practices were fine tuned for the subject wells. The conventional non-aqueous fluid (NAF) was tailored to reduce key risks for drilling these HTHP-ERD-type wells while keeping parameters within necessary specifications to maximize drilling performance and enable completion on the wells with slotted liners without affecting the oil production rates. We will give a technical overview of criteria for several key fluid indicators, proper planning beforehand, and close monitoring and control of many key factors including proper barite sag management, rheology profile optimization for optimum hole cleaning, and fluid stabilizers for an extended logging program, as well as maintenance of the fluid system to meet the drilling requirements.

Our successful campaign of field development with no high-impact events will be presented. This proves that the subject solution met all the required objectives for drilling and logging this section without affecting reservoir performance.

Introduction

The subject campaign is dedicated to developing a conventional Mesozoic reservoir, which is located in a strategically important field. Refer to Figure 1 for the stratigraphic column. The political and economic objective of the Operator in Mexico is to fully develop the potential of the field, while simultaneously place the drilled wells in production to cover local demand and provide adequate support for communities in southern Mexico. The field produces condensates, natural gas liquids, and very light hydrocarbons.

Therefore, both operational and engineering efficiency is critical for the entire campaign. The top of the producing formation occurs at depths ranging from 6,200 m (20,336 ft) to 7,600 m (24,928 ft) true vertical depth (TVD). The bottomhole static temperature (BHST) is above 150°C (302°F) starting at 6,000 m (19,680 ft) TVD. General well design is affected by the presence of a series of folds and faults, as well as salt domes without a predetermined orientation.

Field Challenges

As we will demonstrate, drilling such wells was a challenge of balancing cost benefit with feasibility of solution. The entire campaign of wells was subject to a strategic field development plan where, based on rig sizing and reservoir studies, it was decided to develop the target reservoir vertically through a series of pad-drilled wells.

Wellbore Geometry

While the implementation of this strategy effectively minimizes community disruptions and facilitates surface infrastructure management, it significantly complicates the well delivery process. Most wells in the campaign are drilled with an S-shaped profile. However, the drilling campaign commenced with a few vertical and J-shaped profiles, as illustrated in Figure 2.

The wellbore S-shaped trajectory is strategically designed with a kickoff point between 2,000 m (6,560 ft) and 2,500 m (8,202 ft), featuring a buildup rate of up to 2.5° per 30 m (98 ft) and a building angle of up to 45°. Most trajectories within the field exhibit inclinations ranging between 25° and 35°. To minimize the risks of wellbore collision with offset wells, primarily in the pad-drilling environment, several 3D-steering intervals are incorporated throughout the trajectory.

As expected, the challenging wellbore profile by itself is a hazard. As shown in Figure 3 and will be discussed throughout the paper, a later stage of development of the field contemplates deeper casing points because of the anticlinal nature of the reservoir. This meant the majority of the wells were placed in the ultradeep extended reach category.

One of the casing arrangements for the campaign comprises five strings with three liners, and one of them integrating a tieback casing string. The production section is designed as

either 5-in. slotted or cemented liner or a 4 1/8-in. openhole section. Refer to Figure 4 for wellbore geometry.

The complex geometry of the wellbore poses challenges during the running of casing or liners. In certain wellbore architectures, the combination of increased drag, side forces, and casing rigidity can present significant obstacles to reaching the required setting depth.

For example, well B presented a distinctive challenge for running 13 3/8-in., 72-lb/ft casing with rotation in an S-shaped well with Along Hole Distance (AHD) up to 992.8 m—a scenario uncommon in the field—strategic measures were crucial for ensuring success (Table 1).

High Temperature

The high-temperature (HT) nature of the subject field (Figure 5) presents obvious challenges for drilling fluids, which will be described later. However, it also bears indirect influence on the way the wells are designed and executed. As mentioned above, starting the relatively intermediate section of the 9 7/8-in. casing, the expected BHST would reach the conventional measurement- and logging-while-drilling (MLWD) tools limit. Therefore, special cooling and staging techniques would need to be used to mitigate the temperature. Despite all the precautions, the failure of conventional tools is inevitable. The use of high-temperature versions is restricted only for the most strategically important cases. Furthermore, certain wellbore architectures, contemplate drilling 4 1/8-in. reservoir sections and sourcing tools, turned out to be a real challenge. This implies that real-time annular pressure while drilling (APWD) data or directional surveys in most cases are not available. Hence, the complexity of follow up increases, as it is impossible to correlate models or to get accurate projections for torque and drag (TnD) and hole-cleaning simulations. This prompts drilling engineers to use field trends and assumptions rather than accurate, measured data. Such approach comes with its cost, for example: in TnD requiring to assume less margin of overpull (MOP) available due to higher downhole inclination; or demonstrating worse hole cleaning index than in reality.. See Figure 6 for the influence of projections over directional profile.

Severe Reservoir Depletion

The production commenced in mid-2019 with the drilling of the first exploratory well. Currently, there are more than 20 active wells. Figure 7 illustrates the reservoir pressure history and pressure forecast.

The reservoir is composed of dolomitized carbonate rocks. For this diagenetic model, two types of dolomitization processes are considered, occurring in different periods. The first one was a massive dolomitization in a shallow diagenetic environment (nonsedimentary) by marine water with fine dolomite. The second occurred in a deep environment through fractures, as evidenced by the deposition of baroque dolomite.

Within the reservoir zone, it is evident that the equivalent pore pressure is below 0.75 g/cm³ (6.3 lb/gal), occasionally dropping to values as low as 0.69 g/cm³ (5.8 lb/gal). The combination of low pore pressure and a relatively high equivalent collapse pressure further adds to the complexity of

reservoir section, making it one of the most challenging segments throughout the entire well.

Over the years it has been demonstrated that an upper gas-bearing cap formation remains with its potential to kick. Meanwhile constant production from the lower part causes the equivalent mud weight (EMW) to gradually decline. The resulting mud weight window expands, presenting challenges for the drilling team. It is not uncommon to see the target reservoir being drilled with a theoretical overbalance up to 11,000 psi to compensate for the EMW of the upper drive.

In certain critical scenarios, the simultaneous presence of gas influx in the upper section and significant depletion in the lower part of the production reservoir poses safety challenges for drilling operations. To address this, the higher-pressure zone is isolated with casing to facilitate drilling into the lower section. However, the depletion is often so extreme that it requires a managed pressure drilling (MPD) technique with a-balance or near-balance control. This involves employing a biphasic fluid system with continuous nitrogen injection.

Competitive Environment

As mentioned in the Introduction, the subject field is labeled by the Operator as strategic. Therefore, the key performance objective of this campaign would be not only timely but also cost-effective delivery. This philosophy can be seen taking place in customer operations, as well as in the pricing and tendering model.

For similar reasons the contractual terms and conditions between service provider and client are such that the service provider has virtually no control over the drilling rig provided for execution of the well, nor the surface equipment. Typically, service provider would be responsible for organizing surface tanks volume for upcoming operations. In the pad drilling environment, available space is limited, therefore it is not uncommon for operations to take place with only 200 m³ (1,257 bbl) of surface volume available (not taking into account reserve volume).

At the same time, the mixing capabilities of the rigs are severely limited. Often, due to space limitations and surface pad layout between the neighboring rigs, it is highly complicated to mix fluid onsite. Whenever influx and mud contamination with formation fluids occur, the difficulty of providing mud in good condition increases exponentially.

Lower Completion Architecture

To streamline oil production and minimize disturbance in the well delivery cycle, the slotted liner is selected for lower completion for the majority of the wells in the campaign. Using this lower completion severely limits the operating parameters used while running in hole. The working of the pipe will be limited according to liner hanger limitations, as well as circulation rates allowable through the slots.

Whenever an injector well is planned, oil-swellable packers are implemented. This makes the introduction of the liner time sensitive; Figure 8 shows the swelling time chart. During the introduction, any operational delay may deem catastrophic. The oil-swellable packer is normally introduced as part of either

cased or open hole isolation, depending on completion architecture. In either case, the drift diameter of the parent 7.75-in. casing is as low as 6.201-in. As can be seen in the expansion chart, this gives the operations team only 6 days for the liner introduction until full expansion. To preserve the integrity of the packer, we must get it into its designated position before full contact. According to the chart, the packer normally swells to 6.0 in. over a period of 1.5 to 2.5 days which, taking into consideration the deep setting point, presents a real challenge.

Integrated Solutions for Well Delivery

Offset Wells Analysis

We established an integrated process to identify and solve the key hazards of well construction. Acknowledging the robust organizational structure of the Mexican Operator, the number of parties involved, and complexity of the subject wells, the workflow was divided into two parts—planning and execution.

In the planning phase, the subject matter experts (SMEs) group organized to review the upcoming well feasibility. The simulation on a per section basis are usually supplemented with logistical and volumetric calculations to ensure we were using resources efficiently. After the well was formally simulated and all the major concerns were addressed, it was handed over to the execution team.

The handover process was based on a workshop of lessons learned, dedicated to a revision of previous wells drilled in the campaign. In the case of fluid-related service quality (SQ) events, a formal investigation was also performed as part of the handover. It is important to see all action items being implemented or have fixed dates of closure assigned, before moving into execution of a new well. Finally, a drilling well on paper (DWOP) session is conducted with both field and office personnel aiming to align objectives.

The subject field is being simultaneously developed via several pads, so execution-phase alerts and lessons learned from the closest offset wells are continuously shared, enabling us to increase overall awareness and minimize any nonproductive time (NPT).

Drilling Fluids Overview

All the wells in this field drill the first interval to approximately 1,250 m (4,101 ft) with a 1.25-g/cm³ (10.4-lb/gal) high-performance water-based mud (HPWBM); once the water mantles have been isolated, then the 20-in. casing is run and cemented, and the rest of the intervals are drilled with NAF.

Due to the nature of the wells, the need for performance, and inherent conditions such as troublesome shales, HPHT conditions, ERD, high-compressibility rocks, hydrogen sulfide- and carbon dioxide-bearing formations, and differential sticking, NAF is the preferred option over HPWBM, as it is a cost-effective solution when some of these problems are faced in one or more intervals.

As stated above, while drilling the NAF intervals, different challenges are experienced and a variety of density ranges and fluid properties are required to effectively drill these wells, so

different approaches are taken in terms of drilling fluids. Densities and fluid properties must be adjusted as drilling conditions change. The wells are basically divided into three different zones (Figure 9), transitioning from low-pressure to high-pressure ramp, the high-pressure intervals, and the reservoir.

Transition Zone Interval Fluid Strategy

After the surface interval is isolated, the transition zone is drilled (Miocene formations) with mud weights that vary from 1.20 g/cm³ (10 lb/gal) up to 1.60 g/cm³ (13.4 lb/gal); the maximum BHST for this interval doesn't exceed 120°C (248°F). While drilling this transition zone, the objective is to drill as fast as possible without compromising the integrity of the wellbore, but two major issues are faced: partial losses are expected, and the risk of cuttings packoff due to high rate of penetration (ROP) and low annular velocities. The likelihood of having losses is accentuated while drilling high-permeability sandstone formations. The other contributing factor is gradual increase of mud weight and plastic viscosity (PV) while drilling, contributing both to fluid losses and stuck pipes probability.

That said, the fluid's strategy consists of a proper wellbore strengthening plan (WSP) to minimize the differential sticking and lost circulation risks during this interval, thus optimizing drilling time and reducing NPT. The WSP considers materials such as graphite, cellulose, gilsonite, and calcium carbonate to reduce the fluid loss to a formation and to enhance the wellbore stability. The proposed WSP is tested in the laboratory on a high-permeability aloxite disk that simulates permeable sandstones (Figure 10). The evaluation of the fluid loss in the aloxite disk aims to have a low spurt loss and a flat loss rate increase as time passes (Figure 11). As for the hole cleaning the close collaboration between drilling, fluids, and real-time monitoring team will be discussed below.

Logistics and mud pit management is the key to success, as an average volume of 1,200 m³ (3,937 bbl) are required to drill the transition zone. Moreover, to increase the mud weight as required, the use of barite is reduced, and the additions of spike mud helps to increase the mud weight while drilling and at the same time generate volume at an appropriate rate to keep up with the wellbore demand.

High-Pressure Interval Fluid Strategy

Once the 13 3/8-in. casing is set at the entrance of the high-pressure interval, the mud weight is raised above 1.85 g/cm³ (15.0 lb/gal). Oligocene formations are drilled to the top or inside of the Eocene formations where a 11 3/4-in. liner is set, then the mud weight is raised above 2.00 g/cm³ (16.7 lb/gal) to drill the next interval to the top of the Cretaceous formations. Although the Oligocene interval is relatively short (\pm 500 m, 1,640 ft), there are certain hazards to go through, such as wellbore instability, reactive shales, differential sticking, mud losses, and water influx.

Cutting size and shape are monitored to detect any possible signs of instability (cavings coming over the shakers) or to visually identify the wettability of the cutting. In addition to the

visual inspection, the salinity of the mud is compared side-by-side to the formation by measuring the cuttings water activity with a hygrometer. Usually the salinity of the mud is in a range from 10,000 to 20,000 ppm above the formation, as seen in the example in Figure 12.

Water influx is commonly associated with a salt body close to the field, tectonically affecting these formations. From the point of view of fluids, close monitoring of oil/water ratio, water-phase salinity, pit volumes, and equivalent circulating density (ECD) is key, so that any water inclusion can be detected on time to avoid a well control issue.

After the 11 3/4-in. liner is set, then the second portion of the high-pressure interval is drilled. Eocene formations still have a risk of mud losses because of their layers mudstones and sandstones, especially when using densities above 2.00 g/cm³ (16.7 lb/gal), as ECD values generated oscillate between 2.08 g/cm³ to 2.16 g/cm³ (if mud weight is raised to 2.08 g/cm³). For this, a WSP is put in place. Treatment mainly consists of using carbonates and high-resilience graphite, as they also help to reduce TnD.

Through the whole interval, but mostly at the end of it, barite sag is a major risk in the Eocene, as BHST exceeds 150°C (302°F), so possible mud weight fluctuations are monitored during bottoms up or if long static periods are present [i.e., bottomhole assembly (BHA) change or wireline logging]. A part of established standard procedure is mud treatment prior trips with a wetting agent and viscosifier, to minimize sag risk. It is common to pump lubricants to assist the casing or liner runs in terms of TnD.

Reservoir Interval Fluid Strategy

The reservoir interval is divided into Cretaceous and Jurassic formations. The first formation is known for presenting mud losses in naturally fractured rocks, and the Jurassic interval usually requires a higher-density mud because of the presence of formation gas. In some cases, a 5-in. liner is set at the top of the Jurassic Kimmer Formation so that losses are isolated.

The reservoir strategy set by the Operator doesn't allow the use of any nonreservoir-friendly lost circulation material (LCM). Using this approach, the losses are mainly controlled with MPD equipment and, in cases where the formation gradient is low, with a biphasic fluid (nitrogen + mud). For these cases, the surface mud weight goes as low as 0.91 g/cm³ (7.6 lb/gal) and with nitrogen the downhole ECD can be reduced even further. When trips to the surface are to be performed, the ECD is compensated by displacing heavy mud. This way, the well is static during the trip and additional operations. Fluid rollover usually requires pit management, as heavy mud is left in the wellbore and light mud is stored in frac tanks.

In the reservoir section, the major concern for the fluids is the rheology control. Mud coming through the flowline is monitored and if there are signs of reduction on rheology, fluid loss, and/or electrical stability (ES), the mud is treated with high-temperature products. In addition, with regard to the high-temperature products, the mud is also treated with calcium carbonate (CaCO₃) to have proper CaCO₃ excess to counteract the continuous background gas. Sometimes a hydrogen sulfide

scavenger is also used.

High-Performing Lubricants

In ERD wells, tubulars are worked close to their mechanical limits resulting from the additional drag along the extended wellbore. This friction needs to be accounted for both while drilling (off-bottom torque, limiting the maximum torque available) and while tripping (slackoff and pickup weights broomstick monitoring). In addition, the high-content solids in the fluids result in extra friction created between the metal-to-metal or metal-to-formation contact^[3].

The use of two different lubricants has been a success to reduce the TnD while drilling and tripping casing and liners, and also to help release stuck pipe. Usually, a liquid lubricant is added to the circulating system while drilling/circulating as it decreases the Coefficient of Friction (CoF) and at the same time the product is retained in the circulating system. On the other hand, a solid copolymer bead lubricant is spot across problematic areas in the wellbore when casing/liner is run; this way, the lubricant will act when the tubular is passing through and along the spotted pill. The use of the solid lubricant is preferred when running casing/liner as rotation is limited during the operation.

NAFs by nature have a low CoF, but these lubricants help to decrease the CoF further, up to 50% (seen in the laboratory). A comparison of the reduction on the CoF is shown in Table 2. Although liquid lubricants offered the highest reduction in CoF, care should be taken when high-content solid fluids are treated with it, as usually a high concentration of liquid lubricant adversely affects the rheological profile, so a recommended maximum concentration of 1% v/v is used in most cases.

An example of how a liquid lubricant helps release a stuck liner is shown in Figure 13. In this figure a reduction of the torque amplitude from 31,000 lb-ft to 18,000 lb-ft is observed after adding 5 L/m³ of liquid lubricant to the circulating system. The use of lubricants (solids or liquids) has become a standard practice for most wells when liners are run in open hole, and especially when the clearance between the tubular and the open hole is small, but also when high doglegs are present and mechanical restrictions are found.

Taking into consideration the need for enhanced lubrication, a mechanical lubricant was strategically pumped into the wellbore of well B (see Table 1). Two pills of the copolymer were spotted while pulling the BHA out of the hole, specifically from 2,380 m (7,806 ft) to 2,280 m (7,478 ft) and from 2,200 m (7,216 ft) to 2,100 m (6,888 ft) (see Figure 14).

Note a significant decrease in torque until 3,250 m (10,660 ft), where the torque values begin to align with the predictions made by the simulation. This observed reduction in torque values until 3,250 m (10,660 ft) underscores the notable impact of the employed mechanical lubricant on the casing-running operation. The efficacy of the mechanical lubricant becomes particularly evident in this section of the well, validating its role in optimizing the casing-running process.

Barite Sag Management

Barite sag is a major concern when weighted fluids are used

in extended-reach wells. Although the wells described in this paper are not high angle, the low-viscosity condition given by the high-temperature environment (thermal thinning) can lead to lost circulation, stuck pipe, packoffs, wellbore instability, and/or well-control problems if the fluid properties and drilling parameters are not properly managed [1]. Generally, barite settling can occur in wells deviated 30° or more that are drilled with fluid densities above 1.44 g/cm³ (12 lb/gal), and it is affected by different factors such as annular velocity, hole angle, interval length, flow regime, mud weight, mud rheology, pipe eccentricity, and rotation. When the inherent conditions of the well or drilling parameters can't be changed, we are limited to modify a few parameters to minimize the barite settling, and it is when managing the mud rheology plays an important role in mitigating such risk.

While there is no consensus on a single rheological parameter that has the greatest impact on sag, a close relationship exists between dynamic settling and low-shear-rate yield point (LSRYP). For these wells, a value of LSRYP between 7 to 15 lb/100 ft² for fluids above 1.65 g/cm³ (13.8 lb/gal) (Figure 15) has provided adequate barite suspension; such evaluation has been assessed by determining the rheological properties with a HPHT viscometer in the laboratory (Table 3), monitoring the sag index dynamically at the rigsite via viscometer sag shoe test (VSST) (Table 4), and under static conditions (Table 5). Along with the rheology assessment testing required, there are some other guidelines related to fluids that help to minimize barite sag, such as:

1. Surfactant concentration: Additional treatment of 1 to 2 lb/bbl of wetting agent is used to prevent barite settling and to keep additional solids oil wet, being careful to not over-treat the system to avoid thinning down to undesirable levels.
2. Oil/water ratio (OWR): Usually, rheology modifiers perform better when enough water is available in the drilling fluid. OWRs are kept between 75/25 and 85/15 for NAFs in this project.

HT Additives

When exposed to high temperatures, oil-based systems decrease in viscosity and density (expansivity), but because of compression, high pressures with high-density fluids counteract this expansion.

The impetus behind formulating an NAF to be HT resistant is that conventional products will eventually break down—the fluids will become thinner and lose their thermal stability, affecting hole cleaning, wellbore stability, and promoting faster barite sag, eventually affecting the operations. For this reason, the NAF system must be treated with products that withstand these HT conditions, so that these aforementioned risks do not create NPT for operations [2].

If systems are not properly treated, gelation and excessive viscosity become a major concern, as they can generate high ECDs that could lead to loss circulation events. For this reason, the products selected for these conditions play an important role, especially when smaller-diameter holes are drilled. In the example shown in Table 6, a conventional 1.95 g/cm³ (16.3

lb/gal) NAF was conditioned with two different HT products and dynamically exposed to after hot rolling (AHT) process up to 175°C (347°F) for 16 hours; although both treatments achieved the goal of withstanding the rheology, the first treatment had a higher rheology and gels that can eventually lead to issues described above.

NAFs used for drilling conventional intervals up to 150°C (302°F) do not require extensive additional treatments or dilutions to make them suitable for HT conditions, nor do they require completely swapping the drilling fluid. Therefore, this became a cost-effective solution, as mud used in previous sections can be diluted and reused. Three key products are used to tailor the conventional NAF to HT conditions:

- Special HT organophilic hectorite clay is used to support weighting materials and improve the cuttings removal at downhole conditions.
- A synthetic copolymer is used for filtration control. This polymer improves the quality and thickness of the filtercake while reducing the spurt loss.
- An emulsifier that contributes to filtration control and temperature stability of the system, while retaining gel strength, is used as a supplemental additive.

Usually, these three additives are added in a concentration varying from 1 to 3 lb/bbl when bottomhole circulating temperature BHCT or BHST exceeds 150°C (302°F). The concentration to be used is adjusted depending on the fluid properties obtained when the mud is circulated, or if there is a static requirement for long periods of time.

Lost Circulation Remedial Approach

Although the wellbore strengthening materials (WSM) used while drilling the transition and high-pressure zones usually help reduce the mud losses, there are certain cases where severe or total mud losses are not controlled conventionally, especially in delimitation wells in the field or wells that are in new blocks. If the mud losses are not cured, the integrity of the wellbore can be compromised, and the desired casing point may not be achieved. If this happens, it requires a contingency casing to isolate the area of concern.

A strategy to remediate severe or total mud losses was developed. The remedial approach for severe or total losses consists of spotting a formulated pill and squeezing it into the formation. The squeeze is performed in a hesitation schedule with the blowout preventer closed; each pressure increase stage holds pressure for a certain time, and several stages are performed until the desired ECD is achieved. Once the product is deposited into the fracture, the pill is defluidized, losing the liquid part, and when pressure is released, the active agent is left inside the fractures.

As shown in Figure 16, severe mud losses up to 25 m³/hr (157 bbl/hr) were encountered while drilling sandstone intercalations in the Paleocene formations at 6,228 m (20,427 ft). Once the pill was mixed, it was pumped and spotted in the wellbore through a downhole circulating sub, then subsequently squeezed with a hesitation procedure to reach an equivalent of 1.98 g/cm³ (16.5 lb/gal) by applying 1,300 psi (in 100 to 150

psi increments). Once the squeeze job was completed, the BHA was pulled to the top of the pill and a circulation test was performed. With a loss rate of 3 m³/hr, this enabled us to continue drilling to the casing point.

This treatment has become a standard in the drilling fluids program design as the remedial treatment for severe or total losses before opting for ultimate scenario of squeezing cement. This solution has been implemented in different scenarios of the wells in the field, including curing losses in Cretaceous limestones or as a remedial treatment when a weakly cemented shoe is found after the drillout.

The proposed treatment is tested in the laboratory via a plug-permeability test (PPT) performed on a 4,000- or 5,000- μ slotted disk. In this example, a 1.90 g/cm³ (15.9 lb/gal) NAF was treated with 270 kg/m³ (95 lb/bbl) of LCM products, a 600-psi differential pressure was applied, and temperature was 165°C (329°F). The sealing result is shown in Figure 17.

Two-Phase Drilling practices

A challenging scenario was present in well B, where simulations were initially conducted using information provided by the Operator, allowing for the most accurate reference possible to the onsite operations. However, these simulations were continually updated with real-time values generated during the operation, such as mechanical status, fluid rheologies, BHA, rotation, rate of penetration, and surface backpressure.

It was possible to perform the analysis of adjustable variables during the operation to maintain control over bottomhole pressure (BHP). The MPD system was aligned to initiate nitrogen injection from 6,681 m (21,919 ft), using a mud density of 0.95 g/cm³ (7.9 lb/gal), a liquid flow rate of 138 gal/min and 17 m³/min of nitrogen to achieve an equivalent mud weight of 0.81 g/cm³ (6.8 lb/gal). However, these parameters were consistently adjusted throughout the operation to attain an equivalent mud weight of 0.76 by the very bottom of the well at 7,572 m (24,842 ft).

Figure 18 shows the final parameters while drilling with biphasic fluid [liquid flow rate: 142 gal/min, nitrogen flow rate: 43 m³/min, surface backpressure: 110 psi, rpm: 80, mud weight: 0.95 g/cm³ (7.9 lb/gal) to achieve a calculated ECD of 0.76 g/cm³ (6.3 lb/gal)].

ECD and Hole-Cleaning Real-Time Support

As mentioned before, there are two major concerns related to hydraulics—in large openhole intervals, the concern is hole cleaning, and in small openhole intervals, it is ECD management. For both cases, a real-time ECD and hole-cleaning monitoring is used for NPT reduction or avoidance.

In upper intervals (26 in., 17 ½ in., 16 in. and 14 ½ in. x 12 ¼ in.), the evaluation is focused on a calculated parameter called hole cleaning index (HCI), which is a normalized value to the cutting concentration in the annulus. When the HCI is approaching the limit or showing a trend to deteriorate, other key drilling parameters such as TnD, standpipe pressure, and ECD values (when available), are compared side-by-side against the calculated values provided by the software, and if

the assessment shows a likelihood of having a possible hole-cleaning-related event, alerts are sent to the drilling team, so that action can be taken to improve cuttings transport in the well to avoid an eventual packoff. An example of the output from the software is shown in Figure 19.

In terms of ECD management, friction losses in these ERD wells are high, especially when drilling the 10 5/8-in., 8 ½-in., 6 1/8-in., and 4 1/8-in. intervals. ECD management becomes more critical, as any adjustment may require changes of drilling parameters such as flow rate, rotation, ROP, or surface annular backpressure (in case of MPD). However, adjusting rheology is another parameter considered, although given the high density of the wells, any reduction can accentuate the sag risk. The ECD surveillance in real time enables us to primarily monitor the APWD ECD and compare to the calculated value, but also the calculated value serves as a reference when the APWD is not available. The key hydraulic aspects to monitor in these wells are related to:

- ECD management while drilling the intervals
- swab/surge for pipe and liner/casing runs
- rollover displacement during MPD operations
- dynamic barite settling after long static periods
- cuttings bed disturbance in wells above 40°.

An example of ECD management during an MPD rollover operation is shown in Figure 20.

Conclusions

The development campaign has navigated numerous challenges, including high-pressure high-temperature conditions, ultra deep extended-reach drilling requirements, and severe reservoir depletion issues. The success of developed methodology and continuous learning is represented by 50% of all wells drilled in the field by Integrated project service provider. In none of the delivered wells to date there has been any major NPT event (more than 24 consecutive hours) attributed to drilling fluids, a remarkable achievement for wells with planned time of approximately 100-120 days. From performance perspective, there are two wells currently holding best in class positions, achieving 50.6 days / 10,000 ft and 52.8 days / 10,000 ft. These are the Operator's most sought key point indicators, once again highlighting importance of close collaboration, audits to the mud and timely intervention.

The several key points could be derived and shared with the industry from this campaign. The formulation of Non-Aqueous Fluids with additives resistant to high temperatures is crucial. For instance, the addition of specialized organophilic amine-treated clay, synthetic copolymers, and emulsifiers has been shown to effectively withstand high-temperature conditions up to 175°C (347°F), preventing issues such as gelation and excessive viscosity. The extensive laboratory research and support helped to determine the optimal concentrations of the products.

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[3] Olivares, Tulio, Turi, Zach and Brandon Hayes. "Innovative Solid Lubricant Solution to Reduce Friction in Challenging ERD

Figures

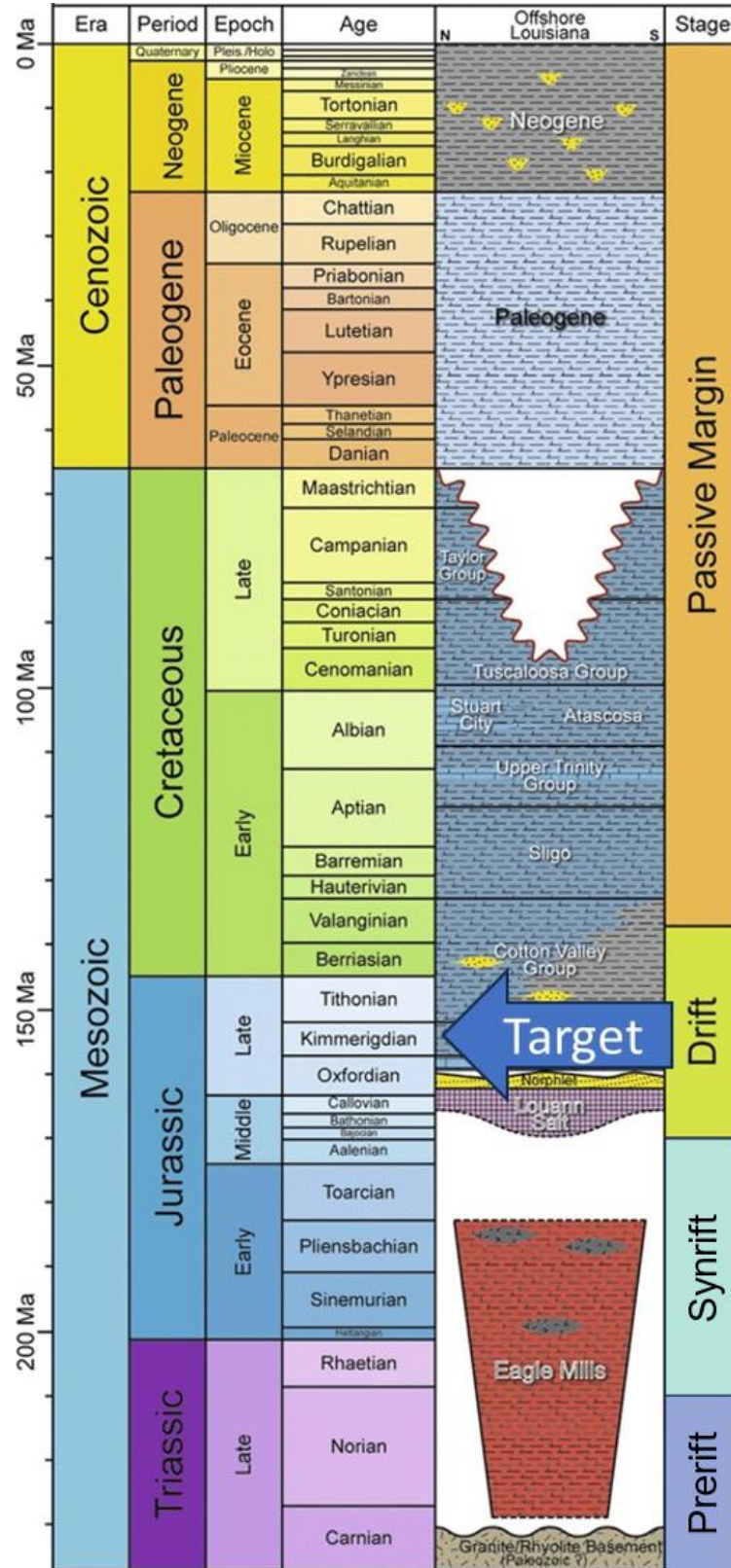


Figure 1—Stratigraphic column of the area, and showing reservoir target.

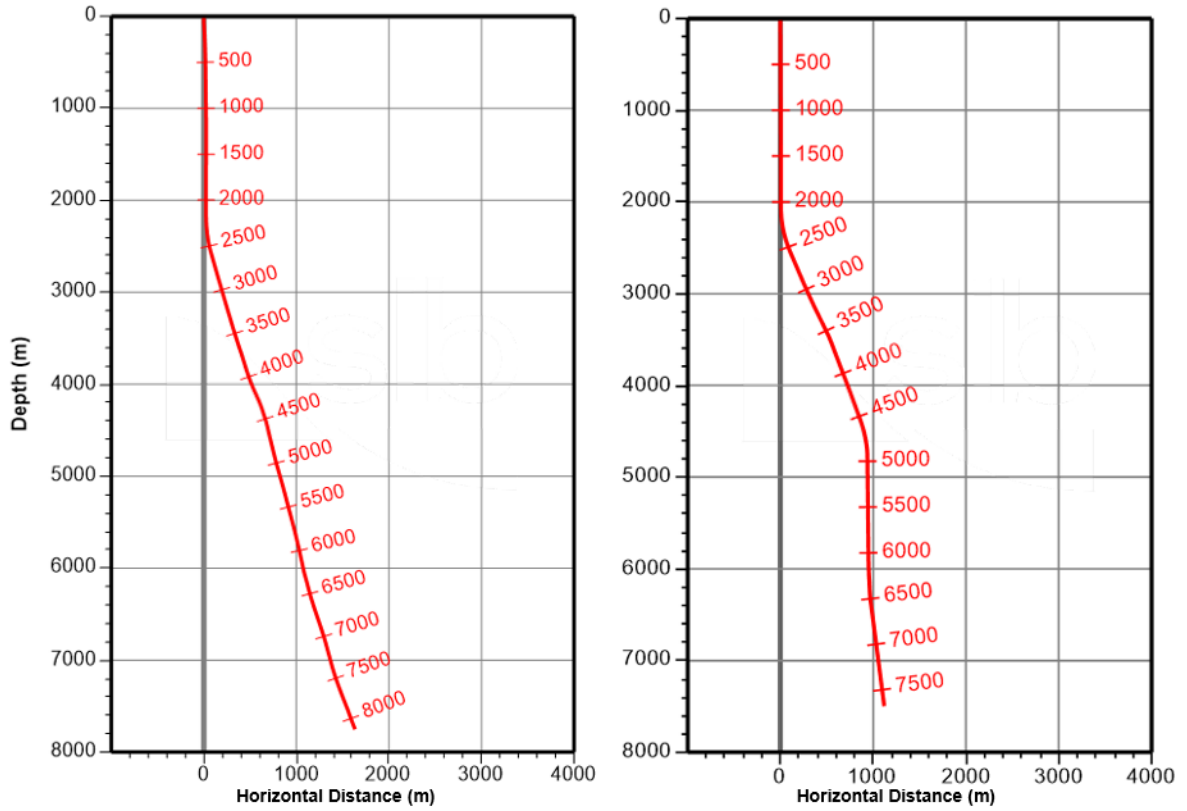


Figure 2—Typical wellbore trajectories for the field.

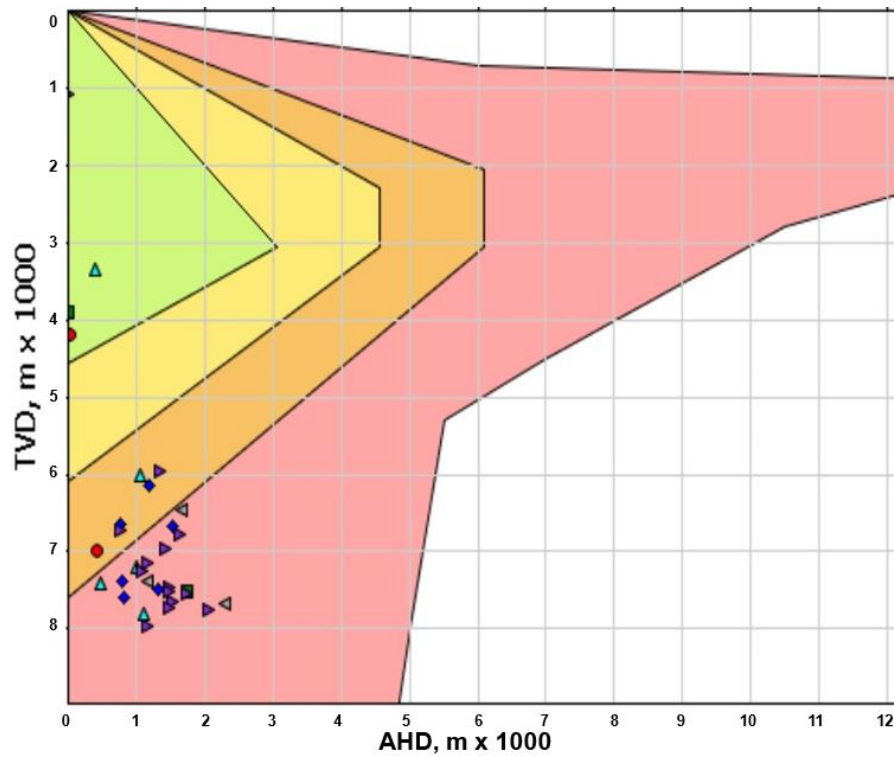


Figure 3—ERD database for wells drilled in the field throughout the campaign.

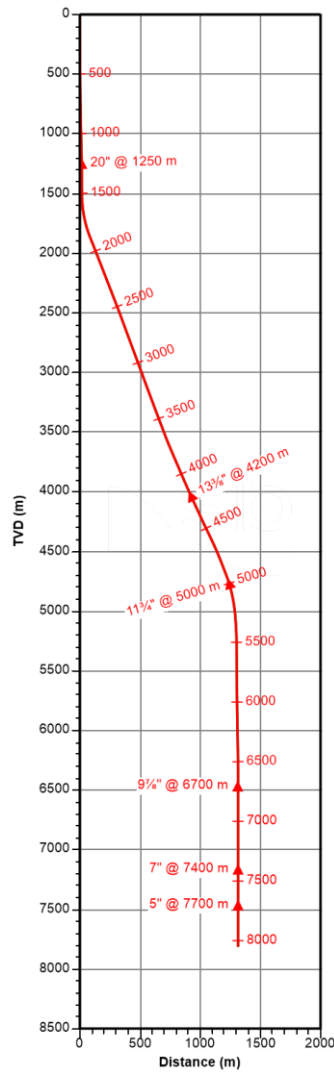


Figure 4—Typical wellbore geometry for late field development.

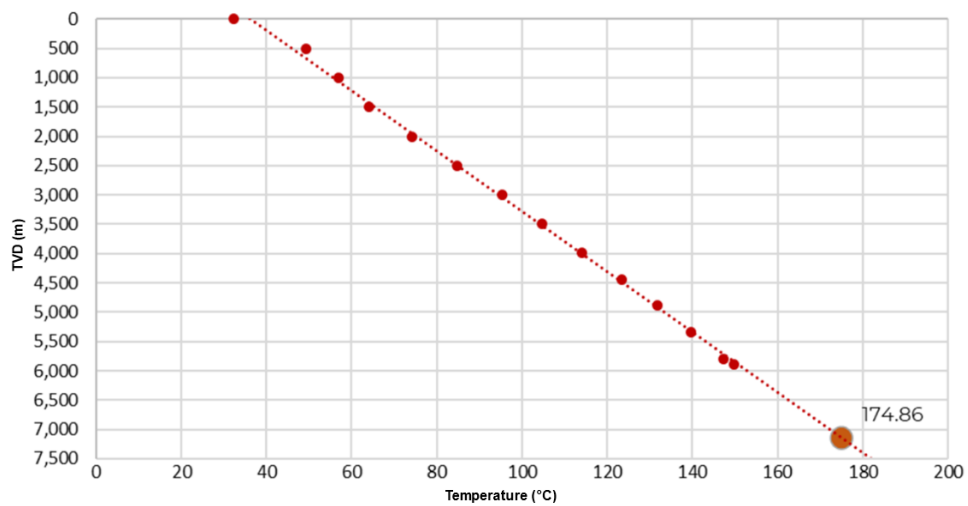


Figure 5—Typical expected temperature formation profile for a well in the field.

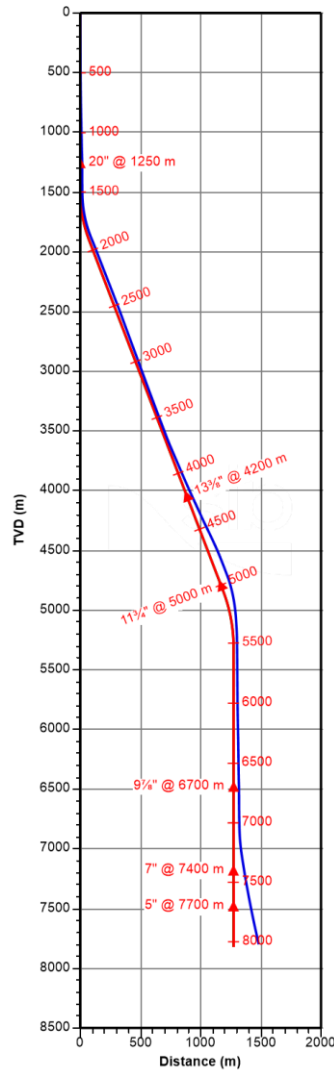


Figure 6—Influence of projection on directional profile.

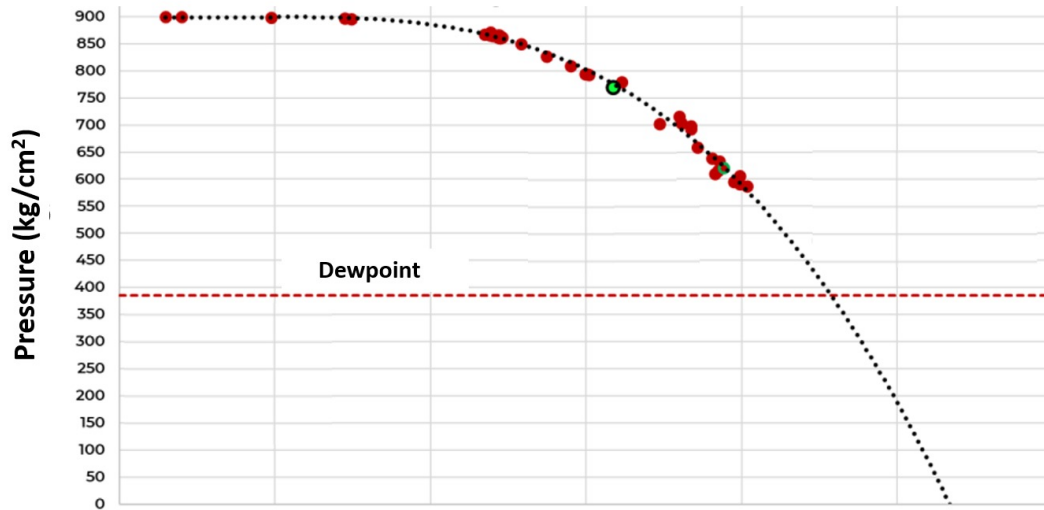


Figure 7—Reservoir pressure history and pressure forecast.

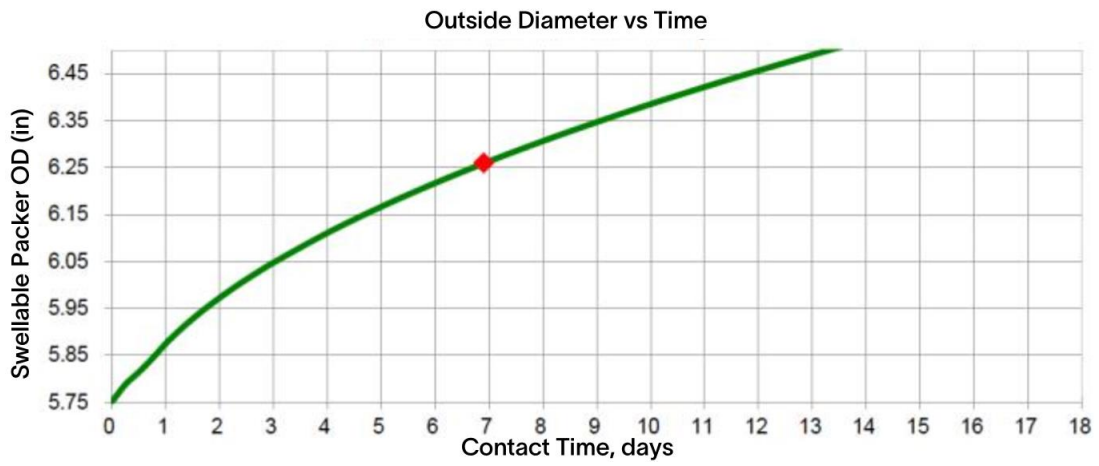


Figure 8—Swellable packer outside diameter (OD) vs. time elapsed.

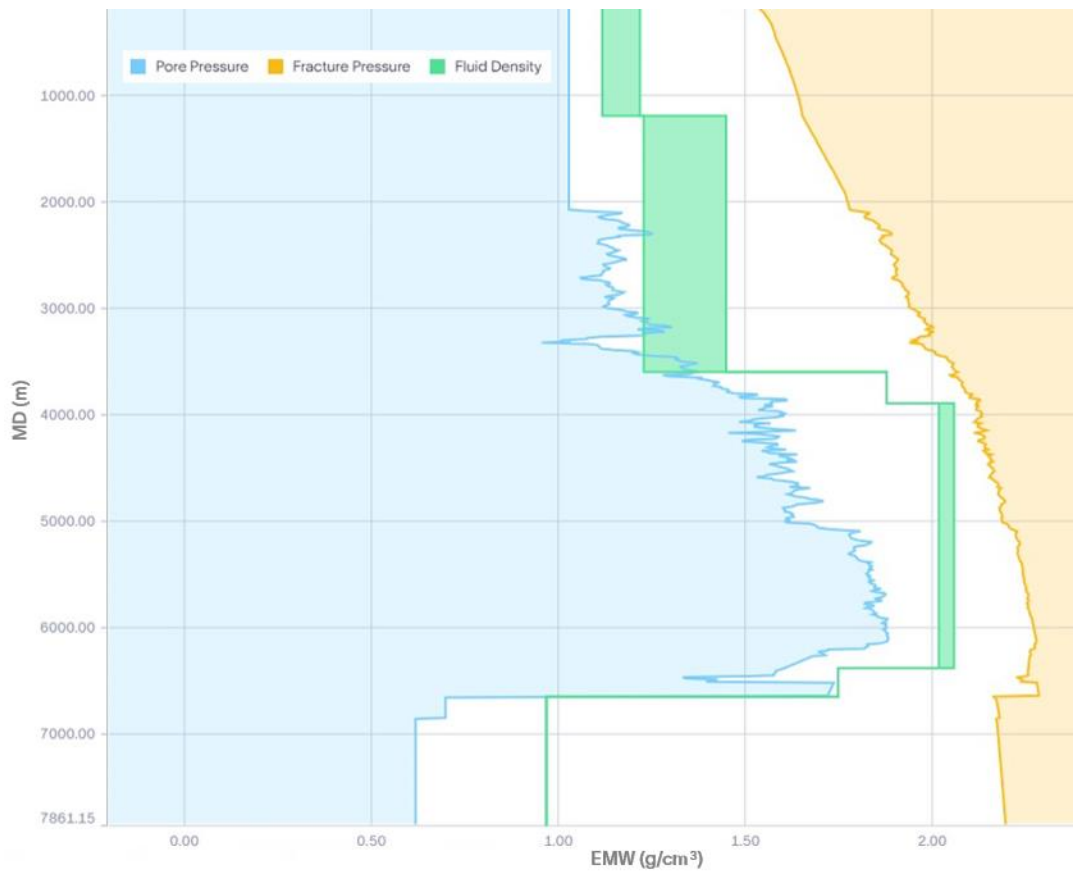


Figure 9—Example of the geomechanics curves vs. formation type and reference surface mud weights.

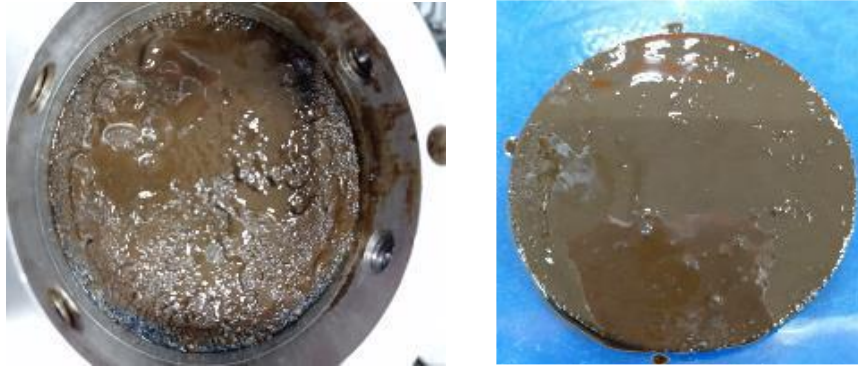


Figure 10—On the left side, 250- μ disk in the PPT cell; on the right side the aloxite disk with the WSM on top of it.

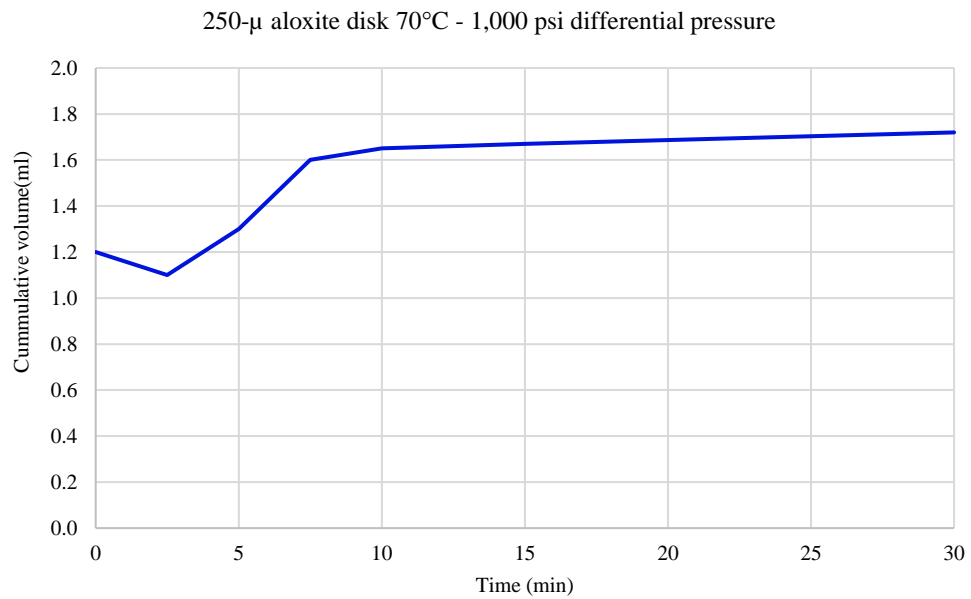


Figure 11—Fluid loss behavior on 250- μ aloxite disk.

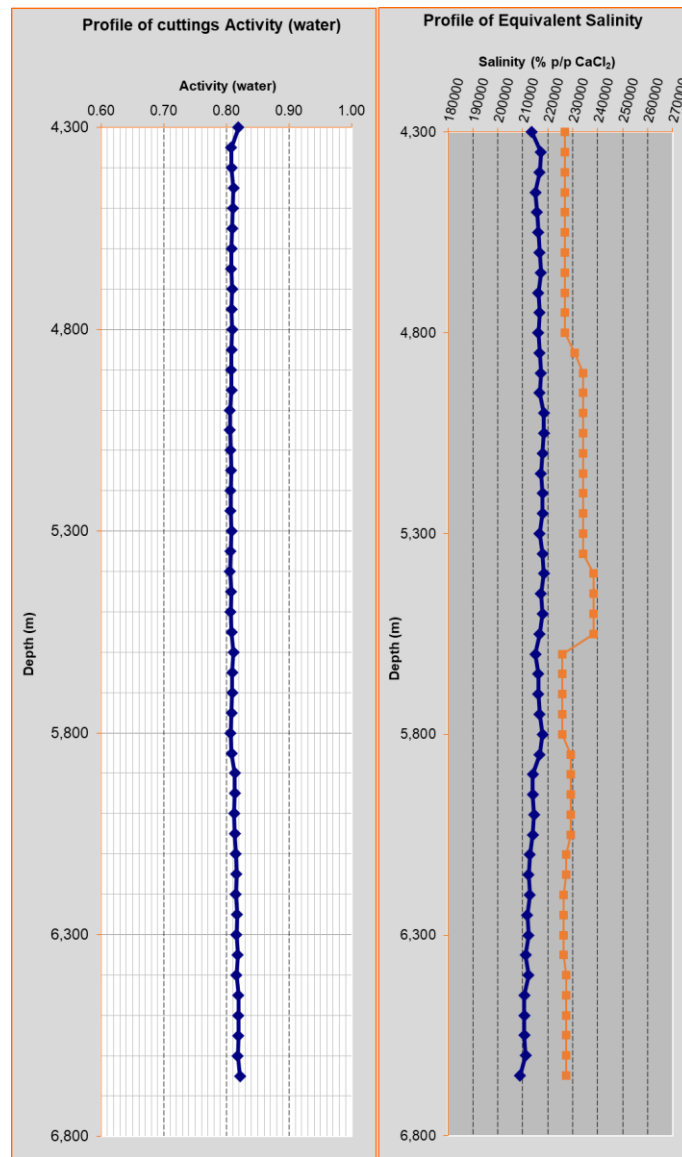


Figure 12—Measurement of the water activity on cuttings (left). Rock vs. fluid salinity (right).

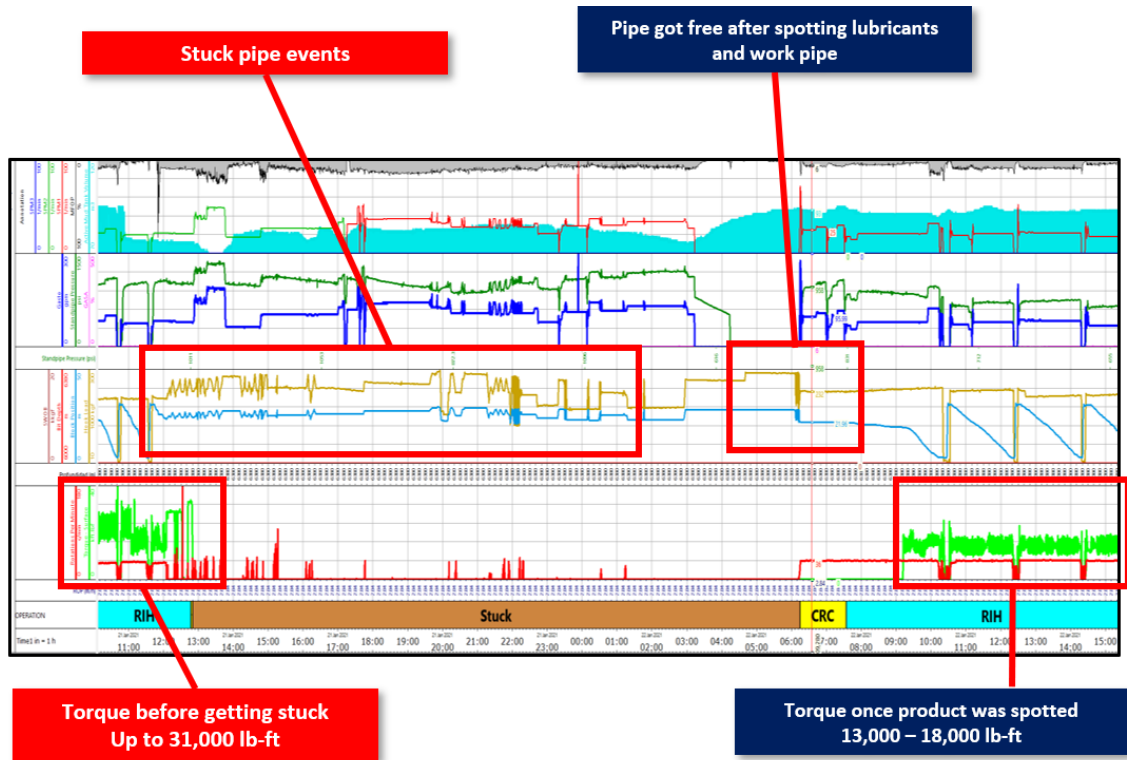


Figure 13—Behavior of the torque in stuck pipe before/after adding lubricant.

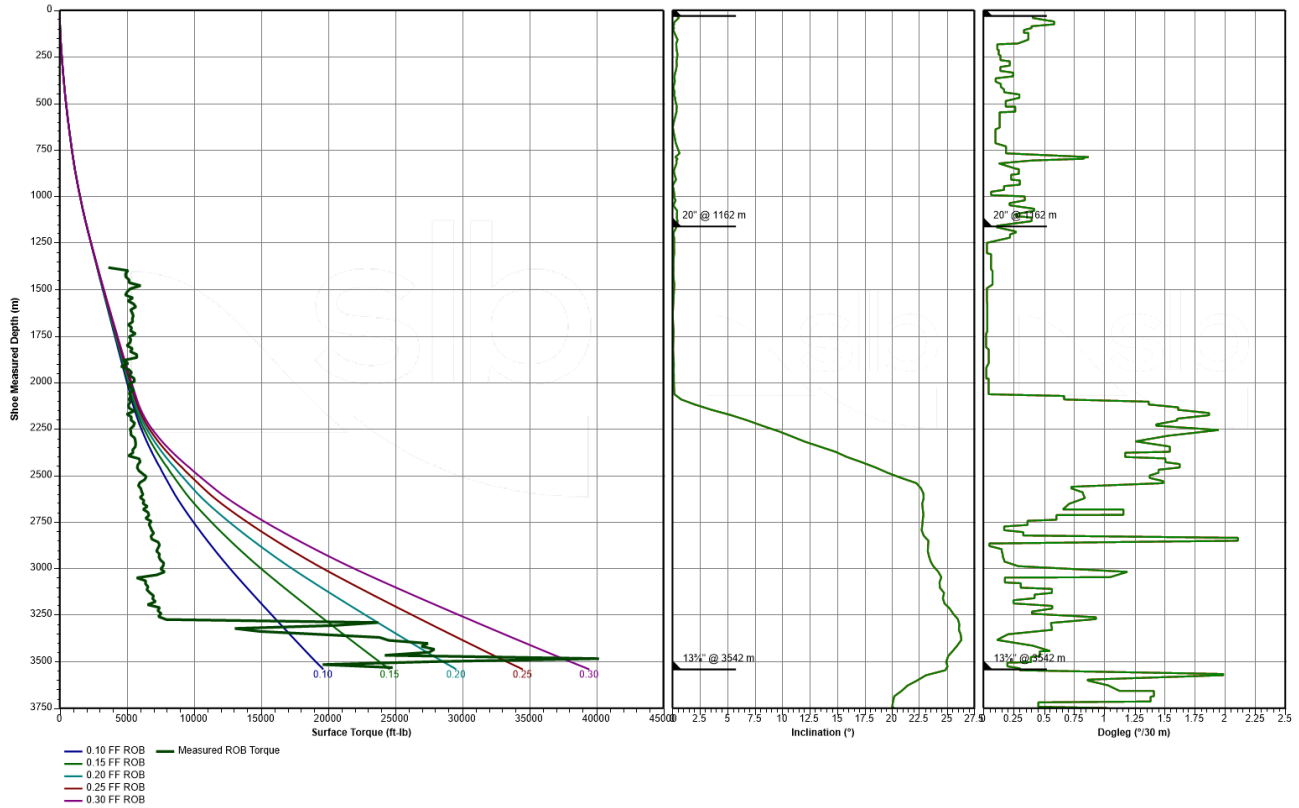


Figure 14—13 3/8-in., 72-lb/ft casing torque simulation and real torque.

LSRYP versus Fluid Density

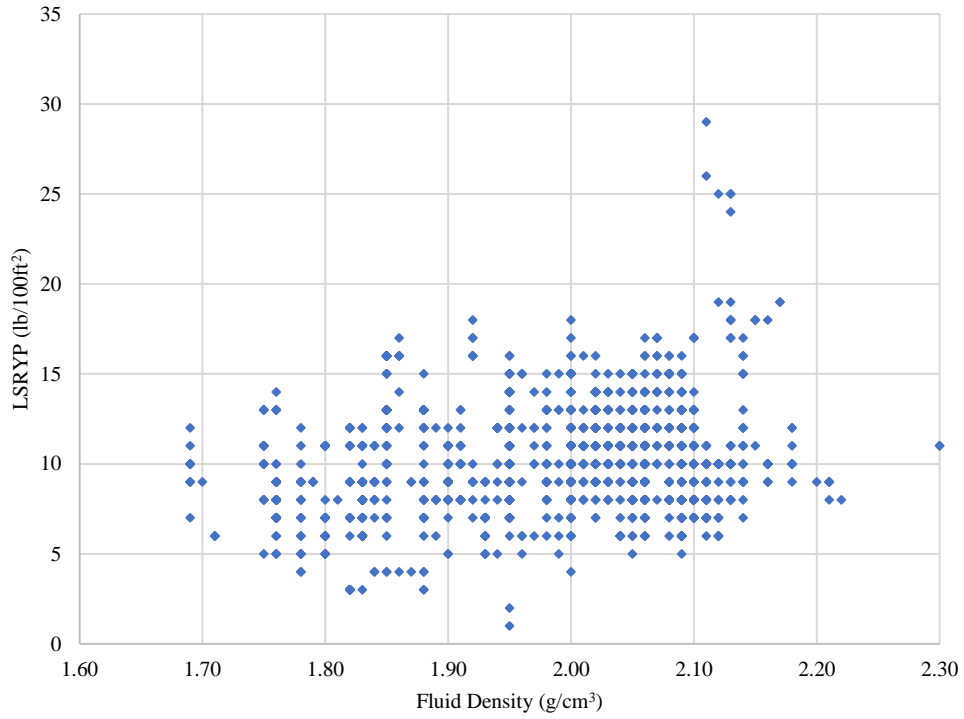


Figure 15—Behavior of the LSRYP as density increases.

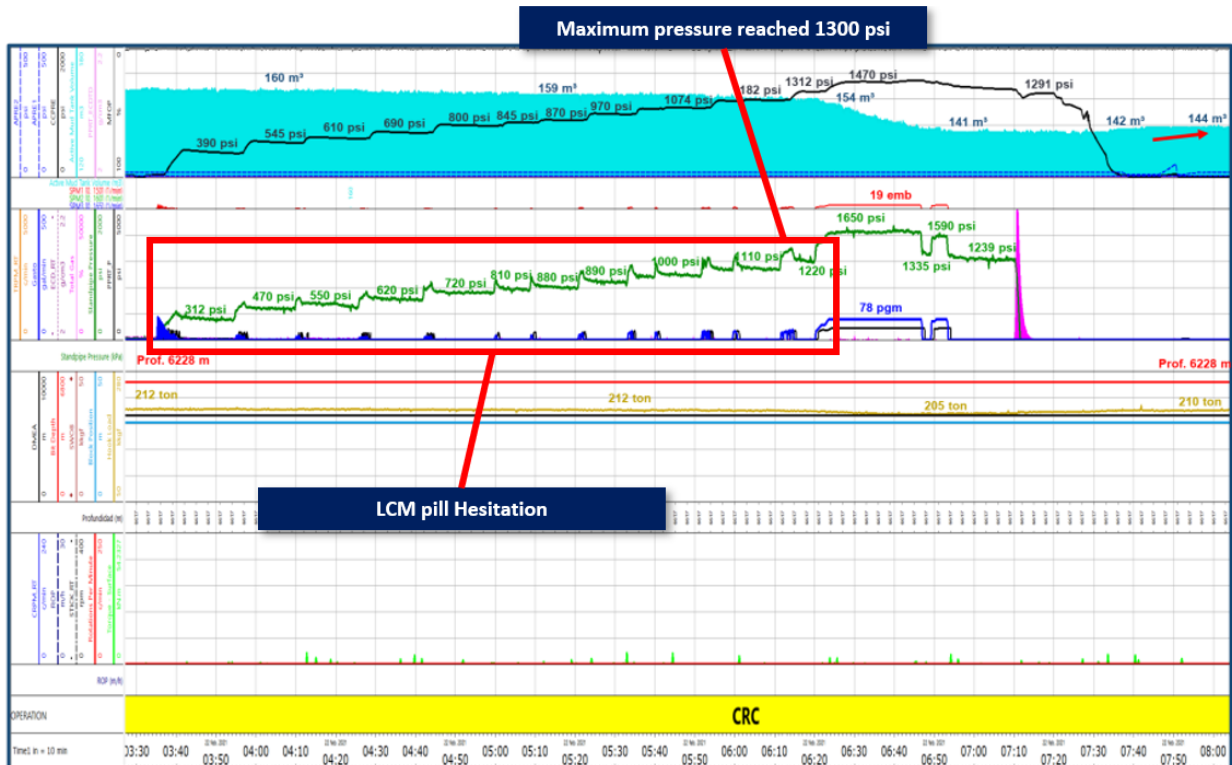


Figure 16—Hesitation process to defluidize pill.

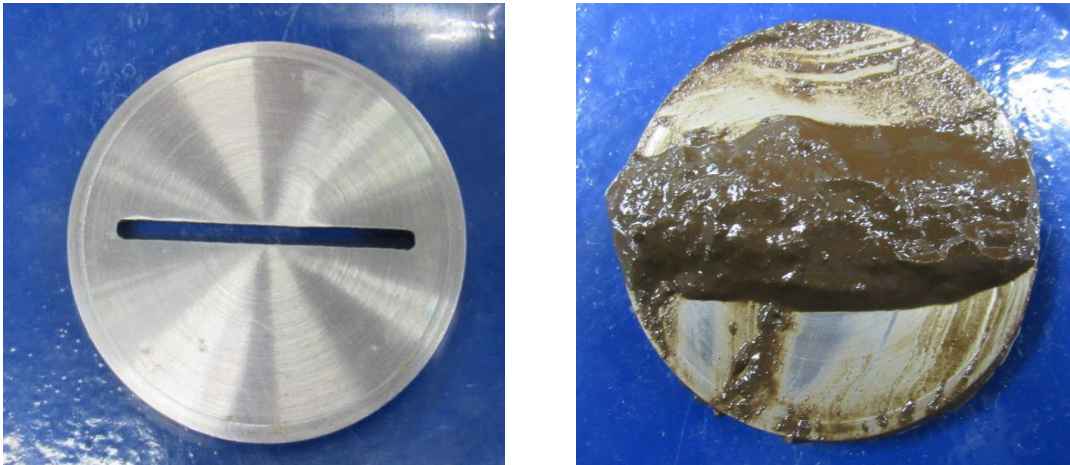


Figure 17—Severe to total LCM treatment on a 4,000- μ slotted disk before/after (left/right).

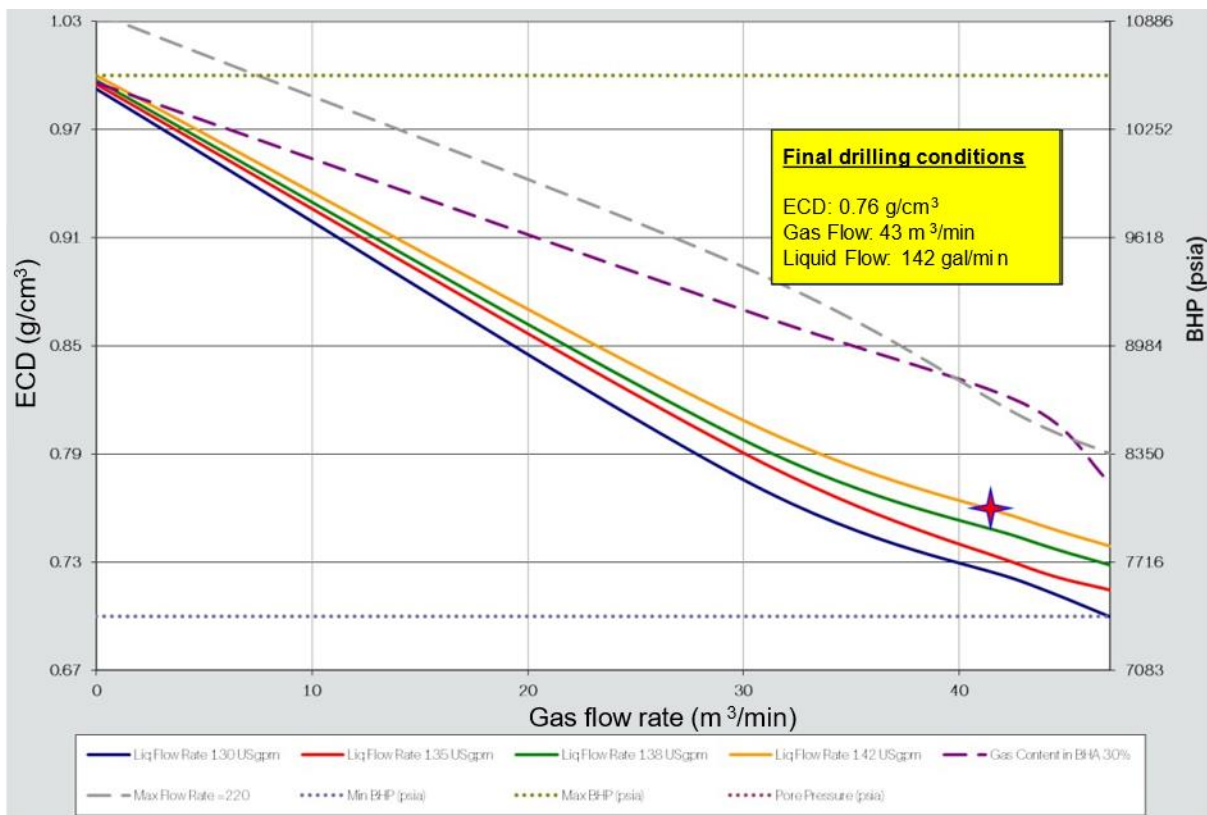


Figure 18—Final biphasic fluid conditions at 7,572 m (24,842 ft).

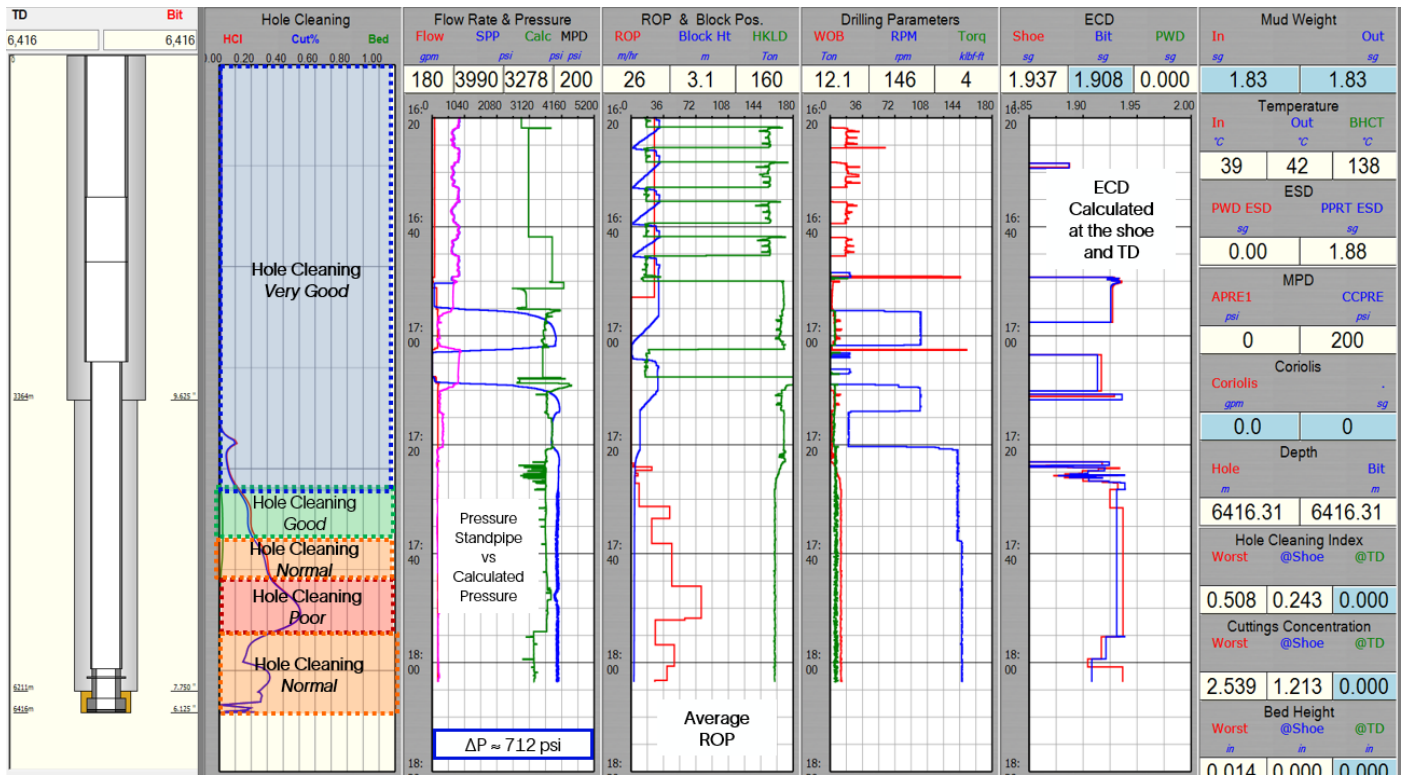


Figure 19—Hole-cleaning and ECD assessment while drilling a 14 1/2- x 12 1/4-in. interval.

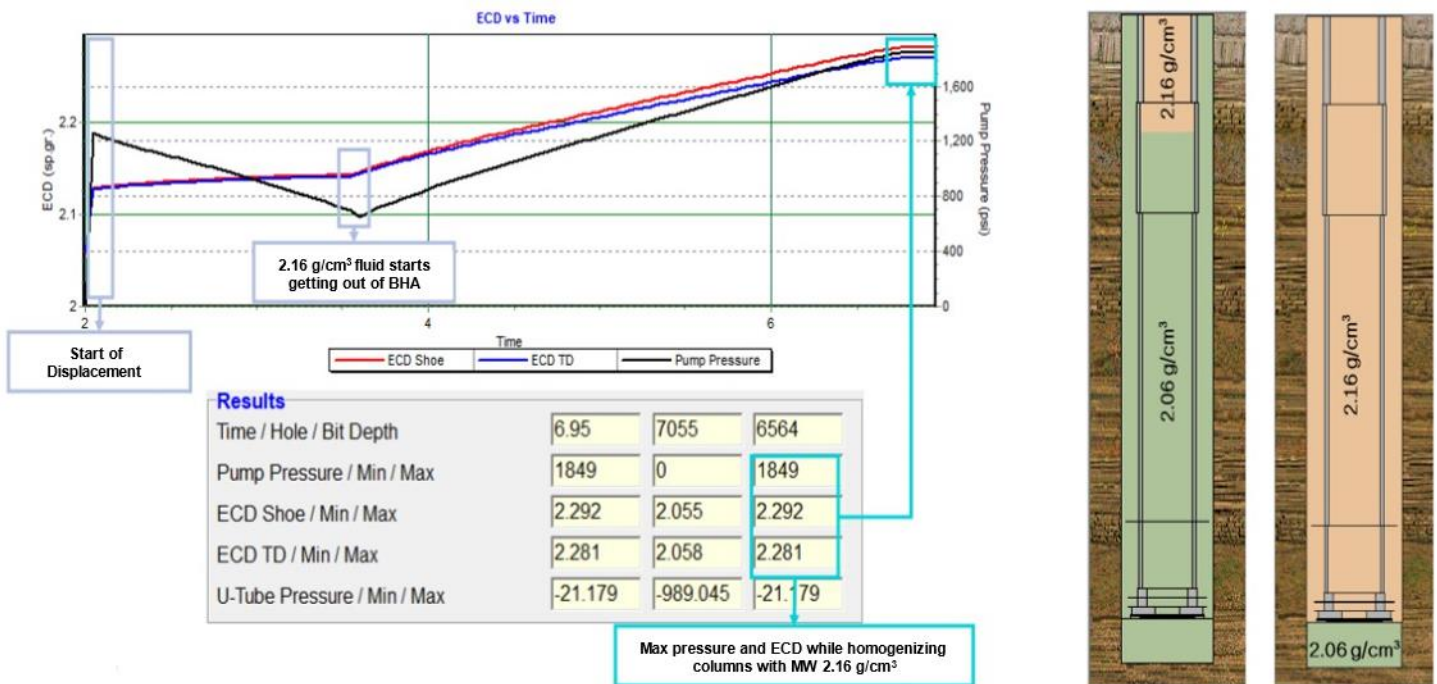


Figure 20—MPD rollover simulation, displacing from 2.06 g/cm³ (17.2 lb/gal) to 2.16 g/cm³ (18 lb/gal) to compensate for frictional losses before pulling out of hole.

Tables

Table 1—Directional indexes comparison for several wells drilled in the field. OBM = oil-based mud; CoF = coefficient of friction.

Well name	Tortuosity	Along Hole Distance (AHD, m)	Drilling Difficulty Index
Well A	145.4	2,064.9	6.0
Well B	102.4	992.8	5.5
Well C	128.7	1,518.1	5.8
Well D	114.7	832.0	5.5
Well E	193.2	1,929.3	6.1
Well F	152.0	1,331.0	5.8

Table 2—Comparison in CoF reduction when using lubricants.

Fluid + Treatment	CoF	Reduction
OBM	0.113	–
OBM + 3% of liquid lubricant	0.055	–51%
OBM + 8 lb/bbl of solid lubricant	0.082	–27%

Table 3—Open-cup and close-cup rheology comparison.

Density at 50°C	2.04 g/cm ³ (17.0 lb/gal)	
Rheology temperature, °C (°F)	65 (150)	140 (284)
Pressure, psi	atmospheric	
PV, cP	67	122
Yield point, lb/100 ft ²	16	10
600 rpm reading	150	254
LSRYP, lb/100 ft ²	6	12
10 s/10 min gels, lb/100 ft ²	11/24	13/14

Table 4—Evaluation of sag via VSST dynamic method in a fluid exposed to 165°C (329°F).

Time	24 hours	72 hours	120 hours
Initial, g/cm ³	1.13191	1.13191	1.13191
Final, g/cm ³	1.13849	1.13813	1.13930
Sag index	0.5029	0.5027	0.5033

Table 5—Evaluation of static sag in a fluid exposed to 140°C (284°F).

Time	24 hours	48 hours
Initial, g/cm ³	2.0672	2.2139
Final, g/cm ³	2.1420	2.2886
Sag index	0.509	0.508

Table 6—Conversion of an NAF conventional system to high-temperature (HT) conditions.

Properties/Condition	Initial	HT Treat 1	HT Treat 2
	N/A	AHR 175°C 16 hr 150 psi	
Density, g/cm ³	1.95	1.95	1.95
PV, cP	47	64	54
Yield point, lb/100 ft ²	27	29	20
LSRYP, lb/100 ft ²	17	19	10
10 s/10 min gels, lb/100 ft ²	30/38	39/52	31/40
ES, volts	715	1,145	1,367
HTHP filtrate, ml/30 min	3.8	3.6	3.4