

Innovative Torque Management Using Dual Cutting Mechanics of Hybrid Bit Enhances Stability While Control Drilling in Sediment and Salt with Concentric Reamer in Gulf of Mexico.

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Abstract

Operators in the Gulf of Mexico (GOM) regularly drill wells in water depths exceeding 4,000 ft. Target reservoirs are frequently under sequence of salt with thickness ranging from a few hundred to several thousand feet, posing challenges due to its unique geo-mechanical properties. Additionally, long-riser sections and deep targets introduce drilling dynamics and hole cleaning challenges, whereby a minimum set of parameters are required to be maintained to ensure hole cleaning at a given penetration rate.

In one such application, a flow-rate restriction required that the hole section be drilled at a controlled penetration rate to avoid potential hole cleaning issues. Including a concentric reamer in the drill string posed an additional challenge of bit-reamer synchronization while drilling through the sections of soft sediments and salt. A polycrystalline diamond compact (PDC) bit was unable to meet the stability requirement due to its aggressiveness and narrow stability window which could have resulted in a tool failure due to vibration and an unplanned trip.

This challenging set of conditions led to the selection of a hybrid bit with roller-cone and PDC cutting elements that enhanced the stability by removing erratic torque fluctuations thereby providing a stable drilling condition and improved bit-reamer synchronization.

This paper highlights the challenges in directional drilling at controlled penetration rate in sediment and salt with a concentric reamer and presents the results of the successful application of hybrid bit technology. The paper also emphasizes the drilling mechanics of hybrid bits and compares it to that of PDC bits.

Introduction

Ongoing drilling in deepwater (DW) area in central GOM (Fig.1) is aimed at the reservoir which is located below thick sequence of salt where the water depth exceeds 4,000 ft.¹

In an application where pumping capacity limitation required operator to drill with 16½" pilot bit and 19" concentric reamer on a rotary steerable system (RSS) at controlled rate of penetration (ROP) to ensure hole remains clean. The offset well was drilled with a PDC bit. However, PDC bit due to its inherent shearing action has higher aggressiveness and could

not meet the application requirement of stability at low and controlled ROP.

Additionally, salt being a plastic formation, required higher



Figure 1 – Target area in central Gulf of Mexico

weight on bit (WOB) to drill which pushed the PDC bit to the zone of instability. Stability being an important requisite, encouraged operator to consider an engineered hybrid bit solution.

Application Review and Challenges

The 16½" x 19" section of the target well was planned to be directional with a "J" profile at 2°/100 ft. dogleg severity (DLS). The planned section was 4,550 ft. long and consisted of sediment and salt.

A 19" concentric reamer was placed in the bottom hole assembly (BHA) to open the hole to a sufficient diameter to facilitate liner placement.

Control Drilling

Availability of limited pumping capacity was a major concern which required that the ROP to be controlled below 50 ft./hr. to ensure adequate cuttings evacuation to avoid the risk of annular pack-off and increased torque and drag. The target well being directional, a string rotation over 120 rpm was required to aid in agitation of cuttings and removing them from the low side of the wellbore.

In order to maintain the low ROP in the soft sediments, the PDC bit required very low WOB while high RPM was required

for hole cleaning creating a possibility for unsustainable lateral vibrations and whirl to occur.

PDC Bit Dynamics

Unlike roller-cone bits, PDC bits produce higher torque due to its shearing action^{1,2}. High torque fluctuations may result in stick-slip, a detrimental downhole drilling dynamic condition. Stick-slip, if it is not controlled, can damage the BHA elements^{2,3,4} resulting into undesired trip which elevates the cost of operation due to non-productive time (NPT) as well as risk to personnel while tripping.

Additionally, each PDC bit based on its design attributes has an associated stability window (Fig. 2) with respect to the operating parameters. In case of PDC bits, the stable operating window is narrow, given that drilling salt would require high WOB and sediments very low WOB, there was increased

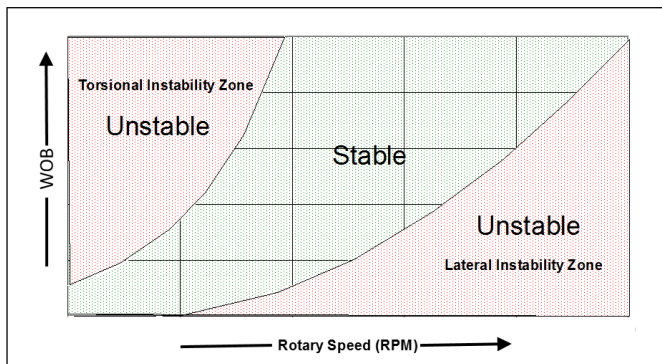


Figure 2 - Generic stability window for PDC bits

likelihood that drilling with PDC bit would push the bit outside its stability window and trigger bit / BHA instability.

In PDC bits, there are features like depth of cut control (DOCC) that provide some level of torque fluctuation mitigation^{2,4}, but it is hard to design a DOCC feature to cover a wide range of formation types and drilling conditions. For example, a DOCC configured for higher WOB while drilling soft sediments proves ineffective, once that bit hits the salt the reduced aggressiveness cannot achieve the required ROP target and may trigger vibrations.

Drilling Dynamics and Wellbore Quality

Torsional oscillations and other drilling dynamics modes are not only detrimental to downhole equipment, they often initiate the rippling, spiraling and hour glassing^{5,6} effects in the wellbore. The tortuosity (Fig. 3) generated in the wellbore by these effects could compromise the log quality, and may also increase the torque and drag in the wellbore. The undesired tortuosity in the wellbore could also pose problems for running casing to the bottom or compromise the quality of cement around the casing. The enhanced stability provided by the hybrid bit limits these phenomenon.

Bit and Reamer Synchronization

In order to ease the casing running, a concentric reamer was placed approximately 130 ft. behind the bit to open the hole to

19.0". This increased the possibility of bit and reamer being

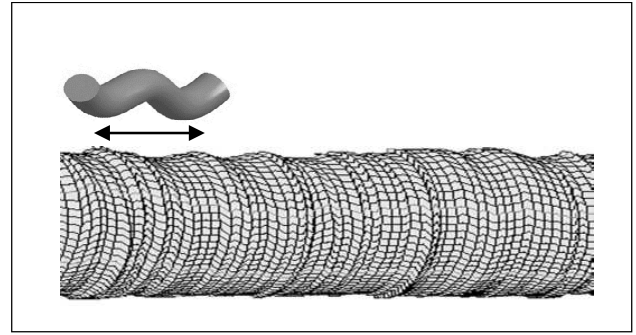


Figure 3 - Wellbore tortuosity due to rippling

placed in formations of different hardness which in turn may increase the likelihood of triggering drilling dynamic issues⁷. Each bit and reamer combination based on its design attributes has a varying ability to cut the rock and having them in formations of varying hardness can cause the loss of synchronization due to fluctuation of compressive load in bit and reamer. This condition could trigger drilling dynamics issues. Having a concentric reamer in the BHA required a pilot bit with matched aggressiveness to remain synchronized with the reamer while drilling formations of varying hardness.

Salt Geo-mechanics

In deepwater GOM, the target reservoir is often located below several thousand feet of salt¹. Salt has a low porosity and permeability and is unable to withstand deviatoric stress causing creep to attain stress equilibrium^{8,9,10}. The tendency of salt to attain stress equilibrium frequently causes local stress anomalies which could distort the stress regimes of the adjoining beds creating wellbore instability, an important and significant drilling risk.

Drilling through distorted stress areas requires caution, it is recommended that entering and exiting salt beds while drilling are performed under stable drilling conditions.

Upon detailed review of the application and based on the facts above, it was evident that an improved bit technology is needed for control drilling the target well which could:

- Remain stable while drilling at ROP of 50 ft./hr. or lower as required to meet the hole cleaning requirements.
- Remain stable while drilling salt with high WOB.
- Provide consistent and linear torque response while drilling sediment and salt and lower the torsional oscillations.
- Remain in sync with the concentric reamer in the BHA.

Hybrid Bit Technology

The hybrid bit combines roller-cone and PDC cutting elements whereby roller-cone provides the gouging and crushing action at the periphery of the bit and the resultant pre-stressed rock is sheared by the PDC cutting elements. PDC cutters provide the desired aggressiveness¹ while the roller-

cone cutting elements mitigate the torque fluctuation providing the overall bit stability.

Having dual cutting elements in a hybrid bit allows it to drill with lower torsional oscillations^{1,11} and provides a wider drilling stability window when compared to PDC bits.

The profile of the hybrid bit is relatively flat with nozzles placed closer to the bottom of the hole which improves bit face cleaning. Having a flat profile also enhances stability which was an important requirement of the current application.

The hybrid bit design selected for this application had three cones and three blades reaching out to the gauge area (Fig.4). Three inner blades were entrusted to drill the center of the wellbore. The PDC cutting elements used in the bit were 16mm in size.

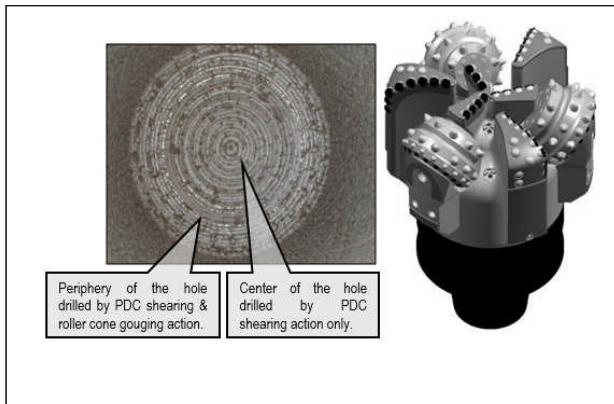


Figure 4 - Hybrid bit with bottom-hole cutting pattern

In order to enhance the stability while control drilling, PDC and roller cone cutting elements were carefully selected and their relative placement geometry was designed to maintain a balanced aggressiveness and remain stable while drilling salt at high WOB.

Offset Well Performance

The 16½" x 19" section of the offset well was drilled with a seven bladed PDC bit with 16mm cutters at a controlled ROP of 60 ft./hr. The downhole dataset measured by drilling performance sub included vibration modes and severity levels, downhole WOB, torque, minimum, maximum and average RPM was reviewed and used for benchmarking of drilling mechanics and drilling dynamics performance (Fig. 5).

While drilling the offset well, there were instances when ROP was lowered to clean the hole, during low ROP instances high lateral vibrations and drillstring whirl were recorded which were managed by adjusting drilling parameters.

While drilling salt with high WOB some high stick-slip and lateral vibration instances were observed requiring adjustment of drilling parameters to ensure stability. During salt entry, instances of drillstring whirls were recorded. The downhole mechanical specific energy (MSE) values while drilling salt

showed wide variation confirming downhole dynamic dysfunctions.

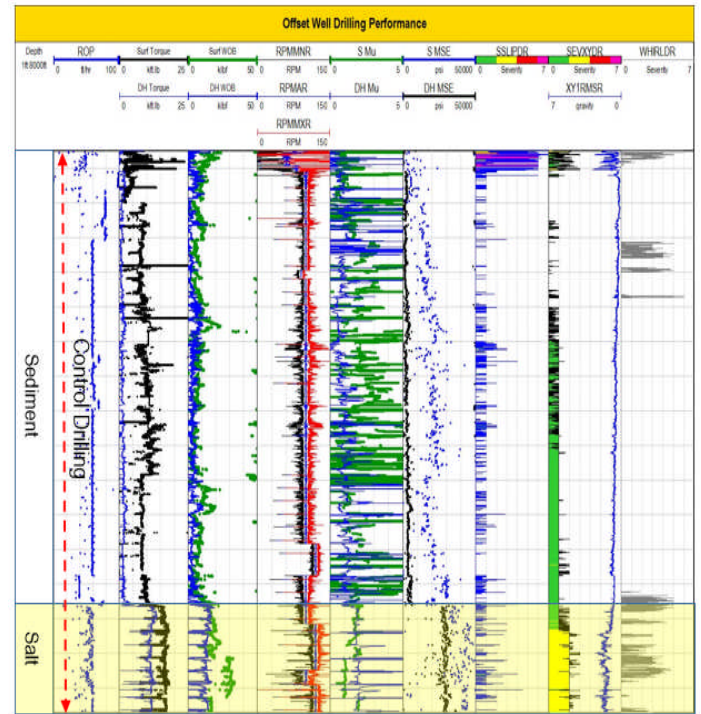


Figure 5 - Drilling performance of offset well

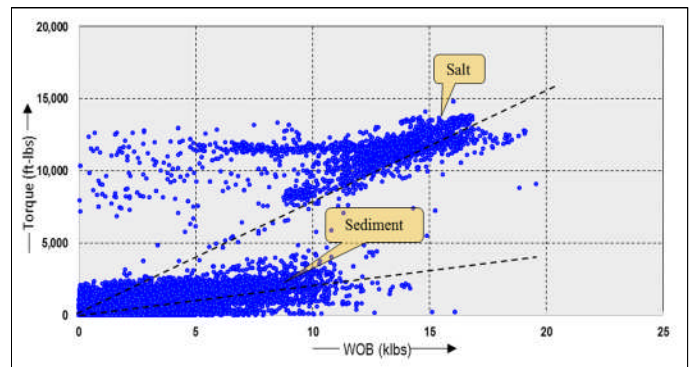


Figure 6 – WOB – Torque relationship with offset PDC bit run

In the 16½" x 19" section of the offset well, two distinct trends for sediment and salt emerged when WOB-torque relationship of the PDC bit was analyzed (Fig. 6). Though it is expected that a bit would display different torque values while drilling different formations, however, in situations of control drilling at low ROP, a consistent and linear torque response is helpful to respond to any drilling dynamics issues as well as address any requirement of drilling parameter adjustments for hole cleaning purposes.

In the offset well, salt was drilled with approximately 12-17 klbs of WOB, as higher WOB could have resulted in a ROP

increase which was not desirable due to limited pumping capacity.

The coefficient of sliding friction (μ), commonly known as aggressiveness or Mu is used for understanding the WOB and torque relationship^{12,13} and is a good indicator to analyze and compare the drilling behavior of different bits.

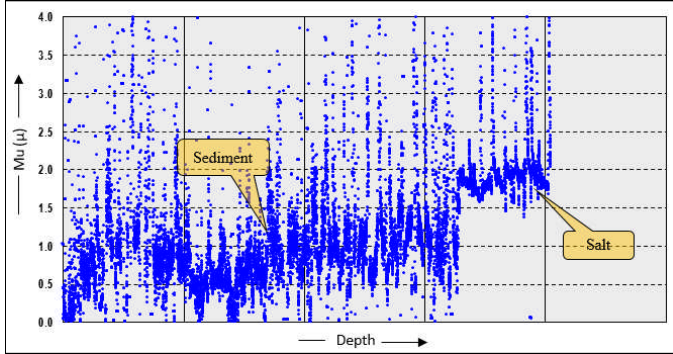


Figure 7 – Mu (μ) value of offset PDC bit in sediment and salt

The aggressiveness of the PDC bit while drilling sediments and salt varied widely (Fig. 7), this wide variation was confirmed by the large standard deviation values of 20.8 and 24.8, respectively (Table 2). The mean aggressiveness was 3.42 and 4.74. Given that this application required control drilling the formation with a concentric reamer in the BHA, it was recognized that a bit with a lower aggressiveness would promote stability while drilling at a lower and controlled ROP. Field experience with hybrid bits indicated that lowering the aggressiveness would aid the torsional stability.

Hybrid Application Results

The downhole data for the 16½" x 19" section of the target well which was drilled with a hybrid bit was compared to the PDC bit run of the offset well. Since two sections were drilled in nearly identical formations with the same BHA and similar trajectories but with different bits, this provided a direct comparison of drilling dynamics and drilling mechanics values.

For the comparison of drilling dynamics performance of two bit runs, downhole vibration severity levels including stick-slip, lateral vibration and drillstring whirl were used. However, for the drilling mechanics comparison, the MSE and Mu values were calculated using standard equations and downhole WOB and torque values (see Formulae section).

Drilling Dynamics

During the hybrid bit run 99.0% of the run was drilled with no stick-slip, (level-1, green) against 97.4% during the offset PDC run (Fig. 8, Table-2), which was an improvement over the offset well. Minor but unsustainable levels of stick slip (level-7, purple) were observed during the offset PDC bit run but were not observed while drilling with the hybrid bit. This was a significant improvement as high level stick-slip could trigger downhole tool failure².

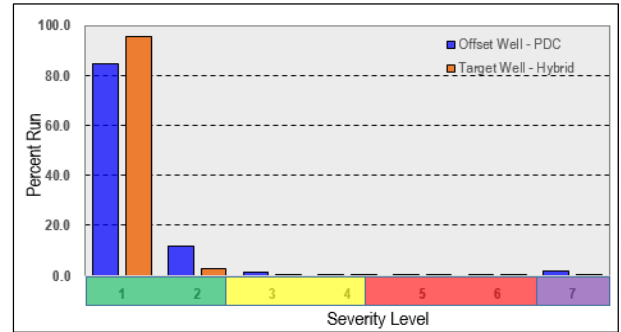


Figure 8 - Stick-slip severity level comparison

Similar comparisons for lateral vibrations showed that no lateral vibrations (level 0-2, green) were recorded during 97.5% of the hybrid bit run. This value was 98.2% for the PDC bit run in the offset well (Fig. 9, and Table 1).

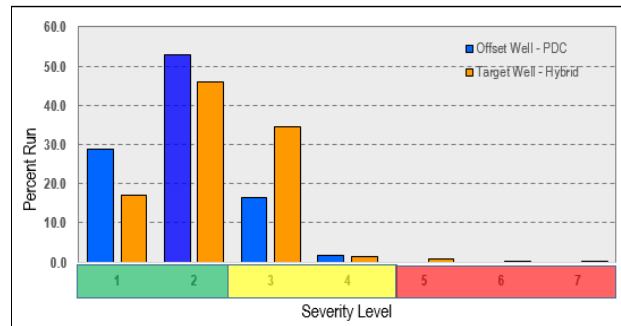


Figure 9 - Lateral vibration severity level comparison

Given that average ROP of the target well on numerous occasions was lowered to 20-25 ft./hr. to ensure hole cleaning, it was a good performance which could have been difficult to replicate with a PDC bit under these drilling conditions.

Drillstring whirl (Fig.10, Table 1) levels when compared between offset and target well, a slight increase of whirl was observed on the hybrid bit run which was attributed to the concentric reamer being unable to stabilize when the well was

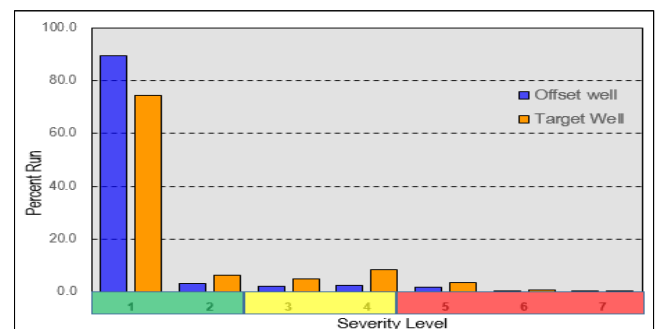


Figure 10 - Drillstring whirl severity comparison

drilled with ROP lower than 40 ft. /hr. It was inferred that a concentric reamer with lower aggressiveness could have managed the instances of drillstring whirl, especially while drilling salt.

Drilling Mechanics

When compared to the offset well, the downhole torque of the hybrid bit showed a linear response (Fig.11) while transitioning from sediment to salt, in stark contrast to the PDC bit which displayed two distinctive trends. Even though, salt with hybrid bit was drilled with 40-50 klbs WOB, torque remained 10,000 – 12,500 ft-lbs indicating consistent and linear response. The linear relationship of WOB and torque displayed by hybrid bit offers an advantage while drilling interbedded formation when downhole dynamics are required to be managed with changing drilling parameters.

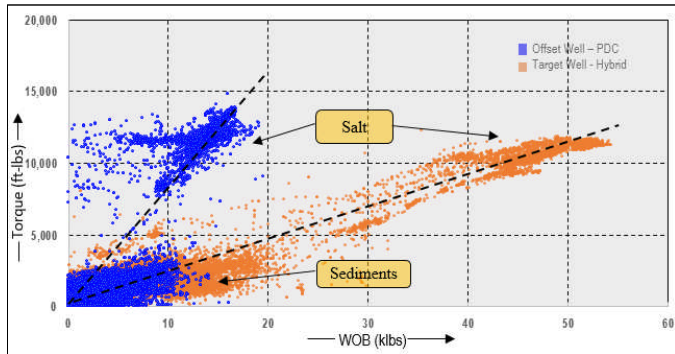


Figure 11 – WOB – Torque relationship of PDC and hybrid bit

The mean and the standard deviation of the torque values when compared to PDC (Table 2) bit run indicated that the torque fluctuations of the hybrid bit were lower even though a much higher WOB was applied with hybrid bit.

The average aggressiveness values of the hybrid bit (Fig.12), while drilling sediment and salt were 1.09 and 0.49 (Table 2) which were significantly lower than the aggressiveness of the PDC bit. This enhanced the required dynamics stability required for controlled drilling with a concentric reamer.

The standard deviation of Mu, which is an indicator of data spread were 3.56 and 0.04 in sediment and salt, respectively. This indicated very consistent bit formation interaction with the hybrid bit, a significant improvement over the PDC bit run.

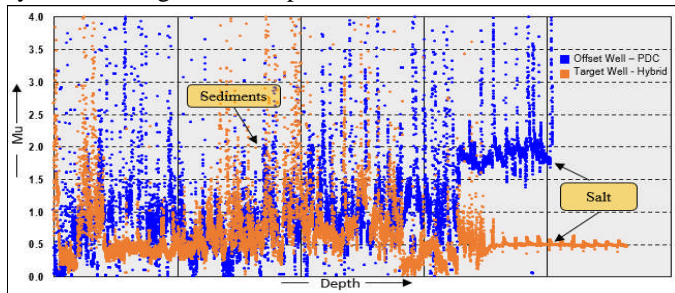


Figure 12 – Mu (μ) of PDC and hybrid bit in sediment and salt

The mechanical efficiency of the offset and target bit runs were compared MSE^{12,13} (Fig.13) which was calculated using the downhole drilling parameters and standard equations. MSE

values were observed to be higher for the hybrid bit. Given that the offset well was controlled drilled at 60 ft./hr. and the hybrid bit on the target well controlled drilled at 42 ft./hr. or lower at times to ensure hole cleaning, the MSE values for the hybrid bit remained slightly higher as a result.

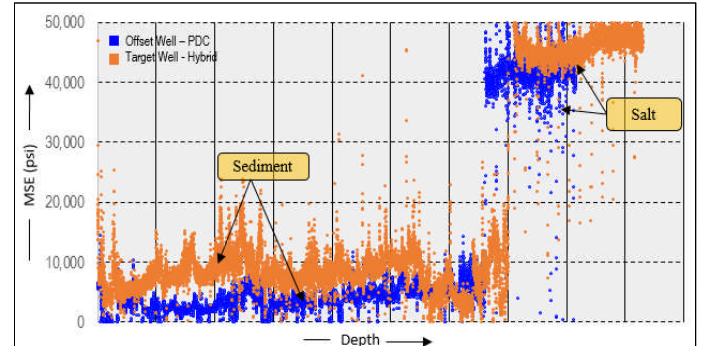


Figure 13 – MSE comparison of PDC and hybrid bit run

Tables

Severity Level	Lateral Vibration		Stick-slip		Whirl	
	Offset Well	Target Well	Offset Well	Target Well	Offset Well	Target Well
0	28.8	17.1	84.6	95.6	89.6	74.4
1	52.8	45.9	11.6	2.9	3.2	6.5
2	16.6	34.5	1.2	0.5	2.1	5.0
3	1.9	1.5	0.5	0.4	2.7	8.7
4	0.0	0.7	0.2	0.4	1.8	3.7
5	0.0	0.2	0.1	0.1	0.4	0.7
6	0.0	0.1	1.6	0.1	0.2	0.4
7	0.0	0.0	0.2	0.0	0.0	0.6

Table 1- Vibration modes and severity levels against percent of run for PDC and hybrid bit

Formation	Bit Type	Torque (ft-lbs)		MSE (psi)		Mu	
		Mean	St Dev	Mean	St Dev	Mean	St Dev
Sediment	PDC	1,235.6	631.5	2,288.2	1,741.9	3.42	20.80
	Hybrid	1,819.5	758.3	8,245.9	3,837.2	1.09	3.56
Salt	PDC	11,282.4	1,377.5	21,514.5	6,236.1	4.74	24.82
	Hybrid	10,226.1	1,505.1	47,163.1	12,756.7	0.49	0.04

Table 2- Torque, MSE, Mu values in salt & sediment for PDC and hybrid bit

Conclusions

Based on the detailed drilling review and comparison of data between offset PDC and target hybrid well, authors concluded that:

- A hybrid bit is able to remain very stable while control drilling at lower penetration rates and with higher WOB when compared to a PDC bit.
- Compared to a PDC bit, a hybrid bit provides lower and very consistent aggressiveness suitable for drilling soft and plastic rocks like salt.
- A hybrid bit provides liner and consistent torque response along different formation types for given set of drilling parameters.
- Due to linear torque response across the varying

formation types, a hybrid bit offers a better solution when managing drilling parameters are required for mitigation of drilling dynamics and/or for changing formation types.

- In control drilling applications with concentric reamers, a hybrid bit offers a better engineering solution.

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Nomenclature

<i>A</i>	= Area of hole
<i>BHA</i>	= Bottomhole assembly
<i>D</i>	= Diameter of Bit
<i>DH</i>	= Downhole
<i>DOCC</i>	= Depth of cut control
<i>DLS</i>	= Dogleg severity
<i>DW</i>	= Deep water
<i>ECD</i>	= Equivalent circulating density
<i>GOM</i>	= Gulf of Mexico
<i>GR</i>	= Gamma ray
<i>MD</i>	= Measured depth
<i>MSE</i>	= Mechanical specific energy
<i>Mu</i>	= Aggressiveness / friction coefficient
<i>NPT</i>	= Non productive time
<i>PDC</i>	= Polycrystalline diamond compact
<i>ROP</i>	= Rate of penetration
<i>RPM</i>	= Revolution per minute
<i>RSS</i>	= Rotary steerable system
<i>S</i>	= Surface
<i>TD</i>	= Total depth
<i>WOB</i>	= Weight on bit

Formulae

$$MSE = \frac{WOB}{A} + \frac{120 * \pi * Torque * RPM}{A * ROP}$$

$$\mu (Mu) = \frac{36 * Torque}{D * WOB}$$

<i>MSE</i>	- pound/inch ²
<i>WOB</i>	- pound
<i>Torque</i>	- foot-pound
<i>Area</i>	- inch ²
<i>ROP</i>	- feet / hour

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