

Reducing Downhole Vibrations through the Utilization of Kymera™ Hybrid Drill Bits

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Abstract

With the industry's increased use of hydraulic fracturing to maximize production in unconventional reservoirs, larger diameter bits are utilized more often to drill the production section of a horizontal well. With the increased footage drilled, roller cones are utilized less often due to low penetration rates and design limitations. Furthermore, the firm, interbedded formation in the Permian Basin causes aggressive PDC bits to experience high vibrations levels resulting in drilling inefficiencies and necessary trips due to bit and down-hole tool failure, increasing the overall cost of drilling the 12-1/4 inch intermediate section.

Inconsistent performances have highlighted the necessity of seeking new paths to improve 12-1/4 inch section performance through series of bit design iterations and optimization of drilling parameters and BHA design. The customer requested an enabling technology to increase stability without sacrificing overall drilling performance. Baker Hughes and Apache Corporation launched a collaborative effort to combine an innovative bit technology with optimized BHA design and drilling practices, which would be capable of consistently drilling the 12-1/4 inch interval with one fast run.

This paper discusses the use of Kymera™ Hybrid bits to reduce lateral and torsional vibrations while improving overall performance in the 12-1/4 inch intermediate section. Also discusses how the collaborative effort helped Apache find a solution to drill the 12-1/4 inch section in one bit with higher overall ROP than a PDC bit. The technology application has decreased overall drilling time by improving ROP by 50% and reducing trips, resulting in substantial reduction in drilling cost.

Introduction

The analysis reported in this study was performed to understand the impact of using Kymera™ bits on down hole vibrations while drilling 12-1/4 inch vertical intervals. Over the years, advances in PDC bit technology have allowed hard rock to be drilled more efficiently, which reduces overall time spent drilling a well. However, the cutting mechanics of PDC bits can cause dynamic dysfunction when drilling in heterogeneous formations consisting of laminated hard and soft layers. Kymera™ bits are specifically designed to increase drilling efficiency in hard, interbedded formations,

thus providing a platform for smooth drilling in these difficult zones.

This paper reviews the collaborative effort used to enhance drilling performance in the 12-1/4 inch vertical section, thus reducing days on well and overall well costs. To fully understand the challenges that were present, a detailed benchmarking study was performed to establish metrics to evaluate drilling performance. A variety of case studies will review the effects of different bottom hole assemblies and bit types on down hole vibration.

After reviewing the data, Kymera™ bits provided significant improvement in drilling performance, resulting in reduced cost. This was attributed to the reduction in down hole vibrations by utilizing Kymera™ bits.

Background and Drilling Challenges

The area of interest is a field consisting of several lease locations known as "Units." The goal for this field is to successfully drill extended reach Wolfcamp horizontal wells. Each well requires the surface interval to be drilled and cased past WBL depth. This is followed by a 12-1/4 inch intermediate section to a predetermined KOP. Upon completion of the vertical section, the curve and lateral are drilled to TD (Figure 1).

Unconfined compressive strengths were evaluated using offset well data for the 12-1/4 inch intermediate section. The interval lithology consists mostly of shale, limestone, and sandstone. Unconfined compressive strengths range from 5,000 psi to 25,000 psi. The San Andres formation contains interbedded dolomite and sandstone, and has a cap that reaches 25,000 psi. Problem formations include the Clearfork and Upper Spraberry, which are highly interbedded shale and sandstones.

Earlier wells in the area of interest were successfully drilled with one to two 12-1/4 inch PDC bits in the intermediate section. As the well locations shifted from the East to the West, the 12-1/4 inch intermediate section required between 2-3 bits to complete the interval (Figure 2).

Multiple PDC bit design configurations were utilized to drill the 12-1/4 inch intermediate section. Bits featuring 13 mm, 16 mm, and 19 mm cutters along with five, six, seven or eight blades all experienced similar issues consistently completing the interval with one bit. All bits exhibited similar dull characteristics with broken and chipped cutters in the nose

and shoulder area. Figure 3 illustrates the typical dull conditions of PDC bits used to drill this interval. These damage modes are indicative of a bit experiencing dynamic dysfunction while it is being ran.

Down Hole Vibrations of PDC Bits

There are three types of dynamic dysfunctions experienced while drilling: axial vibration (bit bounce), lateral vibration (whirl), and torsional vibration (stick-slip) that are illustrated in Figure 4. All of these vibrations potentially pose a risk of damaging the drill bit and bottom hole assembly. It can be extremely difficult to diagnose and prevent dynamic dysfunction using only surface measurements due to the fact that the BHA and drill bit can be thousands of feet below ground. By using a patented down hole vibration sensor, true dynamic dysfunctions can be diagnosed at the bit.

The patented down hole vibration sensor resides in a module that is installed in the shank of the bit as shown in Figure 5. This allows dynamic dysfunctions to be captured and stored in the forms of background data and burst files. Background data is constantly recorded, and burst files consisting of five second, high frequency data bursts are captured at regular intervals throughout the entire run. The device measures axial, lateral, and torsional vibrations through the use of multiple accelerometers. Temperature and RPM measurements are also captured with the module. Proven algorithms convert these raw measurements into average and g-RMS values in order to identify drilling dysfunctions such as bit bounce, whirl, and stick-slip.

The vibration sensor was utilized in a PDC drill bit used in an offset well. The data revealed multiple instances of stick-slip throughout the course of the run as shown in Figure 6. When the bit transitioned from the Clearfork to Lower Spraberry formation the bit experienced more severe levels of stick-slip. The five second burst files revealed large RPM fluctuations accompanied with spikes in lateral vibration, which occurred during the “slip” phase. Figure 7 illustrates one of these occurrences of stick-slip. Soon after the bit experienced these high levels of stick-slip, it was pulled for penetration rate, and, the dull exhibited the same failure modes identified in previous runs (Figure 8).

Overview of Hybrid Bits

The Kymera™ (Figure 9) is a hybrid bit designed by Baker Hughes that combines both roller cone and PDC technology for smoother drilling, remarkable torque management and precise steerability. It combines the efficient PDC cutting mechanism in soft formations and the rock crushing strength and stability of roller cones in hard or interbedded formations. The end result is a bit that can efficiently drill in a variety of applications with enhanced performance. Kymera™ bits have recently entered the Permian Basin to take advantage of its unique cutting mechanisms of first crushing rock with the roller cone elements, followed by the PDC shearing a pre-fractured formation more efficiently.

Kymera™ bits have shown great success in applications with hard, interbedded formations where bits experience

damaging torque and vibration. The added stability increases ROP potential by delivering lower torque fluctuations and lateral vibrations as the bit transitions through interbedded formations. More weight on bit and differential pressure may be applied for higher ROP without generating deviation issues that a regular PDC drill bit may experience. PDC bits can be more prone to stick slip, torque fluctuations affecting ROP, premature bit wear, and down hole tool and motor failures, even with lower WOB and differential pressure.

Initial Findings and Optimization

Case Study 1

For Case Study 1, an existing Kymera™ bit design was ran on the standard BHA for the area. The design featured 19 mm cutters with large chamfers and a heavy-set cone cutting structure. The bit was ran on a pendulum BHA with five 8 inch drill collars and fourteen 6 inch drill collars. Parameters consisted of 25-50 klbf WOB and 70-100 RPM. The bit was pulled at a depth of 2,714 feet due to penetration rate and the dull was a 0-1 (Figure 10).

Penetration rates of the hybrid bit were more weight sensitive than PDC offsets, and the hybrid ROP never reached above 150 ft/hr unless WOB exceeded 45 klbs. PDC offsets drilled the same interval 25% faster with less WOB applied. The performance disparity was more visible in the softer formations, especially when the hybrid WOB was less than 45 klbs. Figure 11 shows the instantaneous ROP disparity in the Seven Rivers was around 130 ft/hr. At this point, the hybrid WOB was around 35 klbs. When the hybrid WOB was increased to 50 klbs, the instantaneous ROP difference was reduced to 60 ft/hr.

Hybrid torque fluctuations were considerably lower than the PDC offsets throughout the interval, even though more WOB was applied throughout the run. PDC torque fluctuations exceeded 5,000 ft-lbs while hybrid torque fluctuations were around 1,000 ft-lbs. Figure 12 compares the ROP, WOB and torque signatures in the San Andres, showing the hybrid bit experienced reduced torque fluctuations with similar rates of penetration and higher WOB.

Although the hybrid bit was ultimately pulled for penetration rate, the excellent dull condition and reduced torque fluctuations showed indications of improved dynamic dysfunction compared to PDC bits. The hybrid bit's response to increased weight on bit demonstrated the need to utilize a BHA designed to deliver at least 50 klbs to the bit without buckling.

Case Study 2

Taking the lessons learned from Case Study 1, the following run was planned in advance in order to achieve success. A collaborative effort between Baker Hughes and Apache Corporation resulted in a new BHA design to maximize the possibility of a successful one bit run. The resulting BHA design was a packed assembly consisting of two 12-1/8 inch IBS, one 11 inch IBS, eleven 8 inch drill collars, and eighteen 6-1/2 inch drill collars. The BHA did not

utilize a motor. A new bit design consisting of 19 mm cutters with smaller chamfers, three blades and three cones with more aggressive cutting structures was utilized. Drilling parameters consisted of 50-60 klb WOB and 80-90 RPM on the rotary. The more aggressive bit design coupled with stiffer BHA allowed the interval to be drilled with one bit at a higher overall ROP than an average PDC in the area of interest.

A down hole vibration sensor was installed in the bit to analyze and compare down hole drilling dynamics to offset PDC runs. Lateral vibration severity levels remained around Level 2 and did not exceed Level throughout the run, as shown in Figure 13. The reduced vibration levels verified that the Kymera™ has an enhanced lateral stability when compared to a standard PDC bit.

When analyzing torsional vibration levels, in particular stick slip, the results were very satisfactory. Stick slip severity levels were not as high as PDC offsets, but at times would reach Level 5, as seen on Figure 14. Analyzing the burst files revealed that even when high torsional vibrations were observed, this vibration was not considered true stick slip, because there were no drastic changes in RPM, as proved by Figure 15. Due to the combination of roller cone and PDC technology, the Kymera™ has a different drilling dynamic from what is observed in other standard bit types. The torsional vibrations observed were a type of whirl that is very common to roller cone bits, and is not considered harmful to the performance of the Kymera™.

The hybrid bit completed the interval, and showed improved stability compared to a PDC even though higher WOB was applied throughout the run. Overall vibration levels were lower, and the Kymera™ dull exhibited one chipped cutter in the shoulder, as seen on Figure 16. The combined effort of designing a stiffer BHA and utilizing a more aggressive bit contributed to the successful run. The 12-1/4 inch intermediate section was completed in one fast run, drilling 5071 feet with an average ROP of 87ft/hr.

Case Study 3

After the successful run in Case Study 2, a similar strategy was utilized on the same pad-site on a well drilled 60 feet from the previous well. The same aggressive Kymera™ was used, but the bottom hole assembly design was changed to use a 9 ½ inch straight low speed/high torque motor in addition to the two 12-1/8 inch IBS, one 11 inch IBS, eleven 8 inch drill collars, and eighteen 6 ½-inch drill collars. This change was made in order to provide more horsepower to the bit. The parameters consisted of 50-60 klb WOB, 40-60 RPM on the rotary and 60 RPM on the motor, totaling 100-120 RPM at the bit.

A down hole vibration sensor was used again to analyze and compare drilling dynamics to the previous Kymera™ run in Case Study 2 and the PDC offset. Lateral vibration severity levels throughout the run remained around Level 1 (Figure 17). No vibrations above Level 2 were observed during the run, proving once again that the Kymera™ has an enhanced lateral stability compared to a standard PDC bit. Also, when compared to the Kymera™ run on a conventional BHA, lateral

vibrations were significantly lower showing increased lateral stability with a motor added to the BHA.

As in Case Study 2, torsional vibration levels in particular stick slip, were improved when compared to PDC offsets. Overall, torsional vibrations were low, but severity levels reached Level 5 occasionally during the run. While drilling through the Grayburg from 1,750 feet to 1,850 feet, occurrences of stick slip were observed in the burst files, as seen in Figure 18. However, the severity levels were lower than PDC offsets when the bit was transitioning from the Clearfork into the Upper Spraberry. The final burst file was recorded within the last 200 feet of the run. Stick slip was observed in higher levels (Figure 19), but lateral vibrations in the “slip” phase were lower when compared to PDC offsets.

Vibration levels were lower, and even though stick slip was experienced at times, it was not the same levels of PDC bits. The Kymera™ dull exhibited three broken cutters on one blade, as seen on Figure 20. The addition of a motor to the BHA appeared to reduce lateral vibrations and increase torsional vibrations when comparing the run to Case Study 2. The 12-1/4 inch intermediate section was completed in one fast run, drilling 5,480 feet with an average ROP of 101 ft/hr.

Results

Figure 21 – Figure 25 demonstrate the improvement in drilling time by utilizing Kymera™ bits for the 12-1/4 inch intermediate section. While running a motor provided a positive impact in some units, others saw little to no difference when compared to running a Kymera™ without a motor.

Figure 26 shows the average number of Kymera™ bits used to drill the intermediate interval per Unit compared with PDC offsets.

Although Kymera™ bits required much higher WOB than PDC bits to achieve good performance, hole deviation was not an issue as seen in Figure 27.

Cost per foot was positively impacted when running a Kymera™ bit, even though the upfront cost of the bit was considerably higher than PDC bits (Figure 28). Although the Kymera™ completed the intermediate interval with one bit, it was not as cost effective in Unit E as the other four units.

Graphics

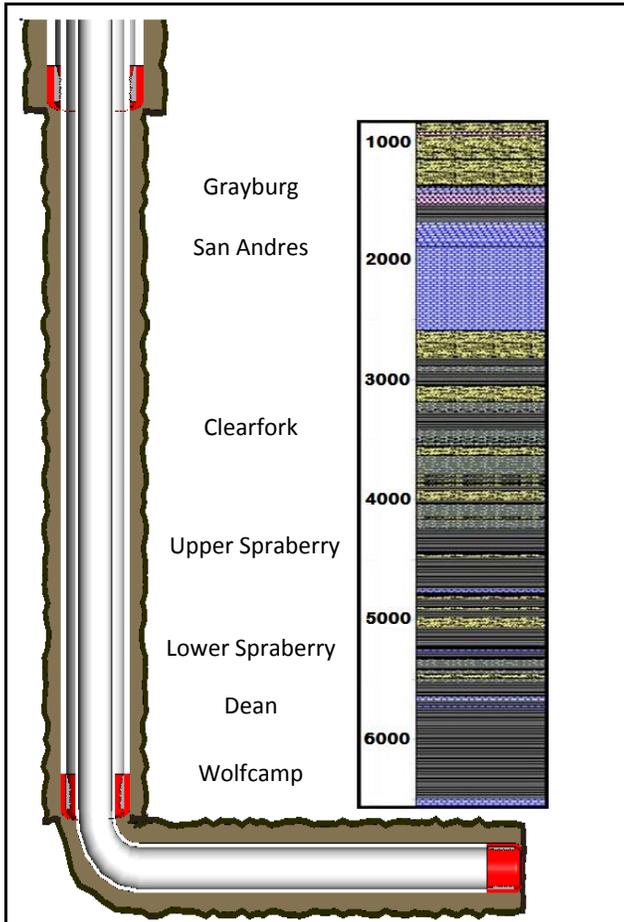


Figure 1: Schematic for Wells Drilled in Area of Interest



Figure 3: Typical PDC Dull in Area of Interest

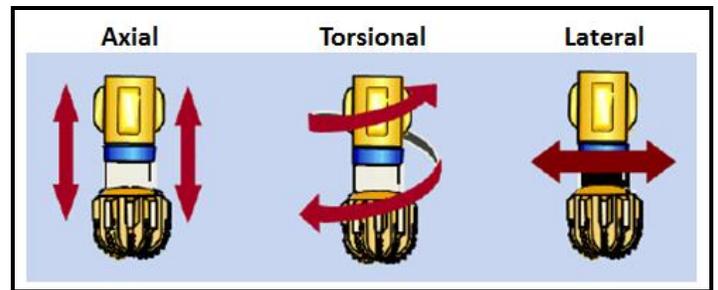


Figure 4: Illustration of Drill Bit Vibration Modes

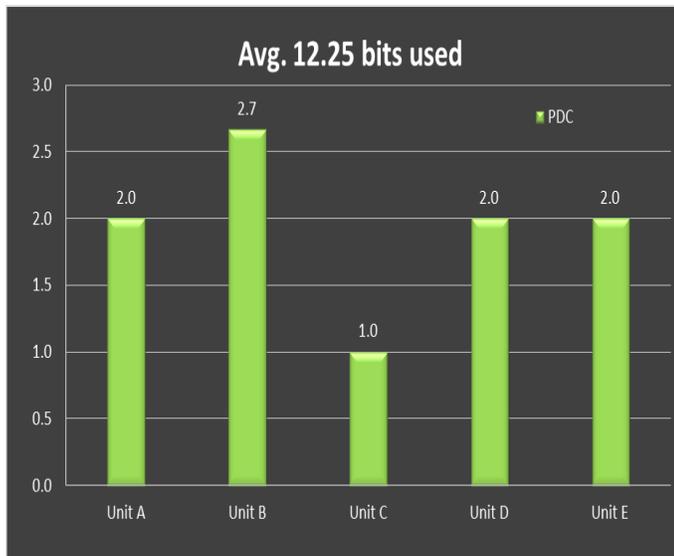


Figure 2: Average Number of PDC Bits Required to Drill Intermediate Interval by Units in Area of Interest

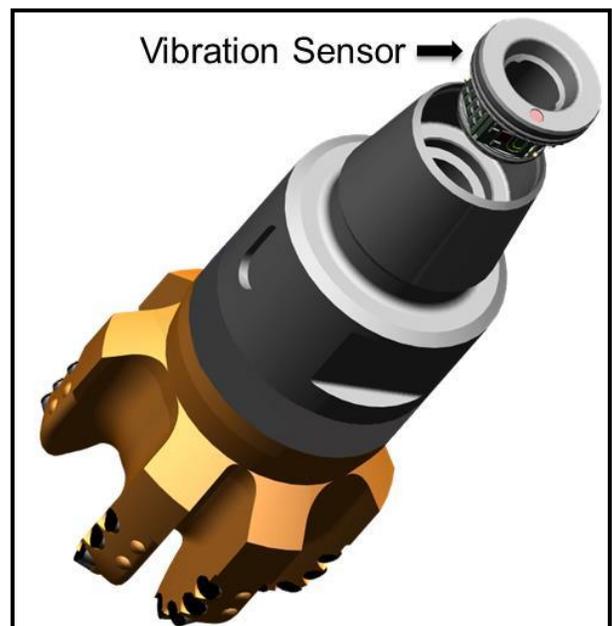


Figure 5: In-bit Vibration Sensor Located in Drill Bit

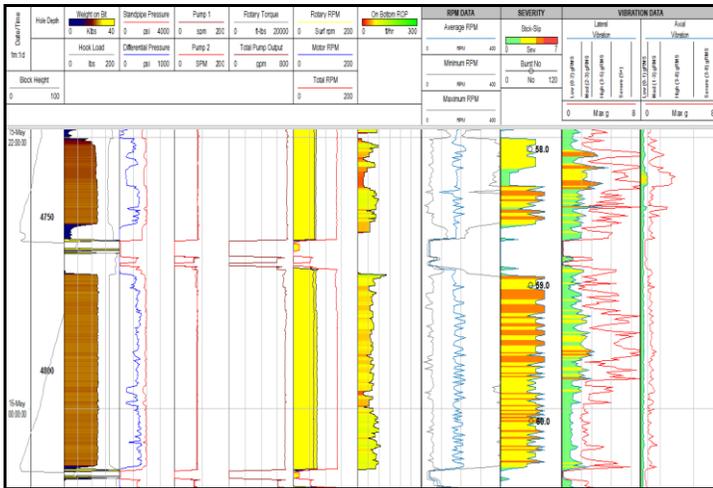


Figure 6: Data Display for In-Bit Vibration Sensor During a PDC Run

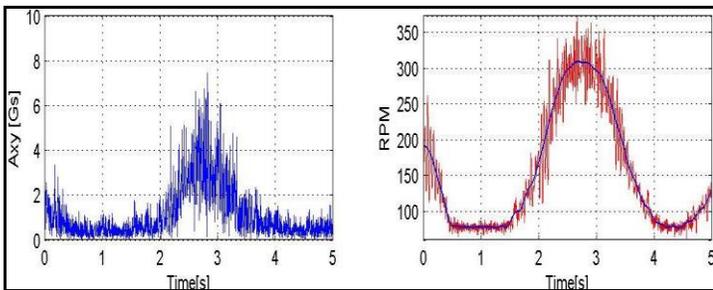


Figure 7: Burst Data During Period of High Stick Slip Severity



Figure 9: Picture of Kymera

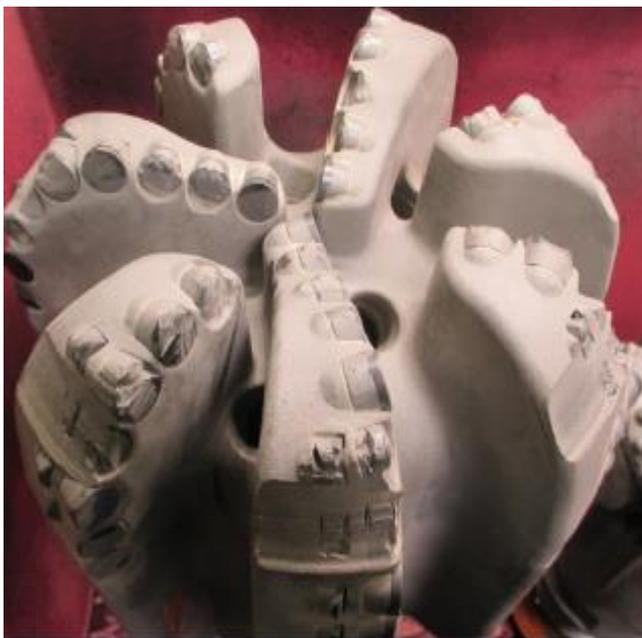


Figure 8: Dull of Bit Run with Vibration Sensor



Figure 10: Kymera Dull in Case Study 1

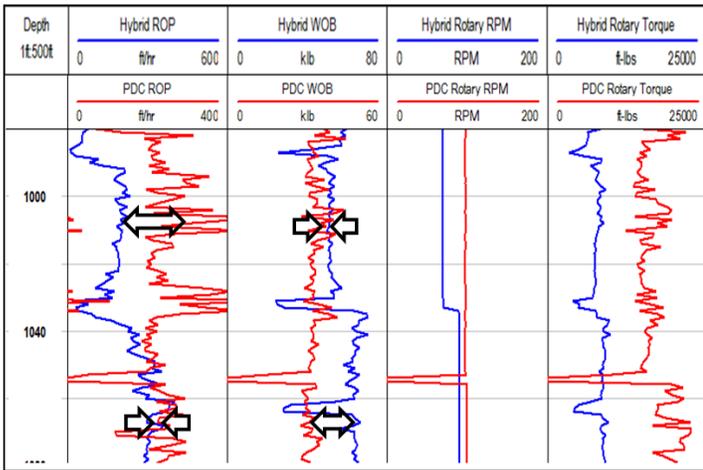


Figure 11: Hybrid vs. PDC ROP and WOB Differences

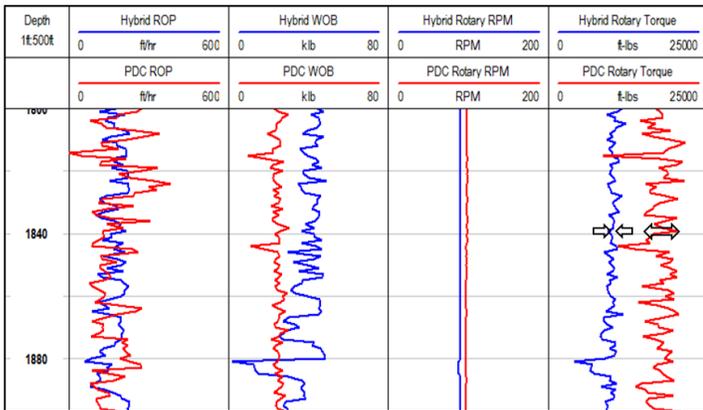


Figure 12: Hybrid vs. PDC Torque Fluctuations

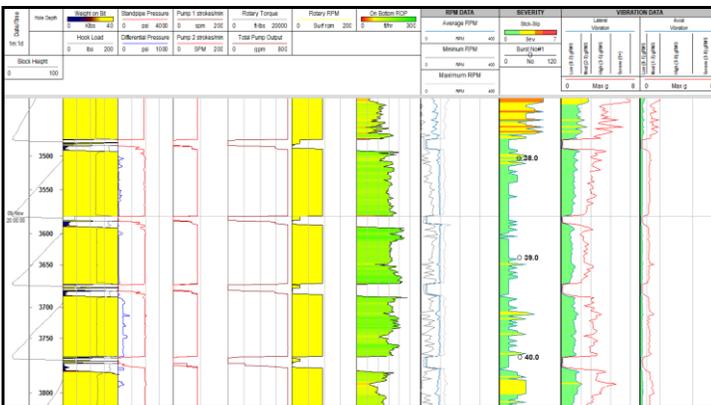


Figure 13: Lateral Vibration Data from Vibration Sensor During a Kymera™ Run in Case Study 2

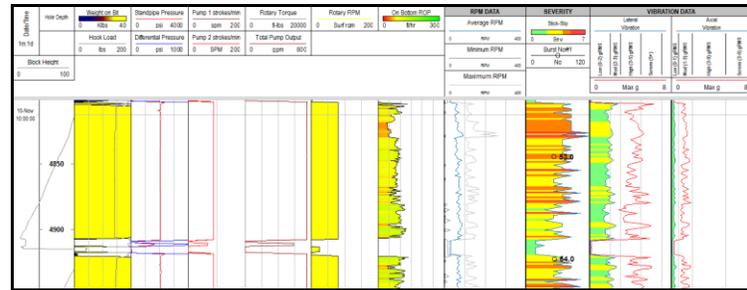


Figure 14: Stick Slip Data from Vibration Sensor During Kymera™ Run in Case Study 2

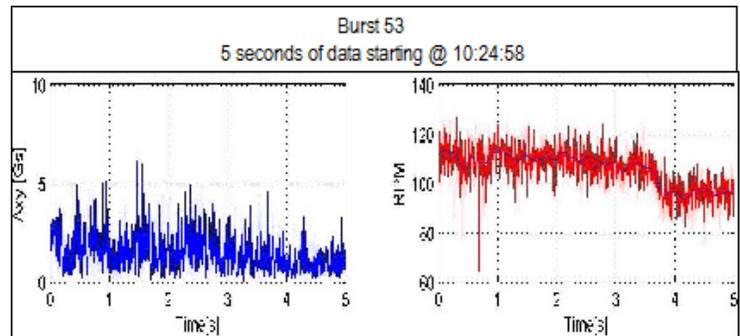


Figure 15: Burst Data During Period of High Stick Slip Severity



Figure 16: Kymera Dull in Case Study 2

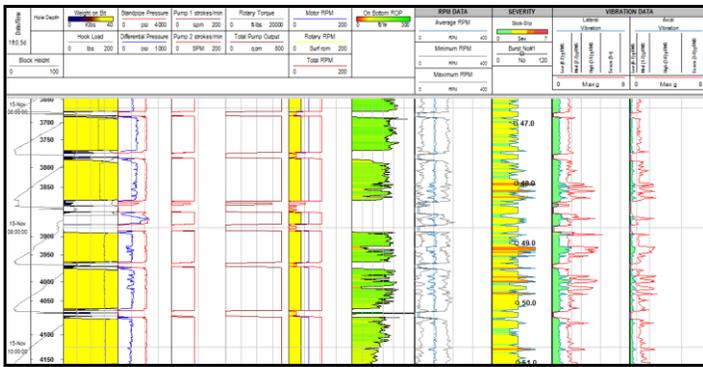


Figure 17: Lateral Vibration Data from Vibration Sensor During a Kymera™ Run in Case Study 3

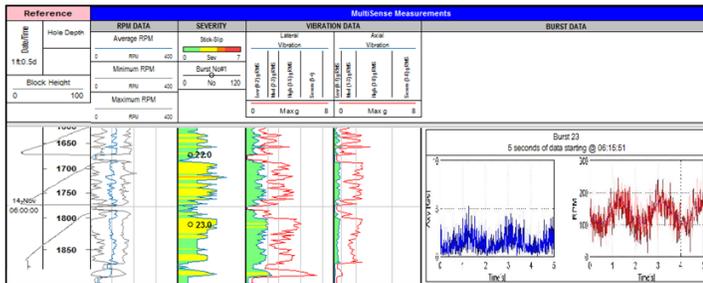


Figure 18: Stick Slip Data from Vibration Sensor During Kymera™ Run in Case Study 3

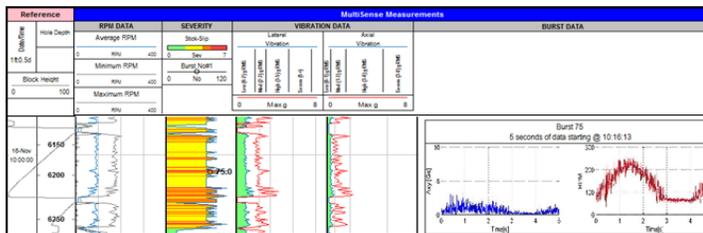


Figure 19: Stick Slip data from vibration sensor during Kymera™ Run in Case Study 3



Figure 20: Kymera™ Dull in Case Study 3

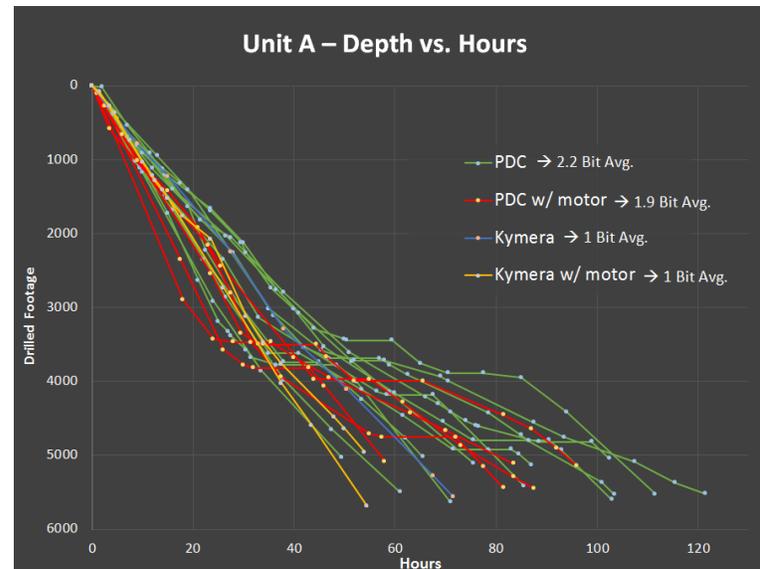


Figure 21: Depth vs. Hours Charts of Kymera™ Runs Compared to PDC Offsets for Unit A

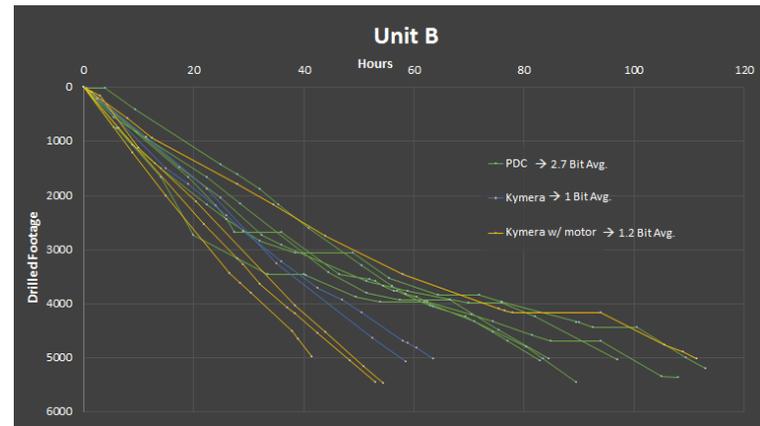


Figure 22: Depth vs. Hours Charts of Kymera™ Runs Compared to PDC Offsets for Unit B

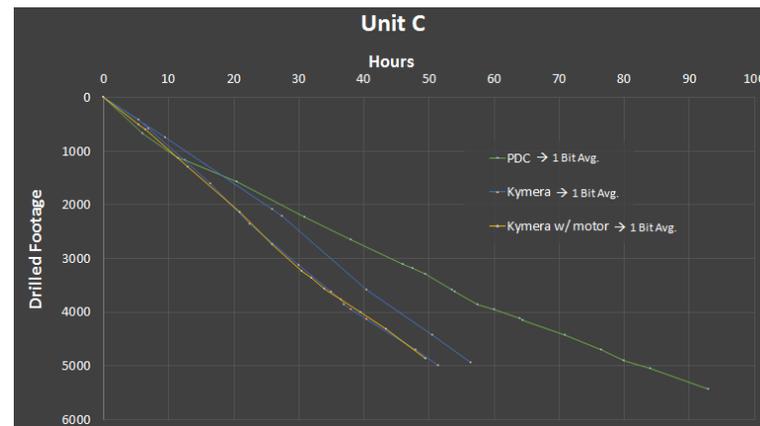


Figure 23: Depth vs. Hours Charts of Kymera™ Runs Compared to PDC Offsets for Unit C

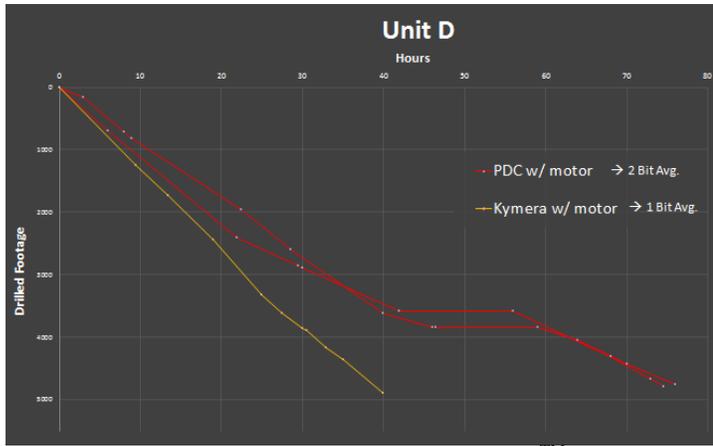


Figure 24: Depth vs. Hours Charts of Kymera™ Runs Compared to PDC Offsets for Unit D

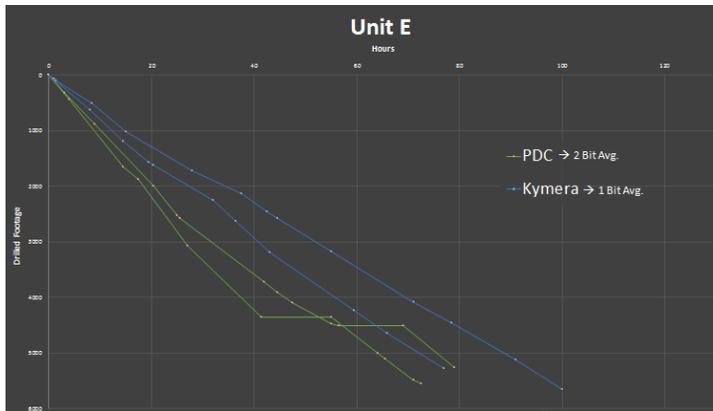


Figure 25: Depth vs. Hours Charts of Kymera™ Runs Compared to PDC Offsets for Unit E

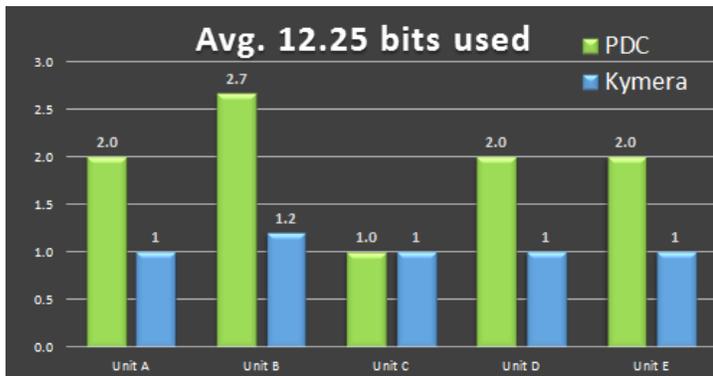


Figure 26: Average Number of Kymera™ Bits Required to Drill Intermediate Intervals vs. PDC Offsets for All Units

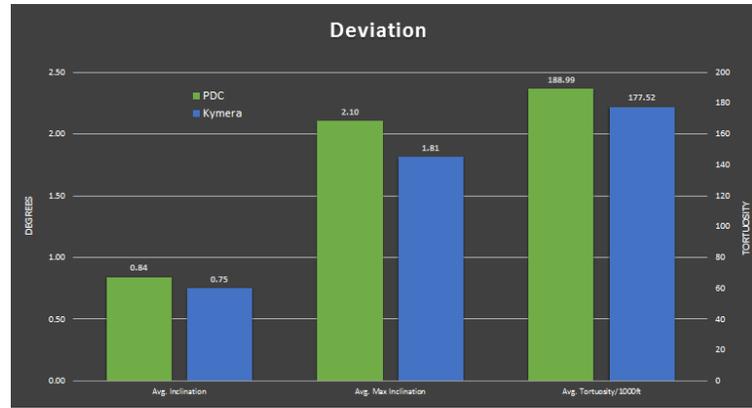


Figure 27: Comparison of Hole Deviation and Tortuosity of Kymera™ Bits vs. PDC Offsets

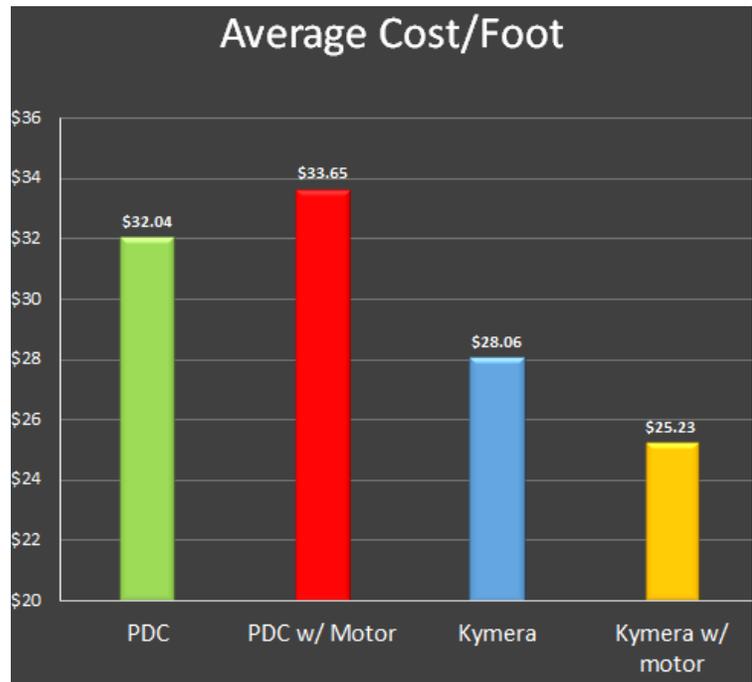


Figure 28: Cost per Foot Comparison of Kymera™ Bits vs. PDC Offsets for All Wells Drilled in Area of Interest

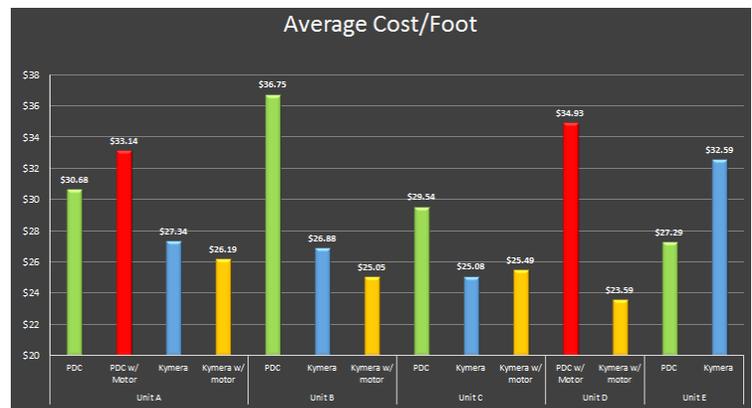


Figure 29: Cost per Foot Comparison of Kymera™ Bits vs. PDC Offsets per Unit

Conclusions

- Although the upfront cost is considerably higher than a PDC bit, the Kymera™ bit provides a lower cost per foot for drilling the 12-1/4 inch interval in the area of interest.
- In the planning phase, it is important to understand the economic breakeven point for running a Kymera™ bit in order to establish performance requirements.
- In order to achieve the required performance of a 12-1/4 inch Kymera™ bit, it is essential to utilize an appropriate BHA designed to take up to 70 klbs WOB without buckling.
- Even though PDC performance is crucial to offsetting today's well costs, certain hole size drilling characteristics cause significant detrimental vibrations, such as stick slip and whirl. Given the drilling dynamics of a hybrid bit in the same environment, not only were significant improvements made in vibration mitigation, but the durability and resulting ROP's helped sustain some of the fastest 12-1/4 inch intervals to date.
- While use of a motor may have a profound impact on the performance of a PDC bit, the cutting mechanics of a hybrid bit cause it to react more to WOB than increased horsepower from an independent energy source.
- The Kymera™ bits ran without a motor experienced less stick slip than the bits ran with a motor.
- Kymera™ bits experience less torque fluctuations as they drill through interbedded formations than PDC offsets.
- Kymera™ bits do not experience hole deviation issues when ran on a stable BHA, even though high WOB is required to maintain fast ROP.

Acknowledgments

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Nomenclature

<i>BHA</i>	= <i>Bottomhole assembly</i>
<i>ROP</i>	= <i>Rate of Penetration</i>
<i>Unit</i>	= <i>Grouping of Wells on a Single Lease</i>
<i>RPM</i>	= <i>Revolutions per Minute</i>
<i>WOB</i>	= <i>Weight on Bit</i>
<i>PDC</i>	= <i>Polycrystalline Diamond Compact</i>
<i>UCS</i>	= <i>Unconfined Compressive Strength</i>
<i>TD</i>	= <i>Target Depth</i>
<i>IBS</i>	= <i>Integral Blade Stabilizer</i>

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