# DOWNHOLE SENSORS SUPPORT SUCCESSFUL DRILLING REDESIGN INITIATIVE IN THE MIDLAND BASIN

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ABSTRACT

The Midland Basin teaches a hard lesson in drilling harder rock. SM Energy first drilled here in 2008 before launching a successful horizontal drilling campaign in 2013. This work focuses on a successful application of the limiter redesign process supported with downhole sensors.

Whirl suppression generates ROP performance improvements. This objective is complicated with a coupling to stick slip in hard rock applications. High WOB and therefore high torque tends to excite stick slip. Torque oscillations start, speed oscillations follow, and result in inconsistent DOC. Bit forensics on large wear flat shoulder cutter wear and delamination indicate high speed, friction, and heat damage under these conditions. This problem is explored in depth across the interbedded intermediate section of three pilot wells within the operator's southern Midland Basin acreage.

All three wells were drilled in a single bit run to TD and successfully cased and cemented by design. Three high frequency sensors recording at 100 Hz were installed in each BHA – one located in the bit, above the drilling motor, and at the drill collars. High frequency surface measurements were successfully tied to subsurface sensor observations. Good wellbore trajectory design, high ROP, and low planned dog leg severity positively contributed to weight transfer exceeding +97% based on WOB measurements in the BHA. Autodriller setpoint control and tuning unlocked ROP gains between 20-40% in the shallow hole section. MSE is reintroduced. Its practical value in baseline drilling surveillance and benchmarking is confirmed.

The first well is treated as the control in the project. The trial starts with the common bit and BHA for the area with planned parameter step tests performed in each significant formation group. The second and third wells repeat the same workflow with progressive BHA changes to a single component. Depth of cut control is designed and utilized successfully on these wells to reduce torque oscillation. Roller reamers implemented on the final well act as a low torque stabilizer to increase useful torque at the bit. Torque stabilization and minimizations strategies must be paired with sufficient drill string stiffness to maximize performance impact in high WOB applications.

The drilling performance initiative outlined in this paper is meant to be accessible to all drill teams and a call to action to redesign problems to the economic limit, forever.

## INTRODUCTION

The Midland Basin occupies the eastern portion of the Permian Basin in Texas (**Figure 1**) and contains significant stacked pay. Conventional oil exploration started with prolific shallow targets in the Grayburg, San Andres, and Clearfork carbonates. Deeper development followed into the Spraberry and Wolfcamp formations. Henry Petroleum kicked off the 'Wolfberry' play, a hydraulically fractured combination of the two, in the early 2000s (Hollandsworth, 2013).

St. Mary Land & Exploration (now SM Energy) acquired the Sweetie Peck field from Henry Petroleum in 2006 and launched a vertical drilling campaign targeting the Wolfberry. Good reservoir and geoscience work inaugurated a successful horizontal drilling program, beginning with the field's first horizontal

Wolfcamp well (Dorcus 3035H WB) in 2013. From that time on, SM Energy has continually developed the field. Over 147 horizontal wells have been drilled to date, coinciding with the Permian Basin's resurgence in unconventional activity over the past decade.

SM's horizontal wellbore construction follows a three-string design (**Figure 2**). An auger drills the initial hole for the 20' conductor set at 80'. The 17.5" surface hole is drilled down to protect the Edwards Trinity freshwater aquifer, the depth established by the Texas Railroad Commission. The subsequent 12.25" intermediate hole section starts with a shallow smectite-rich clay prior to a series of interbedded sand/salt/anhydrite. Hard laminations are abundant and typically detectable with gamma ray logs. Harder limestone/dolomites follow. The carbonate lithology change is the most significant rock strength contrast before reaching the first set of sandy/shaly Spraberry pay zones. No hard nodules such as chert are appreciably encountered in this hole section. The 8.5" production curve and lateral is drilled into the target pay and are outside the scope of this study.

Vertical groundwork over the past 70 years provides a foundation for fluid selection and casing points in the Midland Basin (Franklin 1952). The shallow formations are drilled through with a 10 ppg brine, the heaviest fluid economically possible to ensure good borehole stability. A basic 8.6 ppg water based gel mud is displaced to 'on the fly' in the lower San Andres to maintain good circulation and cutting returns in the deeper zones. The Upper Leonard and Upper Spraberry are weakened by natural fractures or depletion from historic production. An equivalent circulating density of nearly 8.9 ppg typically fractures these zones and results in lost returns.

The intermediate wellbore is designed with an 'S' shaped trajectory. Directional works starts no shallower than 1000' and targets 1°/100' builds and 2°/100' drops with a maximum inclination of 15° to reduce future artificial lift equipment wear. The wellbore is planned to return to vertical by the intermediate casing point to improve anti-collision design for multi-well pad development.

In 2013, the intermediate hole section took 5 days to drill. Progress by 2020 reduced this to 3 days despite drilling an additional 30% more footage. This hole section is targeted for initial improvement due to its heterogenous lithology and low tool loss exposure. Successful sensor work enables pilot study expansion into the production curve and lateral hole sections.

## REDESIGN DRILLING LIMITS TO IMPROVE ROP

ROP limits for each foot of hole always exist. A continuous workflow to economically extend the onset of these limits will improve drilling performance. As early as 2014, SM drill teams successfully incorporated concepts of Limiter Redesign™ into bit and bottomhole assembly (BHA) work.

Overcoming limiters taught an important lesson in creating change. It is critical to address the risk that prevents a person from changing how the work is done. As example, a significant fear that high WOB would damage the bit prevented raising it. At the time, SM drill teams also believed that polycrystalline diamond compact (PDC) bits required 'breaking in'. On bottom drilling started with low WOB and was only gradually increased. Avoidable bit damage and pulls followed shortly thereafter. The practice was maybe a historic holdover from early material limits in thermally stable polycrystalline diamond cutters (TSP). This does not apply to modern PDC bits.

Understanding and applying basic rock cutting mechanics led to initial ROP gains (**Figure 3**). Performance plateaus trailed the small wins. Implementing a continuous change process was critical to avoid this. The SM drilling team met with Fred Dupriest in 2018 to setup a physic-based workflow and advance its drilling practices.

The author worked with the drilling group to develop good physics-based training material. At any time, there is one main bit limiters which prevent raising WOB (**Figure 4**). The wells drilled by the same rig teams and the resulting bit dulls provided the best teaching aids. Education enables positive change. Rig teams were taught onsite how stuff worked uphole and downhole to do the work differently. This was, and still is, difficult to accomplish.

Basic workflow changes made a positive difference. Rig teams improved photographic collection of bits dulls with digital online storage. Access to good bit pictures advanced the bit forensics program. Analysis of the drilling data from the electronic data recorder (EDR) provider completed the story. The author established a weekly drilling performance initiative (DPI) meeting to discuss limiters with the engineering team in mid 2019.

Hole sections can be drilled, cased, and cemented in in a handful of days in the Midland Basin. The workflow (**Figure 5**) requires a minimum speed to complete and repeat the cycle. Data must be analyzed and understood quickly to change or maintain current drilling practices (Dupriest et al. 2012). The author and the drilling team initiated an analytics project to accelerate drilling analysis in late 2019 to address this deficiency. The target features included rapid rig state detection and summary statistic calculation for rotating and sliding footage by formation. Work is ongoing.

## USE MSE FOR SUCCESSFUL DRILLING SURVEILLANCE AND BENCHMARKING

Modern PDC cutters are not worn down when drilling efficiently. Large changes in ROP are due to downhole dysfunction not rock strength. Mechanical specific energy (MSE) illuminates these dysfunctions. MSE physically reflects how energy input into the drilling process outputs either destroyed rock (ROP) or wasted energy (dysfunction). The idea is old. Both the concept and equation were developed over 50 years ago (Teale 1965). MSE equals rock strength under efficient drilling conditions. Teale confirmed this under lab conditions, but the discovery unlocked a quantitative benchmark of drilling efficiency against rock properties.

MSE consists of a crushing and shearing component. Torque primarily drives MSE due to the shearing contribution. The sources of torque affect the analysis of the drilling system. The original Teale equation was modified accordingly. Mud motors are more commonly used in drilling applications to provide additional bit RPM and torque to the system by converting hydraulic to mechanical energy. Frictional losses from rotating the drill string are ignored which makes this 'Downhole MSE' using a mud motor is the most representative of the bit condition (**Equation 1).**

$$MSE_{Downhole} = \frac{4WOB_{Surf}}{\pi D^2} + \frac{480(K_t \Delta P)(RPM_{Surf} + K_n Q)}{D^2(ROP)} \tag{1}$$

**Equation 1 – Downhole MSE is the best representation of bit efficiency alone. A drilling motor is used in this formulation, accounted for with motor torque and speed factors.**

The top drive rotary and torque are incorporated along with the mud motor contribution as 'Total MSE' (**Equation 2**). The top drive torque response is driven by the BHA-borehole interaction. It can overwhelm the MSE calculation in an inclined hole or a poor borehole quality situation due to the high frictional drag forces. Applying more WOB increases depth of cut (DOC) and bit torque requirements which the top drive and mud motor must generate. As a result, the difference between the Downhole and Total MSE also reflects bit weight transfer efficiency.

$$MSE_{Total} = \frac{4WOB_{Surf}}{\pi D^2} + \frac{480TOR_{Surf}RPM_{Surf}}{D^2(ROP)} + \frac{480(K_t \Delta P)(K_n Q)}{D^2(ROP)} \tag{2}$$

**Equation 2 – Total MSE represents the total work performed by the bit and drill string. This formulation also accounts for torque and speed generated by a drilling motor.**

Both Downhole and Total MSE equations were added to rig EDRs to support real time drilling surveillance. Parameter step tests are essential and maximize the value of MSE. Step tests are performed on the rig site where one parameter is changed while holding all others constant. Reducing drilling dysfunction positively improves ROP and MSE (**Figure 6**). The duration for each step may be 5-10 minutes, long enough to record a stable, observable change on the EDR. Fast ROP can make this difficult in practice, therefore an entire stand may be drilled at one target step. Use MSE as a trending tool to drive better decision making. If MSE increases, drill teams should stop adjusting the target parameter in that direction. If MSE decreases, drill teams should continue adjusting parameters in that direction. If MSE stays the same, drill teams should increase WOB or RPM.

Emerging applications for MSE are in development and equation standardization is a work in progress (Dupriest 2020). The concept of baseline MSE is revived as MSE should equal rock strength when drilling is efficient. In practice, MSE exceeding rock strength by as much as 2-3x is consistently observed in the field. Destroying rock in a ductile rock failure condition is overwhelmingly less effective than brittle rock failure which explains this observation (Ledgerwood 2018). Control over rock failure conditions may be limited due to wellbore stability requirements or cost prohibitive wellbore redesign. Step changes in baseline MSE indicate drilling dysfunction from rock lithology changes and one-way divergences confirm bit damage. If MSE returns to the baseline, the bit is undamaged.

Geoscience support is necessary to develop unconfined compressive rock strength (UCS) logs with sonic log data. A side-by-side comparison of UCS to Downhole and Total MSE with formation tops (**Figure 7**) demonstrate lithology changes and how hard rock can drive certain types of dysfunction (stick slip). Again, large drops in ROP are due to dysfunction, not rock strength.

Campaigns to incorporate MSE into drilling programs are challenging. Implementing MSE alone is insufficient. Continuous improvement workflows and drill team education of how stuff works are critical for success. Improvements in ROP, bit/BHA life, and borehole quality are real and verified (Willis 2018). Initial program kickoff will benefit from using DOC as a gateway to changing drilling decisions onsite and understanding both bit mechanics and MSE (Akyabi et al. 2014). The author recommends compiling a few examples of baseline MSE and DOC plots with formation tops and bit dulls to positively generate interest and start limiter discussions within drill teams.

## <u>DRILLING DYSFUNCTIONS ARE OPPORTUNITIES IN PLAIN SIGHT</u>

Bits are designed to drill efficiently when rotating on center. Bit and BHA rock interaction are the primary source of damaging drilling dysfunction. The specific type corresponds to three main types of vibrations: axial, lateral, and torsional. Bit damage forensics enables clear limiter identification (**Figure 8).** Where dysfunction exists, there is ROP opportunity.

Early PDC bit development in the 1970s identified poor impact resistance as the leading cause of failure (Feenstra 1988). Amoco confirmed this and defined the phenomenon as bit whirl (Brett et al. 1990). Lateral bit instability generates high lateral forces/vibrations, low ROP, and poor borehole quality. A sufficient DOC is necessary to indent the cutters deeper than the chamfer edge to stabilize the cutting structure. Bits have a steady baseline of whirl which cannot be fully eliminated but reduced. Apply higher WOB to increase DOC which suppresses bit whirl, minimizes spiral borehole patterns, and increases ROP.

WOB and ROP have a physically linear relation under efficient drilling conditions (**Figure 4)**. Reducing whirl increases ROP non-linearly and decreases MSE (**Figure 6**). MSE is a whirl log but also useful for understanding torque behavior.

The drill string transfers torque to the bit. Torque oscillations twist the drill string periodically which causes speed oscillations and drill string axial movement. This phenomenon is defined as stick slip (Chen et al. 2020). Stick slip torsional oscillations are normally non-damaging. However, it can progress to full stick slip where a complete stopping and starting of the bit and BHA occurs. High WOB and DOC contribute to this condition.

In full stick slip, the required bit torque to destroy the exposed rock is insufficient which causes the initial stop (stick). Bit RPM decreases to 0, the drill string shortens axially, and DOC decreases. The drill string twists as torque builds up until the sticking phase is overcome (**Figure 9**). Rotating torque drops, rapid bit RPM acceleration (slip) follows, and DOC increases as the drill string lengthens axially. The center cutters are tangentially over engaged which causes the characteristic core out bit damage in the cone. Stick slip can be self-sustaining and coupled to whirl. High instantaneous bit speed lowers DOC and causes lateral impact damage.

Stick slip is the primary vibration observed in hard rock drilling (Ledgerwood et al. 2010). The higher operating torque levels can excite this torsional vibration. In these conditions, the torque signature in MSE may be smoothed out until full stick slip is reached. Relieving the high WOB below full stick levels reduces wasted torque and decreases MSE. Drill teams may increase RPM and reapply WOB to attempt to extend the onset of full stick slip.

Non-bit limiters may also contribute to bit related dysfunctions. Bent motor assemblies are commonly used to drill directional wellbores. The bend causes the BHA to behave as a weighted hockey stick in the borehole. This generates additional bit tilt and sideforce which exacerbates lateral damage. The motor bend should be reduced where possible. The economic limit may be sliding speed for a given directional plan in hard rock. Suppressing whirl through high WOB delivers good quality borehole in spite of using these types of assemblies (**Figure 11**).

Drilling across formation strength contrasts as noted by the gamma ray spikes can generate borehole ledging (Boualleg 2006). Higher WOB increases bit stabilization and decreases bit tilt which can reduce this type of ledging. Higher ROP also reduces borehole spiraling as bit side cutting rate and lateral amplitudes are minimized.

The intermediate hole section was historically drilled with fresh water. Drill cuttings and salt dissolution weighed up the fluid cheaply. A combination of inadequate mud weight and salt dissolution destabilizes the borehole. Poor borehole quality is costly and exceeds drilling fluid savings. Cuttings transport is lowered and lateral vibrations increase as the drill string whips from higher lateral displacement inside the enlarged hole. Sufficient instability leads to wellbore collapses which generates rock cavings (**Figure 12**) and can results in stuck pipe incidents. Calculated borehole enlargement using a fluid caliper when displacing to the water based gel mud often exceeded 200%! Drilled solids are evil (Robinson 2006). The wells are now drilled with heavy brine to improve borehole stability. This lowered borehole enlargement to a tolerable estimated 25%.

## PROGRESSIVE REDESIGN MAXIMIZES USEFUL TORQUE

SM drill teams selected aggressive bits and mud motors with high differential pressure limits to maximize ROP through the intermediate section. This compounds existing problems. Elevated bit torque excites stick slip in harder formations. Additional WOB is also necessary to suppress whirl in higher strength zones. Provided these conditions, the drill team targeted three torque stability and oscillation reduction strategies in the pilot project.

Stabilizing DOC reduces torque fluctuations and therefore stick slip severity. Depth of cut control (DOCC) elements are commonly constructed out of tungsten carbide or PDC material which affects its wear rate. DOCC is placed on the bit and when engaged, prevents additional cutter indention by acting like a bicycle brake pad (**Figure 13**). Additional WOB may be applied to suppress whirl without elevating bit torque. DOCC with too low of a target DOC will curtail ROP. Too high will fail to engage the elements.

Sufficient WOB is required to generate enough ROP at a given bit RPM to reach the target DOC (**Equation 3**). A mud motor typically drives the majority of bit RPM. Therefore, the expected operating GPM must be planned across the hole section. The maximum top drive RPM may be limited to reduce high side forces generated by rotating bent motor assemblies.

$$DOC = \frac{ROP}{Bit\ RPM * 5} \tag{3}$$

**Equation 3 - Depth of cut is calculated from ROP and bit RPM. WOB is built into the equation through ROP which is generated when cutters indent into rock.**

The bit vendor must be engaged to design DOCC properly. Bit geometry and cutter placement profiles can cause complex cutting interactions. Selection of the element material and cutter tip offset culminates in a target DOC to enable the DOCC to rub. Loft plot modeling is useful and should be performed at various expected DOCs (**Figure 14**). As a cautionary note, most modeling reflects concentric rotation of the bit and BHA and may not accurately reflect using a bent motor assembly. While dynamic DOCC technology has been developed to self-adapt to the drilling conditions (Jain et al. 2016), this application was outside of the pilot project.

Efficient drilling control systems are critical to minimize wasted torque. The systems, also called autodrillers, have advanced to handle multiple parameters since their introduction in the early 1860s (Florence et al. 2009). Autodrillers chase these setpoints with drawworks control. The drawworks is spooled with drilling line and behaves like a fishing reel. The line payout speed affects how quickly the drillstring is hoisted or lowered and therefore how quickly WOB is relieved or applied. Avoid over or under braking to yield the smoothest, most efficient drilling.

Joysticks have often replaced brake handle controls**.** The physical feedback from the drilling response assisted the driller on those past rig systems. Modern autodrillers are commanded by proportional, integral, derivative (PID) controllers. The PID controller features are used to reduce system errors when compared to a target parameter setpoint (**Figure 15**).

Autodrillers can be complex. The original rig systems may be overridden with aftermarket software. Initial setpoint control should be addressed first. This is the cheapest source of ROP performance improvement in the drilling system. ROP set points should be set out of the way to prevent WOB from oscillating and generating downhole dysfunction (**Figure 16**). In practice this may be setting ROP 100-150 ft/hr above the current operating range.

Gain settings control the drilling line speed at which the drawworks eases off or applies WOB. While WOB and ROP have a physically linear relationship, the slopes are different for soft and hard rock in practice. It is appropriate to have a more reactive system in soft rock and less reactive in hard rock. Controller software should be upgraded to easily change a group of gain settings (**Figure 17).**

The rig in (**Figure 15**) was originally built with an IEC controller. The drilling contractor installed their own controller design to override the IEC on the backend. The proportional gain for each setpoint was controlled as a % of a %. For example, if the P-gain value is 1.0, with a maximum gain adjust setting of 20% the 'setpoint' gain from -100 to +100 gives the driller a 0.8 -1.2 P-gain range. Tuning is difficult without drilling contractor support.

SM drill teams previously encountered unstable control systems on older rigs. Rig teams reported chaotic drill string axial movement on surface. Bits experienced significant axial damage which resulted in premature pulls. Shock sub were required in the vertical and early horizontal drilling program. Late campaign rigs and controller upgrades enabled dropping the shock subs with no noticeable degradation to bit dulls or performance.

Properly tuned autodrillers with good setpoint control improves drilling efficiency. Tight control on WOB within 5 klbs or less is achievable. A clear sign of poor setpoint control is 'painting the screen' with high and low WOB values. In practice, the setpoint instability may be interpreted as 'ratty drilling' by rig teams. This has been confirmed even in fields with long drilling programs (Pastusek et al. 2016).

Ultimately, ratty drilling is self-induced by drilling systems (**Figure 18)**. Rock strength is not changing every 5'. In the case above, two different autodriller systems across two separate rigs drilled an intermediate section offset of each other. Although autodriller WOB and ROP setpoints are not available to plot on the EDR, it is possible to detect the setpoint limiter. WOB is oscillating heavily due to the autodriller hitting a likely ROP setpoint of 275 fph on Rig 1. The same oscillation occurs with Rig 2, but the WOB oscillation amplitude is lower and at an ROP setpoint exceeding 575 fph. Again, the ROP setpoint should be set out of the way to reduce WOB oscillations.

The weight fluctuations are real and cause both torque and differential pressure oscillation. MSE is higher as a result and drilling is less efficient with the Rig 1 system. Shallow bit balling is a valid concern due to the significant difference in GPM pumped by both rigs. However, this is a poor example of balling which would cause low ROP at high WOB. WOB should be stabilized first and then elevated until balling occurs at a higher GPM.

The final torque reduction strategy is using roller reamers in the BHA. Roller reamers behave as low torque stabilizers and improve useful torque transmission to the bit without initiating stick slip (**Figure 19**). Lateral vibrations conversion into torque is reduced which decouples lateral and torsional BHA vibration (Sowers et al. 2009).

Loss of the roller element is real concern. Tool advancements have reduced this risk. Dual mechanical block seals (inner and outer) are installed above and below the reaming element which have been successfully used to improve roller retention. Open seal bearings should be avoided at all costs. Tungsten carbide inserts provide greater impact resistance and low torque generation. Cute rite or PDC elements should be avoided to prevent producing additional torque.

The operator's previous experience with roller reamer implementation in the field dates to early 2014. In the year prior, dual full gauge (12 ¼") integral blade stabilizers (IBS) were installed in the original BHAs during initial horizontal field development. The drilling reports on poor bit dulls are consistent with high torque generation due to the packed BHA design. The whirl sine wave cannot pass through the BHA and the energy is violently dissipated within the system.

## SENSORS MUST RECORD DATA AT A RESOLUTION THAT MAKES SENSE

The right data resolution is necessary to detect downhole dysfunction signatures. This is no different than wearing the right powered reading glasses for corrective vision. The primary sources of bit damage are whirl and stick slip. The observed typical frequencies for both are detectable under 10 Hz (Baumgartner and Oort 2015). EDR providers commonly transmit drilling data at 1 data point/s (1 Hz) where this is visible and actionable in real time.

One pilot project objective is to extend the downhole signal detection to surface data, which is lumps the entire interaction of the bit-BHA system together. Downhole sensors illuminate where and which kind of vibration is happening. The pilot BHA across all three wells was designed to record data at bit, drilling motor, and above the BHA into the drill collars where these damaging vibrations could occur (**Figure 20).** Sensor selection is important. Magnetometers/gyros, accelerometers, and strain gauges provide RPM, vibrations, and torque/WOB readings respectively. Unfortunately, the magnetometer data on the subs was incomplete. Data did not exist in two transverse axes to determine if forward or backward whirl was occurring (Bowler 2016). Ultimately, sensor vendors must be engaged on measurement limitations and tool battery life for successful data capture.

The rig contractor provided higher resolution torque and pressure readings (40 Hz) for the trial well 2. The directional drilling company delivered mud pulse MWD vibration data. Downhole stick slip index (DSSI) and surface stick slip index (SSSI) were calculated (**Equation 4** & **Equation 5)** to provide insight into stick slip downhole with bit RPM and RPM at the subs above the motor and at the drill collars (Lai et al. 2016).

$$DSSI = \frac{max(\omega_b) - min(\omega_b)}{2 * avg(\omega_b)} \tag{4}$$

**Equation 4 - Downhole stick slip index calculated using angular speed at the bit.**

$$SSSI = \frac{max(T_b) - min(T_b)}{2 * avg(T_b)} \qquad (5)$$

**Equation 5 - Surface stick slip index calculated using surface torque.**

The high-resolution rig and sensor data hides information that cannot be detected with log plot diagnostics. An isolated poor weight transfer event occurred where WOB differed as much as 10-15k lbs across the two sensor subs (**Figure 21**). This was likely caused or sustained by severe stick slip at the bit occurring at the time based on minimum bit speed measurements reaching near 0. The bit stick slip index approached and reached 1 across this period, also providing supporting confirmation.

Viewing the magnitude of the high-frequency data over this period was insufficient for interpretation. A fast Fourier transform (FFT) was performed on the torque and vibration data available and plotted as a spectrogram to view the signal as an image. The strong torque (**Figure 22**) and vibration (**Figure 23**) frequency traces over the event confirm expected stick slip (<1 Hz), bit speed (3.7 Hz), and mud motor stator rotation (13.10 Hz). The MWD shock data was captured at too low of a resolution at nearly one data point per minute to corroborate the higher resolution data. Strong signal agreement exists across the top drive, subs, and bit data. The data confirms the expectation on a shared strong frequency between torque and speed - torque oscillations physically drive speed oscillations. Properly captured surface data can provide critical subsurface insight without downhole sensors in the right application.

Although root mean squared (RMS) data is often available from the MWD provider, the purpose is typically for tool vibration mitigation rather than drilling dynamics. Indices such as DSSI are valuable and may be calculated by tools downhole prior to surface transmission. Resolution speed may be improved by switching from mud pulse to electromagnetic systems. The switch will also mitigate motor RPM fluctuations as mud pulse telemetry does not generate a static pressure load as frequently expected.

High resolution surface torque data sources must be selected and analyzed carefully. Surface WOB compared to WOB at the drill collar sub indicated under measured between 60-80% across all three wells. Top drive torque subs are reliable and may be used to validate surface torque and WOB measurements (Lesso et al. 2011).

## TRIAL WELL PERFORMANCE PROVIDES VALUABLE INSIGHT

Suppressing whirl and stick slip were primary targets in the trial and progressive redesign. The initial project was driven by concern about weight transfer due to either BHA lateral vibration chatter (Bailey et al. 2020) or trajectory related drag (Pink et al. 2011). This was unfounded. Weight transfer across all formations and wells generally averaged at +97% across the two BHA sensor subs. Low planned inclination with measured dog leg severity (DLS) < 3° and routinely < 1° drilled at high ROPs minimized trajectory and borehole quality related drag.

Step tests were planned and implemented on all three wells (**Figure 24**) to extend the value of baseline MSE surveillance and sensor recordings. The trial well 1 was used as the initial baseline well with the most common bit and BHA. The second trial well, utilized the same BHA with bit DOCC set to 0.35 in/rev. The third and final trial well , built upon previous designs with an undergauge (1/8”) roller reamer in place of the single string IBS and bit DOCC set to 0.55 in/rev.

GPM step tests were discontinued after the first well. Stalling was observed at low flow rates for the selected motor and the process of having to pick up (restart drilling) to change the flow rate was prohibitive. Documentation of the step tests on the daily drilling report and holding the parameter constant long enough to draw a line on the EDR enabled a good lookback on the step tests. The shallow step tests above the San Andres formation were typically uninterpretable due to significant WOB oscillations which negated the step test stability.

The trial well 2 generally outperformed rotating ROP in the baseline and final wells in formations shallower than the San Andres (**Figure 25).** All three wells performed similarly in the deeper formations with the final well (trial well 3) slightly exceeding the second well between 5-20% in the last two Spraberry formations prior to the target casing point. ROP performance from autodriller set point stability ranged from 20-40% when comparing the trial well 2 to the trial well 1 and trial well 3.

No observable damage was observed post-drill on the BHA equipment across the three wells (**Figure 26** & **Figure 27**). The field has no history of significant BHA equipment damage or abrasion wear. The mud motor inspection also yielded passable wear condition for the baseline trial well 1 (**Figure 28**). No pictures were available on the trial well 2 although slight chunking of the stator was reported. Provided that mud motor power section wear typically occurs towards the bottom of the elastomer due to frictional heat buildup, the motor teardown is consistent with expectations. Severe stick slip causes motor stalls which deform the elastomer and contribute to premature motor damage.

DOCC design efforts were mostly successful (**Figure 29**). The author mistakenly selected tungsten carbide DOCC element material on the 2nd well. The 0.35 in/rev target restricted ROP until the elements fortunately wore down past 2000'. The 3rd well used a PDC element design with a DOCC 0.55 in/rev target that also engaged but did not limit ROP. Both wells successfully engaged the DOCC elements as confirmed by the visible rubbing patterns on the elements.

All three bits drill for several thousand feet past the San Andres with whirl and poor DOC in hard rock as noted by the step change in baseline MSE (

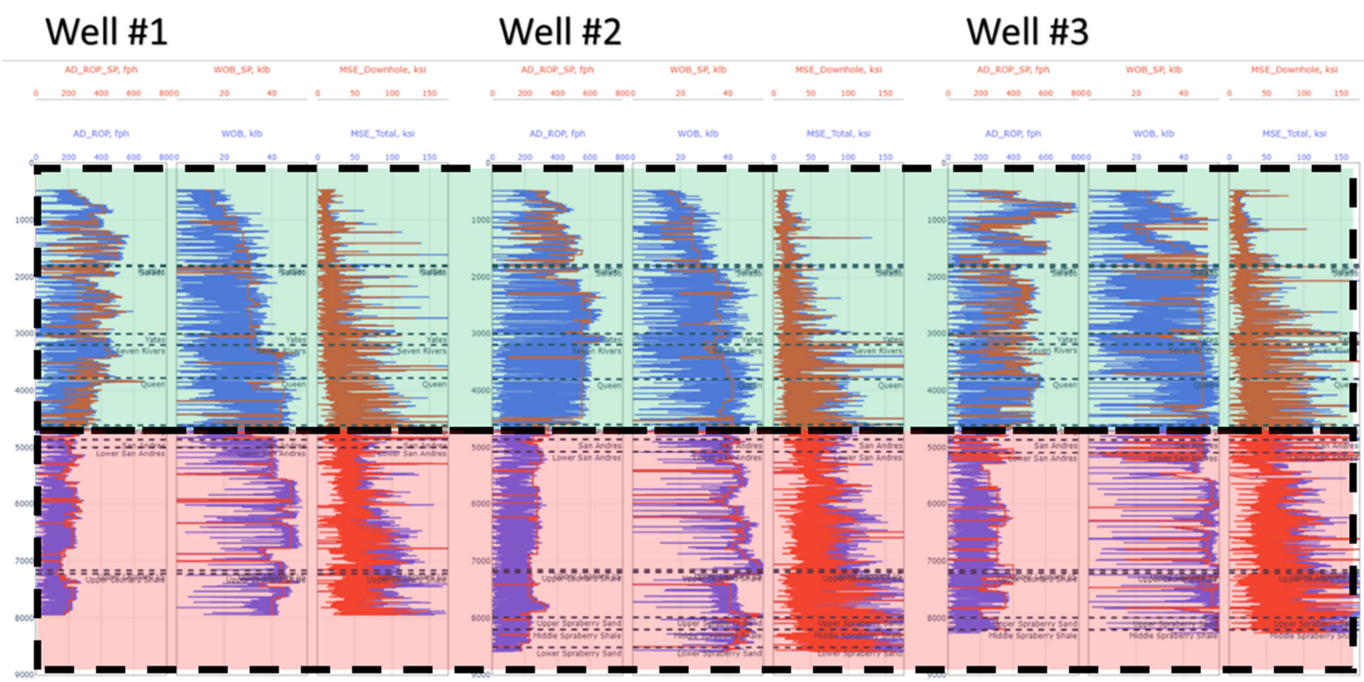


**Figure 33**). Bit dulls across all three wells indicate severe shoulder damage from whirl coupled with stick slip oscillations. Bit forensics and drilling surveillance rule out full stick slip due to the lack of cone damage.

Significant cone cutters pocket loss the trial well 2 bit run was attributed to manufacturing quality control rather than bit dysfunction. Cutter braze issues were reported by the bit vendor for both the cone and shoulder. This is supported by the good pocket integrity despite the complete cutter loss.

The bit secondary cutter exposure is set below the primaries on these bits. Their wear is not consistent with a backward motion of shearing through the substrate and diamond table from either backward whirl or full stick slip. Beachmarks from frontal impact damage due to whirl are limited and non-distinguishable on the delaminated cutters. Delamination is a consistent dull pattern across all three bits.

Aggressive bits are typically designed with low cutter backrake to generate more bit torque for a given DOC. Drilling efficiency improves. The tradeoff is lowering the clearance between the carbide substrate and polycrystalline diamond table. Additional rubbing surface exposure accelerates heat buildup across the less thermally stable carbide. Increasing DOC further exacerbates this problem and contributes to large wear flats.

Prolonged high cutter speed produces excessive frictional heat. Thermal degradation is followed by diamond table splintering/spalling and then cutter failure. Lab bit thermal damage matched bit dulls from drilling hard calcite stringer in the Troll field (Roberts and Hæreid 2013). Drill teams in the Pinedale observed identical wear pattern in similar hard rock drilling and reported a form of stick slip - synchronous torsional oscillations (STO) - as the primary contributor to bit damage (Mann 2015).

Across all three wells, the bit is soaking up heat from poor DOC and severe stick slip. Dually, whirl is still the problem. Higher WOB is necessary to suppress whirl in hard rock. It is clear from applied surface WOB and good WOB transfer across sensor subs in the BHA that additional cutter indention is not occurring despite higher WOB. The high WOB excites and further drives stick slip. DOCC torque stabilization and roller reamer lateral force and torque decoupling are helpful but inadequate. Drillstring stiffness is the limiting factor. Increasing the stiffness with larger drill pipe will provide the most drilling improvement to reduce stick slip and improve whirl suppression (Davis et al. 2012). Pair this with the previous torque reduction strategies, a properly tuned autodriller, surface speed oscillation (soft torque) technology, and modified cutter edge geometries for maximum performance impact.

## CONCLUSIONS

Drilling redesign workflows are critical to continuously improving performance. Drill teams must identify limiters and drilling engineers economically redesign the onset of these limits. Drilling analytics are non-negotiable to effectively sustaining the redesign workflows in an era of accelerated wellbore delivery. Use MSE. It is driven by torque and physically related to rock strength. Baseline MSE benchmarking and MSE surveillance is effective when combined with drill team education on bit mechanics and DOC. Non-bit limiters must also be economically considered and may present the largest opportunity to good quality borehole delivery.

Ratty drilling is self-induced. Stable autodriller systems are a source of hidden ROP performance and downhole dysfunction reduction. Understanding autodriller setpoint control provides immediate ROP improvement. Gain setting tuning also minimizes WOB oscillation and further improves drilling efficiency. Work with the drilling contractor to effectively tune autodriller systems.

Sensor data must be recorded at the appropriate resolution to capture drilling dysfunction. Downhole subs are useful for qualifying new tools and accelerating insight into possible dysfunctions downhole. High frequency surface measurements can confirm subsurface observations without downhole sensors. Use index calculations on low resolution data to support bit forensics and real time surveillance. Spectrograms are useful to visualize signals and uncover value in high resolution data.

A smooth wellbore with minimal inclination and low DLS improves weight transfer. Whirl is still the primary limiter for all hole sections. Stick slip is negatively coupled to this in hard rock drilling. High WOB necessary to suppress whirl in hard rock but the resulting high torque can excite stick slip in these conditions. Large cutter wear flats and delamination indicate inefficient drilling at high heat/friction. Torque stabilization and minimization tools and techniques are helpful but insufficient alone. Drill string stiffness is a significant limiter in high WOB hard rock drilling. Drill with larger drill pipe to provide enough torsional stiffness to reduce BHA torque and speed oscillations. Bit efficiency follows as stick slip reduction improves useful torque transfer to the bit and DOC stability.

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## NOMENCLATURE

| | |
|---|---|
| ω | Angular velocity (RPM) |
| BHA | Bottom hole assembly |
| D | Bit diameter (inches) |
| DLS | Dog leg severity (degrees) |
| DOC | Depth of cut (in/rev) |
| DOCC | Depth of cut control |
| DSSI | Downhole stick slip index |
| EM | Electromagnetic |
| Kt | Motor torque factor (kft-lbs/psi) |
| Kn | Motor speed factor (RPM/GPM) |
| MSE | Mechanical specific energy (ksi) |
| ∆P | Differential pressure (psi) |
| PDC | Polycrystalline diamond compact |
| PID | Proportional integral derivative [controller] |
| Q | Flow in rate (GPM) |
| RMS | Root mean squared |

ROP Rate of penetration (ft/hr)
RPM Rotations per minute (rev/min)
SSI Stick slip index
STO Synchronous torsional oscillation
T, TOR Top drive torque (kft-lbs)
UCS Unconfined rock strength (kpsi)
WOB Weight on bit (klbs)

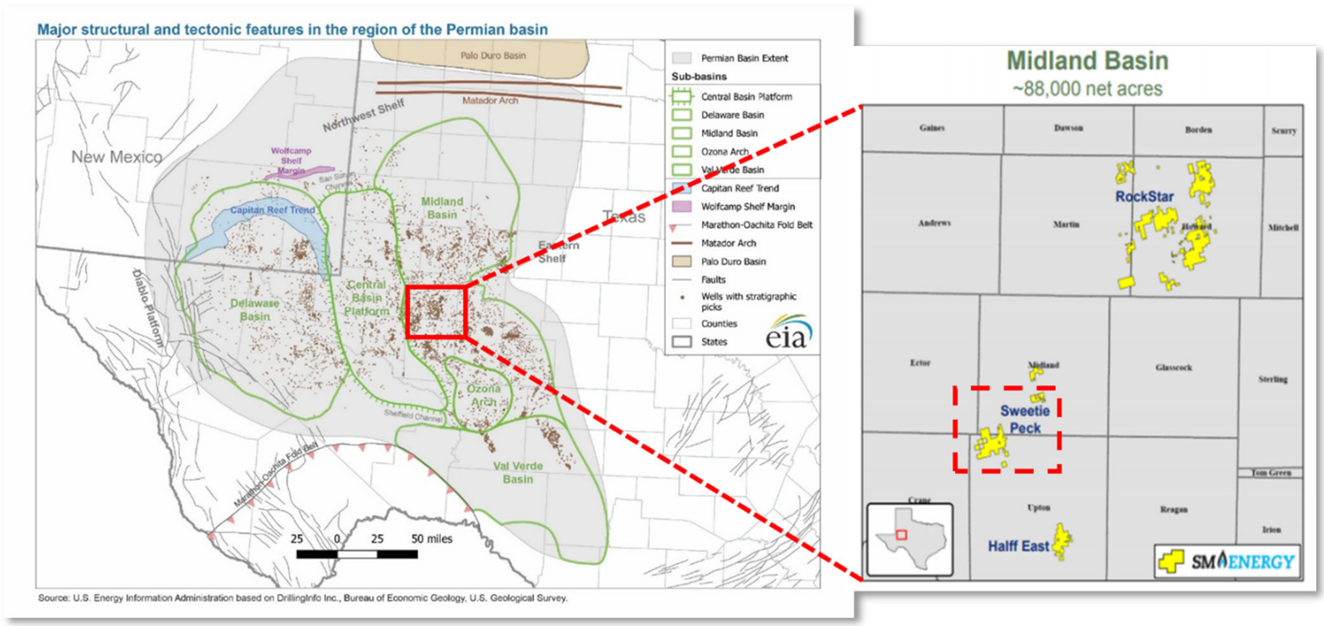



**Figure 1 - Permian Basin Regional Map (EIA 2019) with SM Energy Study Field (Sweetie Peck) outlined.**

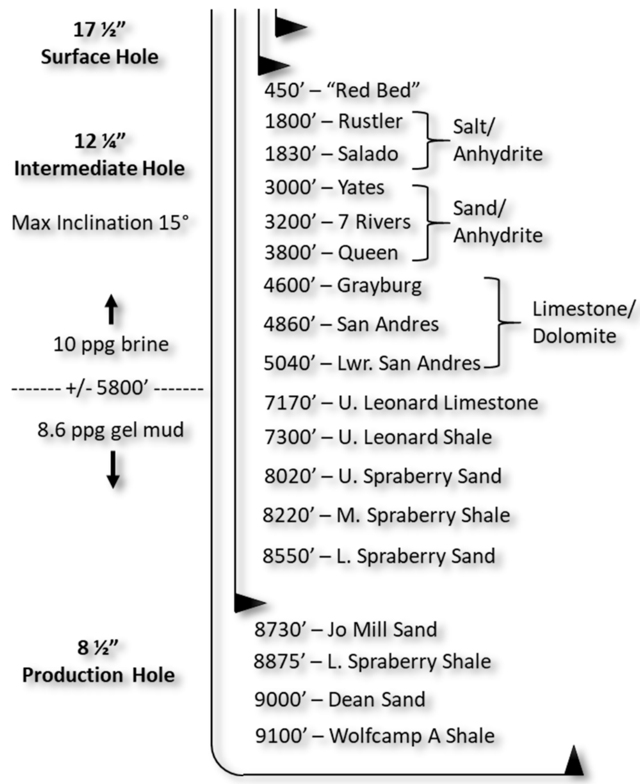



**Figure 2 – Midland Basin common wellbore construction with a three-string casing design, intermediate fluid systems, and formation lithology.**

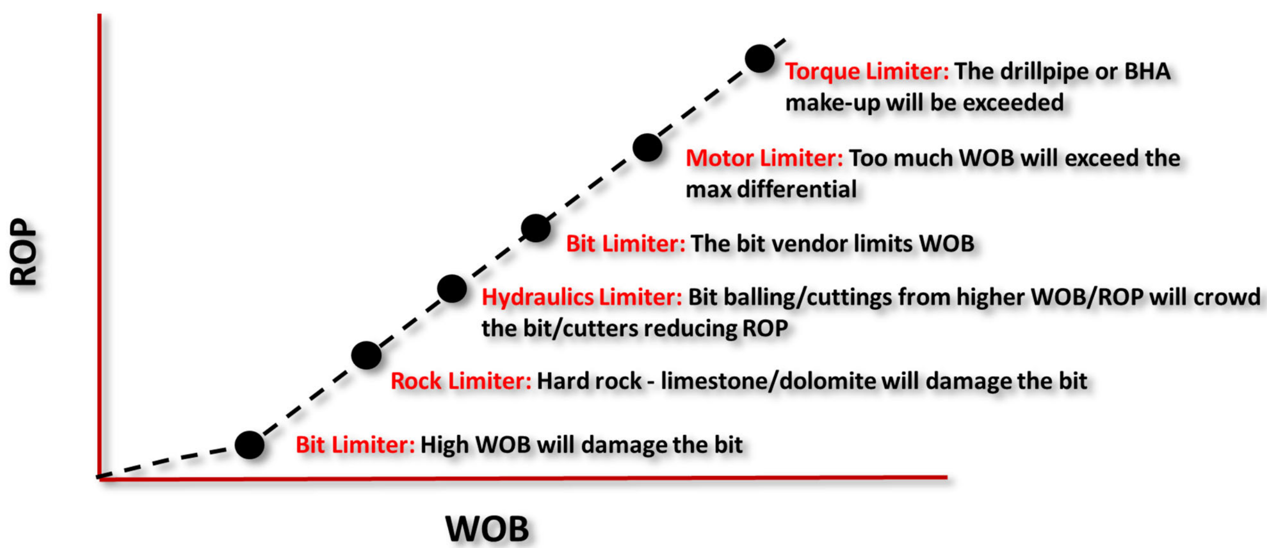



**Figure 3 – Identify and resolve limiters to improve performance. New knowledge addresses existing risks and enables drill teams to change and overcome the limiter.**

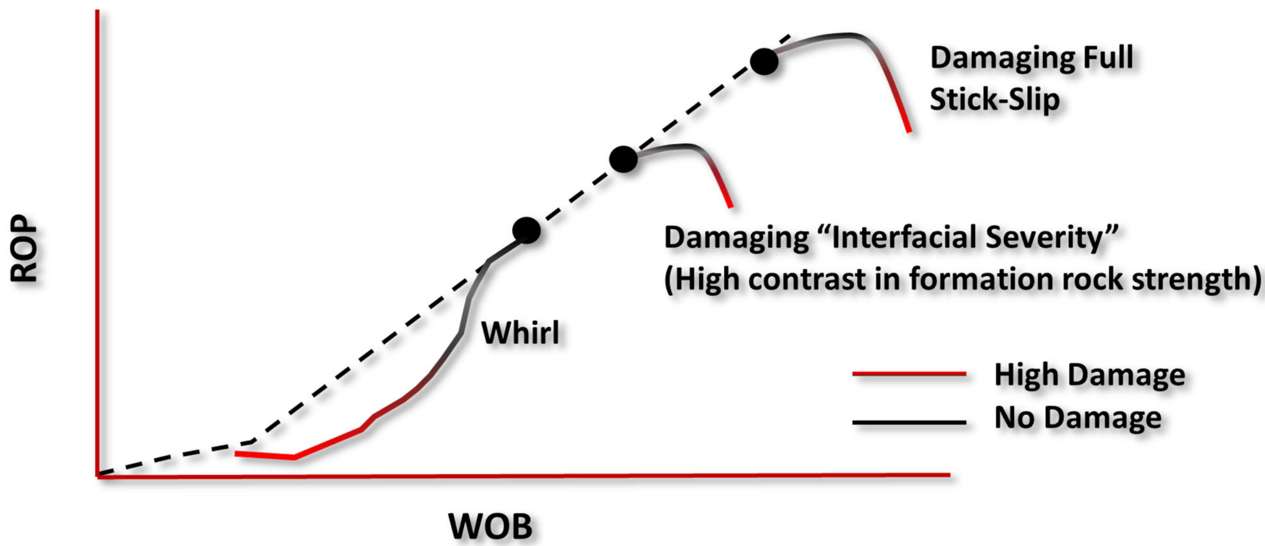



**Figure 4 - Same ROP vs WOB curve. New bit limits are revealed. Understanding the root limiter enables drill teams to change and overcome it.**


**Figure 5 – The Plan-Do-Analyze workflow (Dupriest 2014)**

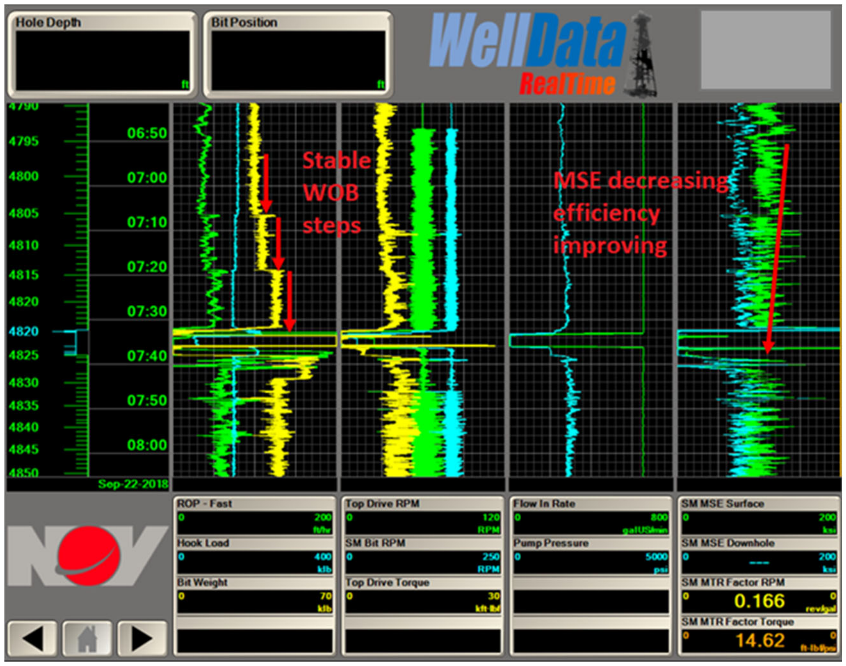



**Figure 6 – Step tests enable drill teams to identify limiters to raising WOB/RPM. Hold all other parameters constant except for the one being changed to successful perform a step test. WOB is increased in this step test to suppress whirl and ROP/MSE positively changes as a result.**

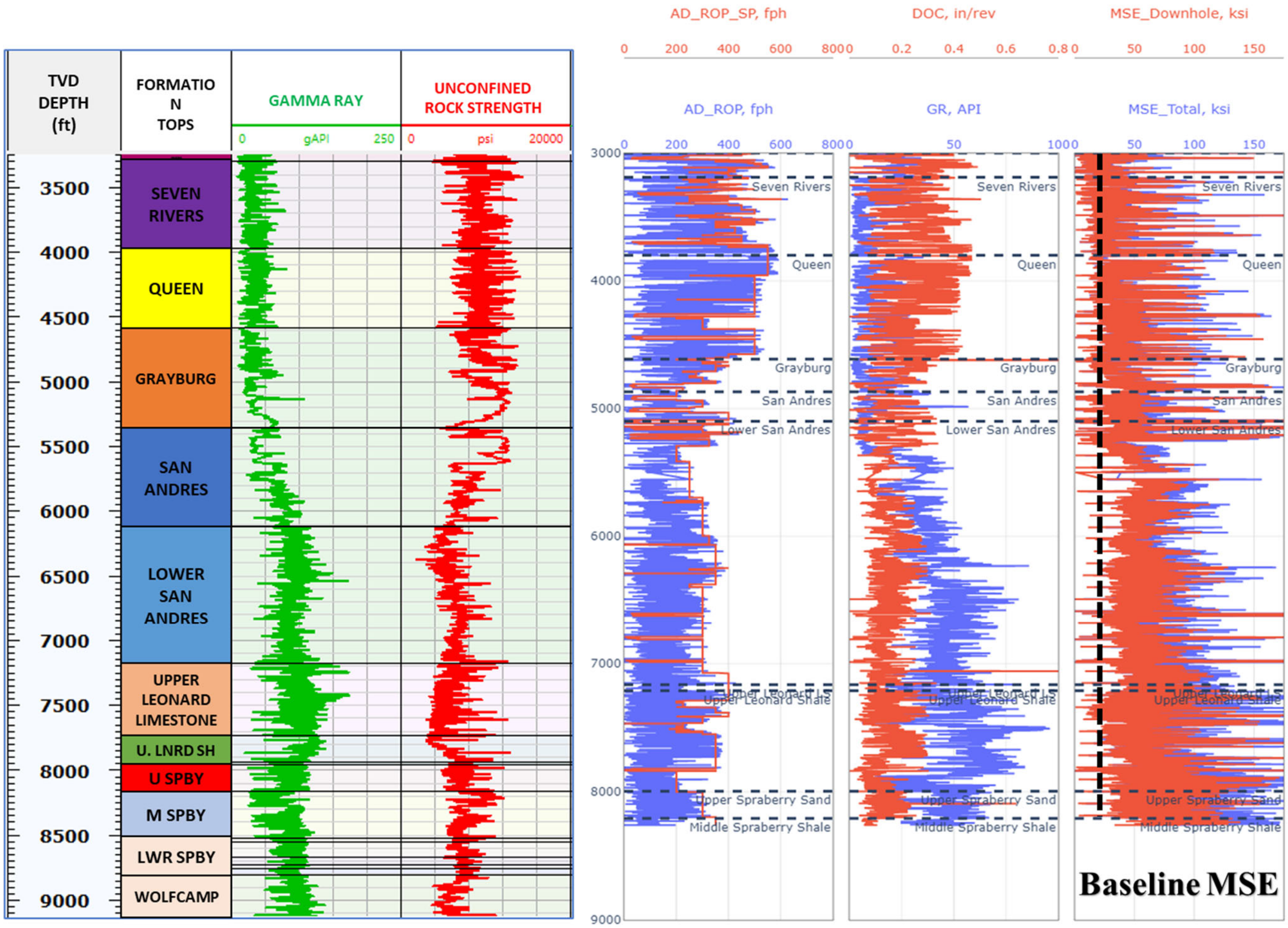



**Figure 7 - Hard laminations observed from ROP and gamma ray match the streaks in modeled UCS. Baseline MSE indicates a 2x increase in rock strength across the San Andres. There is downhole drilling dysfunction, the rock did not become 2x stronger.**

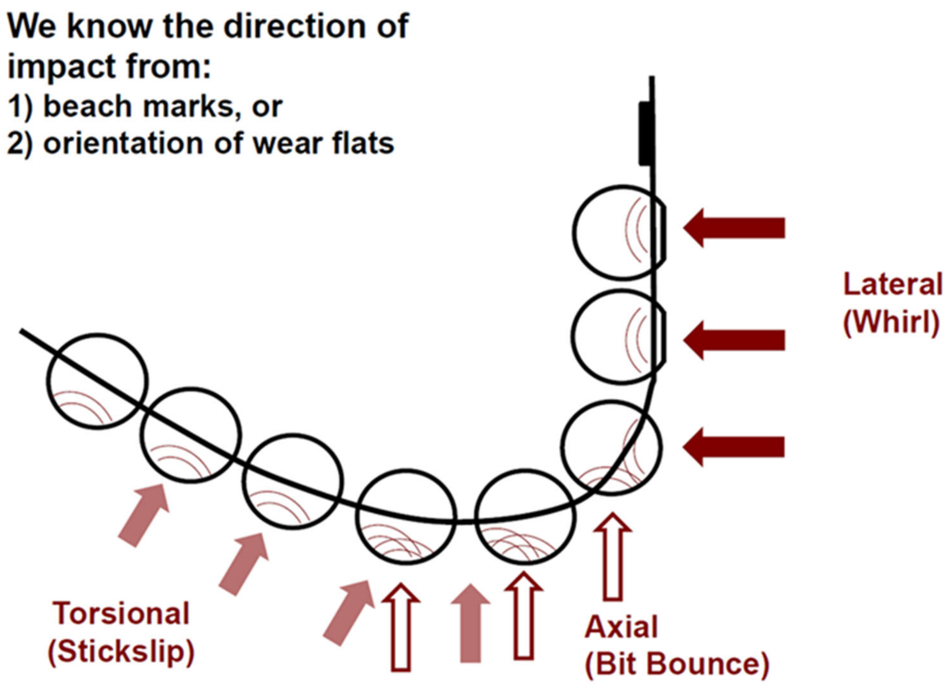



**Figure 8 – The bit damage location and cutter conditions uniquely confirm the type of damaging dysfunction (Dupriest 2014).**

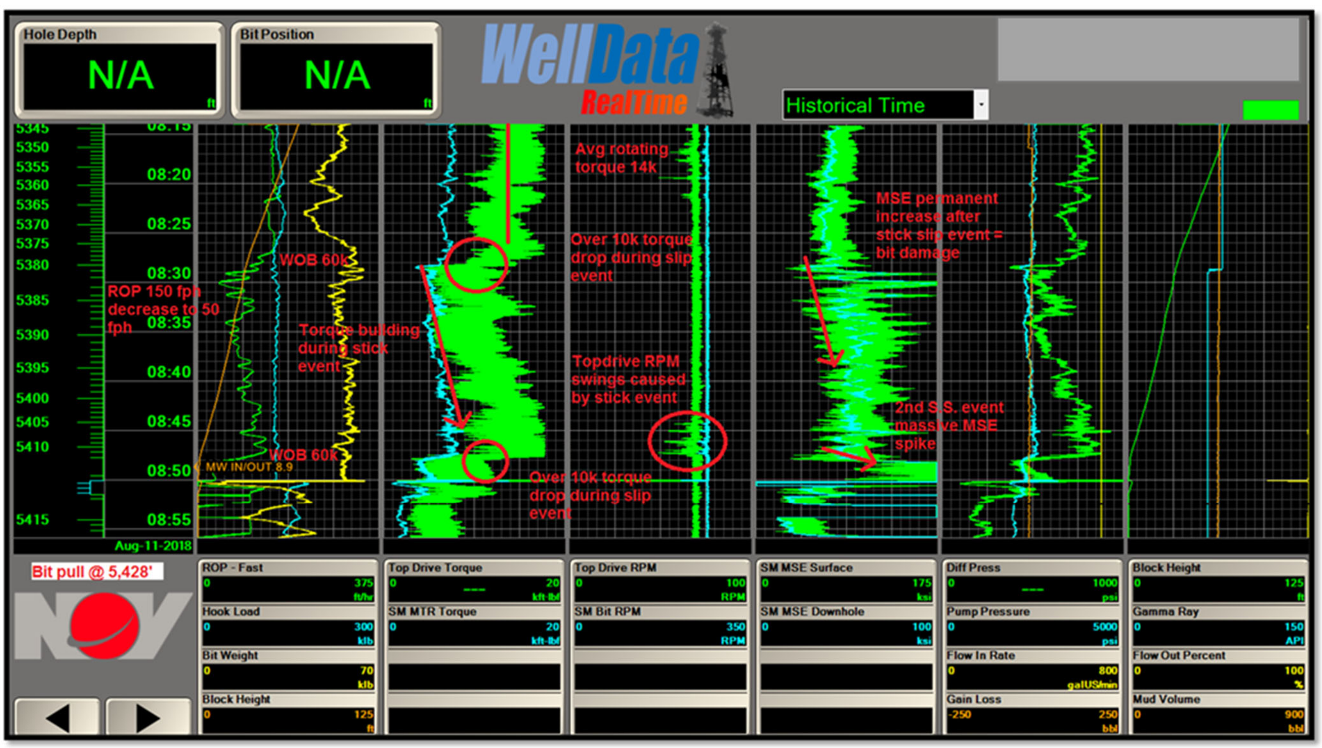



**Figure 9 – An offset well drills through the hard San Andres formation. Top drive torque exhibits a sawtooth behavior in full stick slip. The stick phase causes a high torque ramp which is followed by an immediate drop during the slip phase. Full stick is also clearly observed with the same pattern in differential pressure and MSE.**

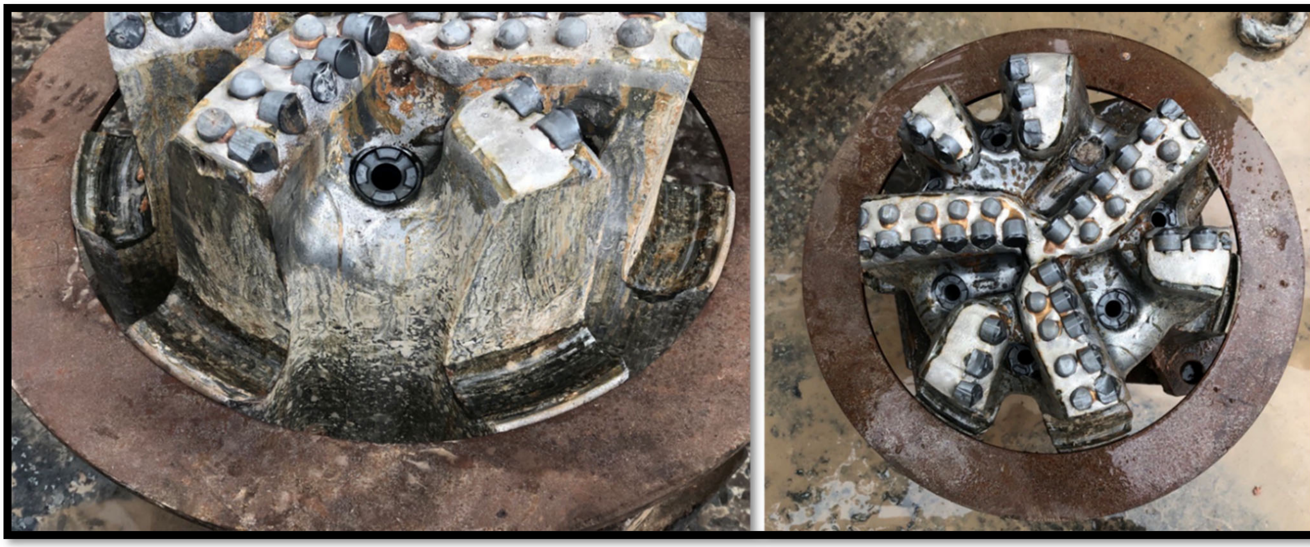


**Figure 10 – The bit in Figure 9 experienced a shoulder ring out from severe stick slip. The lack of cone cutter damage indicates full stick slip was not the leading cause of damage.**

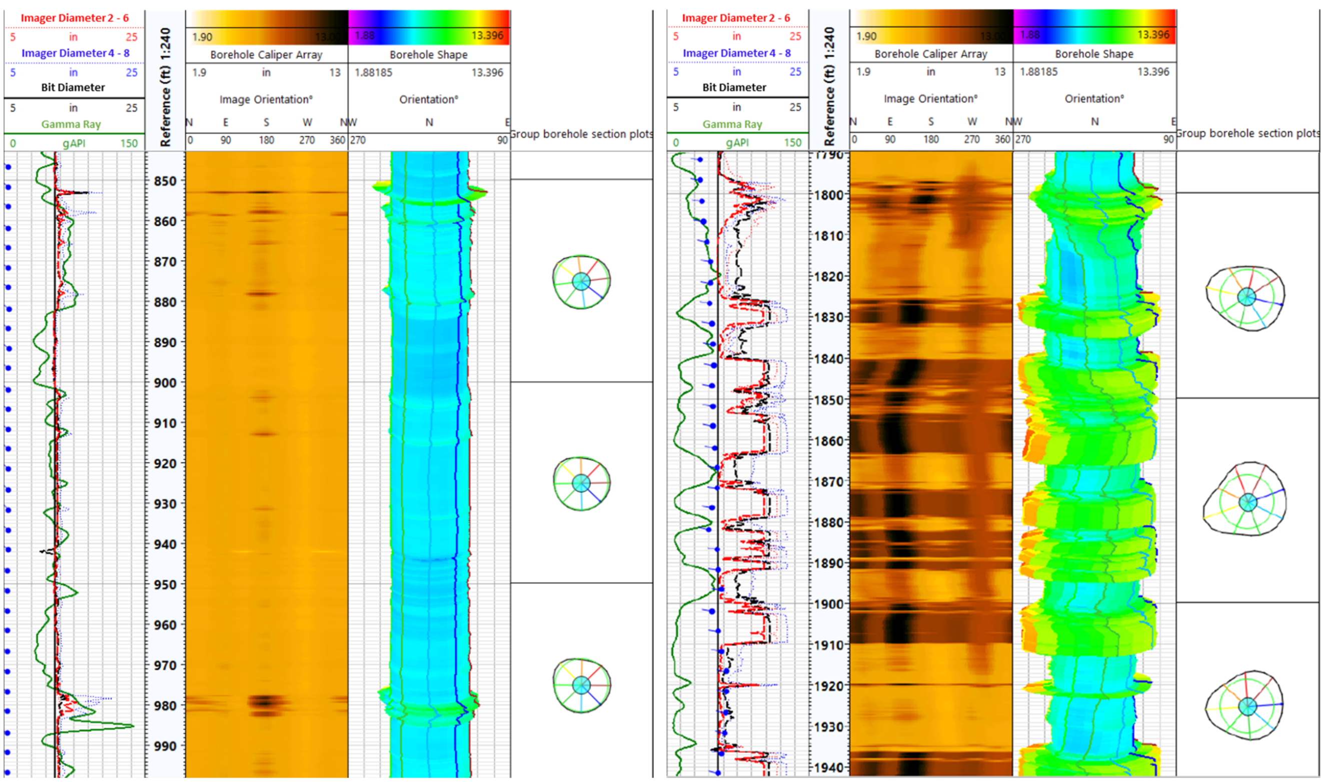



**Figure 11 - Gauge caliper log confirms good quality borehole across shallow 'red bed' formations in offset SM well. Borehole instability into the Salado formation led to trouble time in the same well.**

**Figure 12 – A bit did not cut the rocks on the shaker screen. Fine wetted rock powder is expected from the drilling process. The large rocks are cavings. Angular or rounded edges would confirm the borehole instability severity. Mud weight should be raised immediately.**

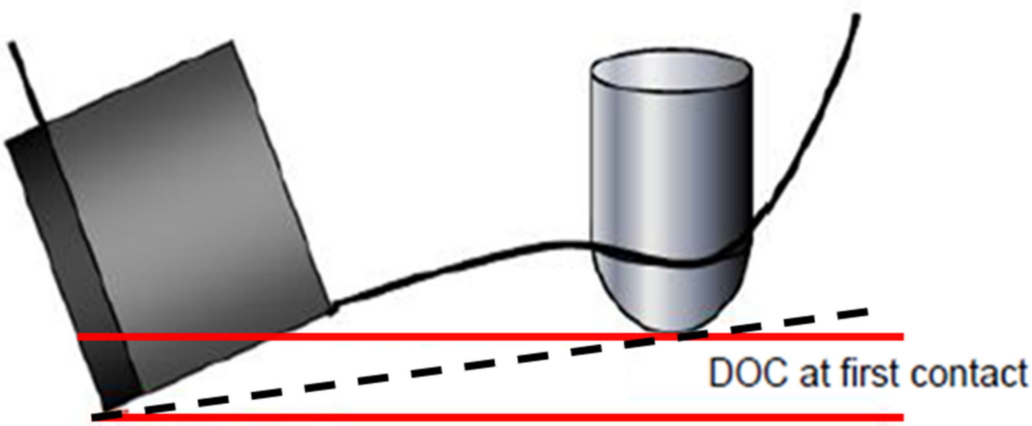



**Figure 13 – WOB indents the cutter into the formation at a given bit RPM. Higher WOB or lower RPM is required to achieve the designed DOC which first contacts the DOCC element (Davis et al. 2012).**

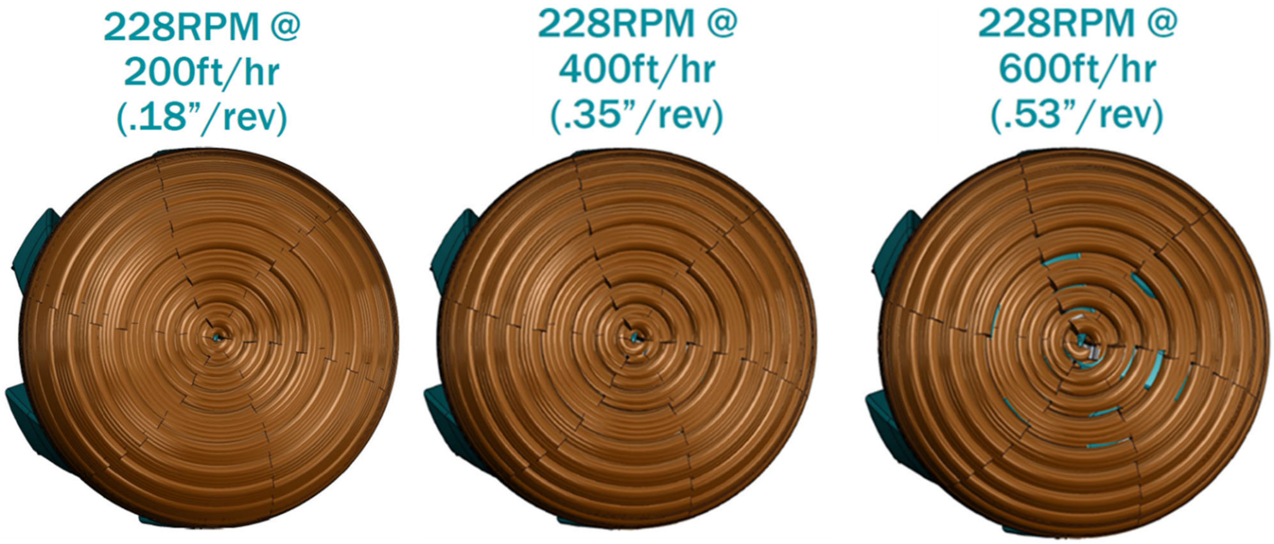



**Figure 14 – Work with the bit vendor to generate loft plot models with input ROPs and RPMs. The plot indicates which parts of the bit, including the blades or DOCC elements, will rub at various DOCs.**

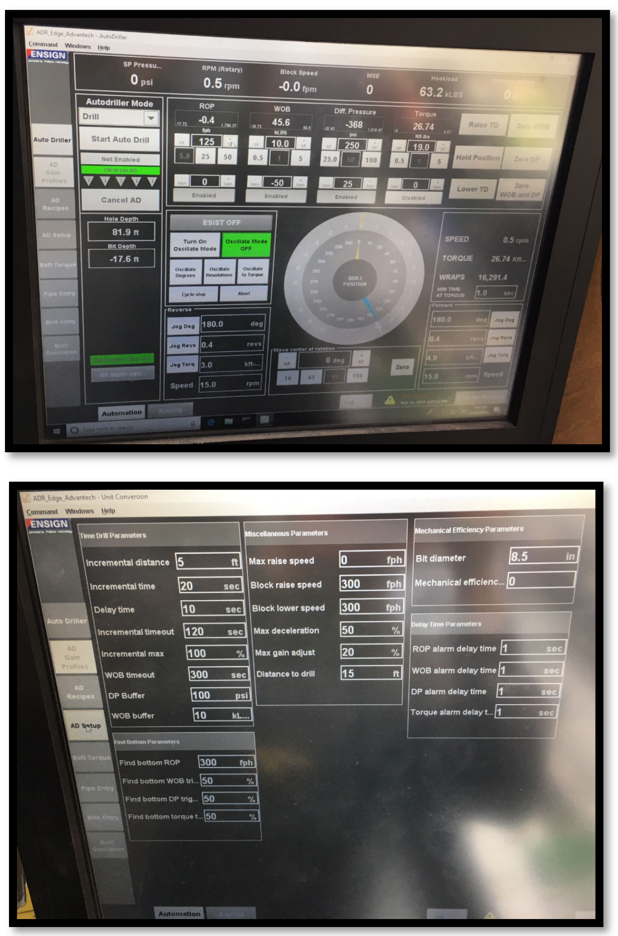


**Figure 15 – Parameter setpoints for ROP, WOB, torque, and differential pressure act as controller limits. Input WOB drives output ROP, torque, and differential pressure. When the limits are**

exceeded, the autodriller reduces WOB to relieve the value limit overload.

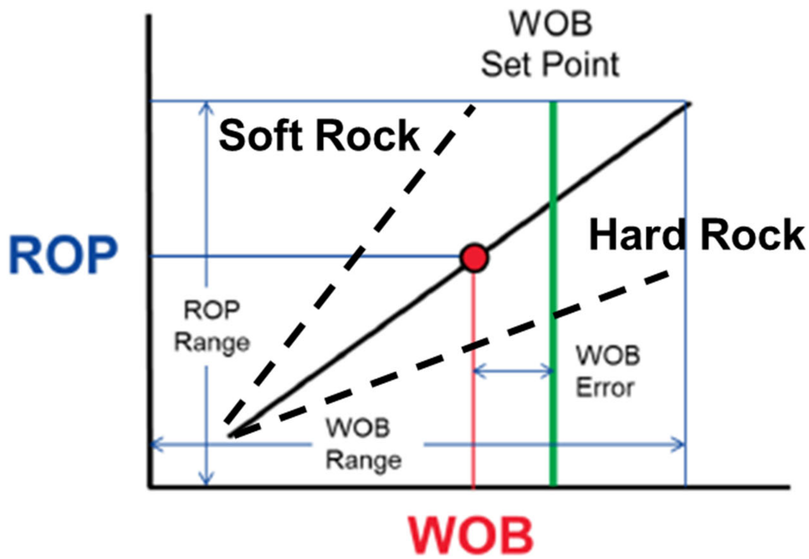
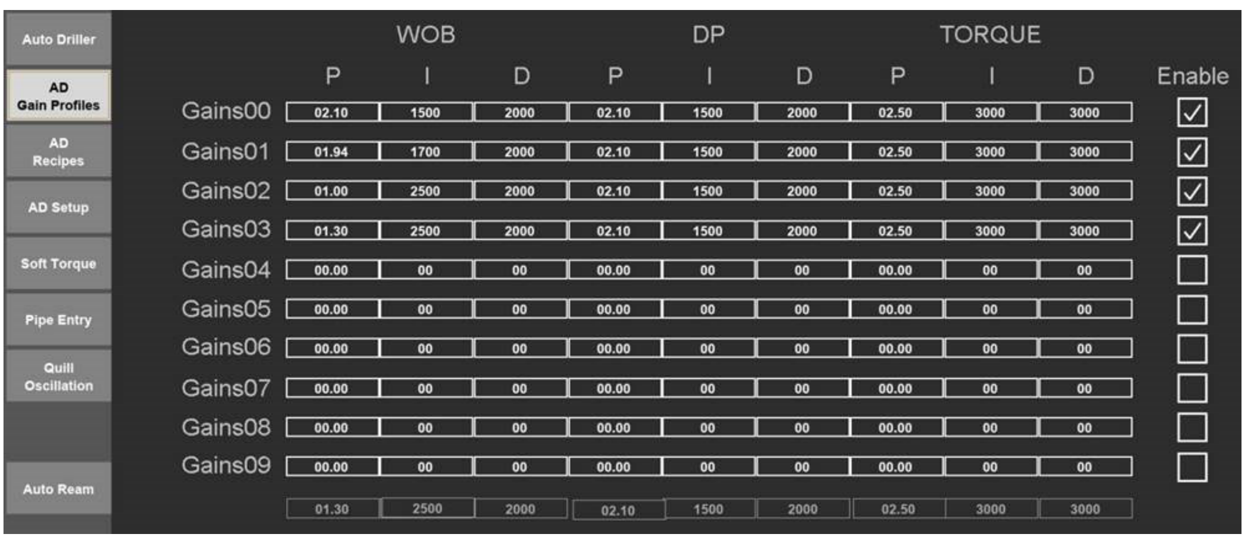



Figure 16 – In this WOB mode, the autodrillers stability is dependent on how quickly the input WOB is adjusted based on the output ROP response. This is the system 'gain' (Pastusek et al. 2016).




| | WOB | | | DP | | | TORQUE | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | P | I | D | P | I | D | P | I | D | Enable |
| Gains00 | 02.10 | 1500 | 2000 | 02.10 | 1500 | 2000 | 02.50 | 3000 | 3000 | ☑ |
| Gains01 | 01.94 | 1700 | 2000 | 02.10 | 1500 | 2000 | 02.50 | 3000 | 3000 | ☑ |
| Gains02 | 01.00 | 2500 | 2000 | 02.10 | 1500 | 2000 | 02.50 | 3000 | 3000 | ☑ |
| Gains03 | 01.30 | 2500 | 2000 | 02.10 | 1500 | 2000 | 02.50 | 3000 | 3000 | ☑ |
| Gains04 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | ☐ |
| Gains05 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | ☐ |
| Gains06 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | ☐ |
| Gains07 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | ☐ |
| Gains08 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | ☐ |
| Gains09 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | 00.00 | 00 | 00 | ☐ |
| | 01.30 | 2500 | 2000 | 02.10 | 1500 | 2000 | 02.50 | 3000 | 3000 | |

Figure 17 – Simplify autodriller gain tuning by partnering with the drilling contractor. Gain setting profiles were setup to easily enable the driller to switch autodriller sensitivity between drilling hard and soft formations.

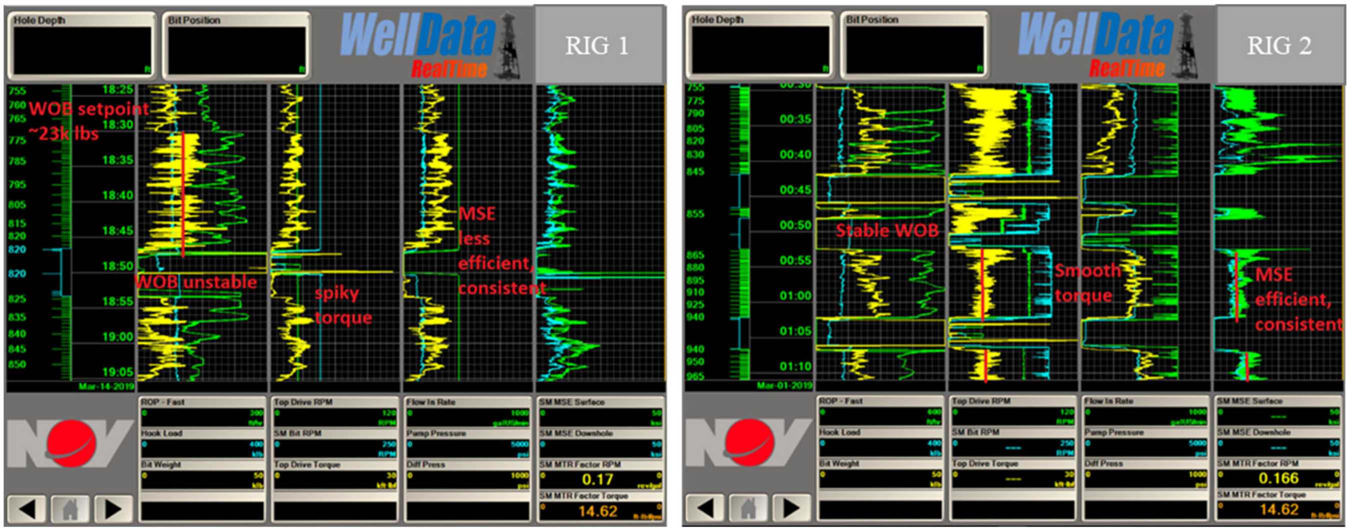



**Figure 18 – Stabilize autodriller setpoints to improve drilling efficiency and ROP. Both offset wells were drilled with two different rigs using the same bit, TFA, and similar BHA.**

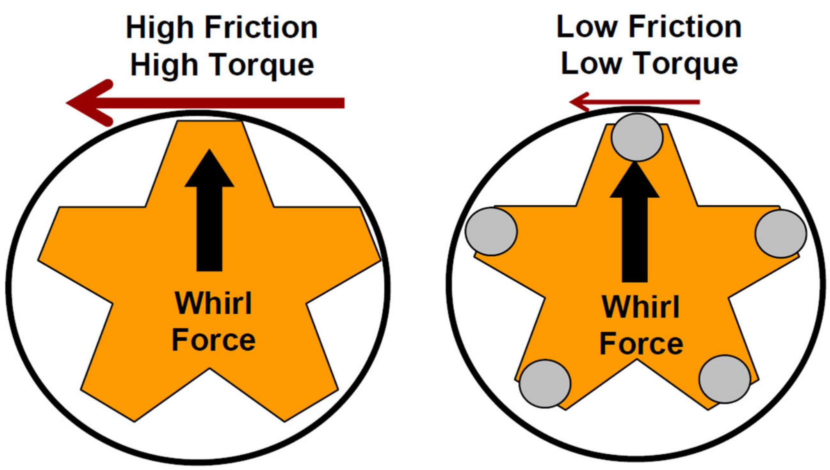



**Figure 19 – Roller reamer elements reduce BHA-borehole friction and prevent lateral whirl force conversion into torque (Sowers et al. 2009).**


**Figure 20 - The project BHA recorded 100 Hz data with sensors installed at bit and subs above the mud motor and in the drill collars.**

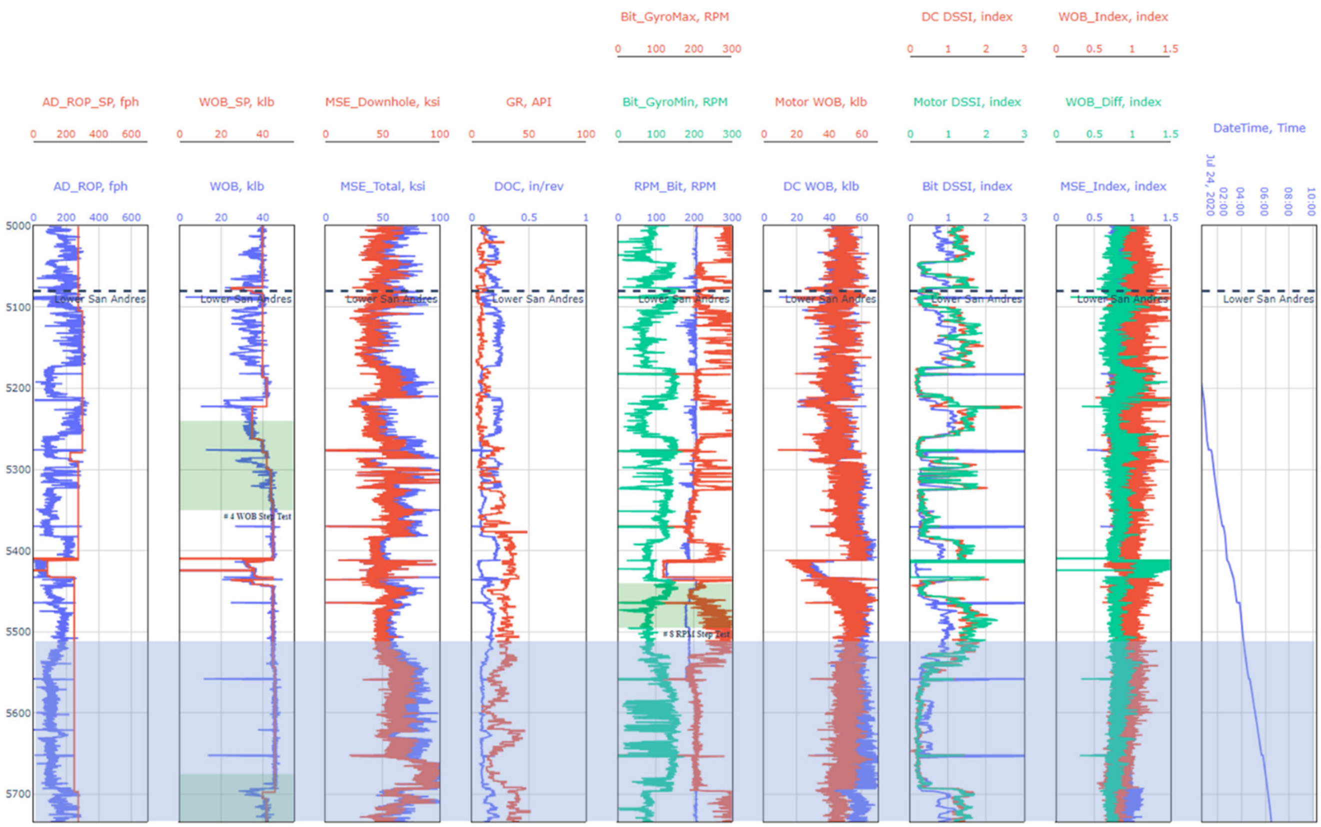



**Figure 21 – Poor weight transfer event on the trial well 2 between the motor and drill collar subs starting past 5500'.**

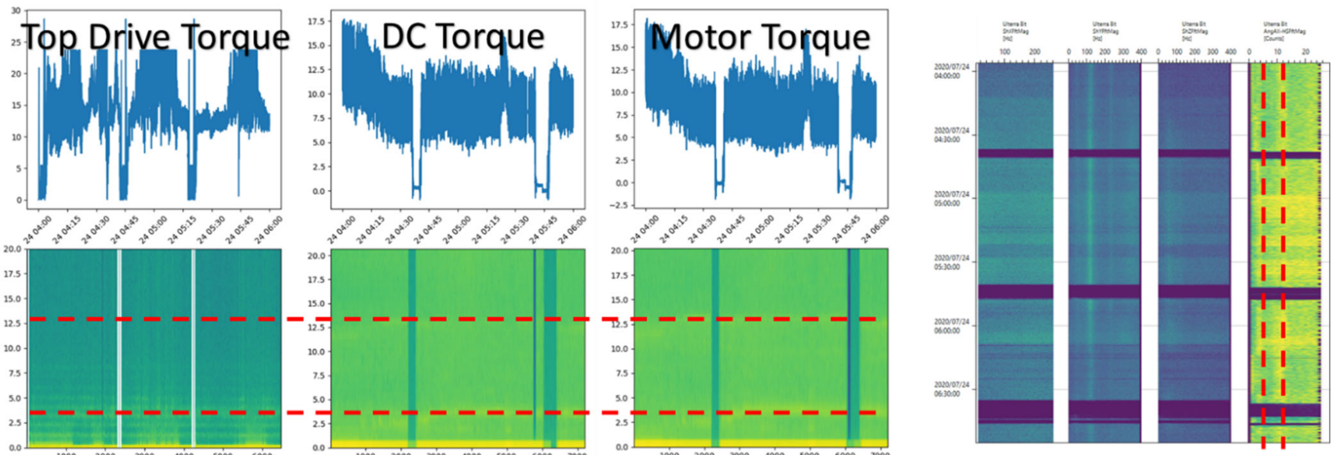



**Figure 22 – Top drive, drill collar, and motor torque all confirm strong frequencies related to bit speed and mud motor rotation.**

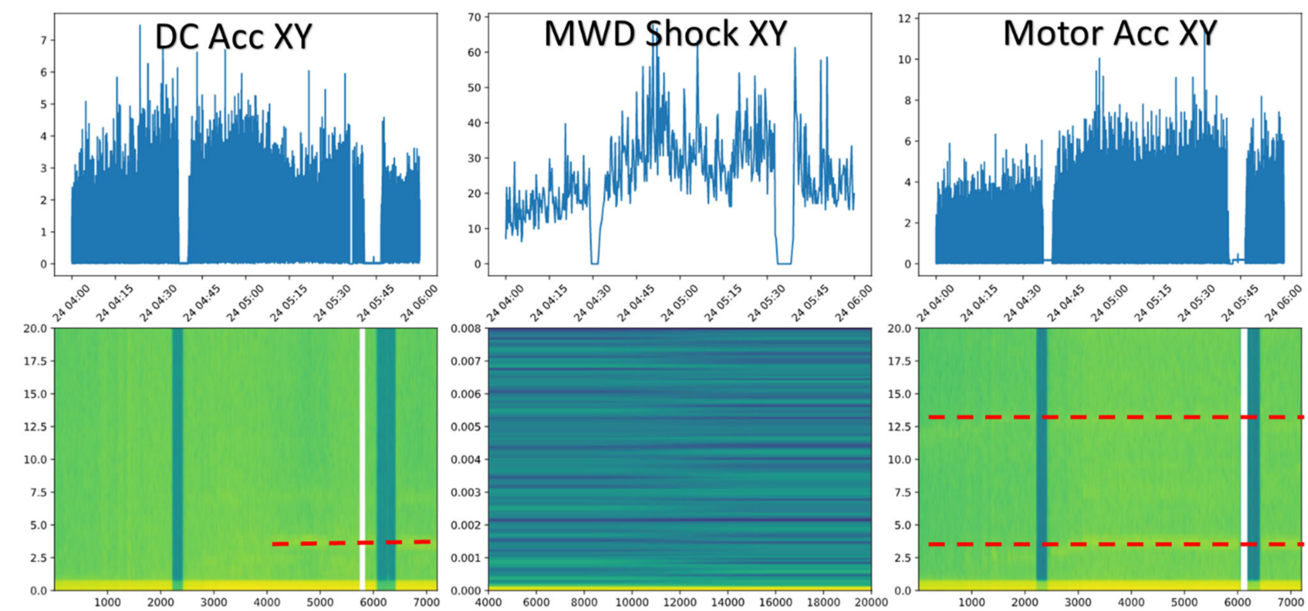



**Figure 23 - Drill collar and motor lateral acceleration confirm the same Figure 23 observation. The MWD lateral shock measurement is recorded at too low of a low frequency to detect the resonance.**

## Trial Well 1 – Planned Parameter Step Tests

| Depth (TVD) | Formation Group | WOB Steps | Rotary Steps | GPM Steps |
|---|---|---|---|---|
| 450' – 1800' | Rustler/Salado | 15, 20, 25+ | 50, 60, 70, 80 | 600, 700, 800 |
| 1800' – 3000' | Yates/7 River/Queen | 35, 40, 45+ | 50, 60, 70, 80 | 600, 700, 800 |
| 3000' – 5000' | Grayburg, San Andres, Lower San Andres | 40, 45, 50+ | 50, 60, 70, 80 | 600, 700 ,800 |
| 5000' – 7800' | Leonard | 40, 45, 50+ | 50, 60, 70, 80 | 600, 700, 800 |

**Objective**: Optimize depth of cut (DOC) through WOB/RPM changes to maximize ROP -> Achieve the best hole hunting

- After 150' into the major formation group, perform at least one WOB, rotary, and GPM step test.
- In the parameter test, hold all other parameters constant, and increase the target parameter (WOB in 5 klb steps, rotary in 10 RPM steps) in **10 min** steps. For each planned WOB step, perform a full rotary step test at that weight (**ex**. Run 45 WOB and then step through 50, 60, 70, 80 RPM for 10 min each).
- Select the best WOB/RPM combination and then perform a GPM step test in **5 min** steps.

**Figure 24 – Parameter Step Test Instructions for the rig team.**

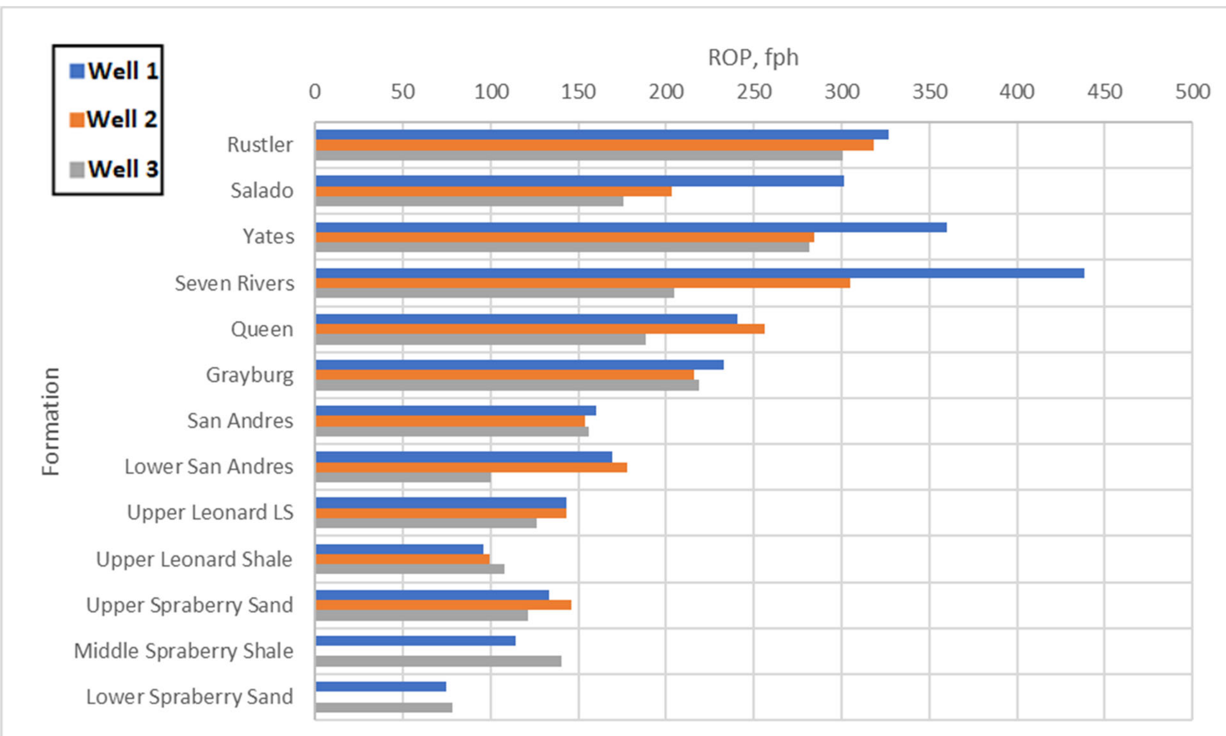



**Figure 25 – Rotating ROP by formation for the three sensor trial wells.**

**Figure 26 – Trial well 3 roller reamer post-drill. Sealed bearing retention system worked effectively. Note the wear on the carbide buttons but no unusual tool integrity damage.**

**Figure 27 – 11 ¾" Straight integral blade stabilizer used on all wells except for the trial well 3. No observable damage, the IBS also measured gauge post-drill.**

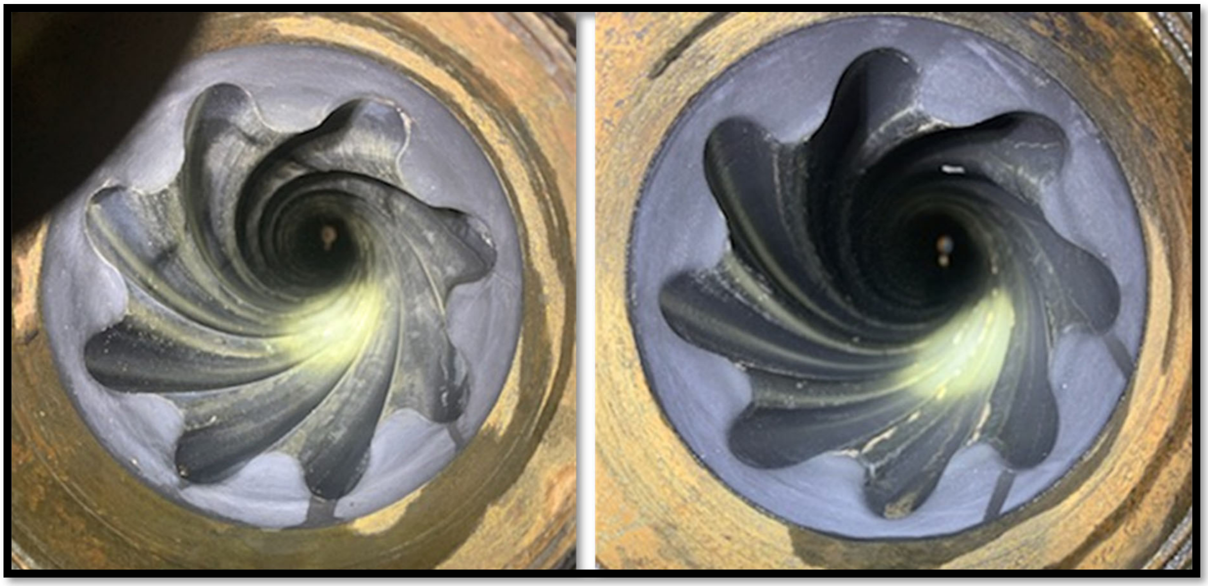


Figure 28 – Trial well 1 slight wear of bottom of the mud motor elastomer, no chunking.

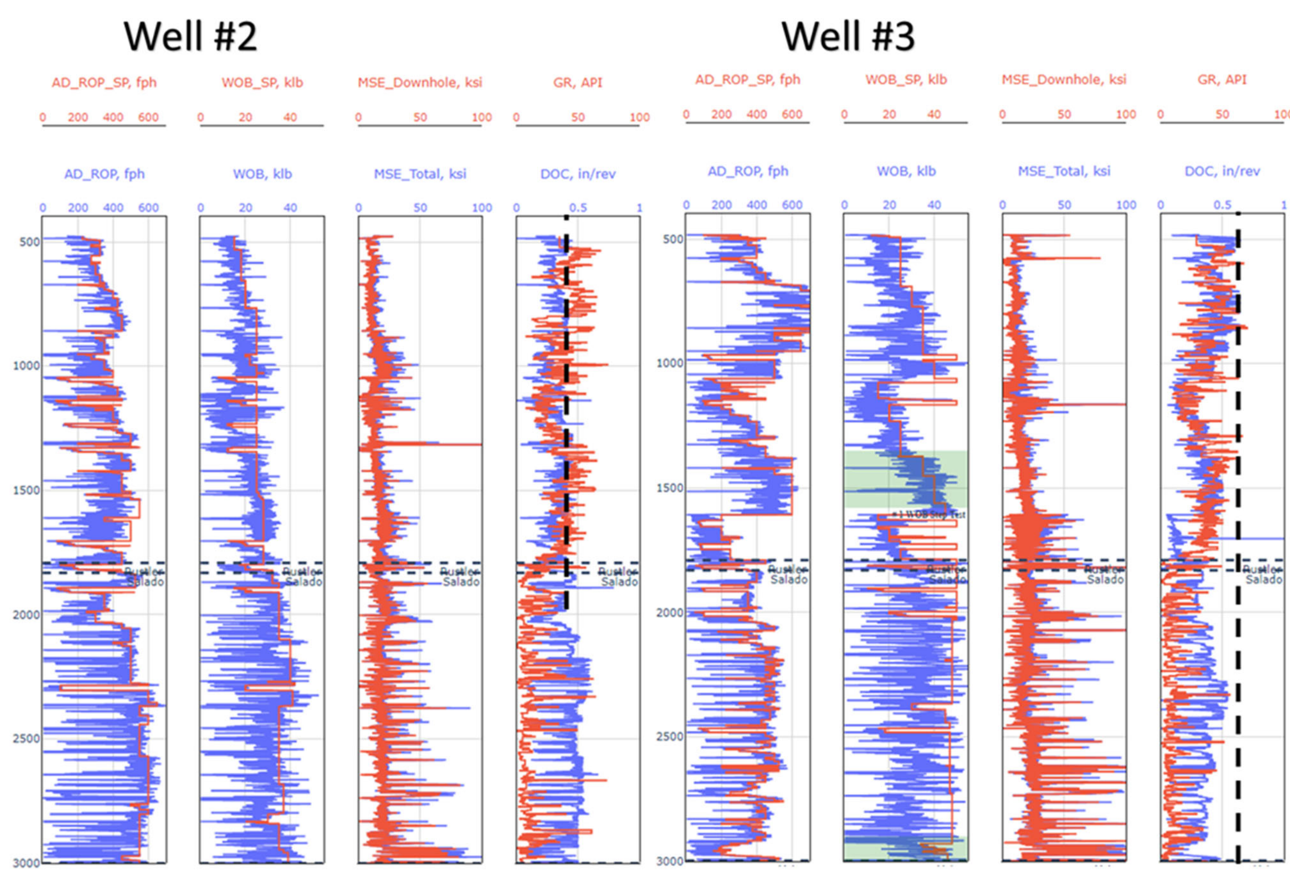



Figure 29 – Nominal DOC calculations are sufficient to determine when DOCC engage for a target DOC. RPM may be increased and WOB raised again to increase ROP before the DOCC reengages.

**Figure 30 – 1st trial well bit dull. Severe shoulder wear flats, delamination, and trim cutter damage. Original default DOCC set a 0.70 in/rev did not engage.**

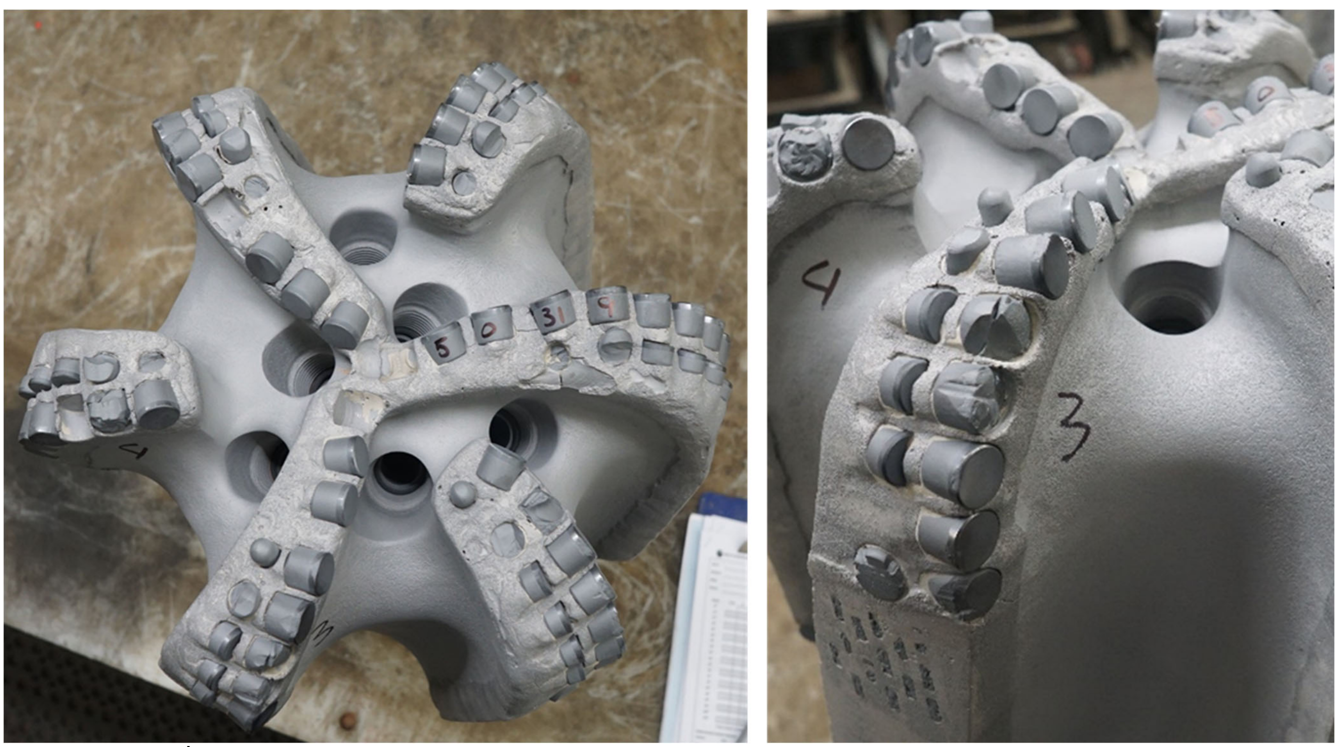


**Figure 31 – 2nd trial well bit dull. Severe shoulder wear flats, delamination, and trim cutter damage. Tungsten carbide DOCC engaged at 0.35 in/rev and worn down.**

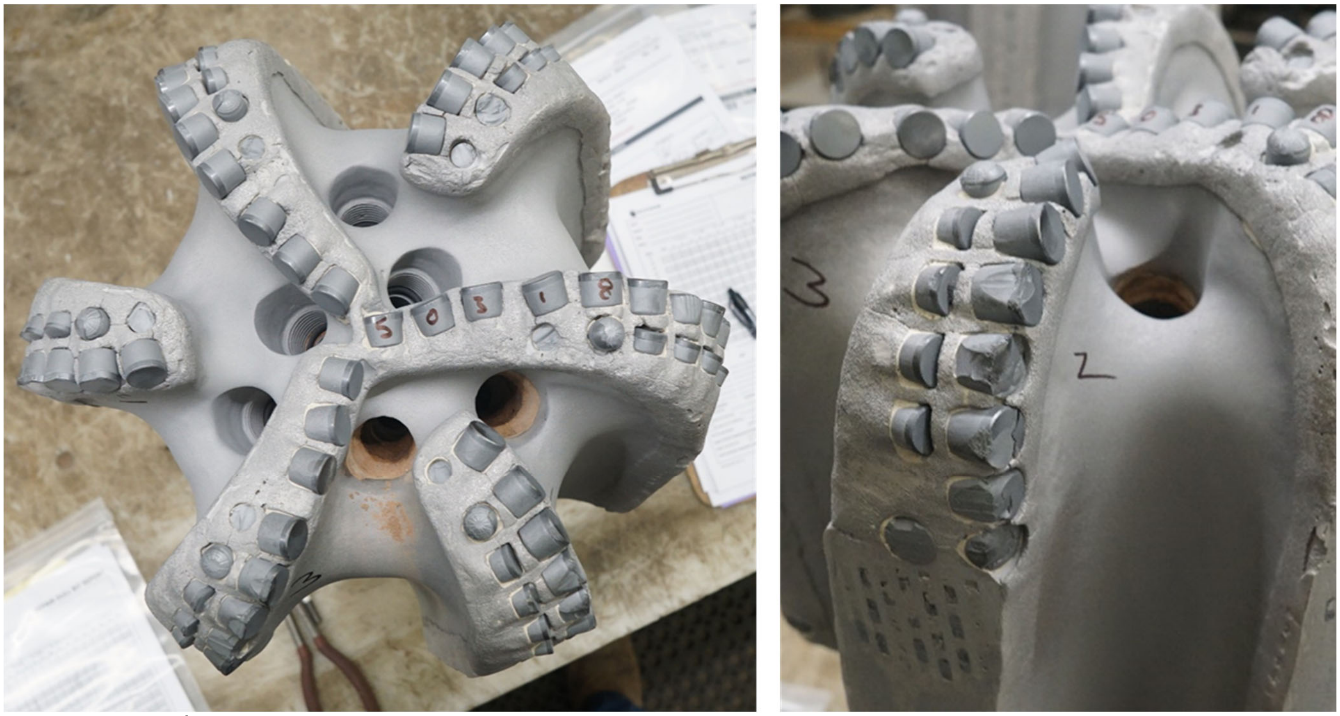


Figure 32 – 3rd trial well bit dull. Severe shoulder wear flats, delamination, and trim cutter damage. PDC DOCC engaged at 0.55 in/rev.

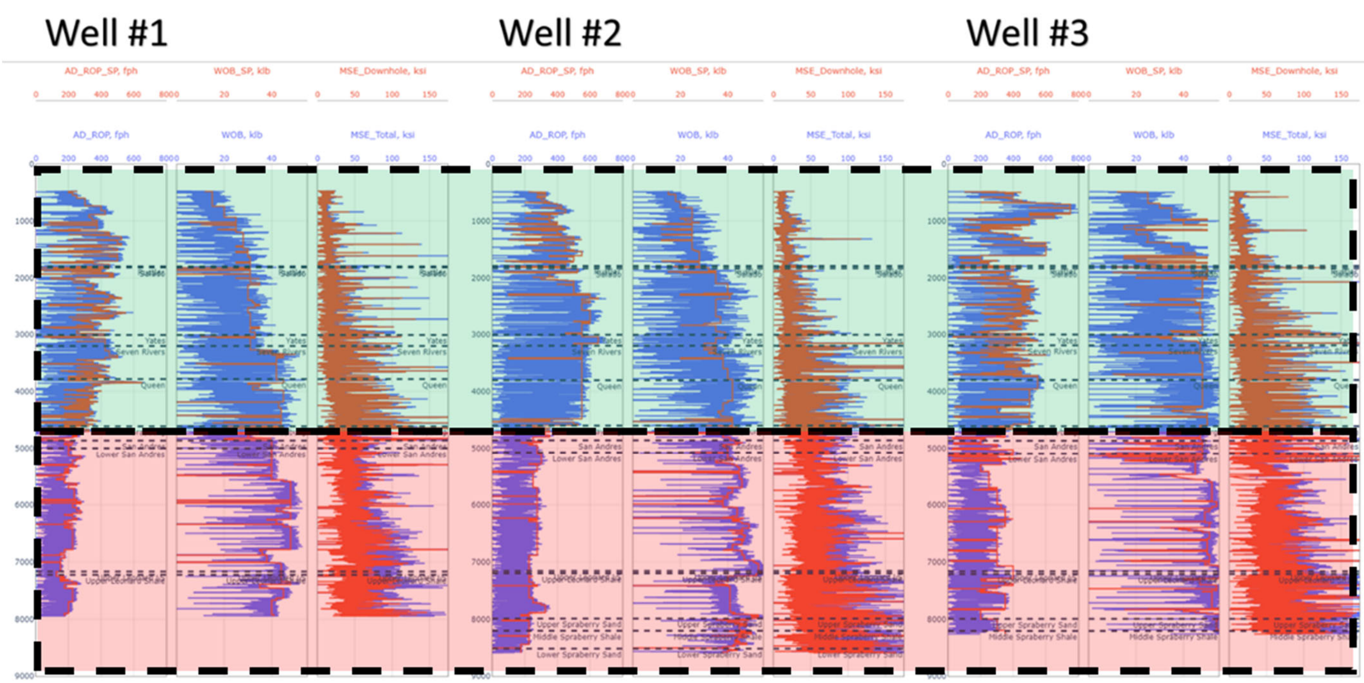



Figure 33 – The three trial well log plots indicate similar limiters: ROP/WOB setpoint autodriller instability throughout the shallow sandy/anhydrite zones, and severe stick slip oscillation in deeper dolomitic limestones. Note the less ‘actively managed’ autodriller setpoint control in the trial well 2 and higher ROP across the shallow interval.