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Stick-Slip and Torsional Oscillation Control in Challenging Formations – A New Solution to an Old Problem

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Abstract

Stick-slip and torsional oscillations can be harmful to drilling performance for both steerable motor and rotary steerable assemblies. These dysfunctions can be controlled to a certain level from surface by limiting drilling parameters, however this also results in a reduction in drilling performance. The ultimate solution is a downhole device that will allow surface parameters to be pushed hard while controlling the levels of stick-slip and torsional oscillations downhole.

A new innovative device has been field tested and qualified to prove performance. The device uses a combination of spring force, hydrostatic pressure and differential pressure for active mechanical control downhole. Differential pressure produced at the motor power section provides the best feedback mechanism for bit and formation interaction. The new device utilizes differential pressure feedback to stroke the bottom-hole assembly (BHA) in and out to limit the depth of cut at the bit.

Using a test strategy of drilling direct offset wells from one pad with comparable BHA's and drilling parameters, runs were performed with embedded downhole instrumentation to compare performance with and without the new device. Onboard instrumentation measured shock, vibration, rotary speed (including reverse rotation speed using gyros) and temperature at the bit and BHA.

This paper will detail the results of qualifying a new stick-slip control device on commercial wells in North America. Data gathered downhole and at surface on direct offset wells will be presented. The results will reveal drilling performance gains, dull grade contrast and downhole dynamic advances.

Introduction

Stick-slip and torsional vibration of drillstring have been a subject of an intensive research since 1960s [1,2]. More recently, Polycrystalline-Diamond-Compact (PDC) bit damages due to stick-slip and low/high-frequency torsional vibration have been studied by various researchers [3-6]. Lines et al. reported 4 different types of torsional oscillations using an angular-rate gyro [7].

It is now well-known that high magnitudes of stick-slip or torsional oscillations can have a negative effect on drilling performance and component life. Many different tools are available on the market that claim to reduce or eliminate stick-slip, either by surface control [8-11] or through a downhole device in the BHA [12-15].

Complete elimination of stick-slip or torsional oscillations is unpractical when drilling at the technical limit for penetration rate and downhole component preservation. The objective to drill as fast and efficiently as possible while preserving the bit through the entire section to reduce/eliminate bit trips means that "management" of downhole dynamic conditions is required.

Under these performance criteria, it is hard to quantify which mechanism/magnitude of stick-slip or torsional oscillations has been controlled by the surface or downhole device. The only definitive method of verification is via downhole instrumentation placed at the "areas of concern", typically at the bit and in the BHA [16-18].

To verify downhole performance of the new innovative SSRT (Stick-Slip Reduction Tool), embedded sensors were placed at the "areas of concern" within the BHA on direct offset wells. The first well was drilled without SSRT, and the offset well was drilled with the new SSRT. Results of these offset tests verify the performance of the device.

Stick-Slip Reduction Tool (SSRT)

The SSRT has been designed to be incorporated into the BHA when drilling with a positive displacement motor (PDM). The SSRT is typically run above the MWD. The typical BHA placement is shown in **Figure 1**.

The SSRT is designed to modify length in response to differential pressure changes at the PDM [16]. The main components of the SSRT are shown in **Figure 2.**

The SSRT reacts to changes in drill string pressure as the differential pressure across the PDM increases/decreases in accordance with changes in torque at the bit. **Figure 3** shows the response of the tool to changes in drill string pressure.

An increase in torque at the PDM will result in a corresponding increase in differential pressure along the drill string. This will cause the SSRT to shorten length (or close), compressing a stack of belleville springs until the closing force and spring force are equal. The amount the tool closes depends on the pressure increase in the drill string.

A decrease in torque at the PDM will result in a corresponding reduction in drill string pressure. This will cause the SSRT to increase length (or open), uncompressing the stack of belleville springs until the open force and spring force are equal. The amount the tool opens depends on the pressure decrease in the drill string.

Because the pressure drop across the bit is held near constant, it does not cause any change in the SSRT length. Only changes in differential pressure across the motor will cause the SSRT to extend or retract. The SSRT has 18 inches of travel on the closing stroke and 11 inches of travel on the opening stroke.

The belleville springs are rated at 4000 lbs. per inch of travel. Hydrostatic pressure is utilized in a unique way to adjust the operation of the tool for different drilling applications. The response of the SSRT is opposite to what is seen from most stroking tools such as jars, shock subs and bumper tools. These tools will extend from the drill string internal pressure.

Embedded BHA Instrumentation

The embedded BHA sensors are designed to be compact enough to fit into existing downhole equipment such as SSRT and PDM [17,18]. The design allows for modification of existing assets to accept the sensors and eliminates the need for additional subs and connections in the BHA.

Figure 4 shows the embedded sensor installed under a hatch cover in the SSRT. **Figure 5** shows the embedded drilling dynamics unit. It is contained inside a pressure barrel that is rated for 15,000 PSI.

The embedded sensors are also designed to fit into the bit box of a PDM to provide at-bit measurements. **Figure 6** shows the embedded sensor installed in a motor bit box. **Figure 7** shows the embedded “puck” shaped unit.

Both sensor designs contain the same electronics, solid-state sensors and batteries. The shape of the package is the only difference between the two sensors.

The sensor packages include onboard 3-axis inclinometers (±16G), 3-axis shock sensors (±200G), 3-axis gyros and two temperature sensors. The sensor records burst data to memory every 5, 10, 20, 30, or 60 seconds. The sampling frequency (and anti-aliasing filters) is programmable between 25Hz and 100Hz.

The embedded sensor package has a communication port for set-up and memory dump at the drilling tool service facility. Once the sensors are set-up (e.g. at the repair and maintenance facility), they autonomously start recording while tripping in and while drilling. No interaction with the sensors is necessary at a well-site, minimizing the cost of sensor deployment and making them transparent to rig crews and on-site engineers.

The downhole datasets gathered with compact dynamics recorders are “small data” which are well-structured and go through well-established physics-based equations to be converted to informative processed data, along with surface data or electronic-drilling-recorder (EDR) data [18].

Proprietary software is used to merge downhole and surface data and provides special visualization tools for data analysis. The software also applies data analytics algorithms to convert “small data” to actionable information as soon as surface and downhole data are loaded into the software. This software and workflow shorten the standard delivery time (several weeks) of processed and actionable information within hours of tools being returned to service base. **Figure 8** shows the basic drilling dynamics measurements recorded at the SSRT and PDM.

Example #1

Example #1 is from two offset wells drilled with the same bit and BHA. Both wells were low angle and drilled in 9 7/8” hole size. The first well (#1a) utilized a carrier sub for embedded sensors positioned above the MWD, and offset well (#1b) utilized SSRT with embedded sensors. Both wells used 7-blade bit with 16mm cutters, 7/8 6.4 PDM with 1.5-degree bent housing.

Well #1a (no SSRT) was drilled in 3 bit runs, drilling a total of 2003m in 110 drilling hours with an average rate of penetration (ROP) of 18.20 m/hr. Well #1b (with SSRT) was drilled in 2 bit runs, drilling a total of 1996m in 82.25 drilling hours with an average ROP of 24.28 m/hr. Well #1b drilled the interval in one less bit trip and at a faster overall ROP. The following discussion highlights sections of data to compare the downhole drilling dynamics response with and without the SSRT. The snapshots of data are from identical depths while drilling the section.

Figure 9 shows a snapshot of data from Well #1a (no SSRT) and **Table 1** gives a description of the drilling dynamics. There are sections where the maximum downhole string rotation speed was as high as 320 revolutions per minute (RPM). These peak downhole rotation speeds correlate with an increase in surface torque and differential pressure.

The axial frequency spectrum data shows that there was axial vibration activity and the lateral frequency spectrum shows that there was stick-slip present with intensity increasing when the maximum rotation speeds were at their peak.

These intervals of very high-peak RPM are the most damaging to bit cutters. The top-drive rotary speed was set to 70 RPM;

however, the downhole components were subjected to intervals where the string was accelerating up to 320 RPM peak. To preserve bit life these swings in downhole RPM must be managed to acceptable levels, while still maintaining a fast ROP.

A photo of the dull bit following this run is shown in **Figure 10**. Damage to the cutters is typical for high stick-slip exposure, with the outer most rows (towards the shoulder) receiving the most damage.

Figure 11 shows a snapshot of data from Well #1b (with SSRT over the same measured depth interval) and **Table 2** gives a description of the drilling dynamics. It is clear from the data that the magnitude of downhole peak RPM was reduced. With the rotary speed still set at 70 RPM, the downhole peak rotation speeds were reduced to 175 RPM. This was a 55% reduction in peak RPM experienced at the string.

The surface torque was smoother, and differential pressure was sustained at higher levels without the subsequent high peak RPM measured downhole. The ROP was also higher than the offset without SSRT.

Figure 12 shows a photo of the dull bit following this run. The bit was still in good condition and better than that experienced on the first well without SSRT (Figure 10).

Overall the data verified that the downhole response of the BHA to stick-slip and torsional oscillations was reduced with SSRT in the BHA. Stick-slip was not eliminated; nevertheless, it was “managed” to acceptable levels to improve ROP and preserve bit life.

Example #2

Two offset wells were drilled with the same bit and BHA in Example #2. Both wells were low angle and drilled in 8 3/4” hole size. The first well (#2a) used a carrier sub for embedded sensors positioned above the MWD, and the offset well (#2b) utilized SSRT with embedded sensors. On this comparison test, embedded sensors were also installed in the PDM bit box to get an accurate data set at the bit itself. Both wells used 6-blade bit with 13mm cutters, 7/8 5.0 PDM with 1.5-degree bent housing.

Well #2a (no SSRT) drilled 1601m at an average ROP of 37.02 m/hr. Well #2b (with SSRT) drilled 2400m with an average ROP of 25.26 m/hr. Well #2b drilled 799m further than Well #2a eliminating one bit trip from the section. The following discussion highlights sections of data to compare the downhole drilling dynamics response with and without the SSRT. The snapshots of data are from identical depths while drilling the section

Figure 13 shows a snapshot of data from Well #2a (no SSRT) and **Table 3** gives a description of the drilling dynamics. There were sections where the maximum downhole bit rotation speed was as high as 500 RPM and SSRT (string) was 420 RPM. The surface rotary speed was set to 20-50 RPM and 130 RPM output from mud motor. These peak downhole rotation speeds correlate with an increase in surface torque and differential pressure. They also correlate with higher ROP and high lateral/axial shocks at the bit.

The axial frequency spectrum data from the carrier sub does not have any clear definition of axial vibration activity. The lateral frequency spectrum shows that there was stick-slip present with intensity increasing when the maximum rotation speeds were at their peak. The bit from Well #2a was pulled for penetration rate and graded 1-2-CT-S-X-0-FC-PR.

These intervals of very high peak RPM are the most damaging to bit cutters. The PDM output was 130 RPM and the surface rotary speed was set to 20-50 RPM; however, the downhole components were subjected to intervals where the bit was accelerating up to 500 RPM peak and the string was accelerating to 420 RPM peak. To preserve bit life, the peak downhole RPM must be managed to acceptable levels, while still maintaining a fast ROP.

Figure 14 shows a snapshot of data from Well #2b (with SSRT over the same measured depth interval) and **Table 4** gives a description of the drilling dynamics.

The data shows a reduction in peak RPM measured at the SSRT and bit. The maximum downhole bit RPM was reduced to 350 RPM and SSRT (string) was reduced to 120 RPM. The surface rotary speed was set to 40 RPM and 180 RPM from the mud motor. These peak downhole rotation speeds correlate with an increase in surface torque and differential pressure. They also correlate with higher ROP; nevertheless, lateral/axial shocks at the bit were reduced.

It is clear from the data that the magnitude of peak downhole RPM was reduced at both the bit and the string. There was a 64% reduction in peak bit RPM and 28% reduction in peak string (SSRT) RPM compared to the offset well without SSRT.

The axial frequency spectrum data from the carrier sub does not have any clear definition of axial vibration activity. The lateral frequency spectrum shows stick-slip levels were lower using the SSRT with lower intensity when the maximum rotation speeds were at their peak. The bit from Well #2b was pulled for penetration rate and graded 2-3-CT-G-X-0-LT-PR (note this bit drilled 799m further than offset without SSRT).

Overall the data verified that the downhole response of the BHA to stick-slip and torsional oscillations was reduced with SSRT in the BHA. Stick-slip was not eliminated; however, it was successfully “managed” to an acceptable level to improve ROP and increase run length by preserving bit life.

Conclusions

The SSRT proved effective at increasing ROP and run length by “managing” the peak RPM seen at the bit and BHA.

The SSRT downhole performance was validated using downhole embedded sensors. The downhole drilling dynamics data verified a reduction in stick-slip, torsional oscillations and shock levels at the bit and BHA while utilizing the SSRT.

Direct comparison of offset wells through the same formations with the same BHA's and bits provided the ultimate data set for direct performance comparison. The downhole data along with run length and bit dull grading proved the SSRT was effective at improving drilling performance.

Continuous implementation of embedded sensors with SSRT and PDM on every well will allow for performance mapping across the pad or field. Further performance improvements can be realized by continuing to use the embedded sensors while experimenting with different bits and motor power sections.

Acknowledgments

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Nomenclature

BHA = *Bottom-Hole Assembly*
EDR = *Electronic Drilling Recorder*
GPM = *Gallons Per Minute*
MSE = *Mechanical Specific Energy*
MWD = *Measurement While Drilling*
PDC = *Polycrystalline Diamond Compact*
PDM = *Positive Displacement Motor*
ROP = *Drilling Rate Of Penetration*
RPM = *Revolutions Per Minute*
SSRT = *Stick-Slip Reduction Tool*
TD = *Target Depth*
WOB = *Weight On Bit*

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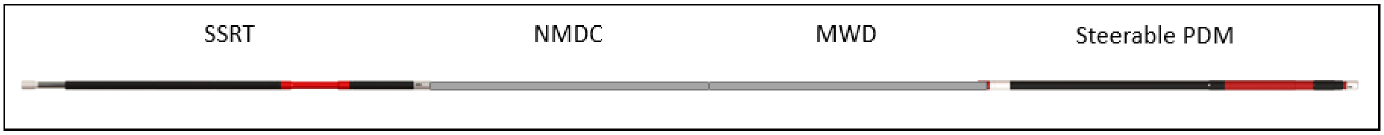

Figure 1: Typical SSRT BHA

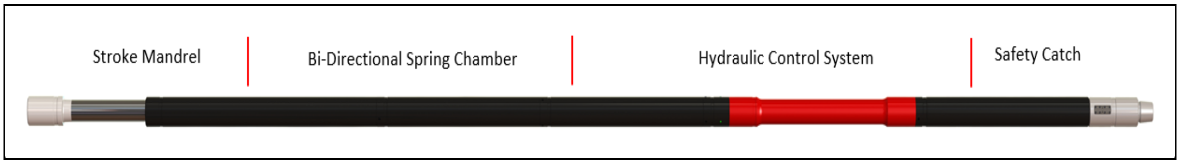

Figure 2: Main Components of SSRT

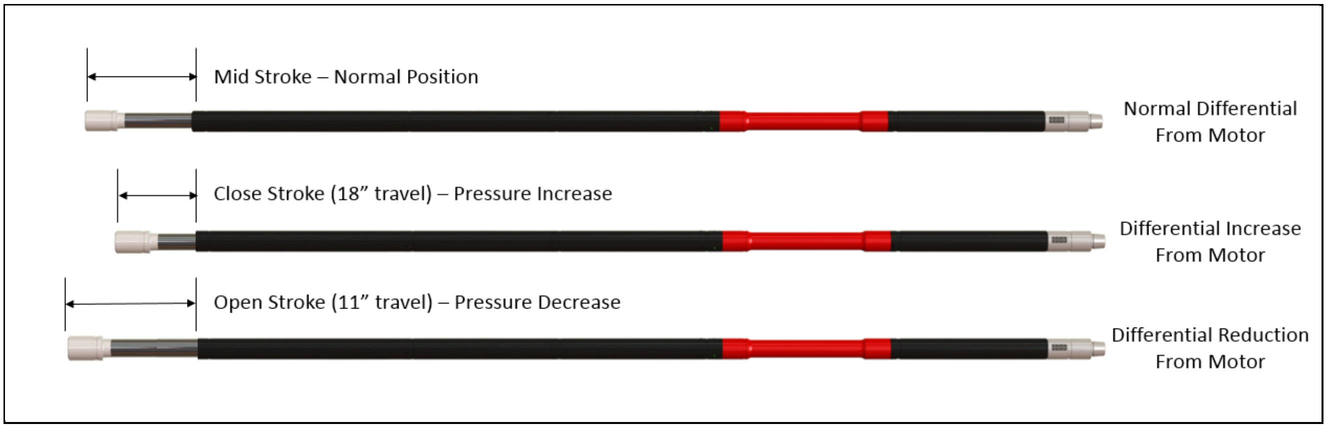

Figure 3: SSRT Length Change Response to Changes in PDM Differential Pressure

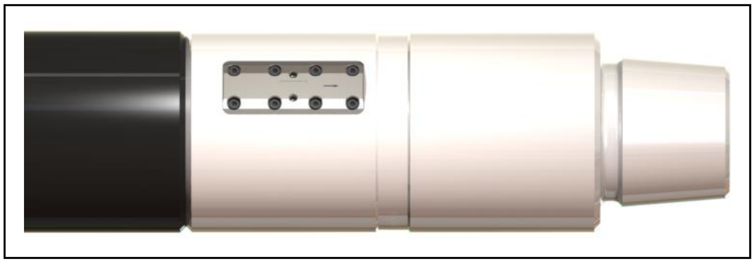

Figure 4: Embedded Sensor under Hatch Cover in SSRT

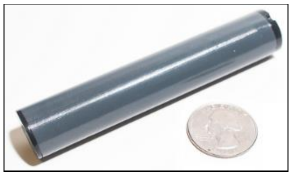

Figure 5: Embedded Drilling Dynamics Unit

Figure 6: Embedded At-bit Sensor in PDM Bit Box

Figure 7: Embedded At-Bit Sensor Installed in a “Puck” Shaped Unit

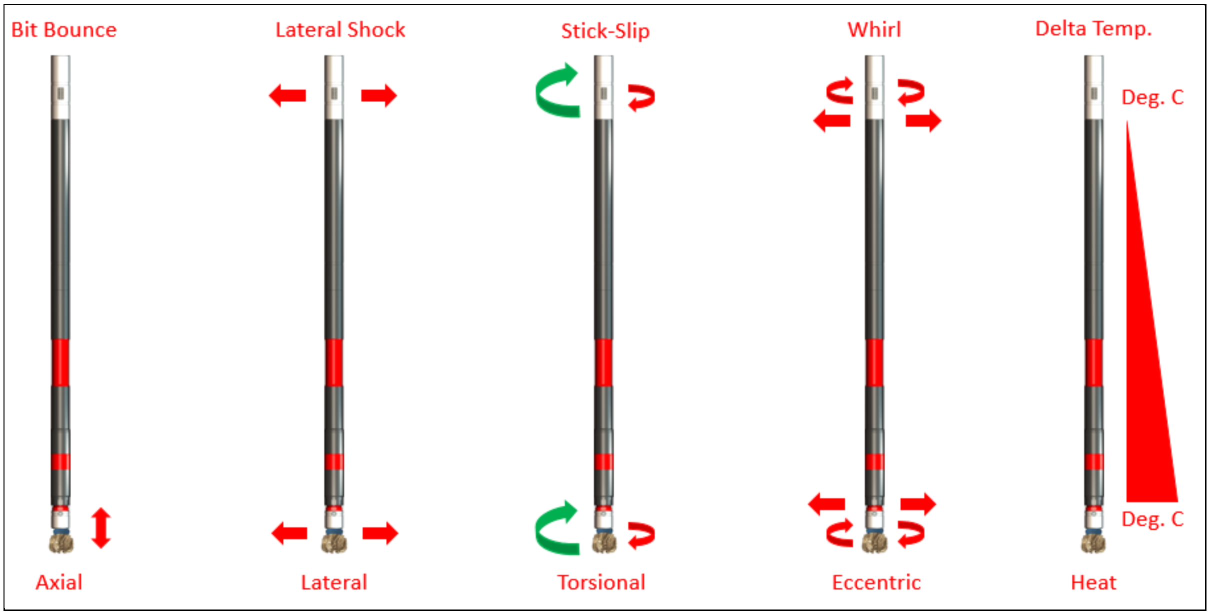

Figure 8: Basic Drilling Dynamic Dysfunctions Measured at Embedded Sensors

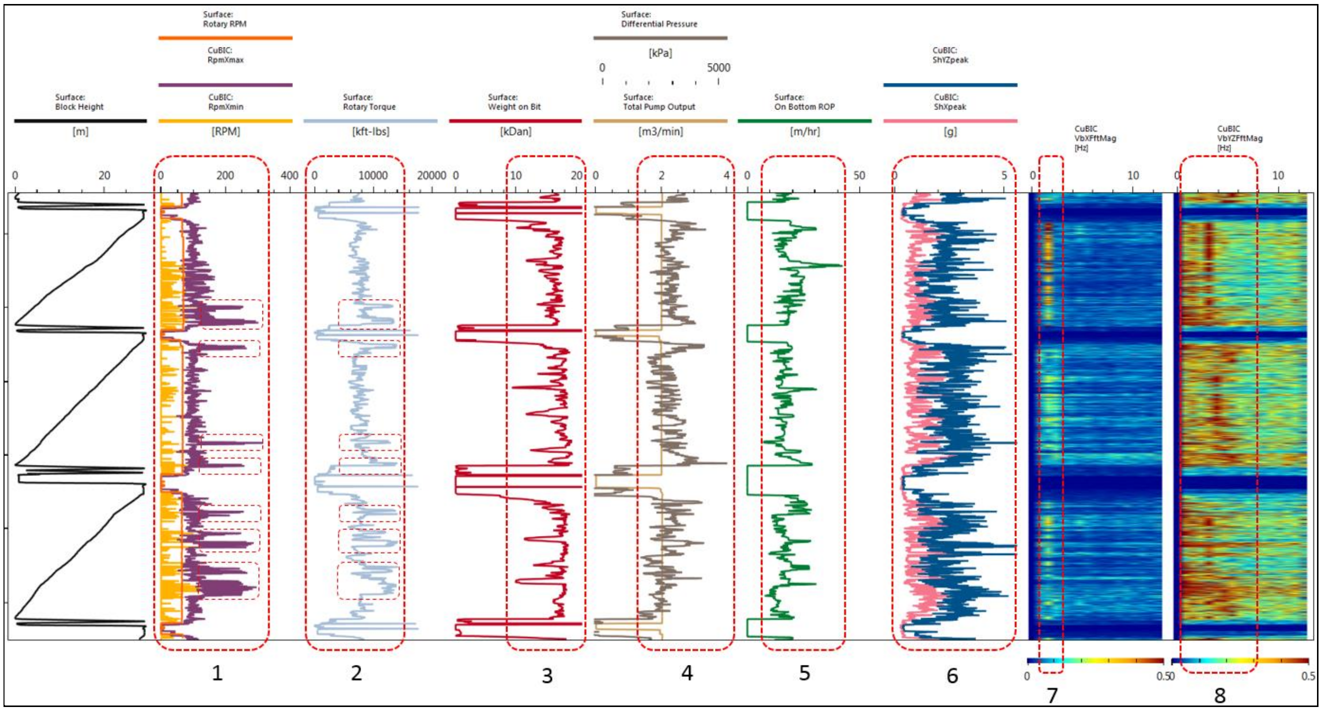

Figure 9: Example #1a – No SSRT (Embedded Sensors in Carrier Sub)

Table 1: Example #1a – Discussion of Drilling Dynamics

Region	Discussion
1	Downhole RPM burst data shows peak maximum values of 240 to 320 RPM. These peak RPM events occur frequently with the longest duration for 10 minutes. Surface rotary speed set to 70 RPM.
2	Spikes in surface torque correlate with peak maximum RPM from burst data downhole.
3	Averaging 17 KdaN (kilodekanewton) WOB.
4	Spikes in differential pressure correlate with peak maximum RPM from burst data.
5	Averaging 18 m/hr. though this interval.
6	Low axial and lateral shocks (less than 5g). Peak shocks correlate with peak maximum RPM from burst data.
7	1.5Hz axial vibration visible on frequency spectrum. Indicates axial vibration possibly resulting from stick-slip.
8	Lateral vibration visible on frequency spectrum. Stick-slip at higher intensity during peak maximum RPM burst intervals.

Figure 10: Example #1a – Bit Dull Photo (no SSRT)

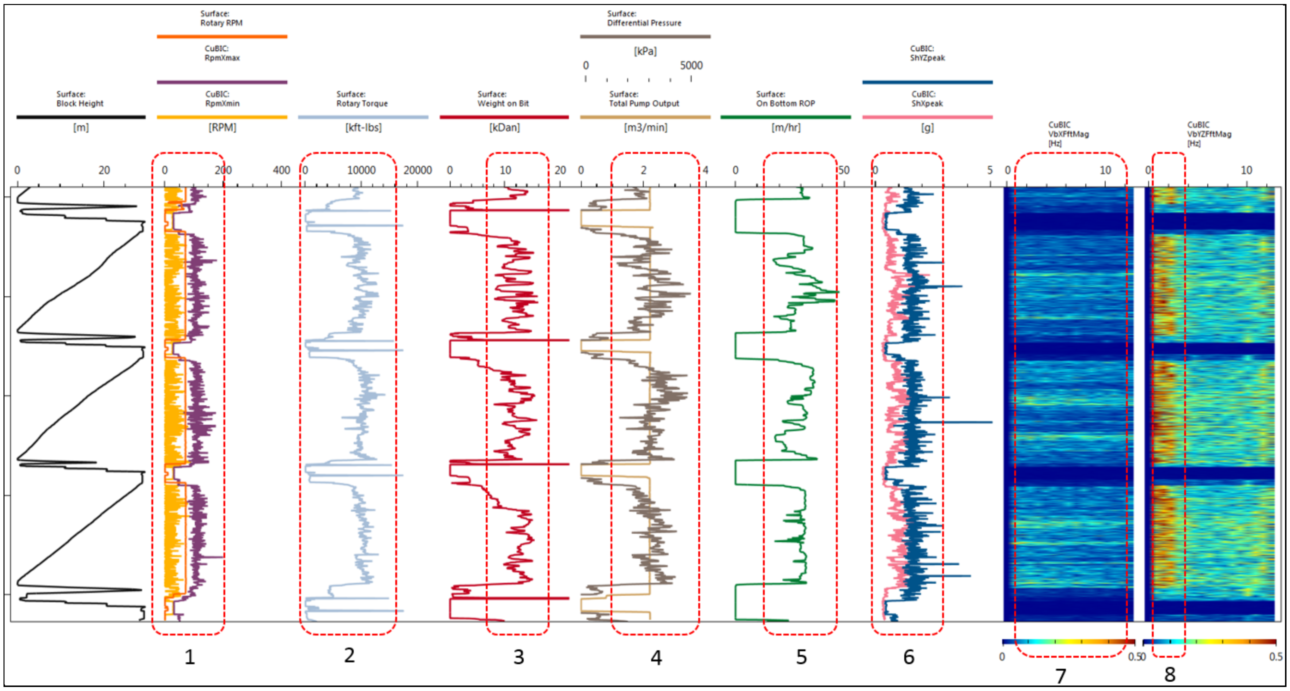

Figure 11: Example #1b – SSRT with Embedded Sensors

Table 2: Example #1b – Discussion of Drilling Dynamics

Region	Discussion
1	Downhole RPM burst data shows peak maximum values of 150 to 175 RPM. This is significantly lower than the 320 RPM experienced on the offset without stick-slip mitigation tool. Surface rotary speed set to 70 RPM.
2	Surface torque is much smoother compared to the offset without stick-slip reduction tool. This is a good indication that the stick-slip reduction tool is functioning.
3	Averaging 13 KdaN WOB.
4	Differential pressure increases/spikes do not correlate with peak maximum RPM from burst data. This is a good indication that the stick-slip reduction tool is functioning.
5	Averaging 30 m/hr. though this interval. Penetration rate is faster with less WOB than seen on offset without stick-slip reduction tool.
6	Low axial and lateral shocks (less than 2g). Shocks are lower than offset without stick-slip reduction tool.
7	No axial frequency visible on vibration spectrum. Indication that stick-slip reduction tool is functioning.
8	Lateral frequency spectrum highlights lower levels of stick-slip which is consistent throughout the interval.

Figure 12: Example #1b – Photo of Bit Post Run (with SSRT)

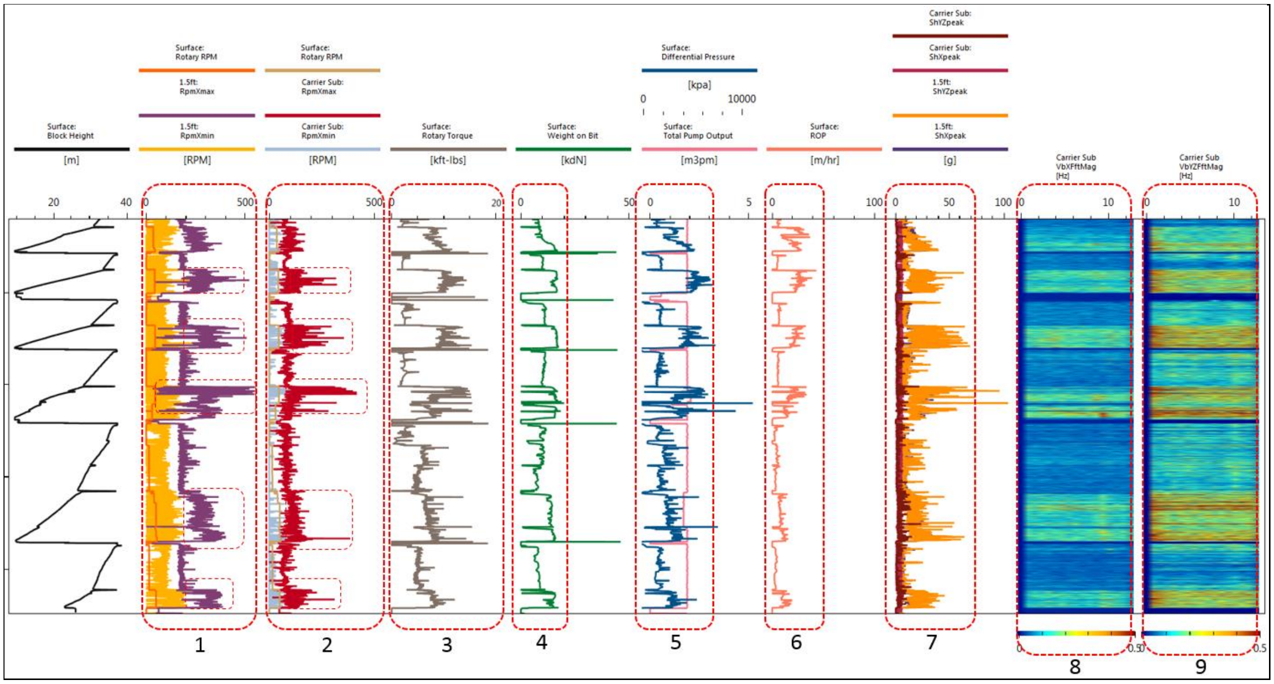

Figure 13: Example #2a – No SSRT (Embedded Sensors in Carrier Sub and PDM)

Table 3: Example #2a – Discussion of Drilling Dynamics

Region	Discussion
1	Downhole mud motor bit box RPM burst data shows peak maximum values of 330 to 500 RPM. These peak RPM events occur frequently with the longest duration for 2 hours. Surface rotary speed set to 20-50 RPM plus 130 RPM from mud motor.
2	Downhole string RPM burst data shows peak maximum values of 160 to 420 RPM. These peak RPM events occur frequently with the longest duration for 2 hours. Surface rotary speed set to 20-50 RPM. String and bit RPM trends correlate well.
3	Spikes in surface torque correlate with peak maximum RPM from burst data downhole.
4	10-16 KdaN WOB.
5	Several motor stalls visible on differential pressure and subsequent pick-up off bottom.
6	Averaging 6-8 m/hr. though this interval. Occasional increases to 24 m/hr.
7	Axial and lateral shocks at bit sustaining up to 30g with peaks up to 70g that correlates with peak maximum RPM from burst data.
8	No distinct features on axial frequency spectrum.
9	Torsional vibration visible on frequency spectrum. Stick-slip at higher intensity during peak maximum RPM burst intervals.

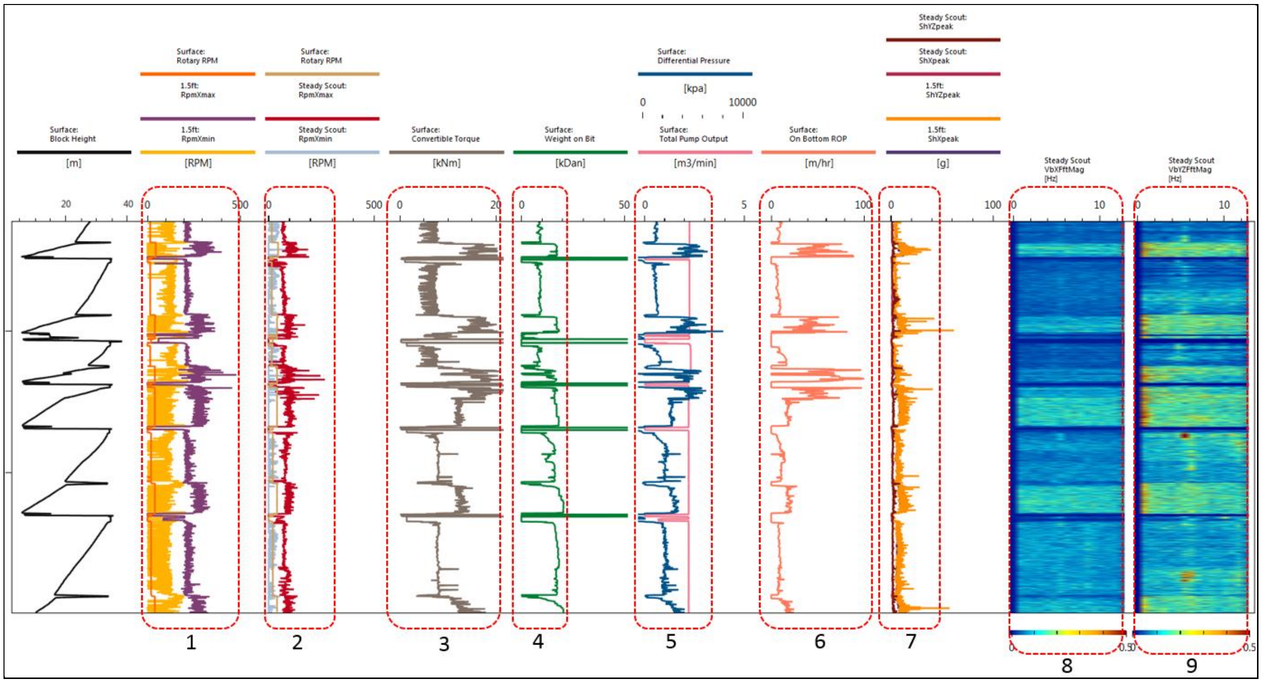

Figure 14: Example #2b – SSRT with Embedded Sensors and PDM with Embedded Sensors

Table 4: Example #2b – Discussion of Drilling Dynamics

Region	Discussion
1	Downhole mud motor bit box RPM burst data shows peak maximum values of 280 to 350 RPM. This is significantly lower than the 500 RPM experienced on the offset without stick-slip reduction tool. Only a few data point spikes above 400 RPM. Surface rotary speed set to 40 RPM plus 180 RPM from mud motor.
2	Downhole string RPM burst data shows peak maximum values of 100-120 RPM. This is significantly lower than the 420 RPM experienced on the offset without stick-slip reduction tool. Surface rotary speed set to 40 RPM. String and bit RPM trends correlate well.
3	Spikes in surface torque correlate with peak maximum RPM from burst data downhole. Downhole RPM remains much more stable and consistent.
4	10-16 KdaN WOB.
5	No motor stalls indicated on differential pressure.
6	Averaging 10-18 m/hr. though this interval. Occasional increases 40-80 m/hr. This is faster ROP than the offset without stick-slip reduction tool.
7	Axial and lateral shocks at bit sustaining up to 12g with peaks up to 40g that correlates with peak maximum RPM from burst data. This is lower than the offset without stick-slip reduction tool.
8	No distinct features on axial frequency spectrum.
9	Torsional vibration visible on frequency spectrum. Stick-slip lower intensity than offset without stick-slip reduction tool.