Challenges evolve for directional drilling through salt in deepwater Gulf of Mexico

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AS AN INCREASING number of 6,000-ft-plus deepwater developments come on stream in the Gulf of Mexico (GoM), project economics dictate that fewer subsurface drill centers be used to develop these fields. This requires longer step-outs, pushing kickoff points higher up the wellbore, often occurring within extensive salt bodies.

Salt drilling is still a relatively new practice and presents drilling challenges that are still not totally understood. Adding a directional component to that not only magnifies existing problems but also introduces new challenges. This article will discuss the challenges faced and the lessons learned by two major deepwater GoM operators and the directional service company in drilling directionally through salt.

Together, these companies have drilled over 100,000 ft of salt in the GoM. They have encountered and managed many of the challenges that extend past the traditional pre-drill and real-time directional issues, into the post-drilling phase with issues such as casing and cement design for managing salt loading and ensuring long-term wellbore viability.

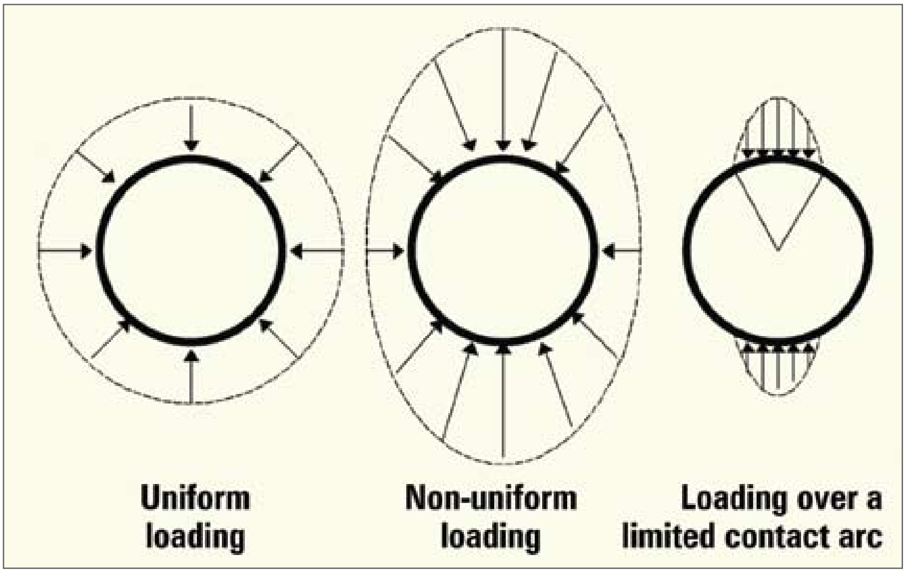


Figure 1: Earlier studies have reported that the ability to assure hole quality can pre-empt the need to bring cement in the casing-salt annulus. A uniform hole allows uniform loading of the casing in salt, thus preventing deformation of the casing. Conversely, an irregular hole can result in non-uniform loading and eventual deformation of the casing in salt, thus requiring cementing of the casing-salt annulus.

BACKGROUND

The GoM is well known for its extensive subsurface salt structures that have aided in trapping much of the hydrocarbons found here. As deepwater exploration successes progress into the development drilling phase, and with the increasingly recognized potential of the GoM's Lower Tertiary trend, the requirement for deepwater wells to penetrate salt have become almost mandatory.

Over the next several years, successful and efficient drilling of salt will play an increasing role in achieving many of the area's deepwater drilling objectives. To meet this challenge, the ability to directionally drill through salt and to understand and manage the issues this introduces will be a key factor for deepwater operators.

This article will present three case studies from different deepwater GoM operators, and the lessons and recommendations derived from them. The article will draw upon these and other GoM salt drilling experiences to formulate a comprehensive package of the requirements for the planning and drilling directionally through salt.

DRIVERS FOR DIRECTIONAL DRILLING IN SALT

While most early drilling through salt has been vertical, an increasing number of wells have trajectory designs that incorporate the ability to directionally drill through salt. The drivers for these trajectories are similar to the traditional drivers for directional drilling, but are worth recapping with the assumed scenario of a deepwater field overlain by a thick salt deposit.

- For deepwater developments where subsea drill centers are being used, the ability to reduce the number of drill centers and related transmission infrastructure costs are critical. The costs for an additional subsea drill center will be impacted by water depth, seafloor topography, pipeline requirements and production type. Clustering wells has the potential to reduce costs by tens of millions of dollars. Many factors can affect that amount, but most clustering savings exceed expected directional costs. Larger but fewer such centers aid in reducing field development costs but require wells to begin deviation at relatively shallow depths in order to achieve the step-out required to intersect reservoir targets.
- As these wells step out further, shallower kickoffs result in reduced maximum inclination. While there are definite benefits to keeping inclination below 40º for drilling purposes, such as reduced torque and drag, there are often subsequent operations in the life of the well that may dictate the maximum allowable angle. Limiting the angle can ease the completion work and improve intervention and workover options.
- For a subsea completed wellbore, the upper limit of wellbore angle is thought to be 50º. However, at total depths exceeding 20,000-ft true vertical depth (TVD) in deepwater, that limit could be closer to 35º or 40º. Beyond that angle, it would be difficult to perform wireline work.

- In development scenarios that utilize floating production centers, with multiple subsurface slots, safe and efficient management of collision and well proximity issues require the ability to nudge and steer wells at any point along their trajectory.
- Often, there may be a geological objective to exit the salt within some predetermined tolerance at a particular point. However, operators may have to choose a seafloor location due to shallow hazards concerns that is not necessarily the optimum location to drill through the salt. For example, the seafloor location may require drilling through an inclusion or directionally drilling to avoid it. Since the potential problems associated with drilling salt inclusions can be unknown, directionally drilling in salt is a comparatively lower-risk option.
- Directionally drilling in the salt may be desired to exit the salt at a low dip interface. Directionally drilling in salt may also be desired to exit a salt body with a dipping base at a deeper TVD for increased pore pressure/fracture gradient margin later on along the proposed well path.
- Directionally drilling in salt may be required to avoid a problem at a particular salt exit, such as tar or a rubble zone. Tar is not only found at the base of salt; some of the most troublesome tar encountered has been at the base of salt. When tar is encountered unexpectedly, the planned casing program is likely to change. This is another reason to directionally drill in salt. Until all the potential problems have been identified, the well plan should not pass up an opportunity to reduce angle or the angle build rate.

In the earlier years of deepwater drilling, salt was avoided. However, with experience and success, wells have continuously increased the total footage of salt penetrated. Salt has gone from being a major problem in some cases to being a potential asset.

SALT DRILLING MILESTONES

The US Minerals Management Service (MMS) lists the **Placid Oil Company**'s 1983 Ship Shoal 366 well as the first subsalt well drilled in the GoM, with **Exxon**'s Mica Prospect tabled as the first subsalt discovery made in the Mississippi Canyon in 1990 as tabled by Montgomery and Moore (1997). By the mid-'90s, a number of operators had announced subsalt discoveries, and the potential of the deepwater subsalt reservoirs emerged as attractive prospects to oil companies. Well-known prospects discovered in the late '90s to early 2000s include **BP**'s Thunder Horse and Atlantis discoveries, as well as **Chevron**'s Tahiti Prospect.

Drilling these deepwater prospects through thousands of feet of salt proved a great challenge for the pioneering operators. Often, the technology required by rigs and equipment were being pushed to the limits as water depths and salt intervals increased. This often limited salt drilling to the constraints of a vertical hole.

ORIGINS, CHARACTERISTICS

One of the most unique and problematic characteristics of salt is its ability to creep or deform. This ability is thought to be due to the fact that, unlike other clastic sediments, salt does not increase in density with depth of burial. As layers of sediment are deposited over salt and begins to compact, a critical depth is reached where the density of the salt equals the density of the overlying overburden, at which point the salt begins to flow.

The rate at which salt moves depends on burial depth, formation temperature, mineralogical composition, water content, presence of impurities (clay), and the extent to which differential stresses are applied to the salt body, according to earlier research by Fossum and Fredrich (2002).

Salt formations currently being drilled in the GoM are theorized to have originated from the Louann salts, originally deposited during the Jurassic period. Over time, the sedimentation process as previously described resulted in the characteristic salt structures seen in the GoM today, including nappes, domes, sheet and canopies. This salt is now referred to as allochthonous salt, or salt that has migrated from its originally deposited location. Evidence strong suggest that the salt penetrated in any one field may actually be the coalescing of various salt bodies that simply appear as one image on the seismic.

As a drilling material, salt is known to have a relatively low unconfined compressive strength (UCS) in the range of 3,000-3,500 psi. Despite this, significantly higher weight on bit (WOB) and torque are required when drilling salt compared with other formations of similar UCS. This additional energy is attributed to the plastic nature of the salt, and the ability of the salt to creep into a newly drilled wellbore presents some of the biggest challenges to drillers.

DIRECTIONAL WELL PLANNING

Directional well planning is a key factor in the ability to successfully drill directional wells through salt. The drilling can be divided into the following categories:

1. Above salt kickoff and build followed by drilling a tangent through the salt.
2. Kickoff in the salt and build angle.
3. Steering in salt to manage collision risk.

In planning directional wells through the salt, geomechanical risks and limits must be factored into the planning phase. These risks and limits arise from the previously discussed complex origins and interactions involved in the formation of salt bodies. Wilson et al (2005) list potential geomechanical risks, including areas of tectonic instability outboard of salt, near-salt rubble zones, tight-hole drilling conditions, long-term casing loading from deformable salts and squeezing sediments entrained in salt seams or occurring as inclusions within the salt. In their analysis, the requirement for higher mud weights in order to manage the wellbore stability when exiting salt under a situation of rotated stress regimes (dipping salt base or hole inclination above vertical) is clearly demonstrated.

Combined with these geomechanical risks are pore pressure uncertainties frequently encountered with inclusions and at the base of salt. Operators frequently need to choose between over-estimating the mud weight and potentially inducing lost circulation, or under-estimating and dealing with a well control kick. To minimize problems at the salt exit, operators frequently take a slower pace – limiting drill rate until the pore pressure and hole stability can be understood.

Well trajectories should be designed to avoid salt seams and inclusions (when visible on the seismic) and should attempt to exit the salt at the flattest or lowest dip area available. This helps to avoid the added instability and associated issues that can arise from rotation of stresses at higher dipping salt bases. One GoM operator is known to define the salt exit as a target in much the same way as reservoir target is defined, to ensure that the directional well exits the salt in an area least prone to problems. Another good practice is to plan a tangent section to exit the salt that extends above the shallowest salt base to below the deepest expected rubble zone. This ensures that the well trajectory will not be compromised either if there is difficulty in continuing to build angle or turn while in the rubble zone or if the risk of stuck pipe or taking a kick is high and a dedicated low-cost BHA is planned for drilling the salt exit.

Another directional consideration related to the geomechanical properties of salt is its natural build-walk tendency. Experience has shown that for the same salt body, the natural formation tendency can push the drilling assembly in one direction in one well and in an opposite direction on another well in another part of the salt body. This may be related to the varying stress directions and magnitudes that might exist in different areas of the salt body and lends more credence to the theory of salt bodies being the fusion of multiple salt sheets.

It is important to understand the magnitude and direction of this tendency and ensure that overly aggressive doglegs are not planned. Experience drilling certain GoM salts has shown that up to 65% of the BHA steering capability has been required to simply maintain a desired direction and inclination in the salt. As such, low build and turn rates (1-3°/100 ft, depending on operator preference) are recommended to ensure that the well plan is not compromised.

This becomes even more crucial in crowded development scenarios, where nudging of the wellbore may be required to maintain the anticollision separation needs. In such a scenario, experience has shown wells drilled from a common template will tend to follow the same directional trend (i.e., all may tend to walk to the southeast). This natural tendency should be incorporated in the plan when possible to avoid unwanted approaches to offset wells. This trend illustrates the need for good directional control.

Drilling mechanics also impacts the trajectory design while drilling salt. As the inclination is increased, contact between the BHA, drillstring and salt wellbore increase. This will increase torque and drag and the potential for stick-slip and other vibration-related dynamics.

The phenomena of its ability to creep had previously been identified as one of salt's most unique characteristics. For the most part, however, the salt bodies encountered to date in deepwater GoM have not had significant creep problems. This is in part attributed to its relative purity of the salt, up to 96% halite (Wilson and Fredrich, 2005). In general, creeping salt can be controlled with increased mud weight, in some cases up to 93% of the overburden. Other operators have turned to the use of under-reamers while drilling in order to provide increased hole diameter in the range of 8-18%.

This additional hole clearance, together with mud weight control of creep, can ensure that issues in getting casing to bottom are minimized, particularly in directional sections through the salt, where opportunity for the casing to lie on the low side of the hole is apparent. Improvements by under-reamer manufacturers on reliability and durability of these tools in salt has made simultaneous under-reaming and drilling of salt a routine operation in the deepwater GoM.

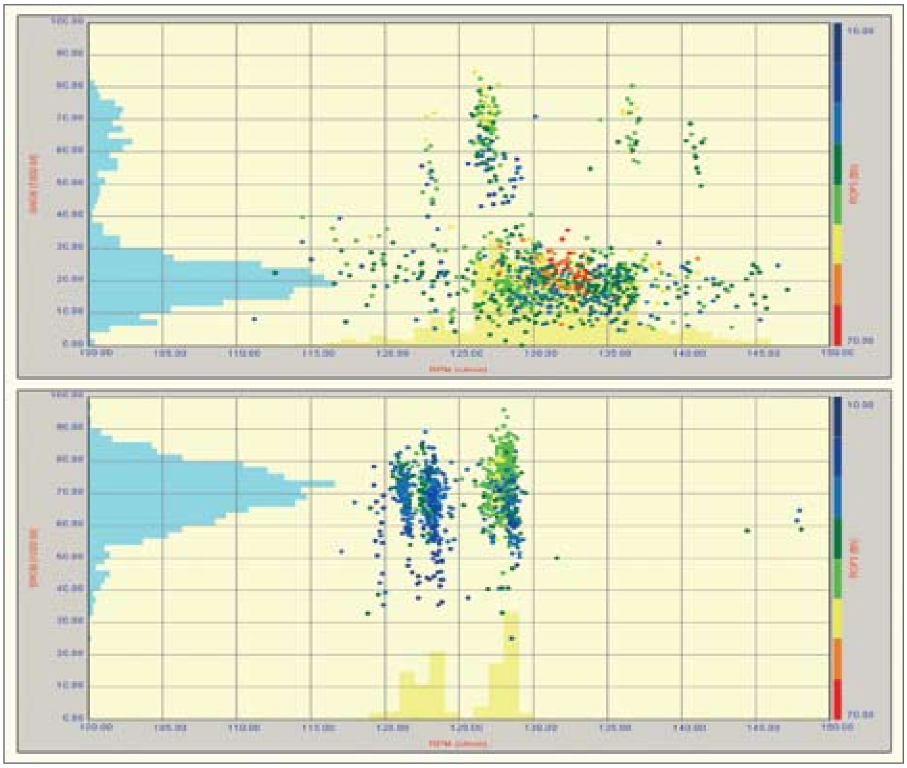


Figure 2 shows rate-of-penetration cross-plots for a 26-in. PDC bit in salt (upper plot) and a 26-in. mill tooth bit in salt, both run in the same well. The plot indicates a best ROP of 60 ft/hr with the PDC bit vs 45 ft/hr with the mill tooth bit.

The impact of hole geometry as it relates to the casing and cement design can be tied back into the directional deliverables; a uniformly round hole is paramount. Rotary steerable systems (RSS) have repeatedly demonstrated their ability to deliver high-quality wellbores with smoother build rates, lower doglegs and fewer ledges.

Many GoM operators choose to use rotary steerable systems when drilling straight holes through salt because of the higher-quality hole. They have been able to take advantage of the extra fracture gradient over thick salt sections in the deepwater to run fewer casing strings compared with drilling outboard of the salt. Often full strings of heavy wall casing are run prior to salt exit to prepare for the unknown pressure environment below. The best-quality hole possible is needed for these casing strings. These casing runs are often one-way trips, so the resulting hole must allow problem-free running of casing to bottom.

Wilson et al (2003) have reported that the ability to assure hole quality can pre-empt the need to bring cement in the casing-salt annulus. A uniform hole allows uniform loading of the casing in salt, thus preventing deformation of the casing (Figure 1).

Conversely, an irregular hole can result in non-uniform loading and eventual deformation of the casing in salt, thus requiring cementing of the casing-salt annulus to avoid this scenario. Additionally, if the hole section needs an effective cement job over the length of the pipe, casing centralization requirements change. Increasing the centralization will increase the casing string's rigidity and may limit the allowable hole profile.

Apart from potential saving in well construction costs, the benefits of uniform loading on casing extend across the life of the well, by reducing the risk of losing the well due to casing deformation and collapse. From this perspective alone, additional costs incurred in using rotary steerables to deliver the quality of wellbore required can be readily justified.

RISERLESS DRILLING OF SALT

In many deepwater applications where the top of salt is shallow (<2,500 ft) below the mudline, the top of salt may be penetrated while drilling riserless. The footage of salt penetrated in such scenarios can range from 300 ft to 2,500 ft, depending on well construction and design requirements. The fracture strength 1,000 ft into salt can be 2-3 ppg greater equivalent than the formation above the salt. This is large hole (26-in. to 22-in.), drilled with returns to the sea floor, typically using salt-saturated mud. From a directional perspective, these sections are often planned as vertical, but with more development wells being drilled, shallow kickoffs are becoming more frequent.

The interval of salt drilled in this section is the major consideration surrounding BHA design. The formation above salt is often controlled-drilled; hole cleaning is the major concern. The high-permeability, unconsolidated formation will drill with low weight on bit. Thus, deviation is not a problem, and the BHA is designed for drilling the salt:

1. The natural directional tendency of the salt, which has shown to typically cause the assembly to build and then walk in some direction that can probably be correlated with the stress directions in the salt. The more salt that is required to drill, the greater the build and walk potential. Without directional control, the salt tendencies may lead to high doglegs. High doglegs at shallow depths have been known to introduce major issues deeper down in the well regarding torque, weight transfer and casing wear.
2. In drilling riserless, there is often a finite amount of mud available. Rate of penetration (ROP) is typically not an issue in the soft sediment just below the mudline, but once salt is encountered, bit selection and BHA design become crucial to being able to drill at an optimum ROP. The faster this section can be drilled, the less likely that available mud will be consumed before the section reaches total depth (TD). In addition to rig time savings, some operators have been able to save on mud costs by reducing the volume of mud brought to the wellsite during the riserless operation.

Based on these points, the BHA design for drilling of riserless salt sections must provide two key features: good directional control and the ability to deliver consistently high ROPs throughout the section. The BHA needs to be robust enough to drill the section in one run, because an unplanned trip during this section will often require additional mud volume to be built and mobilized to the rig.

Three basic BHA options are available in this scenario:

1. Conventional rotary pendulum assembly: Offers no directional control. Reaction when subjected to salt ten-

dencies is unknown. Often, WOB has to be reduced to control these tendencies, resulting in reduced ROP.

2. Steerable positive displacement motor: Offers good directional control to counter salt tendencies. However, slide drilling can often result in unacceptably low ROPs through the salt; in many cases, up to 60% reduction has been observed. Some operators have attempted the strategy of trying to drill the section in rotating mode only, thus letting the assembly follow the natural build and walk tendencies of the formation. In some cases, this may be acceptable, if the natural tendency is aligned with the desired kickoff direction later on in the well. If this is not the case, however, unplanned shallow inclination and dogleg may introduce torque, drag or casing wear issues when drilling deeper sections.
3. Rotary steerable assemblies: Large-hole RSS are available for hole sizes up to 26-in. Israel et al (2007) discuss the application of these in greater detail. As they have done in smaller hole sizes, RSS provide the benefits of good directional control along with the elimination of slide drilling, thus enabling optimum ROPs to be maintained throughout the salt interval. Some commercially available RSS have a closed-loop vertical seeking mode that allows these assemblies to maintain almost near-perfect verticality, with minimum input or intervention from the directional driller. This also provides some rig time savings over the interval, as there is no time spent orienting a steerable motor or attempting to hold a toolface in salt.
4. RSS coupled with high-torque, low-speed motors (powered RSS) have also shown to deliver significant improvement in ROP through salt intervals. Copercini et al (2004) discuss the use of powered RSS.

Drilling jars are not recommended in these large hole sizes for any of the above BHAs. Jars are available in a maximum size of 8 ¼-in. nominal outside diameter (OD) and are often the weak point in the string. This has been proven numerous times in practice as there are multiple instances of the large BHAs twisting off at the jars. The unsuitability of jars in this section is not a major drawback since stuck-pipe instances are rare in this interval. Differential pressures are low, wall contact is low in the large holes, and unstable hole can be easily circulated out and, if stuck in salt, fresh water can open the hole.

Developments in PDC bit technology have allowed larger PDC bits to be run. The shearing nature of PDC bits are more suited to drilling in salt than mill tooth or insert bits, which can induce tracking in the salt, thus reducing ROP.

Mill tooth bits typically require higher WOBs to produce the desired ROP than with a PDC bit. Figure 2 compares ROPs for a 26-in. PDC bit run and a 26-in. mill tooth bit run, both in a deepwater GoM well riserless section through salt. The higher WOBs required by the tooth bit (70 kips), compared with 25 kips WOB, result in increased levels of axial and lateral shocks to the BHA. This dissipation of input energy as shock results in lower ROP and increases the chance of tripping due to MWD (measurements while drilling)/LWD (logging while drilling) tool failure caused by the shock.

Powered RSS, when aligned with stable PDC bits, can often prove to be the best option for drilling these intervals. Apart from reducing the drillstring RPM in the open water, powered RSS delivers the torque at the bit, aiding in overcoming the higher potential stick-slip generated by the large PDC bits by allowing an increased RPM. Higher torque and RPM at the bit contribute to improved penetration rates through salt. The disadvantages of doing this include pushing all of the MWD/LWD sensors further behind the bit and adding another tool to the BHA, with the potential for failure.

In this scenario, a cost-benefit analysis of the rotary steerable system and bit type should be used to determine if the time and mud savings delivered will adequately cover the additional cost of running these tools. Experience has shown that this benefit becomes viable only for intervals where the salt section to be drilled represents about 40% of the section footage and a 30% increase in salt ROP can be delivered. While these numbers will vary with rig spread rate and other costs, they are considered the minimum required to truly derive some cost benefit.

One of the latest developments in the use of RSS with a high-torque, low-speed mud motor in the riserless sections is the ability to perform jet-in operations. This allows operators to pick up the RSS/motor BHA, with 36-in. structural pipe latched on, jet the conductor, unjay and drill ahead with all the benefits of RSS and PDC bits as previously described. This reduces valuable operating time on deepwater rigs not outfitted with dual derricks, where previously either a trip would have been required after jetting in the conductor to pick up the RSS/PDC BHA or the operation would have continued, bound by the limitations of a mill tooth and PDM (positive displacement motor). This operation was first attempted in early 2007 and was successfully repeated at least three more times within a year.

SALT ENTRY

The top of salt is not always encountered in a riserless scenario; as in many GoM fields, this horizon can be deeper than open water drilling allows. In both instances, drilling parameters are often controlled when approaching the prognosed top of salt, as often this interval may harbor various drilling risks that need to be managed. These risks are largely due to stress regime changes in the interval immediately above salt arising from its migration. These scenarios can present risks of wellbore stability.

With a deeper top of salt, fractured or faulted formations have been encountered. These are thought to have formed as the older, higher-pressured sediment was pushed upwards by the salt and subsequently fractured as the pressure "bled-off." Such scenarios introduce loss-circulation risks while drilling into the top of salt. If these zones were prevented from being de-pressured, then over-pressure zones of the top of salt may be encountered.

Reduction of ROP and/or WOB when approaching the top of salt allows drillers more time to interpret and react to any of these potential risks prior to entering salt. Top of salt is often confirmed by an increase in torque and a reduction in ROP. A gamma-ray measurement within 10 ft of the bit is a useful lithological confirmation that the change in drilling parameters can be correlated to the top of salt.

Many GoM operators maintain these controlled parameters until the BHA is completely buried in the salt, particularly if an under-reamer is included in the BHA. This is typically a 100-ft to150-ft interval and usually is long enough to determine background/baseline vibration levels and optimum WOB/RPM parameters. If these can be reasonably established, then there is a high probability that a long interval of salt can be drilled without significant incidents.

SHOCK AND VIBRATION

Shock and vibrations have proven to be one of the most challenging aspects of salt drilling. Excessive vibrations can lead to a trip to replace failed downhole tools or twist-offs; both adding to nonproductive time (NPT). They can be introduced by various mechanisms, including unstable or overly aggressive bits, poorly matched bit-reamer combinations, ratty or laminated salt intervals, and creeping salts.

Pre-drill vibration modeling can be used to provide guidelines for optimizing bit-reamer compatibility and BHA design, but they rarely identify ideal drilling parameters for smooth drilling. These are better determined through real-time analysis of run data, and by adjusting RPM and WOB parameters as dictated by the vibration levels observed.

INCLUSIONS

Inclusions in the salt may present a challenge to the drilling operation for two major reasons:

• The impact of drilling in non-homogenous formation while simultaneously under-reaming: Different formations drill at various ROPs and require different parameters to drill efficiently. When simultaneously drilling and under-reaming in salt and an inclusion is encountered, the bit and under-reamer may be drilling in different formations. This may result in the bit out-drilling the reamer and ineffective weight transfer to the reamer. This can result in shock and vibration levels that can damage BHA components, resulting in a trip to change these tools.

• The uncertainty of pore pressure within the inclusion: The inclusion may be abnormally or sub-normally pressured, depending on the mechanism that formed it and the lithology of the inclusion. Drilling into either of these scenarios present challenges in the form of kicks, loss circulation and stuck pipe.

TAR

Drilling through tar zones can present a significant drilling hazard in the GoM. There are several incidents among most of the major operators where penetrating tar has had a terminal impact on drilling. Major risks associated with tar include pack-offs, swabbing, damage to BHA components and difficulty in running casing.

One primary area where tar has been encountered is the base of salt. Romo et al (2007) have presented a detailed discussion on the challenges associated with drilling tar in a GoM deepwater development. Based on their work, two major recommendations to mitigate the problems tar introduces are to avoid it completely and to drill the interval as quickly as possible. Both of these recommendations are linked to the directional drilling and BHA design. Avoiding tar at the base of salt may mean identifying a specific base-of-salt exit target box (assuming that the location of tar can be reliably estimated pre-drill) that may require kicking off in salt to intersect the target. Drilling the interval as quickly as possible suggests that PDM motors are not suited to salt/tar drilling applications, since sliding ROP in the salt has been observed to be as low as 50% of the rotating ROP. In addition, the ability to keep the BHA and drillstring rotating across a tar interval is an important mitigation method for avoiding stuck pipe in tar.

SALT EXIT

As with the salt entry, several scenarios related to the migration of the salt body and subsequent disturbance of the normal surrounding stress regime have contributed to introducing significant risk to the salt exit phase of the drilling. Wilson (2005) lists the following hazards associated with drilling through the base of salt: rubble zones, subsalt pressure uncertainty, depth errors on base-of-salt and overturned beds. While these are similar to the hazards that have been identified on entering the top of salt, experience has shown the risk to be much greater when exiting the base of salt. As such, most major GoM deepwater operators have developed company-specific salt exit procedures.

Comparison of these procedures for two operators shows many similarities, which can be expected to extend to other GoM deepwater operators. A general exit procedure is as follows:

1. Reduce ROP to 40 ft/hr about 200 ft above the expected base of salt, depending on the uncertainty.

2. Monitor drilling parameters – torque, WOB, bottomhole temperature, equivalent circulating density (ECD), vibration data, near-bit gamma-ray, if available. First sign of base of salt is usually a significant reduction in torque with ROP increase.

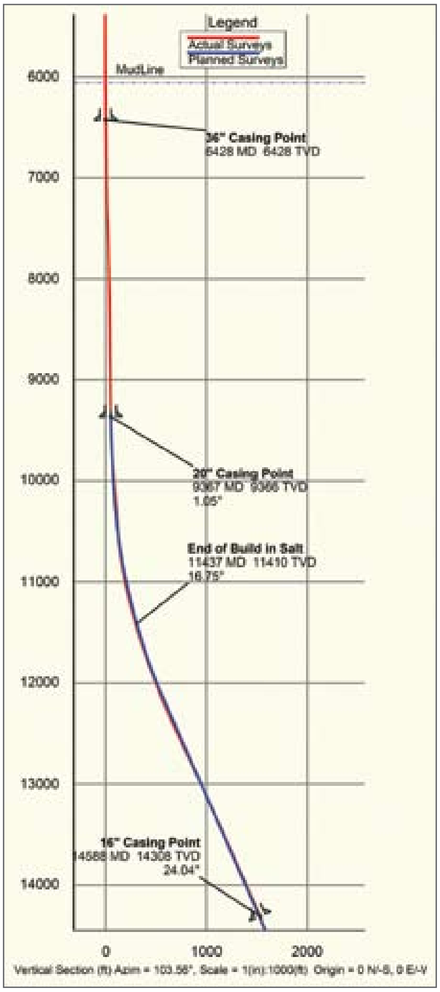
3. Once the base of salt has been established by a drilling break as described above, the bit is usually pulled into salt and a flow check is done and cuttings circulated above the BHA.

4. Following this, a bottoms-up circulation may be done, and drilling resumes in 10-ft to 15-ft intervals, checking hole conditions (drag, fill), and constantly circulating cuttings above the BHA. The flow check may be repeated as needed; otherwise drilling can continue in 10-ft to 15-ft increments, repeating this step.

5. Provided that there are no indications of pressure increases, loss circulation or poor hole conditions, the increment is increased to 15-ft to 30-ft intervals, prior to checking hole conditions. Any indication of unsatisfactory conditions usually results in the bit being pulled back into salt and a bottoms-up circulation done before slowly going back to bottom.

6. This step is typically repeated until either two stands are drilled below salt or 300 ft, depending on operator preference.

These procedures are not definitive and are often customized by the rig and operations teams prior to the salt exit, depending on the specific well situation.



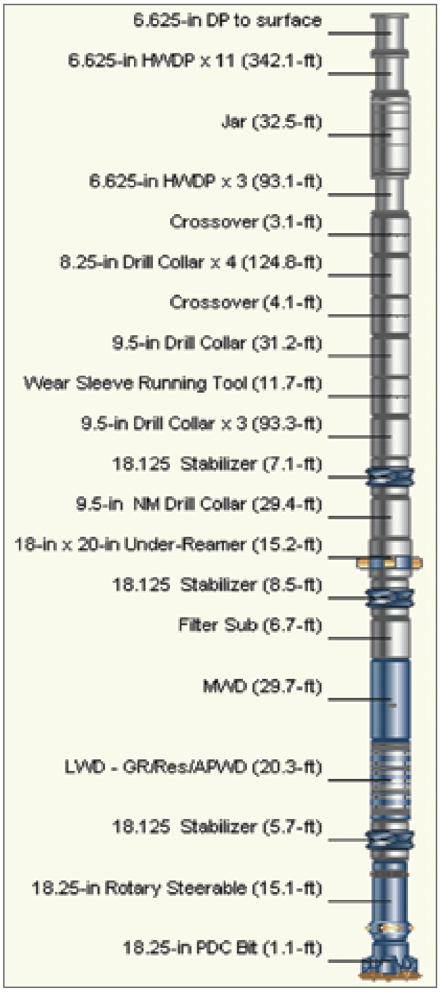


Figure 3 (left) shows the directional plot and Figure 4 (right) shows the bottomhole assembly, both for the well drilled in case study one.

ENABLING AND EMERGING TECHNOLOGIES

Improvements in directional drilling through salt have been supported through fit-for-purpose technology developments that, in some cases, have limited applications outside of deepwater salt drilling.

Rigs

Fifth-generation drilling rigs offer improved ability to drill through salt. They can provide increased torque at the increased rotary speeds needed. Hydraulics have improved with higher-pressure pumps and larger drill strings – made possible with increased derrick capacity. Increased hook rating allow the ability to run long, heavy casing strings through thick salt sections. Increased storage capacities are important when drilling riserless into salt with salt-saturated mud in a pump-and-dump method. The large holes require high-volume cement jobs. An estimated nine new deepwater rigs are under construction for the GoM, all expected to have the capacity required for large salt drilling operations.

Rotary steerable systems

Experience has shown that the slide/rotate mechanism of drilling with PDM motors is inefficient and unsuccessful in salt, particularly in directional applications. RSS have shown the ability to increase ROP, drill a smoother wellbore and deliver more consistent doglegs. As well construction needs have changed, larger RSS (up to 26-in.) have been built and run successfully in salt. The high cost of deepwater operations makes rotary steerable systems a cost-effective option for salt drilling.

Bits

One key factor in PDC bit designs for directional drilling in salt is the inherent stability of the bit. In general, for salt drilling applications, aggressive bits with six or fewer blades and 19-mm cutters can generate drilling-related shocks that can result in premature tool failure or, in a worse case, the parting of one of the BHA components. It is a recommended practice to choose and run less-aggressive bits. A good rule of thumb is 13-mm cutters (or 16 mm for bits larger than 18 in.) and more than seven blades on the bit.

Cutter compatibility with any concentric reaming device being used is also essential. The general rule, from a shock and vibration mitigation perspective, is that the bit should not out-drill the reamer.

Within the last year, the GoM deepwater market has driven the need for large PDC bits (26-in. to 18 1/8-in.) to run on similar-sized rotary steerables. Experience has shown that good gauge length is critical for maintaining the stability of these large PDC bits.

Under-reamers

Concentric reaming devices have come a long way. In the past, these devices were plagued with mechanical failures associated with the opening and closing of the reamer arms. Today, reamer reliability is on par with other drilling tools, especially with regards to ball-drop activation of the reamer arms. The use of these devices for salt drilling applications is critical when drilling salts that have strong creep tendencies. By running a concentric reamer on the BHA, the driller can drill and simultaneously open the hole to provide added insurance and time, effectively giving the drill crew more chance of a successful casing running operation.

In selecting the under-reamer, it is important to ensure that its cutting structure matches the planned bit. The goal is to ensure that the bit does not out-drill the reamer, which can induce unmanageable levels of shock, vibration and stick-slip to the drilling assembly.

Subsalt imaging

Seismic imaging through thick salt bodies presents many challenges to geoscientists. The large contrast in seismic velocity between salt at 14,500-15,200 ft/second and surrounding sediments, with velocities often at less than half that value, can distort structures imaged with traditional time-migration methods, as discussed by Albertin et al (2002).

For drillers, this meant that locating an intended drilling target (including a base-of-salt target) was much more difficult, with key horizons appearing on seismic hundreds of feet from their actual location. Three-D pre-stack depth imaging has been able to resolve this problem to some degree, refining the seismic image and reducing the errors of time-migrated data by an order of magnitude.

Large uncertainties still exist, however, due to limitations of the time-depth transforms being used in managing issues with formation anisotropy. New methods are being developed to further refine the subsalt image that will significantly reduce the drilling risks. These improvements will help to improve the pre-drill positional accuracy of salt inclusions, base of salt (and dips) and better image rubble zones and reduce the pore pressure uncertainty below salt.

Real-time monitoring

If there is a clear conclusion about salt drilling, it is that there is no room for poorly informed decisions. This has pushed operators and service companies to adopt new approaches to ensure that the right information is constantly available to reduce the response time when challenges arise.

Real-time monitoring or operation support centers are becoming a standard when facing salt drilling complexities. They aid in enhancing the communication channels to improve synergies between the offshore and office teams. Data need to be quickly turned into information that can be displayed with minimum latency in the right context in a format that can benefit decision-makers.

Centers can be set up to monitor shocks and vibrations, torque and drag, hole cleaning and pore pressure prediction. They facilitate optimization of the drilling parameters and allow the early detection of problems, and have reduced NPT in various types of drilling operations, including deepwater salt drilling.

Measurements while drilling

Drilling dynamics measurements required for salt drilling are not different to those used in other harsh drilling environments. These include vibrational data (lateral, axial and torsional), stick-slip and downhole WOB and torque measurements. Annular pressure for ECD measurements are also a requirement, particularly in instances where the drilling rate below salt will be confined by this measurement.

One of the latest developments in data transmission technology being adapted for salt drilling is the ability to program into the telemetry tool, the option to transmit different data arrangements. This means that, while drilling salt, the telemetry bandwidth can be optimized with stick-slip and vibration data points. Once out of salt, a command can be sent to the tool to switch to a different pre-programmed data frame that may increase the resolution of the sonic and ECD data points for use in real-time pore pressure modeling in the subsalt interval.

Logging while drilling

Although few petrophysical measurements are required in salt, specific measurements have application to improve drilling. Drillers are now understanding how to maximize the real-time benefits of these measurements to make positive impacts on salt drilling performance.

Gamma-ray: Useful measurements near bit (within 10 ft) that can confirm/correlate changes in drilling parameters (ROP, WOB, torque) with changes in lithology associated with entering the top of salt, exiting salt or drilling an inclusion.

Sonic: Compressional data is used in real-time pore pressure while drilling to improve accuracy of model through inclusions and in the interval below salt (resistivity measurements here are still influenced by the salt and result in inaccurate models).

Sonic shear data is also important for post-drilling geomechanical modeling of the salt. These models can determine the stress regimes in the salt and tell if they vary with depth into the salt. This data is then fed back into the well construction process for the next well. Sonic data can be negatively affected by drilling noise, and a rigorous BHA design is required to minimize the impact of noise on the measurement. BHA vibrational analysis to optimize the placement of the sonic tool in the string helps to improve acoustic data quality by minimizing noise caused from downhole shocks.

Seismic while drilling: Checkshots obtained from seismic while drilling can be used to update the base-of-salt depth in real time. Adjusting the base of salt may also shift the prognosed depth-of-target horizons below the salt. This information can then be used to make changes to the trajectory to change the inclination in salt to avoid missing a target and having to side-track.

CASE STUDY ONE

Background: A deepwater GoM operator

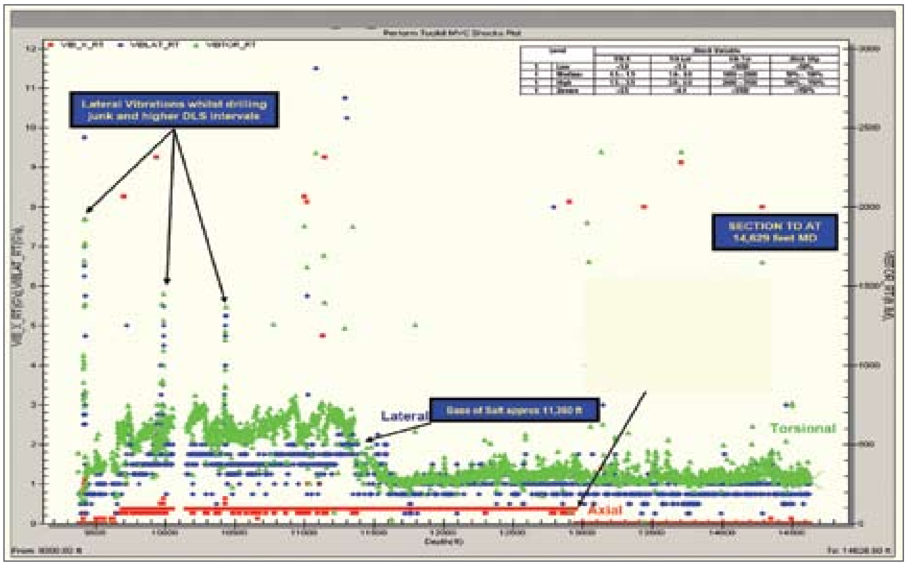


Figure 5: In the first case study, there was a decrease in shock and vibration levels as the reamer exited the salt and began drilling the same formation as the bit.

planned to kick off and simultaneously drill and under-ream salt in an 18.25 in.-by-20 in. hole.

Challenge: The kickoff was planned 100 ft below the 20-in. shoe, set in salt, and designed to first nudge the well to the east to mitigate collision risks, then turn and build to 16.8° inclination at 1.0°/100 ft, maintaining the tangent through the base of salt. Once through the salt transition zone, the BHA was required to build to 23.8° and hold to the 16-in. casing point. The section was planned to be drilled in one run.

Operations summary: The BHA (Figure 4) was made up with the reamer 87 ft behind the bit. Severe levels of shock and vibration were encountered while drilling the shoe track. The formation leak-off test was conducted, and drilling proceeded, hampered by high levels of lateral shock and extremely low ROP (approximately 3 ft/hr), a possible indication that some junk from the shoe track was trapped beneath the bit. Drilling parameters were adjusted in an attempt to free the junk.

Changing of the drilling parameters allowed shock levels to subside, and ROP increased to 30 ft/hr. This suggested that the junk had been cleared from below the bit. The reamer was opened, and drilling continued. The RSS was unable to give the desired turn, and the decision was made to trip to surface. Once at surface, it was discovered that the bit, RSS and reamer had suffered severe junk damage. The damaged components were changed, and an otherwise identical BHA was run in hole.

Once back on bottom, drilling and under-reaming operations in the salt continued with low shock and vibration levels. Directional work in the salt proved challenging. The BHA built angle without issues, but the natural tendency of the salt pushed the assembly hard to the southeast. To counter this tendency, maintain the desired trajectory and manage anti-collision risks, the RSS was steered at maximum setting to the left for 75 ft in order to generate enough left turn to maintain required separation and catch up with the planned trajectory. The maximum dogleg generated over this interval was 3°/100 ft.

After clearing the anti-collision risk, drilling continued at 140 RPM while pumping 1,400-1,500 GPM. WOB ranged from 20-30 kips with low vibration levels, although some elevated vibrations were observed while the reamer drilled through the high dogleg interval. ROP in the salt averaged 60 ft/hr. Directional work continued without issue, even though 2°/100 ft doglegs were required to approach the planned trajectory.

The base of salt came in 1,700 ft below the 20-in. shoe. The inclination at this point was 16.5°, just 0.3° off of the planned inclination. There was a pronounced drop in background levels of lateral and torsional shock along with stick-slip as the reamer exited the salt and began drilling the same formation as the bit (Figure 5). No other issues were observed while exiting the base of salt and drilling through the transition zone.

Once the bit and reamer were completely in shale, the ROP increased to over 100 ft/hr. The assembly continued to drill directionally as required for 3,200 ft below the base of salt. At this point, the well was back on plan, with an inclination of 25° and a 97° azimuth, with the maintain inclination feature of the RSS used over the last 300 ft of the run. No drag issues were experienced during the multiple trips through the salt, and 16-in. casing was run to bottom and cement, with cement volumes corresponding to a 20-in. hole.

Lesson learned: Directional work is achievable in large hole while under-reaming. Salt tendencies must be incorporated into build rates in planning.

CASE STUDY TWO

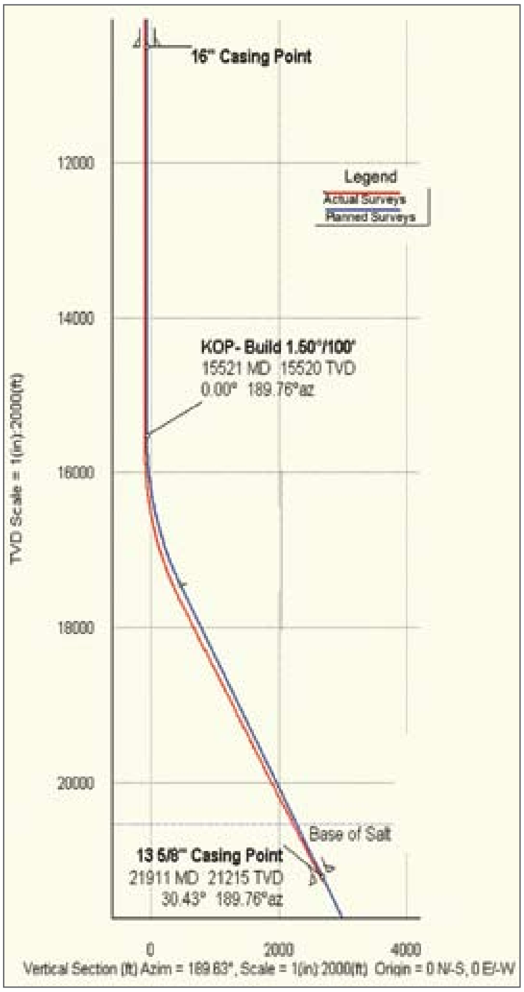
Background: A deepwater GoM operator planned to kick off and simultaneously drill and under-ream salt in a 14.75 in.-by-16 in. hole. The goal was to drill the section in one run.

Challenge: Well plan involved drilling out of the 16-in. casing shoe and continuing vertically to the kickoff point at 14,431 ft, building inclination at a rate of 1.5°/100 ft to 20° and continuing tangent section through the salt base to casing point at 21,911-ft MD. Hole size was 14.75-in. with an under-reamer opening to 16-in. Severe shocks and vibrations while drilling salt were present in offset wells.

Operations summary: At the start of the run, the RSS was programmed to drill vertically. The maximum angle during this section was 0.10˚. The well was kicked off at 14,331 ft. Various steering commands were downlinked to the RSS to achieve build up to 14º. At this point, downlinked into inclination hold mode where the BHA had a tendency to drop in the early stages but later held. Directional issues arose with 1˚/100 ft to 1.5˚/100 ft right-hand walk while in inclination hold mode. Steering settings were adjusted to mitigate this walk, continuing until below the base of the salt.

After drilling out of salt, a flow check was done, and drilling continued until the base of the salt was seen on the log, then circulated out. Drilling continued to 19,510 ft, when the well took a kick. Well control procedures were successfully executed, and the well was steered below salt as per directional plan to TD. Minimal shocks were experienced during this run, mostly while off bottom. These were treated by reducing the rotary until on bottom and easing back to bottom.

Lessons learned: Three components of



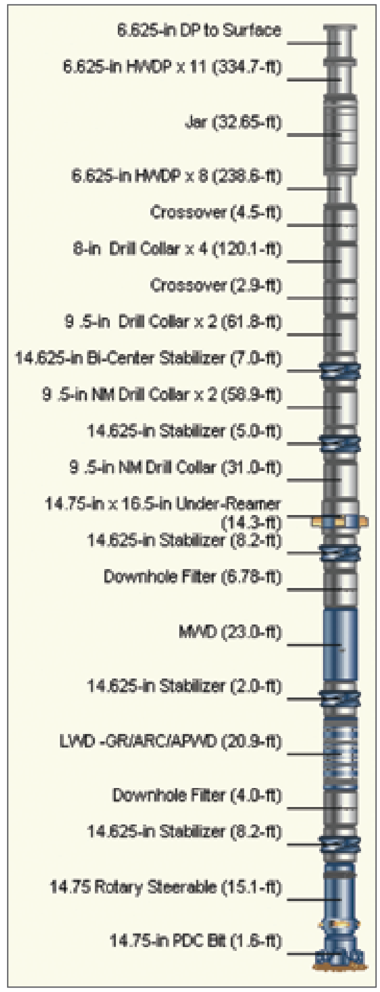


Figure 6 (left) shows the directional plot and Figure 7 (right) shows the bottomhole assembly, both for the well drilled in the second case study.

the BHA (Figure 7) were thought to have contributed to the low shocks:

1. A seven-bladed bit fitted with 16-mm cutters with a 4-in. gauge. The bit at surface presented two chipped cutters.
2. A "bi-centered" stabilizer was run 90 ft behind the reamer to provide near-full gauge stabilization in the 16-in. hole.
3. Only two cutters in the reamer were missing due to bond failure. The reamer selected had cutters matched with the bit to ensure that minimal shocks were introduced due to bit-reamer interactions.

CASE STUDY THREE

Background: This well was located in more than 6,000 ft of water. The salt section to be drilled was in 18,000-plus ft.

Challenge: Due the extended depth of this well and the existing risk of large side forces while drilling deeper in well, the objective of the three initial hole sections was to keep the inclination below 2° and the doglegs below 1°/100 ft.

Operations summary: The 26-in. section was drilled riserless into salt using a salt-saturated mud. A RSS assembly with a 1-1-5 insert bit was chosen. Drilling started with slow RPM as the majority of the BHA was still in casing, and once the top stabilizer was in contact with the formation, WOB and RPM were increased to obtain maximum penetration. Transferring the WOB while avoiding downhole vibrations was a challenge; a heavier assembly with more mass and therefore more inertia could have been a better choice. More challenges were experienced as jars parted at the base of the mandrel while they were passing through the top of the conductor.

From the learnings acquired on this BHA, the second assembly was made up without jars and three extra 9 ½-in. collars plus three more 8 ¼-in. collars were added to increase the inertia and available WOB. Both assemblies drilled using the same rock bit, and flow was kept between 800-900 GPM.

The 18 ⅛ in.-by-21-in. section proved to be a difficult one, and despite water-base mud being displaced to synthetic oil-base mud, slow drilling and low but constant stick-slip plus shocks and vibrations were present throughout the section.

Three different assemblies were used to accomplish the objectives. The first BHA drilled more than 3,500 ft when a pressure drop was noticed and a washout was found in the circulating tool. The same assembly was picked up again without the circulating tool, and this time only about 100 ft were drilled when about 50,000 lbs of weight were lost. The wear bushing running tool was left on bottom, and fishing operations started. After fishing the bottom of the BHA, it was decided to only wash out the rat hole with the reamer and set casing at the shallower depth.

Initially in the 16 ½ in.-by-20 in. section, the hole size and drilling system appeared to be a more effective combination. ROP in the salt was steady at about 30 ft/hr from the beginning, and shocks and vibrations were kept to an allowable level. WOB was increased to achieve a higher penetration rate of 40-50 ft/hr, but shocks and vibration also increased. While analyzing the drilling parameters vs vibrations, a zone was found that allowed the 40-50 ft/hr ROP to be maintained while keeping shocks below the severe level. However, a drop in standpipe pressure was noticed with a decrease in the MWD turbine RPM, indicating a drop in flow through the MWD tool. Upon pulling out of the hole, a washout was found between the second and third joint of heavy-weight drill pipe (HWDP).

The HWDP was replaced, and drilling the salt resumed. Severe lateral and torsional vibrations were present, together with high stick-slip. However, this time the main contributor was rough weather. The heaving of the rig made it challenging to keep a consistent WOB and weight on the under-reamer. A shale inclusion was found during this run and was drilled without difficulty. However, the assembly became stuck while back-reaming the inclusion; jarring and 150 kips of overpull freed the assembly.

Mud weight was increased, and the section was reamed down. While doing so, lateral, torsional and axial vibrations and stick-slip reached severe levels as a loss of over 300 psi was noticed. After pulling out of the hole, it was found that one of the connections backed off, and the drilling system was left in the hole.

After fishing the drilling system, a new assembly was picked up, swapping the 5 7/8-in. HWDP for 6 5/8-in. HWDP and changing the 16 ½-in. PDC bit. The mud weight was kept at a higher level to reduce the risk associated with the shale inclusion. Drilling operations resumed until reaching section TD.

Lesson learned: Despite all the engineering work done to simulate the drilling environment and vibrations, it proved extremely difficult to predict the behavior of the assembly and the formation while salt drilling. Qualitative shock and vibration analysis helped to choose a better assembly. Real-time drilling optimization monitoring could increase the drilling efficiency and avoid the events encountered.

Despite all the challenges that were encountered, the goal of drilling these three vertical sections under 2° of inclination and keeping the DLS under 1°/100 ft were achieved satisfactorily, ensuring low side forces for the rest of the well (Figure 8).

SUMMARY

The following summarizes the major recommendations and lessons learned.

1. Rotary steerable assemblies are the best option for drilling salt, with improvements seen in directional control, ROP and hole quality.

2. RSS, in combination with motors, can deliver higher torque and RPM at the bit and can improve ROP over extended salt intervals.

3. Include geomechanical considerations into directional design. Plan salt exit across a tangent section and at a flat or low dipping area of the salt base. Salt exit can be defined as a drilling target.

4. Plan with low dogleg severity (<2.0°/100 ft). This ensures that if steering is required to counteract the salt tendency, the assembly still has enough capability to drill the desired trajectory

5. Avoid drilling jars in hole sections larger than 18-in.

6. PDC bits are best for salt. A general guideline is for heavy set bits with 16-mm or 13-mm cutters. Ensure bits

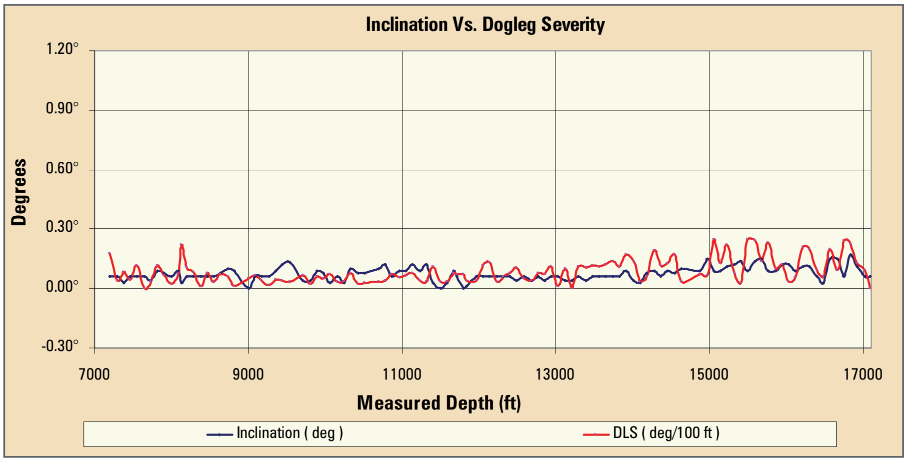


Figure 8: Many challenges were encountered drilling the salt interval in the third case study. Still, the goal of drilling the three vertical sections under 2° of inclination and keeping the DLS under 1°/100 ft were achieved satisfactorily.

are matched with under-reamer to avoid inducing shocks from incompatible bit-reamer combinations

7. Control drilling parameters when entering and exiting salt until both bit and under-reamer are in similar formations.

8. Real-time monitoring of salt drilling parameters, including shocks and vibrations, either at the rig-site or from remote centers, aids in optimizing drilling performance and extending BHA life.

Directional drilling in salt is not a new technique but is evolving in its frequency and complexity. Based on the areas covered in this article, it is clear that the motives, opportunities and methods required to support the current requirements of directional drilling in salt exist and will continue to expand. The need to do so is driven by cost savings and geological needs; the opportunity provided by the large subsalt reservoirs in the deepwater, and the processes supported by existing technology (rigs and directional) and the experience of personnel. Limits still exist, but these may be more constraining in salt. It is important to understand the limits of build rates, casing, drill pipe, rig, completions and interventions on the design of the well.

The need to extend current limits will arise as the industry requires more complex directional work to be done in salt (e.g., 3-D designer wells, high-angle or extended-reach). Operators, drilling contractors and service providers all have recognized these needs and are working to ensure that the required technologies are developed. This collaboration will prove beneficial for meeting the future challenges of directional drilling in salt.

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