



IADC/SPE 98962

A New Approach to Stick-Slip Management Integrating Bit Design and Rotary-Steerable-System Characteristics

M.R. Niznik and A.D. Carson, ExxonMobil Development Co.; K.J. Wise, Schlumberger; and F. Carson, ReedHycalog

Copyright 2006, IADC/SPE Drilling Conference

This paper was prepared for presentation at the IADC/SPE Drilling Conference held in Miami, Florida, U.S.A., 21–23 February 2006.

This paper was selected for presentation by an IADC/SPE Program Committee following review of information contained in a proposal submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the International Association of Drilling Contractors or Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the IADC, SPE, their officers, or members. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the International Association of Drilling Contractors and Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 1.972.952.9435.

Abstract

North Sea fields continue to benefit from improvements in PDC bit and rotary steerable technology. There are, however, ongoing issues in these fields relating to very hard inter-bedded formations that result in stick-slip, bit and bottom hole assembly (BHA) wear, shocks / vibration, tool failures, and short run lengths.

Rotary steerable systems (RSS) are essential to drill the challenging well paths. Push-the-bit RSS tools were first employed along with early versions of point-the-bit systems; all suffered premature tool failures due to tool wear and extreme shocks and vibration attributable to excessive stick-slip. Tool and BHA modifications to increase ruggedness, have led to longer runs and reduced shocks / vibrations in the harsh drilling environments.

PDC bits are utilized and there has been an evolution in cutter technology and bit design. The PDC cutters have higher wear resistance and are able to drill formations that were previously not PDC drillable. Bit designs evolved as RSS tools have changed: point vs. push-the-bit systems. The new point-the-bit systems require modifications to bit gauge designs. High stick-slip and vibration are the main constraints to performance but are greatly reduced by designing the bit to complement the RSS.

This paper will build on previously published data showing how modifications to bit designs (based on the steering characteristics of RSS tools), and modifications to operating parameters of the RSS tools (based on the characteristics of PDC bits) have been brought together for the first time to yield a significant improvement in drilling performance. Results from initial test runs in one field were then incorporated in the plans for another field yielding similar improvements in performance.

This paper will offer both the specific details of how the integration of the bit and RSS characteristics was achieved in this example as well as more generic principles for wider application.

Introduction

BHA and bit technologies have progressed out of necessity due to spiraling drilling costs in the North Sea. Tool failures and short run lengths are all too common in the hard, abrasive and inter bedded formations found in North Sea fields. These failures and short run lengths are often a result of stick-slip along with shocks and vibration.

In order to understand how stick-slip, shocks and vibrations are generated, and their location in the drilling assembly, both bit and BHA need to be considered. Shock / vibration monitoring sensors are incorporated in the BHA to measure and locate lateral, torsional, and axial shocks / vibration. Drill bit design with inherent stability is a primary focus of bit manufacturers.

Redesigning and enhancing specific BHA and bit characteristics can then achieve performance improvements. Integrating BHA and bits has yielded substantial improvements, which are discussed later in this paper. These physical improvements along with optimizing operational practices are further minimizing stick-slip, shocks / vibration.

Within this paper, specific details on BHA progression followed by bit progression are presented. Evidence of findings is then supported by case studies demonstrating successful bit and BHA integration. Areas for future development are then covered along with conclusions.

BHA Progression

Point-the-bit and push-the-bit RSS tools from all service providers have been utilized in the Beryl area. Directional well difficulty is always increasing in brownfield applications such as Beryl due to the small number of available slots and ever decreasing target sizes. It is widely recognized that to match this increased drilling difficulty, it is essential that BHA strategy, tool design, and bit selection must be continuously improved in order for the wells to remain financially viable drilling options.

Schlumberger is the current directional drilling, MWD and LWD contract holder, initially providing push-the-bit systems

during the drilling of 8-½" sections. Improvements over previous systems have resulted; with regard to drilling performance (feet drilled against circulating hour), this has been further improved with the introduction of a point-the-bit system.

The BHA design was continuously modified and improved using an integrated approach of analyzing the problems encountered, in both real-time and post well, with evaluation of all available performance data. Real-time downhole data was used to adjust drilling parameters in an effort to mitigate or reduce shock levels and avoid compromising BHA longevity. The first steps in this process were to evaluate the drilling dynamics. The chart (Appendix 1 - Drilling Dynamics) was taken from well B60; at this stage, detailed shock / vibration data was not being fully utilized.

The basic shock measurements gave an indication that the BHA and bit were under-going severe loadings. There were periods of good ROP where directional response was maintained, highlighting that BHA and bit functionality was improved over previous runs. More analysis of the dynamics was required, so a 4-axis shock cartridge was run in conjunction with the standard MWD / LWD tools. This provided shock and vibration data including shock peaks, shock risk over 50g, axial shocks, lateral shocks, torsional shocks and stick-slip variations. The increased number of measurements (Appendix 2 - Drilling Dynamics: Push-the-bit System, Beryl Area) highlights the high levels of torsional shocks and medium to high-level stick-slip.

Increased loads are the result of formations encountered while drilling hard and abrasive inter-bedded zones^(1,2). The Tertiary, Cretaceous, Jurassic, and Triassic sands and shales are of medium compressive strengths (5,000-20,000 psi), but they are inter-bedded with multiple high compressive strength limestone stringers (up to 80,000 psi) including some with pyrite nodules. A detailed description of Beryl area stratigraphy is included in Appendix 3. These hard inter-bedded stringers have resulted in excessively high wear in the tools along with vibration-induced failures. Simple BHA modifications included the introduction of rolling contact points (roller reamers) in the upper BHA and stabilizers to reduce the amount of lateral movement. At the same time, redesign of the bias unit (pushing element) was carried out. This included redesign of the retention system and introduction of different metallurgy for specific components.

Detailed analysis was carried out both onshore and offshore using the No Drilling Surprises* (NDS) service in conjunction with ExxonMobil** drilling engineers at the wellsite⁽³⁾. By having the same people analyze the data that were planning wells and visiting the well site, a continuous closed loop input and evaluation was carried out. The NDS service was introduced to the project during the initial evaluation of the rough drilling problems encountered.

The next step was the provision of the point-the-bit system which is specifically designed for tougher drilling environments making it more suitable for the Beryl area. Further bit enhancements and BHA modifications had an

immediate impact on the damaging torsional shock, which were reduced to a manageable low level (Appendix 4 - middle chart).

Following on from improvements to the dynamic environment, several steps were taken to reduce stick-slip. The drilling parameters have been continuously evaluated, and the use of high RPM (>200) had a significant effect on stick-slip with no adverse effect on lateral shocks. This is illustrated in Appendix 5 (Drilling Dynamics: Point-the-bit System, Increased RPM). There is a direct correlation with the offset well as detailed in case study 2.

Bit Progression

Formations such as the Maureen (a sequence of Tertiary marls with hard interbedded limestone stringers) have traditionally been non-PDC drillable. By utilizing Thermostable PDC cutters, bits have become more abrasion and wear resistant, and the Maureen is now routinely drilled with PDC bits. Previously, heavy set bits with high blade counts (>7) and a high density of small PDC cutters were used. Now, 6 blades and 16mm cutters are in the basic bit design. This gives the required point loading to breakdown the formation while still maintaining the durability to give an extended run length^(4,5).

The first bits used were 8-bladed, 16mm and 13mm cutter designs. The observed stick-slip was difficult to mitigate; reduced weight on bit (WOB) to combat stick-slip also limited the ROP, and level 3 shocks were recorded on RSS systems and MWD tools. The dull conditions indicated there was adequate durability in this design and that an 8 bladed design was not necessary for these applications.

The decision to drop two blades and move to a 6-bladed design was taken for the following reasons:

- A more aggressive cutting structure results in less torque for a given WOB.
- Increased aggression requires less weight to achieve an acceptable depth of cut and hence ROP allowing stable drilling with reduced stick-slip (Figure 1 below).

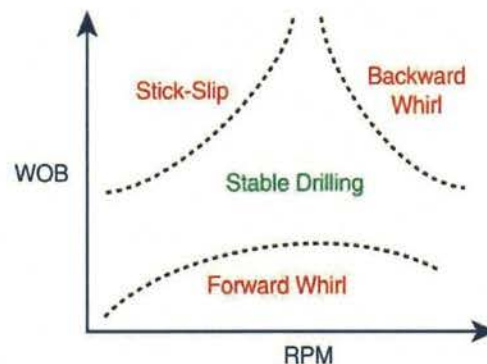


Figure 1 - Stable Drilling: WOB vs. RPM

The 6-bladed, 16mm design with an active cutting structure at gauge was selected and run on a push-the-bit system. This bit

had new generation Thermostable PDC primary cutters and non-planar interface backup cutters. A consequence of this first configuration was the bit returning a dull of 1-4-WT-T-X-IN-CT-TD after drilling 3,609 ft at 87 ft/hr – an excellent performance in terms of ROP and durability. Wear flat development on the shoulder may have contributed to shocks towards TD.

The wear on the shoulder was a concern so Thermostable PDC cutters were used for both the primary and backup cutters on the next run. The expectation was that a more even wear pattern would be observed and sharper cutters requiring less weight would initiate less stick-slip.

This version drilled a similar interval (3,760 ft) and was dull graded 2-2-WT-A-X-IN-CT-PR. Reduced shocks and vibration were observed, though stick-slip and shocks were seen towards TD. This reduction in overall shocks was the result of slower development of wear flats which require the application of greater WOB to maintain ROP. The more even wear pattern was observed as predicted (Figure 2 below).

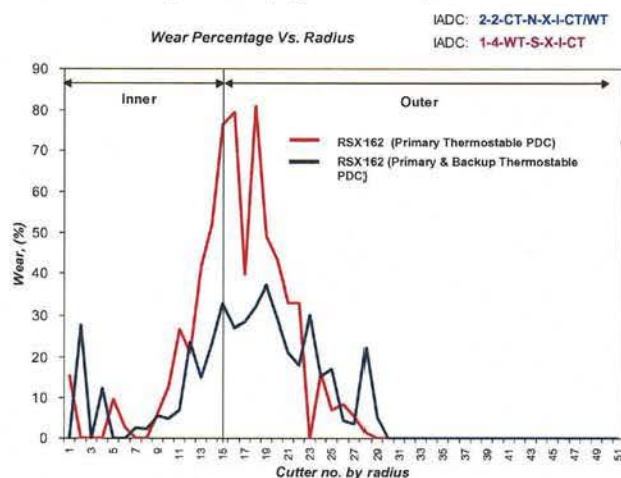


Figure 2 - Wear Percentage vs. Radius

A move to the point-the-bit system occurred at this time and required a different selection criterion. The active gauge set was not considered suitable, so a dual action gauge configuration was adopted (one that is selectively active or passive depending on tool settings). This was expected to deliver good directional control and drilling dynamics as a result of reduced torque at the bit gauge / wellbore interface. This bit design variant then drilled 3,305 ft and was pulled for an undergauge stabilizer that was beginning to cause steering problems. It was dull graded 1-2-CT-N/S-X-IN-WT/ER-BHA. Stick-slip was observed within the interval drilled, but the use of equipment to adjust surface torque reduced stick-slip and downhole vibration.

Based on encouraging results with this bit design, it was proposed that a higher cutter back rake version would reduce stick-slip further by reducing torque fluctuations in interbedded formations. A theoretical reduction in rate of penetration (ROP) was anticipated due to the reduced cutter aggression.

This design variant drilled 2,825 ft at 34 ft/hr (versus 59 ft/hr with previous design). The bit did not generate significant shocks in the 83 hours drilling. Higher weight on bit (WOB) was required due to the less aggressive nature of the bit, and this resulted in increased stick-slip even though shocks were low. Due to this reduction in ROP, it was decided not to run this bit design again and to continue with the previous standard aggressive cutting structure.

The next step of development was the introduction of a tapered-gauge concept. This idea was born from the realization that the point-the-bit system orientates the bit at an angle of 0.6 degrees. A taper was applied to the gauge of the bit to exactly match this angle (Figure 3 below).

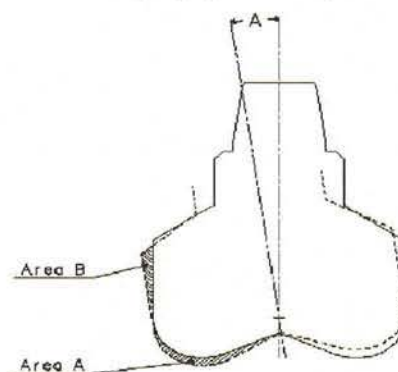


Figure 3 - 0.6 degree Taper

Tapering the gauge avoids the frictional resistance produced in deviated drilling which can result in fluctuations in torque and instability. The tapered geometry achieves this by eliminating the impingement of the trailing edge of the gauge pad with the wellbore while maintaining dogleg capabilities of a standard design.

These latest enhancements in drill bit design together with BHA improvements and a systematic approach to stick-slip and vibration management resulted in a step change in drilling performance.

This performance improvement is the focus of the following case studies.

BHA and Bit Integration: Case Studies

CASE 1

The first run of a tapered-gauge 8-1/2" PDC bit with a point-the-bit system was on a platform well, 9/13a-B65z. The bit drilled out the shoe track and went on to drill the Maureen and Shetland formations (refer to Appendix 3 for formation information) where a trip was planned to pick up LWD tools. This assembly drilled 4,192 ft of Maureen and Shetland formations in 4.19 days at an average of 138.8 ft/hr and was still drilling at 90 ft/hr before being pulled at the planned trip depth. It was graded 1-1-CT-T-X-In-WT-BHA. During the run, stick-slip levels were significantly lower than previously observed. This was aided by the use of higher rotary speeds than had been used before (up to 200 RPM).

This performance set a new 24-hour footage record for the Beryl area of 2,619 ft (higher than the previous record of 1,543 ft). A second record was achieved: the average daily footage record over entire run of 1,001 ft/day. This included trips and broke the previous record which stood at an average of 906 ft/day.

The same tapered-gauge bit was re-run, drilling a further 277 ft at 36.8 ft/hr to TD the section. Overall, it drilled 4,469 ft at an average ROP of 118.4 ft/hr.

CASE 2

Further evaluation of the tapered gauge 8-1/2" bit took place directly after Case 1 on a subsea well drilled with a semi-submersible rig. The first assembly run used a non-tapered bit design with a point-the-bit system. This resulted in high stick-slip, whirl and tool joint wear. Subsequent BHA modifications, in addition to the tapered-gauge bit design, included 15 stands of 5-1/2" drillpipe added to the bottom of the string of standard 5" drillpipe and a second roller reamer. Both these modifications were to stiffen the assembly reducing whirl and stick-slip. The increase in drill pipe size has only been applied to this well, hence the conditions have not been repeated to allow further evaluation.

The run drilled 2,277 ft of high compressive strength sandstone (Cormorant formation, refer to Appendix 3) at 392 ft/day. There was a 16% increase in ROP from the earlier run and had reduced stick-slip / BHA component wear (see Appendix 5 of stick-slip in 65 pilot hole in light blue vs. 65y production hole in pink). The bit was graded 2-4-WT-N-X-IN-NO-TD. This was the longest Cormorant formation interval drilled in the Beryl area.

Subsequent to Case Studies 1 and 2, this tapered-gauge bit design has been run as standard on all 8-1/2" holes involving the use of point-the-bit systems. The data collected shows that this bit has consistently produced lower vibrations. This has led to more uninterrupted on-bottom drilling time giving high ft/day average ROPs and leading to longer bit runs (less damage to bit and drilling assembly). The string has been rotated up to 200 RPM throughout the runs; this was not previously possible without inducing whirl. This high RPM has reduced stick-slip significantly. The following tabulated data (Figure 4) shows the significant stick-slip reduction achieved within the cormorant formation:

Stick Slip	Run 1	Run 2	Run 3
8 1/2" BIT TYPE	Non Taper	Non Taper	Taper
Tight Cormorant	201		89
Cormorant	224	201	73
Run Avg Stick Slip	223	201	73
SRPM	160	167	186
Stick Slip Ratio	1.39	1.20	0.39
Total Footage	2391	797	2277
Average ROP	34.9	27.9	31.6
Drive System	Point bit	Point bit	Point bit
Rig Torque Suppressor	Yes	Yes	No

Figure 4 - Stick-Slip: Tapered Gauge vs. Non-Tapered

Next Steps

Bit Related: The current tapered-gauge bit design in use has a 1.75" gauge length. At time of writing, it is planned to evaluate a 2.5" tapered-gauge length bit design. If this proves successful then the gauge length may be further extended until an optimal length is found taking into account dogleg requirements. The longer gauge should help restrict the bit in the hole and further enhance bit stability. However, with the unique design of the specific point-the-bit system, it is uncertain whether or not a longer gauge will improve stability. In addition, improved stability may be achieved by incorporating a ring of contact at the gauge.

Previously a 4" gauge (non-tapered) bit design was run on the point-the-bit system however overall results in the Beryl area have shown higher reliability and steerability with shorter gauge length bits. Note: in other areas, longer gauge length bits have been run without issue.

A limited number of runs have been carried out using a tapered-gauge bit design on a 12-1/4" push-the-bit system. These runs have shown lower vibrations and improved drilling performance. Further runs are needed to fully understand the interaction between the push-the-bit system and the tapered-gauge bit design. The 12-1/4" push-the-bit system applies a small tilt-angle to the bit when the tool is in biasing mode. It was proposed that applying a taper of a similar angle to the gauge pad of the bit would decrease the wellbore contact at the rear of the pad, thereby reducing torque and lessening stick-slip. It was suggested that this would promote more efficient drilling and increase ROP.

Initial results have been encouraging showing improved stability, ROP, and durability of the bit. This was particularly clear once the data was analyzed by formation interval drilled. Evidence of this is presented in the following Figures 5-7:

	NWB2 (66z) A6		NWB1 (66) A10				NWB1 (66x) A10	
	Heimdal I	Maureen	Heimdal I	Maureen	Near Crest	Jorsalfaro	Heimdal I	Maureen
Stick Slip Average	0.66	1.32	0.74	0.64	1.07	1.24	0.67	0.86
A10 Stick Slip compared to A6			-22%	-52%			-8%	-35%
Run Average	1.12		0.62				0.87	

Figure 5 - Stick-Slip Reduction Across Formations

	NWB2 (66z) A6			NWB1 (66) A10				NWB1 (66x) A10		
	Heimdal I	Maureen	TD	Heimdal I	Maureen	Near Crest	Jorsalfaro	TD	Heimdal I	Maureen
Top ft MO	7471	8320	8736	7586	8409	9264	9442	9552	7604	8252
Interval ft	849	416		823	855	178	110		646	429
Avg WOB	8.7	13.6		9.4	14.0	20.0	25.6		5.9	7.7
Avg RPM	139	132		133	130	136	133		145	141
ROP ft/hr	52.9	27.4		95.5	59.9	12.9	29.6		64.3	41.0
ROP Increase over A6				+80%	+118%				+22%	+50%

Figure 6 - ROP Increase by Formation

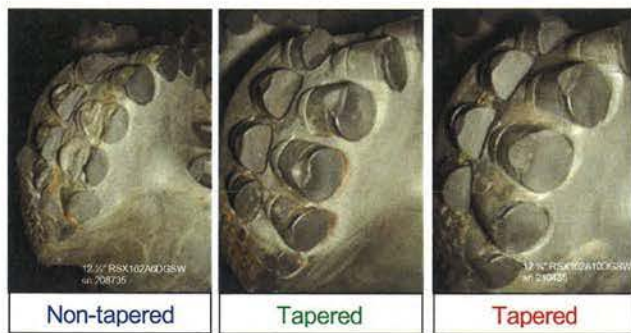


Figure 7 - Bit Wear: Tapered Gauge vs. Non-Tapered

A further area for improvement is the continued development of new generation, highly abrasive-resistant cutters. A significant further enhancement of Thermostable cutters has been achieved and is planned for use in future Beryl area drilling applications. Extending cutter life, in addition to reducing stick-slip by offsetting bit dulling, gives the opportunity to utilize more aggressive cutting structures and seek ROP gains. An area of future development of the current bit design is the incorporation of further back-up cutters at the shoulder of the drill bit. Figure 8 clearly shows increased wear on the shoulder cutter where a back-up cutter was not present. This design modification, together with the use of the latest generation of Thermostable cutters, is expected to yield further gains in stability and longevity.

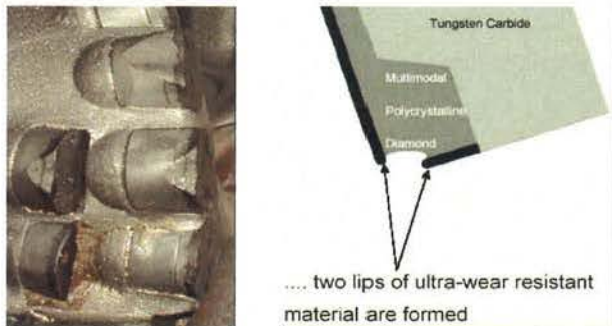


Figure 8 (Left) - Photograph Showing Increased Wear at the Location Without a Backup Cutter

Figure 9 (Right) - New Thermostable PDC with Wrapped Configuration to Prolong Cutter Life

As the drill bit and BHA design are fine-tuned to the specific demands of the application, there is an opportunity to analyze in detail the stick-slip and other vibrations that are present at certain locations in the BHA using an advanced vibration measurement sub. The compact sensor is located in a sub and can be located in varied locations in the string. This records 3-axis accelerations over the duration of a bit run which can be analyzed subsequently to correlate events at the sensor location with drilling events such as formation changes or changes in drilling parameters. A customized sub has been built for this purpose, and it is anticipated that the results from this will help to further understand the impact of drill bit and / or BHA

modifications on the management of stick-slip. The data from this tool is time-based, but can be correlated to depth. The following graph shows an example of a time-based output from a run showing a stick-slip event (See Appendix 6: Stick-Slip Indicator Data)

BHA Related: Both push-the-bit and point-the-bit systems are still being used in the Beryl area; the key is when to apply each system. Point-the-bit systems in 8-1/2" hole sections have proven themselves able to achieve high, predictable, consistent doglegs in tough drilling environments with up to 12°/100ft doglegs. Future Beryl area wells have large step outs that may require rig upgrades. The modifications to the BHA include the successful recent trials of trajectory hold with a point-the-bit system. This will reduce the tortuosity in the wellbore by allowing the tool downhole to maintain a trajectory negating the need for some rig upgrades. This modification holds both inclination and azimuth, to within 1 degree of desired profile as illustrated in the Figure 10, taken from a trial on a recent platform well.

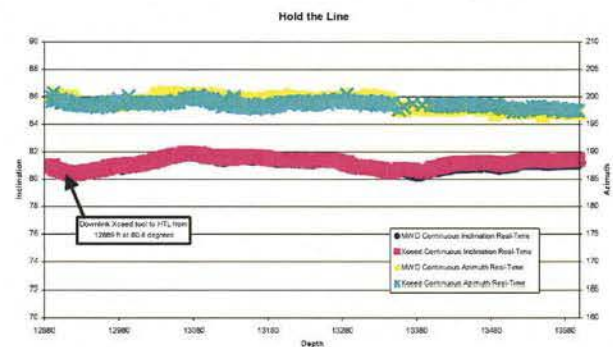


Figure 10 - Trajectory Hold

A combination of a high-torque positive-displacement mud motor placed directly above a rotary steerable system in the BHA is also being considered. This will allow rigs with RPM limits to be able to achieve 300 bit RPM's while continuously steering. The positive displacement motor acts to de-couple the bit from the drillstring. In addition, the higher RPM's (as illustrated on Figure 1) can reduce stick-slip.

Conclusions

Progressive bit design and BHA enhancements in hard, abrasive, and interbedded formations, have been discussed. The case studies presented have demonstrated both reduced vibrations and stick-slip leading to record breaking ROP's and run lengths. This success is a combination of technological development, close analysis of real time data, and application of learnings. Another key element is the relentless optimization of drilling parameters with focus on stick-slip management carried out at the well site.

This methodical approach to bit and BHA design will challenge the ultimate goal of a zero stick-slip environment.

Acknowledgements

The authors express their appreciation to ExxonMobil Development Company, Schlumberger and ReedHycalog management for allowing the publication of this paper along with co-ventures Shell Exploration and Production, Amerada Hess, and OMV. Also, they acknowledge the field personnel for their contributions. Additionally, they express gratitude to the following people for their input and assistance in developing this paper: G. King, J.B. Young, R.N. Cutt, A. Herron, J. Blackburn, A. Wilson, Paul Wilkie and Tarik Boukherissa

References

1. Cutt, R.N. et al.: "Beryl Field: Extracting Maximum Value from a Mature Asset Through the Evolution of Technology" paper presented at the 2005 SPE/IADC Drilling Conference, Amsterdam, Netherlands, 23-25 February.
2. Bonnett, N. et al.: "High Angle Drilling in Severely Depleted Reservoirs," paper SPE 49984 presented at the 1998 SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia, 12-14 October.
3. Dupriest, F. et al.: "Fracture Closure Stress (FCS) and Lost Returns Practices" paper presented at the 2005 SPE/IADC Drilling Conference, Amsterdam, Netherlands, 23-25 February.
4. Roberts, T.S. et al.: "Optimization of PDC Drill Bit Performance Utilizing High-Speed, Real-Time Downhole Data Acquired Under a Cooperative Research and Development Agreement" paper presented at the 2005 SPE/IADC Drilling Conference, Amsterdam, Netherlands, 23-25 February.
5. Wise, J. et al.: "Hard-Rock Drilling Performance of Advanced Drag Bits" paper presented at the 2004 Geothermal Resource Council Annual Meeting.

* Denotes mark of Schlumberger

** Exxon Mobil Corporation has numerous affiliates, many with names that include ExxonMobil, Exxon, Esso and Mobil. For convenience and simplicity in this paper, those terms may sometimes be used as abbreviated references to specific affiliates or affiliated groups.

List of Figures

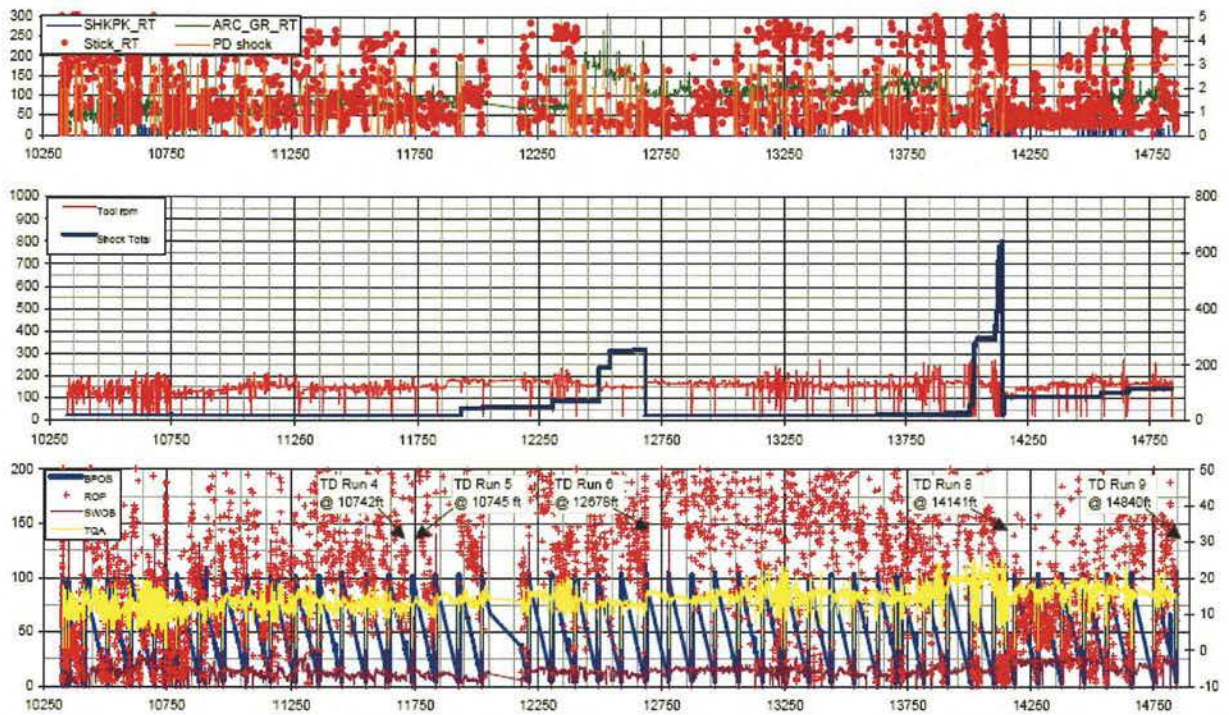
1. Stable Drilling: WOB vs. RPM
2. Wear Percentage vs. Radius
3. 0.6 degree Taper
4. Stick-Slip: Tapered Gauge vs. Non-Tapered
5. Stick-Slip Reduction Across Formations
6. ROP Increase by Formation
7. Bit Wear: Tapered Gauge vs. Non-Tapered
8. Photograph Showing Increased Wear at the Location Without a Backup Cutter
9. New Thermo Stable PDC with Wrapped Configuration to Prolong Cutter Life
10. Trajectory Hold

Appendix

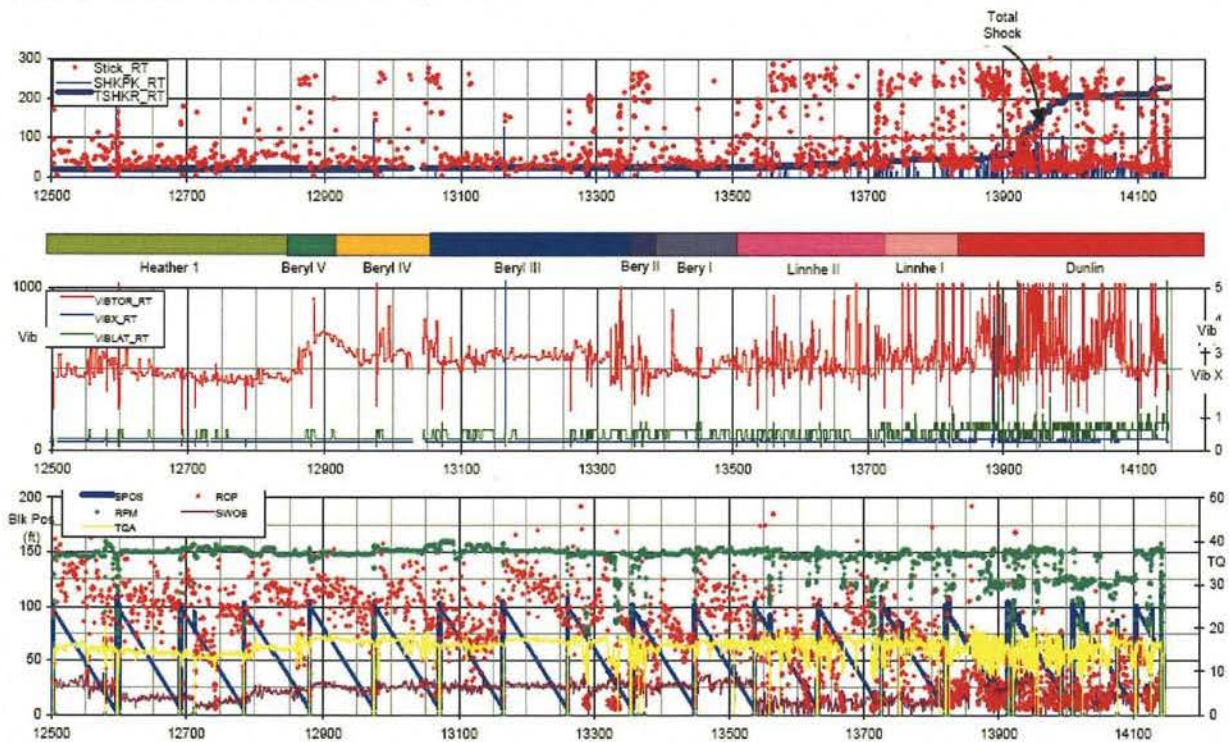
1. Drilling Dynamics
2. Drilling Dynamics: Push-the-bit System, Beryl Area
3. Beryl Area Stratigraphy
4. Drilling Dynamics: Point-the-bit System, Beryl Area
5. Drilling Dynamics: Point-the-bit System, Increased RPM
6. Stick-Slip Indicator Data

Appendix

1. Drilling Dynamics



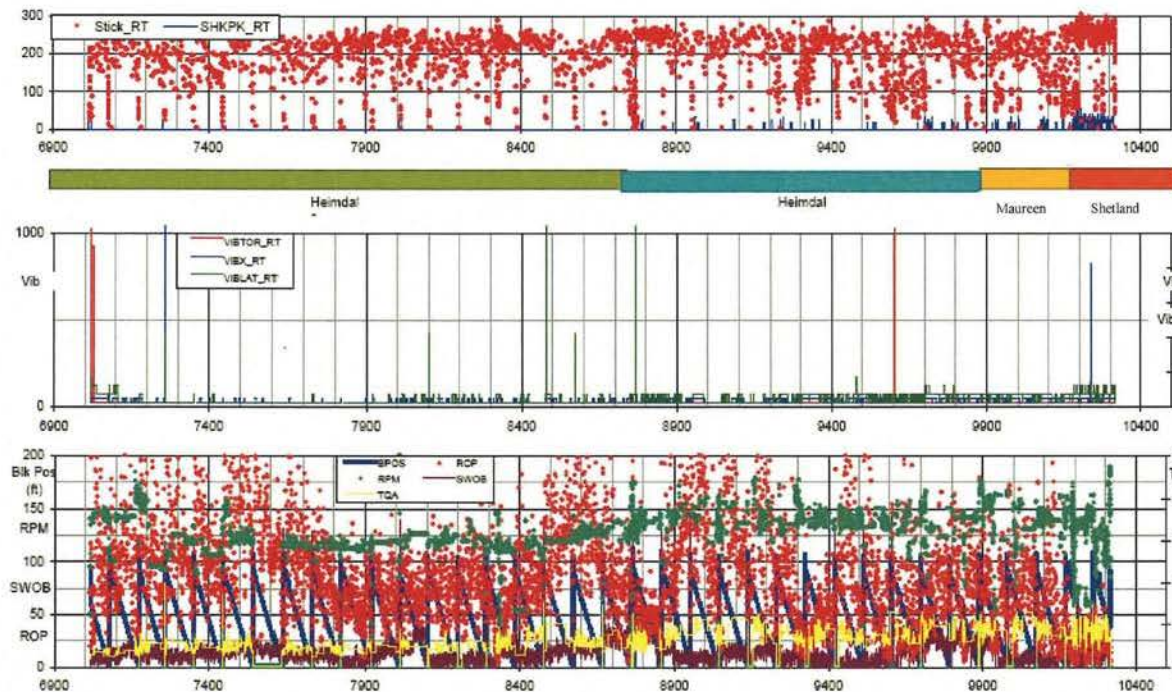
2. Drilling Dynamics: Push-the-bit System, Beryl Area



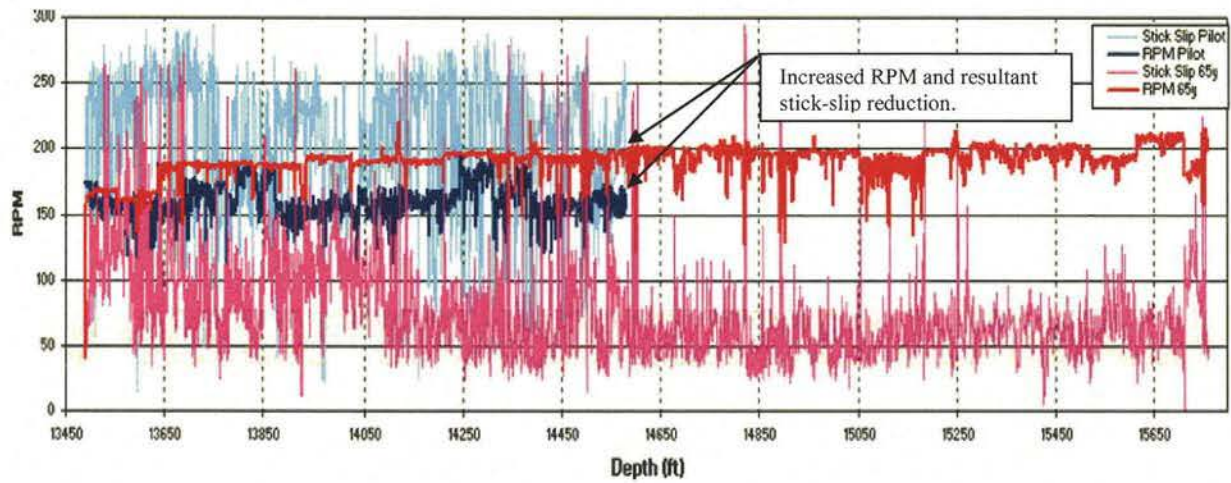
3. Beryl Area Stratigraphy

PERIOD	AGE	GROUP	FORMATION & SEISMIC MARKERS	MEMBER/ UNIT	LITH.	H/C	DEPOSITIONAL ENVIRONMENTS	PRODUCING INTERVAL	RESERVOIR PARAMETERS				
									POR. %	NTG %	SHC %	PERM. MD	
JURASSIC	CENOMANIAN	J	HIDRA FM.				MARINE SHELF						
	ALBIAN TO RYAZANIAN		RODDEY FM.				OUTER MARINE SHELF						
	VOLGIAN		VALHALL FM.				SUBMARINE FAN	KATRINE	0.15	0.43	0.76	150	
	KIMMERIDGIAN	Jo2	KIMMERIDGE CLAY FM.	BRÆ MBR.									
	OXFORDIAN	Jo1	HEATHER FM.	II									
	CALLOVIAN	Jb3		KATRINE MBR.									
	BATHONIAN	Jb2		I			OUTER MARINE SHELF						
	BAJOCIAN to AALENIAN	Jb1	BERYL FM.	ANGUS MBR.			DELTA FRONT						
	TOARCIC	Jt		IV			ESTUARINE DELTA	BERYL	0.18	0.86	0.89	350	
	PLIENSCHACHIAN			III			ESTUARINE BAY	LINNHE	0.15	0.37	0.74	100	
	SINEMURIAN		UNDIFFERENTIATED	II			FLUVIAL						
	HETTANGIAN			I			MARINE SHELF						
	RHAETIAN		NANSEN FM.	III			MARINE SHORELINE	NANSEN / EIRIKSSON	0.16	0.62	0.78	200	
			EIRIKSSON FM.	II			FLUVIAL						
			RAUDE FM.	I			ALLUVIAL PLAIN						
TRIASSIC	NORIAN	Tr		IV			FLOOD PLAIN / CHANNEL FILL DISTAL SANDEFLAT						
	CARNIAN		LEWIS FM.	III			PROXIMAL SANDEFLAT	LEWIS	0.14	0.35	0.70	50	
	LADINIAN			II			LACUSTRINE						
	ANISIAN		UNDIFFERENTIATED	I			FLUVIAL - SANDEFLAT FLOOD PLAN						

4. Drilling Dynamics: Point-the-bit System, Beryl Area



5. Drilling Dynamics: Point-the-bit System, Increased RPM



6. Stick-Slip Indicator Data

