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Field Proof of the New Sliding Technology for Directional Drilling

Eric Maidla, SPE, and Marc Haci, SPE, Slider LLC; Scott Jones, SPE, IDR Inc.; Michael Cluchey, SPE, and Michael Alexander, SPE, ChevronTexaco Corp.; and Tommy Warren, SPE, Tesco Corp.

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Abstract

This work shows how sliding to make a trajectory correction can significantly improve directional drilling with a mud motor and measurement while drilling (MWD) system using a new surface only technology called Slider.

Slider deploys a small robot to interface with the trop drive control panel that automatically rocks the pipe to the right and left following a rigorous analysis of torque by a computer/software that receives the surface torque and stand pipe pressure values as feedback.

Improvements from this sliding technique included the following:

- Increasing sliding rate of penetration (ROP) by more than three-fold in some cases.
- Reducing motor stalls to zero (sometimes seven stalls per slide were recorded for the conventional method on a slide distance that ranged from 5 ft to 15 ft).
- Reducing time to orient tool face by an order of magnitude. Tool face orientation was obtained in about 1½ to 2 minutes without coming off bottom, as compared to enormous difficulties while trying to do this manually for the larger horizontal departures.
- Providing a means to release the bottomhole assembly (BHA) when becoming differentially stuck without having to come off bottom and with minimal disturbance to the tool face.
- Removing the tedious work the directional driller had in "rocking" the pipe, which also reduces the risk of torque breakouts.

Introduction

Steerable motors have been used for about 20 years to drill directional wells. These motors include a bend at the motor bearing housing so the bit points at an angle relative to the borehole centerline. The bend (typically 0.5° to 2°) can be selected to allow the borehole trajectory to be changed by several degrees per 100 ft when the drillstring is advanced without rotation. This bend is sufficiently small so the entire assembly can be rotated for drilling a tangent section.

Large portions of most directional wells drilled with motors are drilled while rotating the drillstring; drilling proceeds without drillstring rotation—sliding—when it is desired to change the borehole trajectory. An MWD tool detects and transmits the orientation of the bend (tool face) so the directional driller can orient it in the desired direction by slightly turning the drillstring. The mud motor powers and rotates the bit so the drillstring can be advanced without pipe rotation. The geometrical configuration of the motor assembly determines the curvature of the drilled section. Although this process is conceptually very simple, it can often be difficult and inefficient to implement.

Rotary steerable directional tools were introduced in the mid-1990s to address limitations of steerable motors.[1,2] Rotary steerable tools are now routinely used for the directional work on most high-cost drilling operations. They are readily available for wellbores larger then $7^{7}/_{8}$ in. and significantly improve directional drilling efficiency. They are not currently economically practical for most onshore operations and some marginal offshore operations. The daily charge for a rotary steerable system may be twice as much as the cost of the rig used on an onshore well. Limited availability in small sizes also restricts their use in these onshore wells. Rotary steerable tools are just now becoming commercially available in a limited supply for use in $6^{1}/_{8}$-in. wells, and none are yet available for 4¾-in. wells.

The high cost and limited size of commercial rotary steerable tools provided the impetus for the development of technology to improve steerable motor efficiency for cost-constrained directional wells. Warren[3] highlighted the deficiencies of steerable motors at the time rotary steerable systems were being introduced. These deficiencies can now be addressed economically by using the technology discussed below.

Based on a study of 172 directional wells drilled with steerable motors, Warren found that about 35% of the motor drilling time is spent sliding. Drilling in the sliding mode is much less efficient than drilling in the rotating mode. The motor must be oriented before a slide can begin; orienting the motor involves two steps accomplished simultaneously. The drillstring is rotated incrementally to put the motor bend in the desired direction. As the bit direction is being established, the twist is worked out of the drillstring so the bit orientation will stay relatively constant. Otherwise, the energy stored in the drillstring may cause the tool face to change as the drillstring is advanced for drilling. The bit is initially pointed in a direction clockwise from the desired drilling direction, thereby counteracting the reactive torque of the motor.

Cuttings removal is less efficient during sliding without pipe rotation, and cuttings may collect on the low side of the hole. As the cuttings accumulate, the drillstring becomes progressively more difficult to slide smoothly. If left unimpeded, the cuttings buildup can stick the drillstring.

Even in a clean hole, the drillstring often cannot be advanced smoothly because of the friction acting on it. This friction makes it difficult to keep a constant load on the bit. Maintaining an acceptable ROP while preventing the motor from stalling requires the motor to be operated in a rather narrow load range. Although many formations can be drilled faster with polycrystalline diamond compact bits, they can exacerbate the problems with maintaining weight on bit (WOB) and ROP. Thus, roller cone bits are often preferred for use on steerable motors.

The directional plan for a well is generally specified as an average curvature for several sections that define a path from the surface location to the bottomhole target. The average curvature for a section comprises a series of rotating sections and sliding sections. Because the ROP for the sliding sections is less than that for the rotating sections, the motor geometry is generally selected to minimize the number of slides needed to follow the directional plan. This technique also minimizes the amount of nonproductive motor orienting time but often results in a rather tortuous well path that can affect subsequent operations.

These issues combine to make the overall gross ROP much less during sliding with a steerable motor than during rotating. It is not unusual to have the sliding ROP be reduced as much as 80% from the rotating ROP. These problems are largely eliminated by the use of expensive rotary steerable systems. These same problems may also be significantly reduced by the use of a new technology for controlling a steerable motor system.

Cause of Sliding Inefficiency

Understanding the nature of frictional resistance to pipe movement is key to understanding the causes of the inefficient drilling process during sliding. It is also the key to understanding how the new control system overcomes these limitations. Friction always acts on the drillstring in a direction to resist movement or impending movement if the pipe is not moving. As the drillstring is lowered in the hole without rotation, the friction force is axial and reduces the hook load. When the pipe is rotated without axial movement, the friction is tangential and causes torque to resists pipe rotation. If the pipe is both rotated and moved axially, the friction acts in a direction opposite the vector direction of motion of a point on the pipe. In other words, both a torque and axial component are generated. This basic concept implies that a rotating drillstring will seem almost frictionless in the axial direction if the rotational velocity is much greater then the axial velocity.

The magnitude of the frictional force is given by a friction coefficient multiplied by the cumulative lateral contact force between the pipe and borehole wall (or casing inside wall). The friction coefficient is nearly independent of sliding velocity, providing there is movement, but it is substantially greater before motion is initiated. As a force is progressively applied to a stationary body to initiate sliding, the frictional resistance increases until movement begins and then abruptly falls to a lower level as the movement continues. The friction coefficient at the point where motion is impending is referred to as the *static* friction coefficient and is typically about 25% greater then the *dynamic* friction coefficient after motion begins **(Fig. 1).** This change in the value of the friction coefficient is the primary mechanism that governs stick/slip motion.

In a drilling operation, the driller directly controls the advancement of the top of the drillstring to indirectly control WOB (and the loading on a steerable motor). The link between the surface drillstring advancement and the force applied to the bit is a combination of the elastic nature of the drillstring and the frictional force acting on it. In the case of a rotating drillstring, the friction acts in the form of torque because the rotational velocity is normally considerably higher than the string advancement rate. This allows WOB to be related to block movement by only the elastic properties of the drillstring and is little influenced by friction. (Of course, this ignores the effects of cuttings or ledges that may provide a direct axial force to the drillstring.) Thus, a steerable motor can be operated quite efficiently while rotating. It can also be operated effectively if the ROP is high enough so that the drillstring can be continuously advanced so that the friction is constant.

The relationship between surface drillstring movement and WOB can be much more complicated if the drillstring is not rotating. Often the ROP is so low that the drillstring must be advanced with a series of small, discrete movements that cause the friction to alternate between the dynamic and static values. In an overly simplified case, the drillstring friction and elastic properties can be considered independently **(Fig. 2).** The drillstring is represented as a series of mass elements with no elasticity and are connected by a series of spring elements with no mass. If the drillstring is suspended in the borehole and rotated, the mass elements will move axially to a position (neutral position) determined by the inclination and the spring properties. In this neutral position, the tension in the springs will differ only by the effective axial gravitational component of mass of the elements.

If rotation is then terminated and the drillstring upper end is advanced a small amount, the tension on the upper spring will decrease. The decreased tension will allow the mass element to move downward, but this movement will be resisted by friction. The element will not move until the spring force on the upper mass element is reduced by an amount greater than the static friction on this element. Once friction is overcome, the element will move downward until the difference between the tension on the spring above it and below it is equal to the dynamic friction acting on the block. This will reduce the tension on the next spring by an amount equal to the tension reduction in the first spring minus the dynamic friction. This process will continue until the tension reduction in one of the springs is less than the static coefficient of friction. If the blocks are advanced sufficiently at the surface, all the elements will move downward and a force will be applied to the bit, but the decrease in surface hook load (surface WOB) will be more than the increase in bit force (downhole WOB).

The friction acting on the mass elements causes elastic energy to be stored in the spring elements. If the blocks were advanced without drillstring rotation until the bit just touched the bottom of the hole and then the drillstring were rotated, the axial friction on all mass elements would be released and the elastic strain energy would be applied to the bit as WOB. In fact, an immediate WOB equal to the summation of the lateral contact force times the *dynamic* coefficient of friction would be applied to the bit.

On the other hand, if the bit is on bottom with no WOB or drillstring rotation and the blocks are advanced with small increments, each advancement will cause more and more of the mass elements to move. The surface WOB will increase with each advancement, but the downhole WOB will remain zero. When sufficient elastic energy is stored in the drillstring, a small surface advancement will cause all the mass elements to move downward. This will abruptly increase the WOB by the difference between static and dynamic coefficient of friction times the summation of the lateral contact force.

This effect can easily be seen on directional wells while sliding if there is substantial friction on the drillstring. As the drillstring is advanced incrementally, the surface WOB increases but there is no corresponding increase in motor pressure to indicate that the downhole WOB is increasing. At some point, the surface WOB abruptly falls off, and the motor may stall, indicating an abrupt transfer of force from drillstring friction to axial load on the bit.

The real situation affecting the sliding of a drillstring in a directional borehole is much more complicated than even that described above. The frictional state along the drillstring is path dependent. Fundamental physical principles make it difficult to manage the frictional and elastic properties of the drillstring so that the WOB can be effectively controlled by advancing a nonrotating drillstring from the surface. Drillstring rotation makes almost all these problems disappear. Simply put, a means for causing the drillstring to behave as if it were rotating is needed to provide an effective sliding process with a steerable motor.

New Steerable Motor Control System

Maidla and Haci[4] describe a new technology that uses the above principle to overcome many of the limitations of steerable motors without the expense of a rotary steerable system. This technology consists of a surface control system that interfaces with the top drive control system to overcome many of the friction-related problems of steerable motors. The control system works by rotating the top of the drillstring, alternately clockwise and counterclockwise, so the upper part of the drillstring always experiences tangential motion. This method keeps drillstring friction in the dynamic mode and significantly reduces axial friction.

The amount of cyclical torque applied at the surface depends on the particular frictional characteristics of the well. For example, consider a horizontal well being drilled with 3 ½-in. drillpipe ($6^1/_8$-in. hole), as shown in **Fig. 3**.

The torque expected during drilling can be calculated with a typical torque and drag program.[5] These programs calculate the torque along the drillstring when it is rotating. If the torque is calculated with the static coefficient of friction, the values can be manipulated to determine the maximum depth that a particular applied surface torque would twist the drillstring. **Fig. 4** shows the depth at which the pipe would be affected by the surface application of the specified torque to a nonrotating drillstring for the well depicted in Fig. 3.

For example, an applied torque of 2,000 ft-lbf would cause the pipe to twist down to a depth of 6,400 ft. Below that depth, friction would effectively anchor the drillstring against tangential movement. Continuous application of +2,000 ft-lbf and -2,000 ft-lbf would cause the drillstring down to 6,400 ft to be in continuous tangential motion. This would minimize the axial drag, caused by the pipe, from the surface down to its deepest point of influence. Because the friction would be dynamic rather than static, the depth of influence would be deeper than 6,400 ft.

If a motor that generates 1,000 ft-lbf torque is used, the bottom end of the drillstring will undergo a counterclockwise torque because of the motor reaction. This torque is not steady, and the vibrations from the motor probably keep the lower portion of the string in a state of dynamic friction that would reduce the axial friction.

Through manipulation of the surface torque oscillations, the point of influence can be moved as deep along the drillstring as desired. The Slider control system uses this principle to improve the performance of drilling with steerable motors. The system drives the point of influence deep enough to significantly reduce the axial friction that causes stick/slip during sliding. The depth to which the point of influence is driven is limited such that a section of drillstring remains in static friction above the section influenced by the motor torque. This static zone provides rotational stability for the motor tool face similar to the way a keel stabilizes a ship. In practice, the optimal oscillating torque applied to the drillstring is determined dynamically at the rig rather than through calculations, as done in this example which simplifies the concept to help explain how the system works.

System Description

The technology works with an automated control system that has three main inputs: information coming from a manual input screen, measurements of surface torque from the top drive, and measurements of standpipe pressure as an estimator of reactive torque. **Figs. 5 and 6** show simplified diagrams of this system.

Initial field tests verified the discoveries made in the laboratory using a scaled physical model of the directional drilling system, which included scaling the rig, wellbore, drillstring and all related torque and drag effects, and the interaction between the formation and bit. The laboratory system was instrumental in the discoveries[6-8] and was used as a training tool to help directional drillers understand the new field operating procedures required to optimize the system.

Rig Interface

The rig interface for the top drive control uses a robot that allowes an external automation system to control the top drive **(Fig. 7).** An electrical interface that allows the external automation system to control the top drive could also be used. So far, the robots have been the interface of choice because they do not require any changes to the drilling contractor's top drive.

Lessons Learned

The efficient operation of this technology depends on the level of commitment of the directional driller. Getting the directional driller to accept this technology was most productive by implementing the following:

- The directional driller should be trained on the simulator first. On the drilling jobs in which the directional driller was not first trained on the simulator, the Slider technology was ineffective. These directional drillers tended to operate the equipment in a similar mode to the way they drilled manually. Conversely, drillers trained on the simulator the first time around have shown a high degree of comfort in operating the system using the new operational procedure. Thus, they have produced the expected results as outlined in the field case study described in this paper.
- The directional driller should be the only person allowed to operate the equipment right from the beginning of field implementation. He typically has in-depth local knowledge of what has proven to work and what has not. If a third-party directional driller or other individual starts operating the equipment in the field, results tend to be poor. Such cases create a lower level of responsibility for, and hence commitment by, the directional driller, who would tend not to operate the equipment at maximum efficiency. Directional drillers who introduce the system showed a high degree of self achievement, by having the technology perform at its optimum (as shown here).

New Operational Procedures

To understand this new technology it is first necessary to understand the conventional procedure when making a directional correction.

Following the rotation of the complete drillstring (drilling the tangent section of the well) for the conventional procedure, the directional driller stops rotating the pipe, pulls the bit off bottom, and works out the torque from the drillsting. He orients the tool face at an angle such that when he returns the bit to bottom, the tool face angle has enough compensation to allow the reactive torque on bottom to take the BHA to the correct final tool face needed to make the correction. This operation could take a few minutes to nearly a hour[4], depending on drilling conditions.

The alternative presented in this paper allows an immediate shift from the fully rotational mode of the drillstring to the automated torque rocking mode without coming off bottom. The tool face is adjusted to the desired value with the bit on bottom, using the "bumping" technique either to the right or left. During one rocking cycle, this bumping technique[4] increases the corresponding torque value in the direction to be turned. The importance of this procedure is that the resulting surface slackoff is kept close to the WOB values that preceded the sliding correction, thus avoiding a large buildup of drag. This method helps avoid motor stalls and provides numerous advantages (described above). This, in itself, will increase the life of the motor. More importantly, it allows for a very efficient transfer of weight to the bit (as shown in the case history in the Results section that follows).

Primary considerations are the shift in the skills and procedures required from the directional driller and the implementation of a simple surface hardware system.

Field Results

Fig. 8 shows a well drilled on the Louisiana outer continental shelf. The directional driller was trained for 3½ hr on the laboratory simulator before applying it in the field **(Fig. 9).**

The first analysis consisted of observing the increase in sliding ROP compared to the preceding rotating ROP **(Fig. 10).** The data presented here came from the operator's morning reports. Some of the sliding drilling was performed in formations softer than the preceding rotating runs, which helps explain the one event in which the sliding ROP was actually higher than the preceding rotating ROP. The results were analyzed in a macro view instead of a focus on individual runs, such as that one, to look for trends and not exceptions. On average the increase in performance ranged from 20% at the beginning to 75% toward the end of the well. This performance increase resulted from the technology performing as designed and the exceptional skills of the directional driller (whose skill and effort cannot be understated). This increase in performance definitely indicated a learning trend. The results exceeded all expectations and constituted the major motivation for this paper.

Figs. 11 and 12 show the ease of adjusting the tool face direction without picking the bit off bottom. In Fig. 11, the tool face was changed to the right 45˚ following a bump to the right (slight increase in torque over one torque cycle to the right). This increase closed the gap between the surface torque dissipation distance that moves towards the bit and the reactive torque dissipation distance that moves towards the surface. Note that the left-hand torque cycles were lower than the right-hand ones. This difference results from the reactive torque being to the left; field experience has shown that to maintain constant tool face, a slightly smaller torque value to the left is needed when rocking to maintain constant tool face angle. Fig. 12 shows a 135˚ turn to the left following a large bump to the left and then two turns to the right following bumps to the right. The average response time for the angle correction was 1½ min.

Another field observation was obtained following a succession of differential sticking incidents. The directional driller would start reciprocating the pipe to release the drillstring and therefore losing time and the orientation of the BHA tool face. On one such occasion, depicted in **Fig. 13,** the directional driller actually decided to bump in a consecutive procedure first to the left, and then followed immediately by a bump to the right. With this technique, the pipe was freed without loss of tool face orientation. The evidence was in the increase in standpipe pressure, which showed that drilling resumed, and the measurement of the tool face angle, which remained constant.

Fig. 14 illustrates the difficulty in making a manual slide (the purple line shows the tool face setting). Although it was possible to obtain the desired tool face, there was a significant time gap during which this was impossible. The red line shows the differential pressure changes; the high peaks correspond to motor stalls (seven stalls occurred during this particular slide). The green curve shows the average ROP. Surface ROP was not a good indication of actual ROP because of extensive pipe stretching. The best way to check ROP is to check the average value of the pressure differential during sliding. The yellow line shows that the manual slide did not include rocking the pipe (the torque is mostly a straight line).

Fig. 15 demonstrates the ease of using this new sliding technology. The yellow background (torque) corresponds to the continuous rocking motion that was the basis to the success of this slide. The desired tool faces were always obtained, as shown by the purple lines. The ROP was stable (red lines); the two distinct trends show how the directional driller tried to increase ROP.

Fig. 16 depicts the domain of torque values used with this technology. Typically during rocking, 80% of the rotating torque value is used as the rocking limits (for example, in Fig. 12 this would be 80% of 4,600 ft-lbf). Note that this value is quite small in comparison to the breakout torque of 14,000 ft-lbf. This is the justification showing why many directional drillers have already adopted rocking the pipe, even manually, as an acceptable directional drilling practice. The Slider technology takes this technique to the next level through automation.

Conclusions

This new technology proved that it is possible to optimize the trajectory correction while sliding. It proved to be easy to learn and applied in the field and once mastered by the directional drillers, the sliding rates of penetration trippled, the tool face orientation was easily obtained in 1 ½ minutes or so, and the number of motor stalls was eliminated.

Acknowledgments

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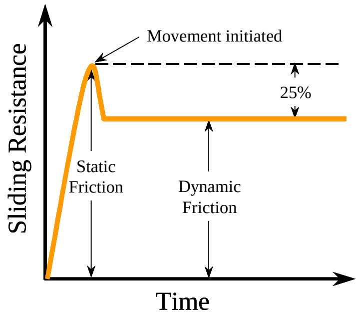


Figure 1: When a force is applied to a stationary body and slowly increased until the body slides, the force will reach a peak and then fall to a much lower value as the body begins to slide.

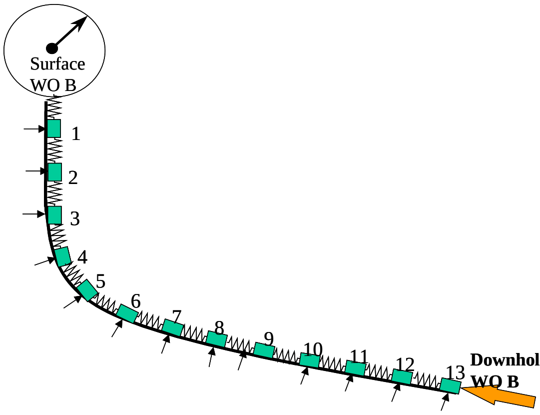


Figure 2: The drillstring can be represented as a series of spring and mass elements.

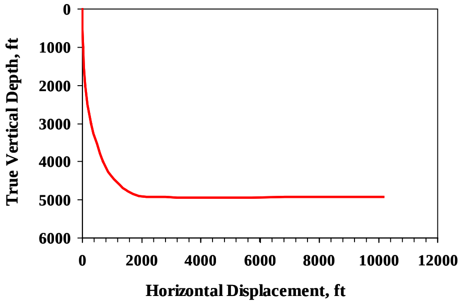


Figure 3: Example of a horizontal well that might experience difficulty sliding.

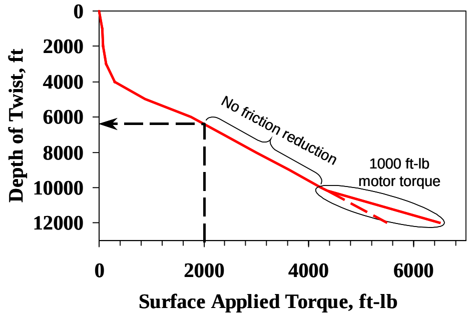
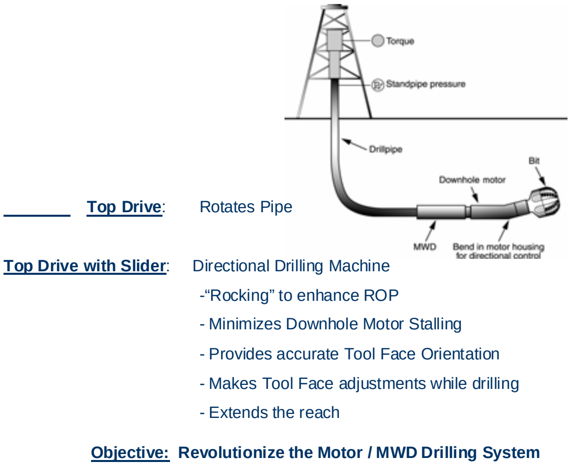


Figure 4: A surface applied torque will tend to twist the drillstring to a depth shown above for any applied torque.



Top Drive: Rotates Pipe

Top Drive with Slider: Directional Drilling Machine
- "Rocking" to enhance ROP
- Minimizes Downhole Motor Stalling
- Provides accurate Tool Face Orientation
- Makes Tool Face adjustments while drilling
- Extends the reach

Objective: Revolutionize the Motor / MWD Drilling System

Figure 5: Some advantages of using the Slider Technology.

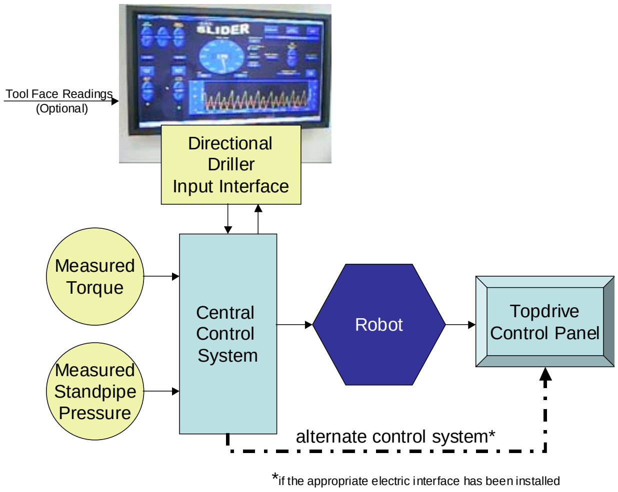


Figure 6: Control System Architecture

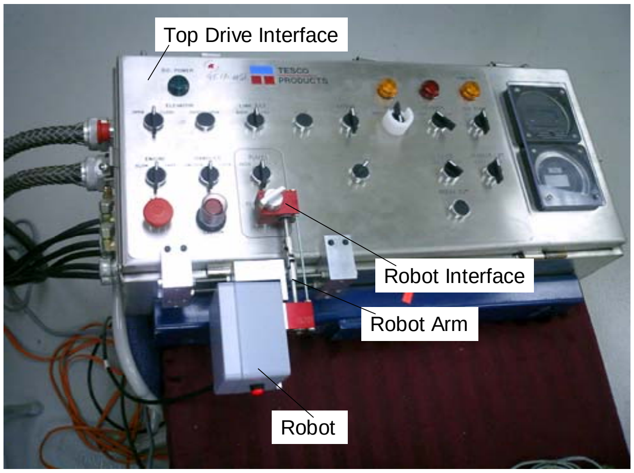


Figure 7: The Slider Control system robotically interfaces with the top drive control system.

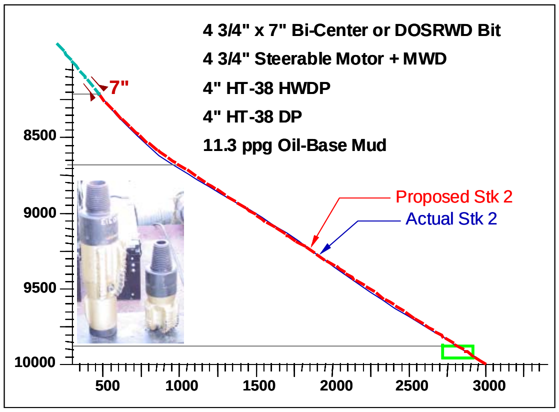


Figure 8: Field Proof - Details of the wellbore geometry, bit and trajectory for the well drilled in Louisiana (USA).

Figure 9: Physical Simulator of the Directional Drilling Process Used for Training.

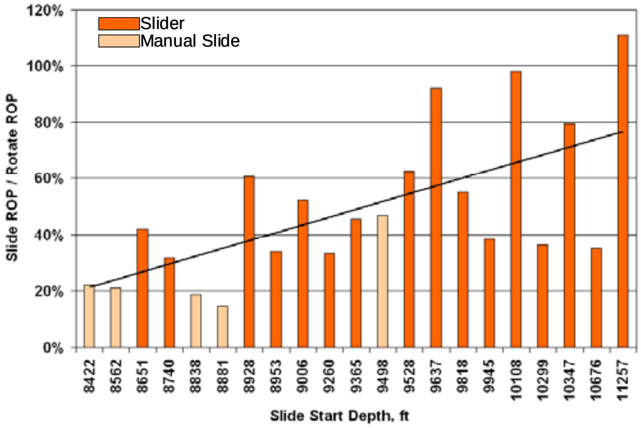


Figure 10: Demonstration of fast learning by the directional driller that used the Slider technology for the first time in the field. His average improvement increased from 20% to around 75% when comparing the ratio of the sliding rate of penetration (ROP) with the immediate preceding rotating ROP.

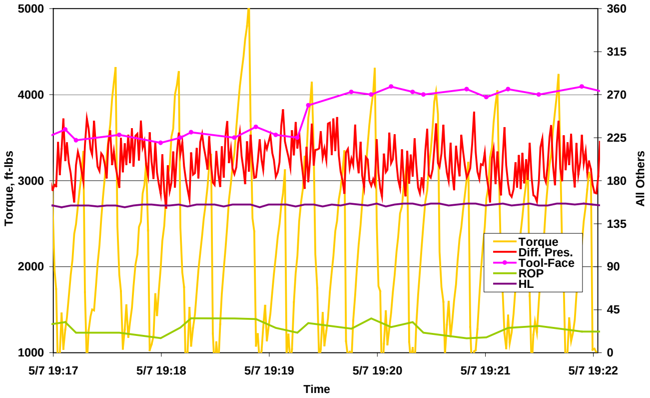


Figure 11: Field example of tool face correction to the right. This is demonstrated by a larger torque value during one right turn cycle that resulted in a tool face change to the right (transmitted by the MWD a few seconds later).

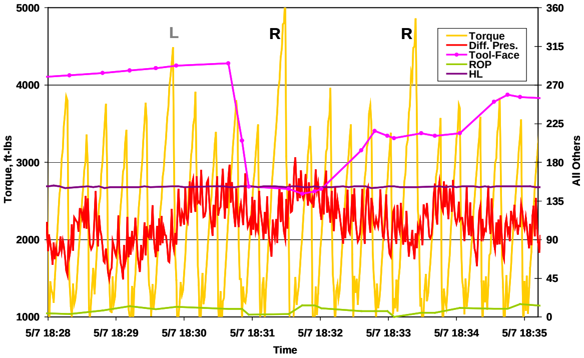


Figure 12: Example of tool face correction to the left (after an increase of the left torque during one cycle) then two times to the right (after an increase of the torque to the right during one cycle each time).

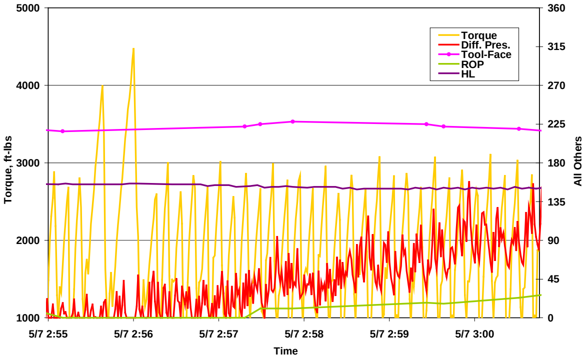


Figure 13: Coming unstuck from a differential sticking event using the Slider technology

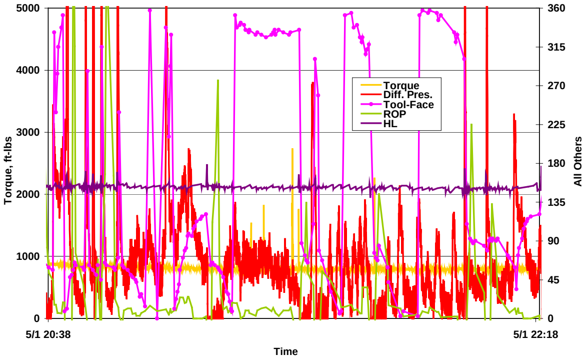


Figure 14: Demonstration of the difficulty of the Manual Slide, 8864'-8874'. There were 7 stalls of the downhole motor and certain difficulty in maintaining the desired tool face angle.

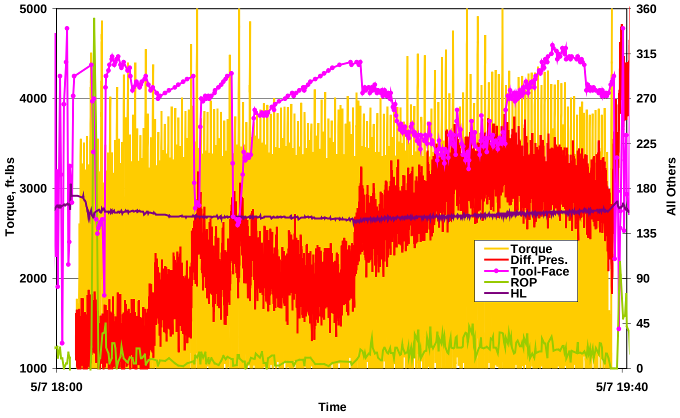
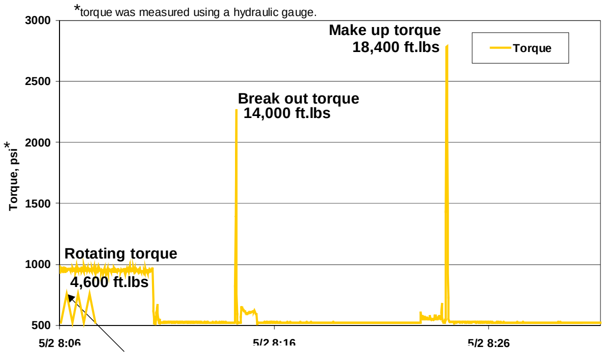


Figure 15: Slider Assisted slide between 10106'-10129'. There were no stalls and the directional driller managed to increase the rate of penetration while maintaining the desired tool face angle.



*torque was measured using a hydraulic gauge.

Maximum rocking torque is below the rotating torque
(inserted here only for clarification – not part of the
original data displayed)

Figure 16: Comparison of the different torque values demonstrating that the rocking torque was well below the make up torque for this particular job.