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Optimization of PDC Drill Bit Performance Utilizing High-Speed, Real-Time Downhole Data Acquired Under a Cooperative Research and Development Agreement

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Abstract

PDC drill bit performance has been greatly improved over the past three decades by innovations in bit design and how these designs are applied. The next leap forward is most likely to come from using high-speed, real-time downhole data to optimize the performance of these sophisticated bits on an application-by-application basis. By effectively managing conditions of lateral, axial and torsional acceleration, damage to cutting structures can be minimized for improved penetration rates. Avoiding these damaging vibrations is essential to increasing bit durability and improving overall drilling economics.

This paper describes one set of independent drilling optimization results obtained as part of a series of controlled demonstrations of PDC bits. Sandia National Laboratories on behalf of the U. S. Department of Energy (DOE) managed this work. The effort was organized as a Cooperative Research and Development Agreement (CRADA) established between Sandia and four bit manufacturers with DOE funding and in-kind contributions by the industry partners. The goal of this CRADA was to demonstrate drag bit performance in formations with degrees of hardness typical of those encountered while drilling geothermal wells.

The test results indicate that the surface weight-on-bit (WOB), revolutions per minute (RPM) and torque readings traditionally used to guide adjustments in the drilling parameters do not always provide the true picture of what is really taking place at the bit. Instead, a holistic approach combining traditional methods of optimization together with high-speed, real-time data enables far better decisions for improving bit performance and avoiding damaging situations that may have otherwise gone unnoticed.

Introduction

Sandia National Laboratories established a CRADA between four industry partners, including ReedHycalog. The goal of the CRADA was to demonstrate drag bit ROP and durability performance improvements in hard-rock applications. To achieve this objective, ReedHycalog adopted a holistic approach that involved bit modeling analysis and design for maximum durability and dynamic stability of the cutting structure, hydraulic optimization, rock strength analysis, high-performance thermally stable cutter technology and full-scale laboratory testing.

The Diagnostics-While-Drilling (DWD) system developed by Sandia National Laboratories was utilized,^{1,2,3} to support this work and illustrate the optimization of bit performance with real-time decision-making data. The DWD enabled the transmission of real-time data from immediately behind the bit. Data included lateral, axial and angular accelerations, WOB, bit torque, bending, internal and external pressure and temperature, and system diagnostic data. The real-time data was transmitted to the surface via wireline at approximately 200,000 bits per second (BPS), compared to the existing mud pulse telemetry capacity of only 8-16 BPS. It is anticipated that other data links will be made available in the near future including wired pipe.⁴

Phase 3 Drilling Outline. This final phase of the CRADA project allowed each drill bit manufacturer to demonstrate its "best-effort" bit design. Phases 1 and 2 involved the characterization of performance for a baseline drag bit; initially without real-time, downhole data feedback for drilling control (Phase 1) and later with downhole data feedback (Phase 2) to optimize bit performance with the aid of an experienced drilling engineer.^{5,6} The data sets from these earlier phases, which contained both surface and downhole information, were provided to each bit company for analysis prior to Phase 3. These earlier phases will not be discussed in detail except for comparison with the final phase of the project.

Only ReedHycalog bit performance will be explicitly discussed within this report since detailed results achieved by the other parties are proprietary to those companies under the terms of the CRADA. Prior reports published by Sandia for the Geothermal Resources Council (GRC)^{5,6} cover the earlier

Phases (1 and 2) of the project. Furthermore, the second of these reports⁶ anonymously compares the performance of each manufacturer's PDC bit, providing a useful perspective for interpreting the results summarized within the present paper.

Testing Facility. The Gas Technology Institute (GTI) Catoosa Test Facility was chosen for the bit demonstrations because it satisfied the criteria of (1) being independently operated and (2) affording the desired formation types.

The formation interval specified for bit evaluations begins at a depth of 1100 ft and consists predominantly of sandstone and shale sequences overlaying a 300-ft thick section of Mississippi limestone. With compressive strengths reaching above 35 kpsi, this limestone section extends from 1274 to 1571 ft (see **Figure 1**). Below this hard limestone is a short, 29-ft section of shale followed by the coarse-grained and highly abrasive Misener sandstone, which has abundant quartz overgrowths. The 27-ft Misener section is historically renowned for causing high levels of abrasive bit wear.

Below the Misener sandstone is a fine crystalline-to-dense dolomite known as the Arbuckle group, which extends from 1627 to over 1950 ft. The Arbuckle formation is highly fractured with numerous chert nodules and angular chert pebble conglomerates. It also consists of interbedded dense pyritic shale, dolomite and fractured quartz sandstone. Understandably, the rock strength through this highly interbedded section fluctuates considerably from the occasional low of 15 kpsi to peaks reaching almost 40 kpsi.

PDC Test Bit and Thermostable Cutters

When drilling in hard rock intervals with PDC bits, selection of a design with greater stability will help reduce impact damage to the cutting structure. With this in mind, a stabilized full contact gauge ring bit^{7,8,9} would be an obvious choice, as this would stabilize the design and eliminate any lateral vibration. However, in this application a fairly rigid bottom hole assembly (BHA) was chosen with a near-bit stabilizer that was 1/16-in. under gauge and a full-gauge stabilizer immediately above the DWD measurement sub.⁶ The stabilizers were positioned immediately below and above the DWD sub to protect this tool from large-amplitude lateral shocks and impacts during drilling. During the initial baseline testing in Phase 1 very little lateral vibration was recorded due to this stabilization, so it was decided that a stabilized ring design would not be used for this vertical test well. Instead, the team chose a medium set design shown in **Figure 2** equipped with thermostable PDC cutters. The decision to run this thermostable PDC bit design (previously referred to as a "best-effort" bit by Sandia within various technical publications)^{5,6} was made with the help of an in-house computer program that has been developed to model various aspects of bit performance, including bit dynamic response.

Fixed-Cutter Bit Performance Modeling

To determine the optimal cutting structure, the advanced modeling system was used to calculate individual cutter forces, dynamic stability of the cutting structure and cutter wear comparisons. This software has been in use for almost a

decade and has proven to be extremely useful for optimizing bit designs.

Several cutting structures were evaluated using the program to compare predicted wear, ROP and torque for a given WOB, and also to compare levels of dynamic stability. The chosen cutting structure exhibited lower predicted wear (as viewed in **Figure 3**) when compared with both the offset design and baseline bit used in Phases 1 and 2. More importantly, the sophisticated cutting structure design was predicted to exhibit very even wear. However, as will be discussed later, the program highlighted that the central cone cutters had a large surface area in contact with the formation, leading to high drag forces and accounting for a high percentage of the vertical WOB (see **Figure 4**). It was these same cutters that experienced impact damage while drilling through the Mississippi limestone.

Drilling Laboratory Testing. To verify the results obtained from dynamic modeling, the bit was manufactured and run in the laboratory using a full-scale drilling test rig. Test parameters were chosen to simulate the capabilities of the GTI Catoosa facility. The relationships between RPM, WOB and measured torque were plotted to understand the bit's drilling characteristics. Dynamic stability was measured using a sophisticated sub mounted immediately above the bit. **Figure 5** shows a screen capture of the results from one test that compared extremely well with the dynamic model predictions. Similarly, the overall predicted WOB and bit torque matched very well with the previous simulations run through the bit performance modeling software.

Previous Experience. Internal records showed that we had drilled the targeted Catoosa formations successfully during the 1990s with a popular 7-bladed bit design. However, this bit suffered fairly heavy abrasive wear to the nose and shoulder PDC cutters. To overcome this weakness the new thermostable PDC bit design needed more durability in this region. Developments in cutter technology since the 1990s were expected to significantly improve durability.

Bit Durability. As an additional measure to improve durability without sacrificing ROP, a secondary cutting structure was added and positioned off-profile.¹⁰ The design chosen shown in **Figure 2** was a 6-bladed, 13-mm PDC cutter bit that had recently performed exceptionally well in a North Sea application, tripling ROP through high compressive strength formations and increasing the interval drilled by over 25%. The primary cutters on the nose-to-shoulder area were augmented by a secondary cutting structure.

The secondary cutting structure, positioned off-profile, was designed to perform only after reasonable wear of the primary cutting structure. In addition, if the bit suffered severe impact, the secondary cutters would provide extra durability to complete the interval.

As will be discussed later during the dull evaluation, the primary cutting structure showed no sign of abrasive wear to the ultra wear-resistant thermostable PDC cutters. Therefore,

in hindsight, for this relatively short application the secondary cutting structure was not necessary. However, building greater durability into the design without sacrificing ROP is desirable in most applications.

Bit Hydraulics. In an attempt to increase ROP, the design had a very open face to improve cleaning through the upper shale sections. The design had optimal hydraulics carefully directed onto the bit profile for each blade to provide good cleaning and cooling. In addition, a central built-in jet in the shape of a crow's foot was added to remove any chance of formation balling in the cone area; this may be viewed in **Figure 2**. Various hydraulic configurations were evaluated using a proprietary hydraulic program. The program takes into account the hydraulic horsepower available from the pump together with system losses across the modeled BHA as well as mud properties. The output solution provides the optimal/maximum bit hydraulic horsepower per square inch (HSI) by modifying available flow rate and bit total flow area (TFA). The calculated standpipe pressure (SPP) at various start and end depths matched those recorded within flag files during the Phase 3 drilling, providing increased confidence in the accuracy of the hydraulic program.

Real-Time Surface Displays. **Figure 6** displays the screen layout of the surface data in the form of strip charts showing RPM, WOB, and torque together with instantaneous digital parameter values. The real-time surface display was customizable and, due to the large amount of data available, it was necessary to plan the screen layout to present the data most relevant for optimization.

A total of three downhole real-time displays were utilized. The first, shown in **Figure 7** displayed strip charts of measured data over time. The display shows WOB, torque, and RPM charts on the left side, and lateral, axial, and torsional acceleration charts on the right. In this example, the onset of increasing angular acceleration fluctuations can be clearly seen to correlate with the increasing range for WOB, torque and RPM fluctuations as the cursor line travels from left to right. Another screen was set up to record and display plots of XY bending, lateral vibration and frequency content.³

Testing Outline of Phase 3

During Phase 3 each bit company was assigned five working days at the rig site. However, two or more days were required to set up and reach the test interval of interest. Due to a wireline failure experienced during the second day, drilling in the official test interval did not commence until the third day. By the end of the third day, drilling in the Mississippi limestone interval was almost complete since the bit had advanced from 1100 ft to 1507 ft. The bit was tripped out of the hole and found to be in good condition with only minor evidence of impact damage in the cone area. Although the DWD signals held up well for a large portion of the run, all signals were lost midway through the limestone section at 1412 ft. During that day the team decision was to continue drilling to 1507 ft without the downhole measurements, as drilling performance was good and there was a time constraint to meet. Later the team decided that continuing without the

DWD measurements would not only be detrimental to the bit but, more importantly, was defeating the point of the exercise. Very little progress was made during the fourth day as the DWD system was repaired. Once the DWD problems were rectified, drilling continued into the abrasive Misener sandstone that started at 1600 ft.

By the end of the week all objectives had been reached. The thermostable PDC bit had drilled through the Mississippi limestone section and continued with no problems through the abrasive Misener sandstone. Drilling continued through the hard Arbuckle to 1913 ft when the allotted test period expired. At this point, the bit was still drilling strongly but additional drilling time was not available under the terms of the CRADA.

Thermostable PDC Cutter Performance in Abrasive Formations

It is normal practice to reduce RPM in abrasive formations so as to decrease shoulder wear caused by the higher tangential velocity experienced by cutters in this region of the bit. However, this practice may have a negative effect on performance that may even lead to the initiation of stick-slip, which is generally more pronounced at a lower RPM range. The unique, ultra wear-resistant PDC cutters utilized in the thermostable PDC bit performed exceptionally well through the abrasive Misener section. They showed no signs of abrasive wear after drilling the entire interval, as viewed in **Figure 8**.

These results matched well with laboratory test data that indicated a large increase in abrasion resistance for thermostable cutters relative to standard PDC cutters. In comparison, **Figure 9** illustrates the heavily-worn shoulder dull condition for standard PDC cutters that drilled exactly the same formations at Catoosa in 1993 with a popular 7-bladed design. This comparison illustrates how far cutter technology has progressed, thereby satisfying a primary CRADA objective.

Discussion of Main Dynamic Events

An enormous amount of data was collected during the bit demonstration tests at Catoosa. Therefore, this report will concentrate on specific areas of interest that include the onset of torsional vibration leading to full stick-slip, as well as various forms of axial and lateral vibration that were encountered.

Stabilizer sticking. While drilling with a utility bit to reach the target starting depth of 1100 ft, an interesting observation was made (See **Figure 10**). The DWD sub was installed in the BHA during this work to verify that all measurement channels were functioning correctly. At a depth of 900 ft (200 sec) bending was experienced, indicating a firmer formation. This effect declined somewhat, but 15 ft deeper the top drive stalled for several seconds. The maximum available surface torque of 12000 ft/lbs had been reached. However, downhole torque measured near the bit remained below 5000 ft/lbs.

This event corresponded to sticking of the stabilizer while entering a tight spot. The high bending experienced before

this event was considered and it was noted that the distance traveled by the drilling assembly before stalling was approximately 15 ft; this equaled the distance from the bit to the second stabilizer. Therefore, it was determined that the firmer formation had created a tight spot for the stabilizer to drill through, and this had caused the eventual stalling of the top drive.

Surface whirl may not be detrimental to bit performance.

While drilling through the hard limestone section, many problems were experienced due to surface pipe whirl. Although this reverse surface whirl was taking place, it was clear from the downhole data that no dynamic events were taking place at the DWD sub; i.e., there was smooth drilling downhole. Without downhole diagnostics, the common conclusion in normal drilling operations might have been to blame the bit for the surface whirl.

Due to its severity, the surface whirl needed to be smoothed, and this was achieved by reducing the rotary speed. Unfortunately, although this solved the up-hole whirling motion, the reduced RPM caused severe dynamic events to take place downhole, as shown in **Figure 11**, which displays strip charts of WOB, TOB, RPM, X and Z vibration, and angular acceleration. These events may have caused some of the impact damage in the bit cone area, as noted for the dull shown in **Figure 12**.

When the surface whirl was initially experienced, the WOB was allowed to drill off and the RPM was reduced. This appeared to eliminate the problem and we were able to commence drilling with WOB again and gradually step up the RPM from around 60 RPM back to 130 RPM. Drilling appeared smooth from 500 sec to 850 sec at which point some axial (Z) and lateral (X) vibration was experienced. This occurred at the beginning of the Mississippi limestone section. Action was taken to decrease the vibration by reducing to 100 RPM in an attempt to increase the depth of cut. This resulted in some signs of recovery with a slight reduction in lateral vibration, but caused the onset of torsional vibrations. The WOB was allowed to drill off to eliminate the vibration.

When the drilling commenced again at 1000 sec, the torsional oscillations resumed. A lower RPM was attempted, as the vibration was still apparent both laterally and axially. It was decided to take the RPM back up to 100 RPM and commence drilling again at 1300 sec. At this point the vibration, which was experienced in all directions, was predominantly torsional, reaching 5000 rad/s² consistent with the highly fluctuating torque. At 1500 sec the RPM was increased to 130 and the torsional oscillations were suppressed. It was apparent that the surface drill pipe whirl, although not damaging the bit, had led to many dynamic problems downhole due to the modification of drilling parameters in order to solve the surface whirl.

Onset of stick-slip at startup. A common practice when breaking in a bit is to tag bottom with low weight and RPM for the first foot to cut the bit profile into the formation. We had generally found that contacting bottom at 100 RPM and

increasing the WOB gradually worked well at start up. However, when a much lower RPM of 60 was utilized while drilling the Arbuckle formation, an adverse effect on the downhole dynamics was experienced. Although the WOB and torque rose smoothly as shown by the downhole data in **Figure 13**, we experienced a problem with stick-slip initiation at a time of 10:06:30. We quickly overcame this problem by increasing to 110 RPM to obtain smooth drilling. It is clear that more damage may be experienced in firmer formations when following guidelines that are not always ideal for the application. This situation highlighted the need for downhole data so that this type of dynamic behavior may be corrected.

Bit Performance Comparisons with Baseline Bit

The thermostable PDC bit drilled much faster than the baseline bit used in CRADA Phases 1 and 2. **Table 1** provides the ROP for each bit through each formation together with overall ROP for the run. It is evident that the baseline bit with no face waterways was restricted in the upper shale formations. For example, in the Fayetteville shale the baseline bit in Phase 1 and 2 had an average ROP of 77 ft/hr and 84.9 ft/hr respectively, while the thermostable PDC bit, with open face volume and improved hydraulic configuration, averaged 259.7 ft/hr.

As highlighted in the Sandia report,⁶ most drill bits slowed considerably in the Misener sandstone. However the thermostable PDC bit drilled this formation with no signs of the bit dulling at an average ROP of 93.8 ft/hr, a clear indication that the cutting structure was still in good condition. The thermostable PDC bit drilled more footage than any of the other drill bits tested during CRADA Phases 1, 2 and 3, and it had the highest average ROP.

Calculated Rock Strength. The formation mechanical properties were computed using advanced modeling software to guide the bit selection process and identify potential drilling risks. Digital gamma ray and compressional sonic log data from an earlier Catoosa well was loaded into the program and the section lithology was interpreted. Elastic properties of the formation were then computed from the digital log data set and interpreted lithology to calculate the compressive strength values. The formation compressive strength is a significant material property and can be used to define the drillability of a rock formation. **Figure 1** illustrates the calculated compressive strengths of the formations together with the ROP of the thermostable PDC bit (i.e., Bit A). The Mississippi limestone is clearly highlighted by a sudden increase in compressive strength that jumps to 35 kpsi at a depth of 1274 ft. The Arbuckle group also exhibits high rock strength beginning at a depth of about 1627 ft and continuing at fairly high levels (approximately 40 kpsi) for the remainder of the interval.

Bit Specific Energy vs. Depth. The specific energy formula was used to compare the mechanical efficiency of the baseline bit used in Phases 1 and 2 with the efficiency of the thermostable PDC bit design. Specific energy is defined as the energy required to remove a cubic inch of rock. A low specific energy is highly desirable. The calculated specific energy is highly dependent on the bit type and design chosen

for a given rock formation. Therefore, specific energy provides effective guidance for bit selection for an application.^{11,12,13}

Several specific energy formulas have been defined which differ slightly; the formula used for our calculations is shown below. The WOB is neglected in the formula since it has very little effect on the result.

Formula for specific energy in drag-bit rotary drilling:

$$Es = \frac{120 \text{ NT}}{ROP \cdot r^2}$$

Where

Es	=	Specific Energy (psi)
N	=	RPM
T	=	Torque (ft-lbf)
ROP	=	Rate of Penetration (ft/hr)
r	=	Borehole radius (in)

Figure 14 illustrates the calculated specific energy based on surface measurements of RPM, torque and ROP. All three Phases of the project are plotted for each formation, together with Penetration rates and time on bottom. The Mississippi limestone and Arbuckle group had by far the highest compressive rock strength, which commonly exceeded 35 kpsi. The thermostable PDC bit provided a low specific energy of approximately 15 kpsi until reaching the Mississippi limestone. The specific energy rose above 25 kpsi while drilling through the limestone. Trends in the calculated specific energy correlated closely with variations in the predicted rock strength. There was a slight trend of increasing specific energy as the run progressed, and a corresponding trend of increasing rock strength through the Arbuckle formation, as highlighted in **Figure 1** which was discussed earlier. The maximum measured specific energy did not exceed 45 kpsi while drilling the Arbuckle formation. The thermostable PDC bit performed consistently throughout the entire run as shown within **Figure 14**.

Comparison of the thermostable PDC bit results with those for the baseline bit during Phase 1 shows similar results before reaching the highest common depth of 1492 ft. However, during Phase 2 when optimization was based on DWD feedback and the judgment of an experienced driller, far higher specific energy values were obtained for the baseline bit as compared to the thermostable PDC bit for depths exceeding about 1400 ft. The specific energy of the baseline bit reaches a peak of 73 kpsi at a depth of 1534 ft. It is possible that this bit had experienced impact damage while drilling the upper portions of the Mississippi limestone, leading to drilling inefficiency later through the interval. The run was cut short at 1632 ft when the rig time allocated for Phase 2 work was exhausted. The final dull for the baseline bit after Phase 2 showed many impacted and worn cutters with one of the studs entirely sheared off.

The complete set of specific-energy data for baseline and “best effort” bit runs during CRADA Phases 1, 2 and 3 is illustrated in the 2004 GRC Transactions.⁶

Bit Dull Analysis Remarks. The thermostable PDC bit experienced no wear to the shoulder cutters despite drilling hard and abrasive formations. Some impact damage was sustained by the central cone cutters and, to a lesser degree, the nose of the profile. The baseline bit used in Phases 1 and 2 suffered high impact damage that eventually led to a loss of penetration rate in Phase 1. As with all applications, there is room for improvement. In this case, combating the damage by alleviating the dynamic events that most likely caused it or improving the design’s ability to withstand such impacts is the next step.

Conclusions

Optimizing the performance of drilling involves a holistic approach including experience and knowledge of past or similar operations, modeling bit dynamic behavior, hydraulic optimization, and rock strength analysis. Programs that simulate the drilling operation and categorize the formations in terms of rock strength and drillability are essential tools for ensuring a successful bit run. However, there are still many unknowns. For example, the downhole vibration modes primarily responsible for mechanical damage to the bit’s cutting structure are difficult to identify.

Real-time monitoring of bit performance will increase our understanding of downhole dynamics, and the knowledge gained will contribute to enhanced PDC cutter technology and improved bit designs. More importantly, improvements in bit design coupled with real time optimization will significantly expand the range of applications that can be addressed because of better drilling economics.

During Phase 3 the team were able to recognize the onset of torsional vibration based on DWD downhole data, and then initiate corrective action before problems were noticeable at the surface. In most cases, full stick-slip motion was avoided. The real-time monitoring provided immediate feedback from visual displays that clearly illustrated whether any changes in parameter settings had successfully addressed a particular concern.

It is clear that there is much to be gained by acquiring and applying real-time downhole data with surface data. The present system embodiment that accomplishes real-time downhole monitoring via a wireline connection to the surface is not an attractive option for the field. However, newly emerging technologies, such as wired drill pipe,⁴ will enable these drilling operations in the near future, particularly for difficult applications where downhole dynamics must be understood to fully optimize performance.

Acknowledgements

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Special thanks go to Sandia National Laboratories for organizing and managing the overall CRADA-based research program. Moreover, Sandia's DWD team, which worked many extended hours to ensure the successful completion of the CRADA tests, deserves high accolades for developing and fielding a viable system for monitoring surface and downhole drilling conditions.

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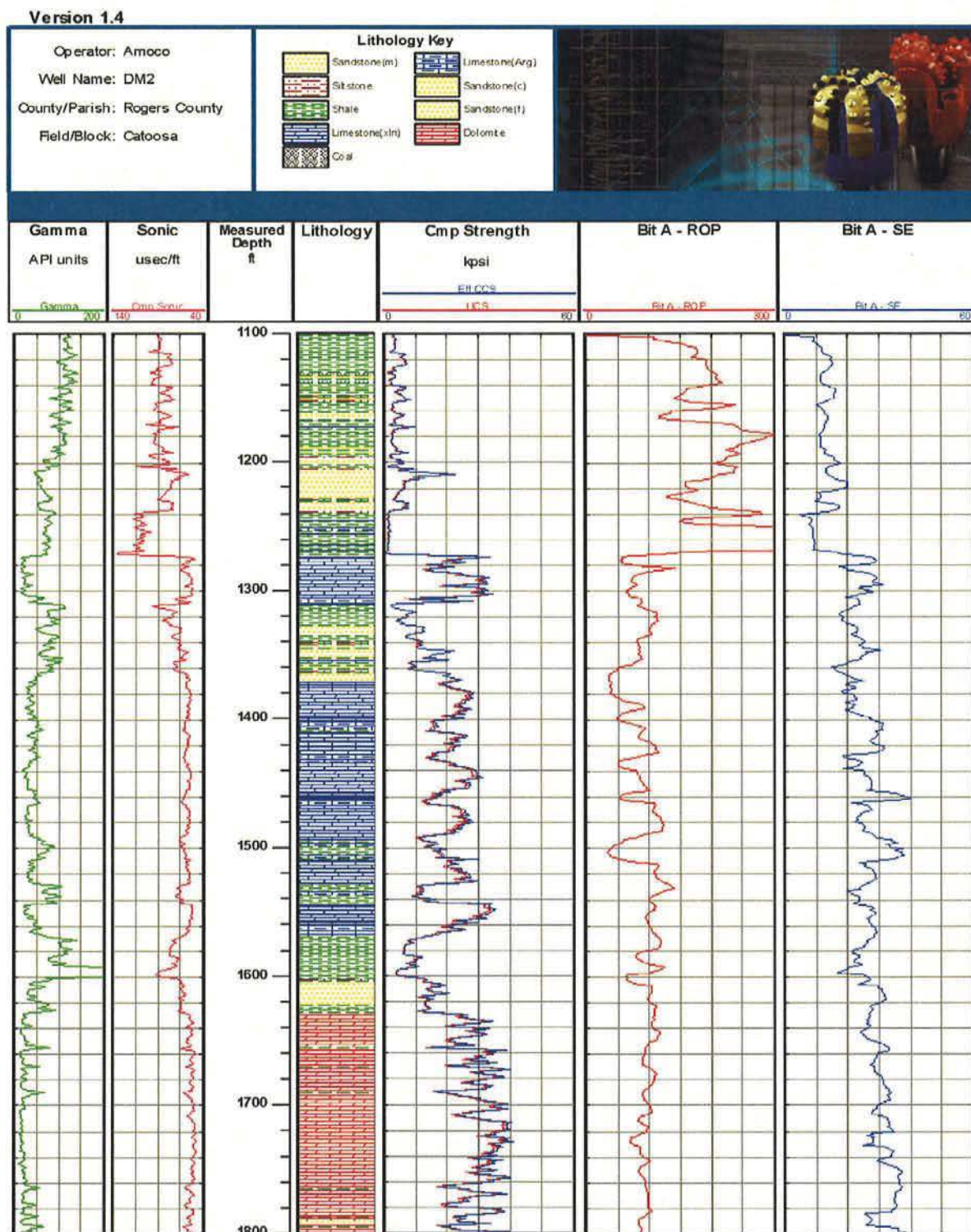


Figure 1 – Calculated Catoosa formation rock strength at measured depths



Figure 2 – New 8-1/2 inch thermostable PDC bit

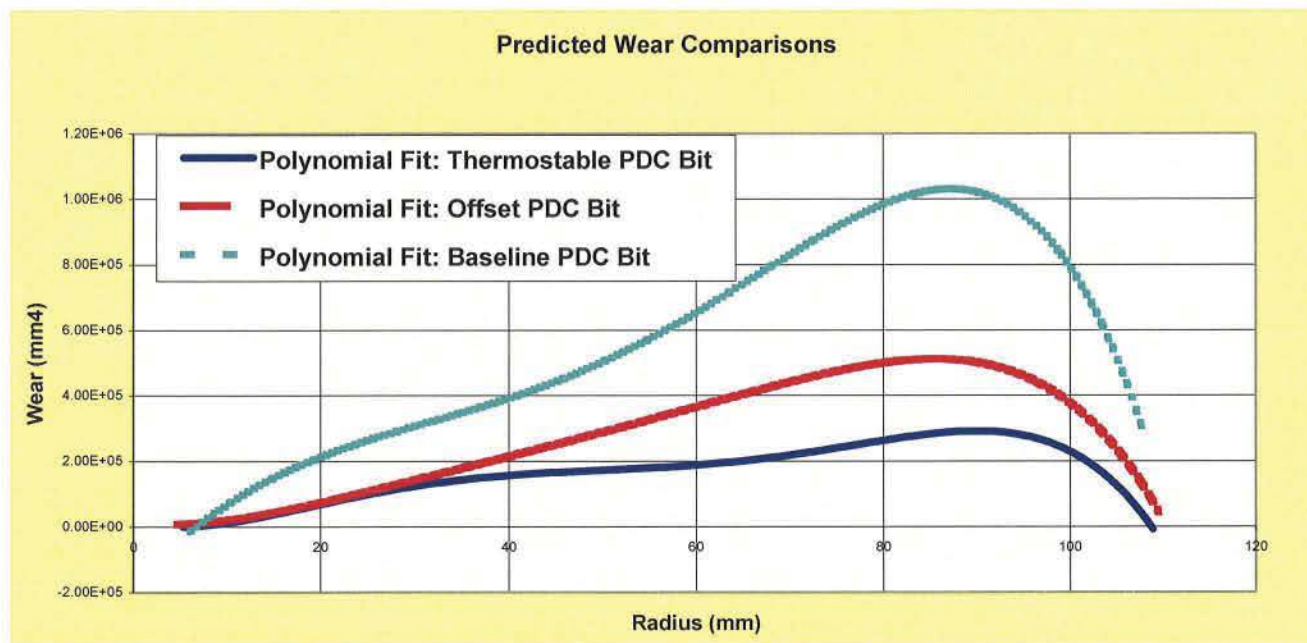


Figure 3 - Predicted wear comparisons for previous bit designs and the new thermostable PDC bit

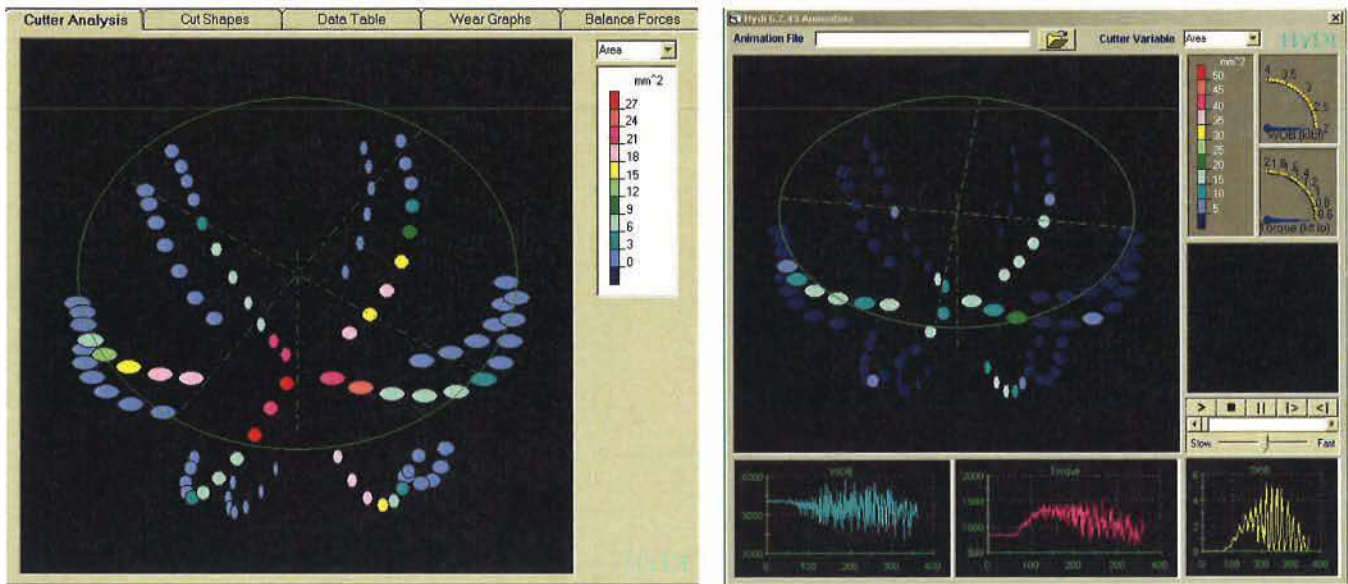


Figure 4 - Typical outputs of steady state and dynamic cutter analysis of thermostable PDC bit

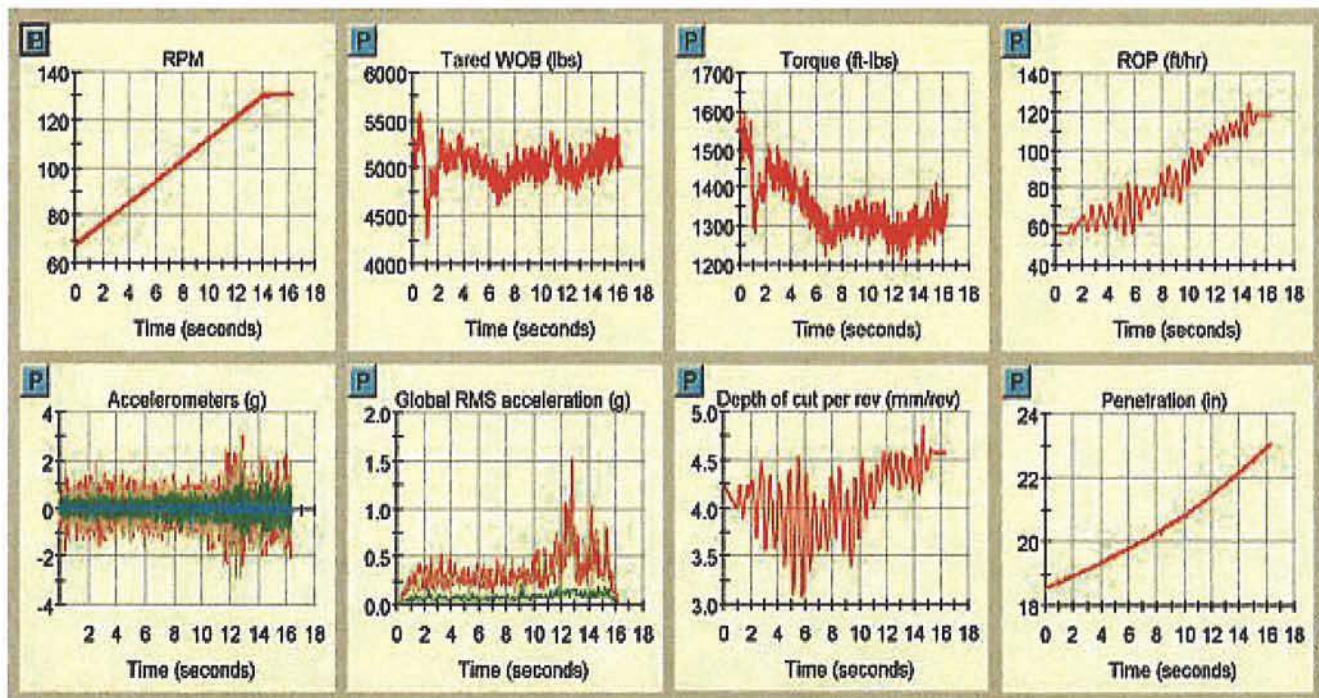


Figure 5 - Screen output for laboratory full-scale drilling test with thermostable PDC bit

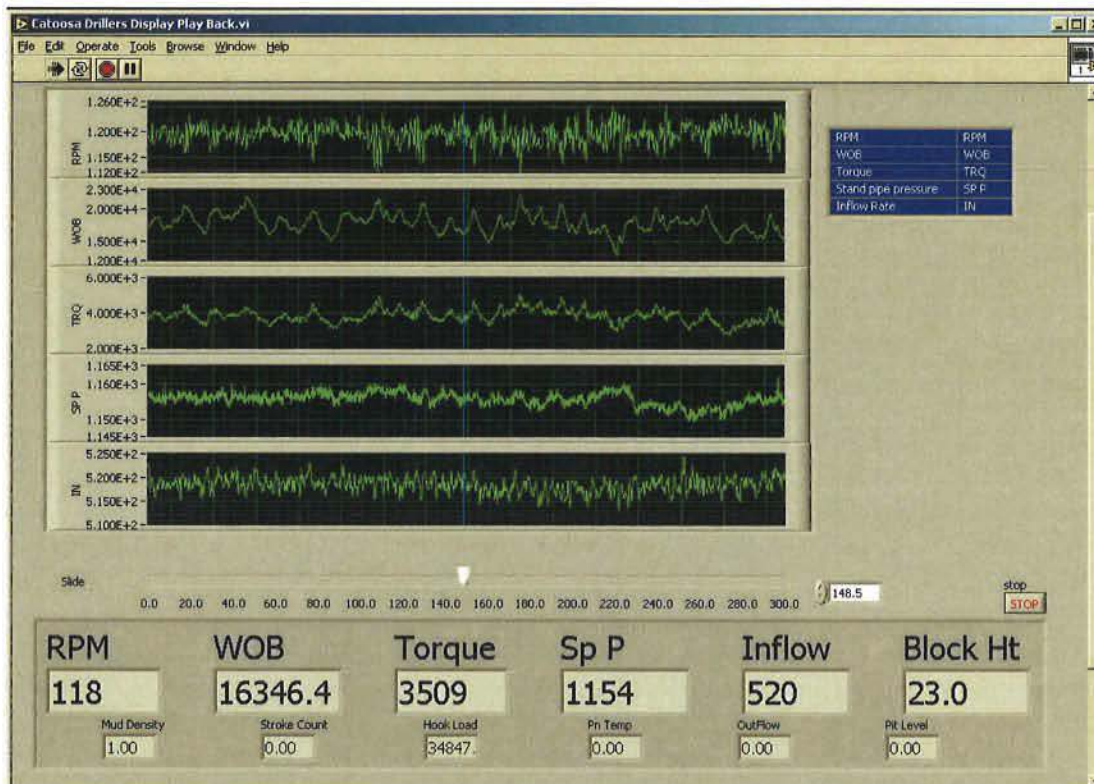


Figure 6 - Example of screen layout for surface data

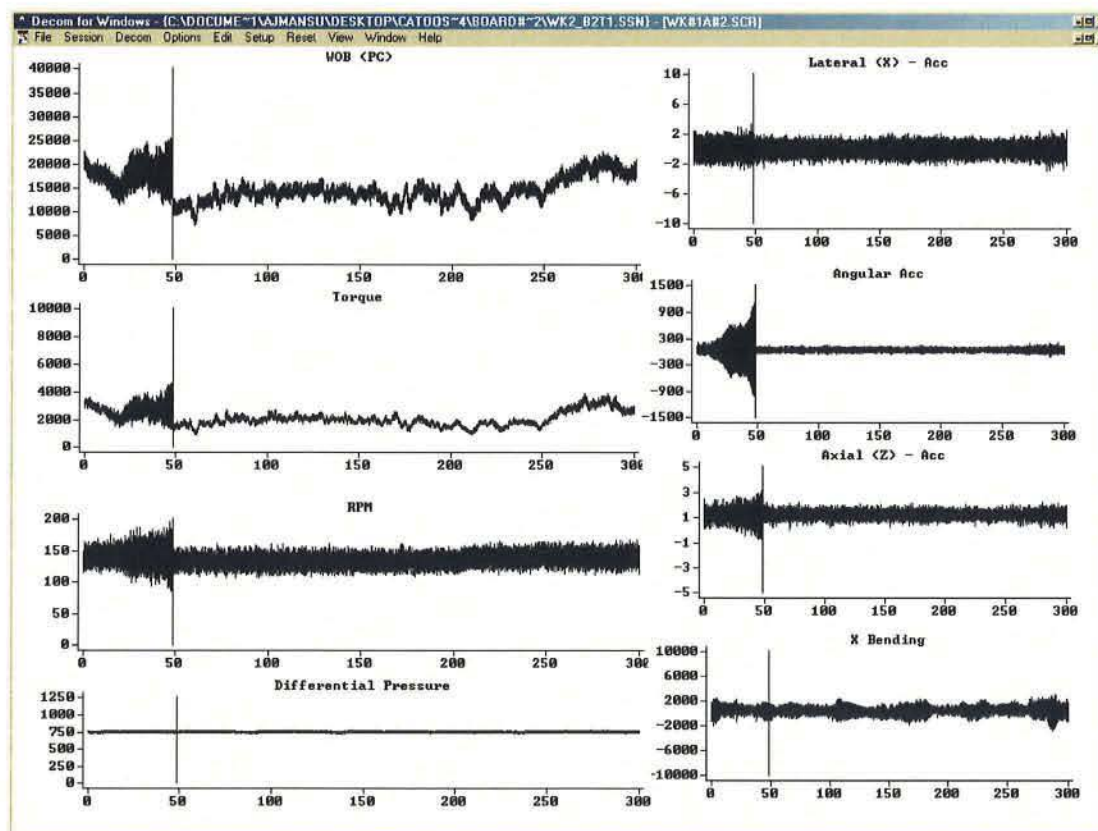


Figure 7 - Strip charts of real-time downhole data vs time



Figure 8 - Nose-to-shoulder dull of PDC bit with thermostable cutters



Figure 9 - Nose-to-shoulder dull of bit with standard PDC cutters – having drilled the same formations during 1993

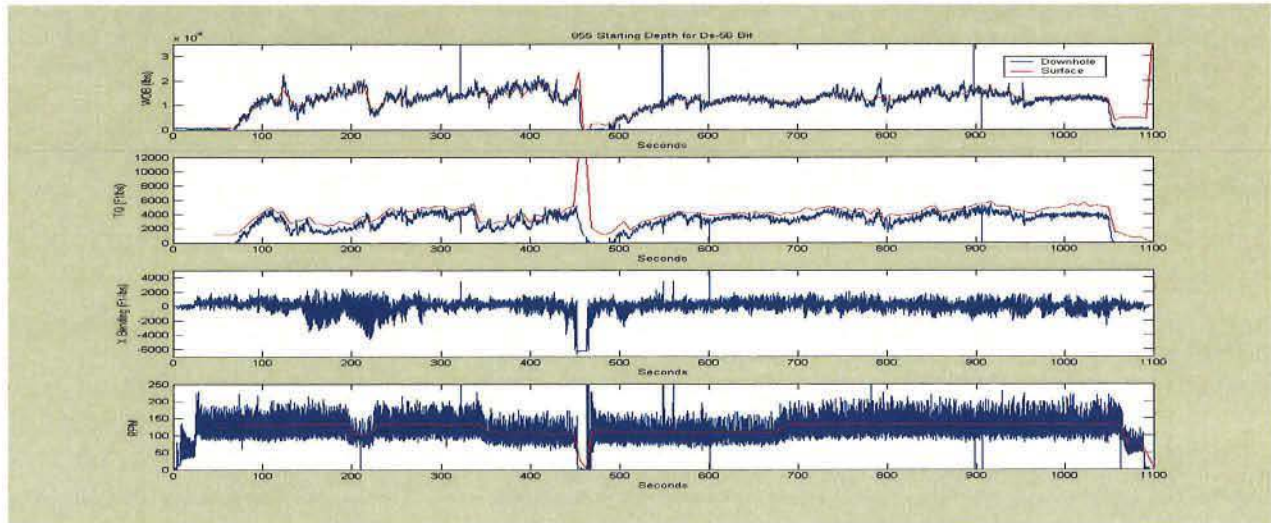


Figure 10 - Indication of stabilizer sticking causing top drive to stall

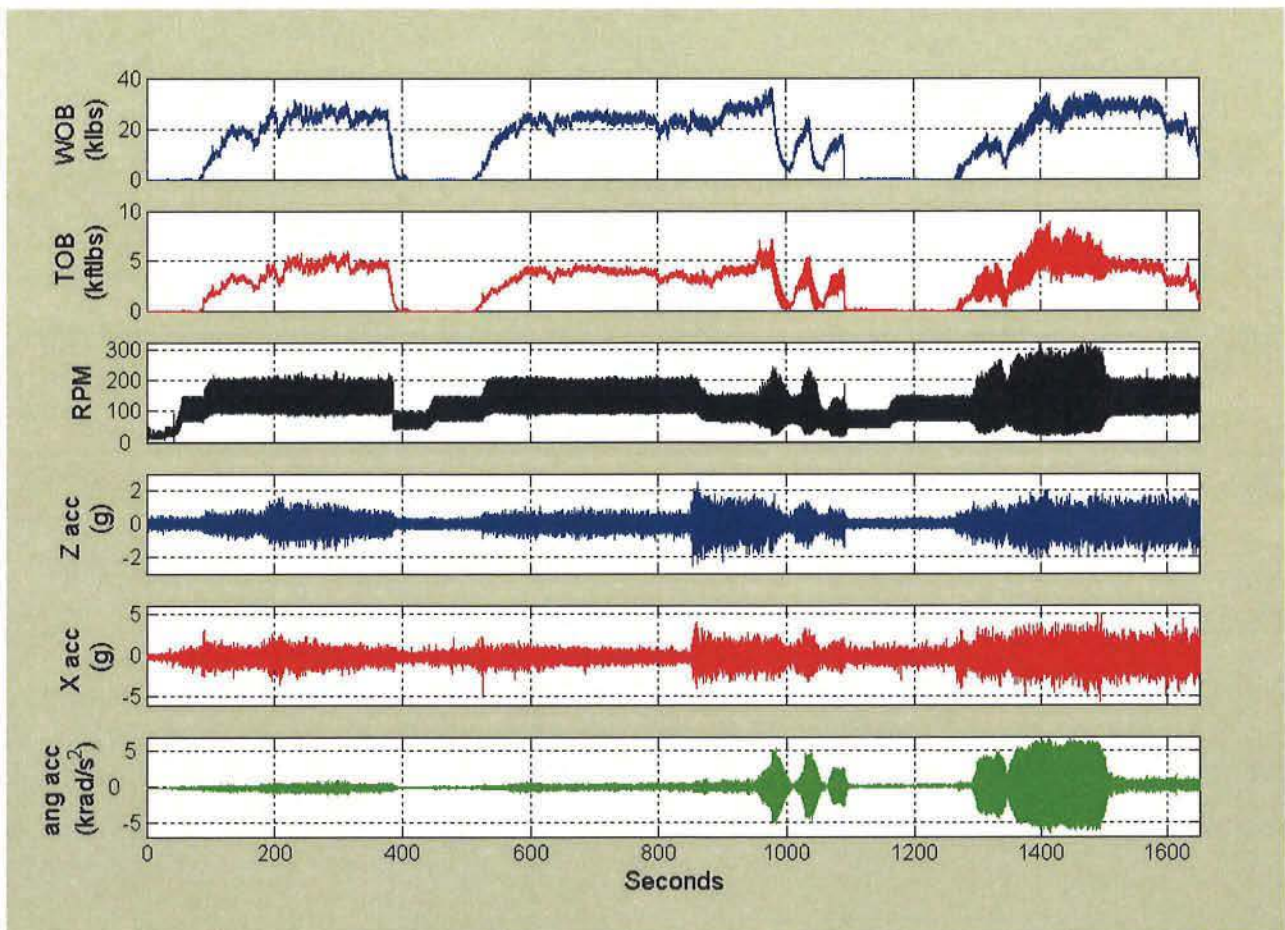


Figure 11 - Downhole dynamic events during drilling in the Mississippi limestone



Figure 12 - Thermostable PDC bit dull condition after drilling the Mississippi Limestone

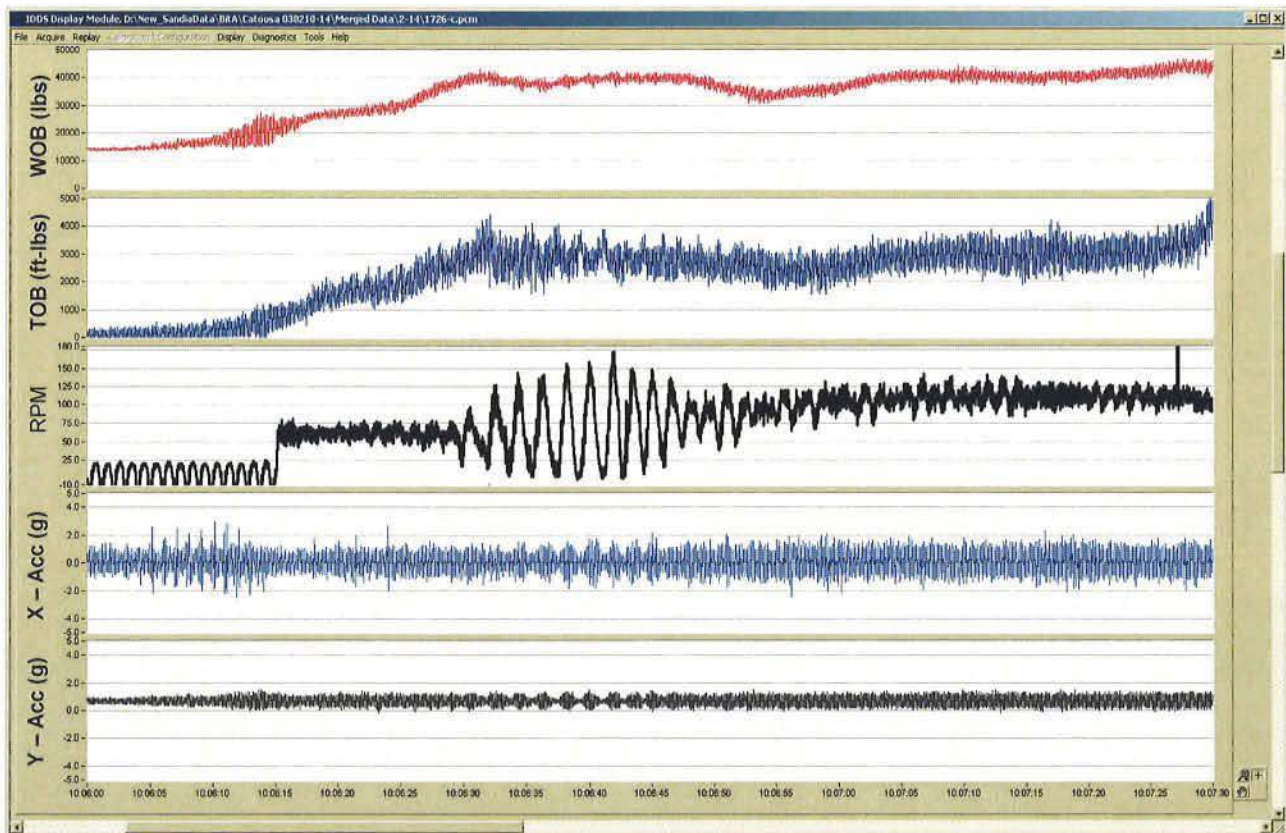


Figure 13 - Stick-slip oscillations at start up with low rotary speed

Depth Interval (ft)	Formation Name	Rock Strength (Kpsi) Range	Average Rate of Penetration (ft/hr)		
			Phase 1 Baseline Bit	Phase 2 Baseline Bit	Phase 3 Thermostable PDC Bit
901 - 1208	Booch Sandstone	4 - 8	104.9	89.2	191.1
1208 - 1238	Burgess Sandstone	8 - 23	90.7	69	178.1
1238 - 1274	Fayetteville Shale	3	77	84.9	259.7
1274 - 1571	Mississippi Limestone	> 35	57.8	33	78.2
1571 - 1600	Woodford Shale	5 - 11		53	103.8
1600 - 1627	Misener Sandstone	20 - 30		67	93.8
1627 ~ 2942	Arbuckle Group	25 -40		66	86.5
Overall Rate of Penetration			69.6	43.7	95.1
Footage / total hours			(386.6 ft / 5.554 hrs)	(525.5 ft / 12.029 hrs)	(811.6 ft / 8.535 hrs)

Table 1 - Depth and formation table indicating penetration rates of "best effort" thermostable PDC bit compared with earlier baseline bit runs

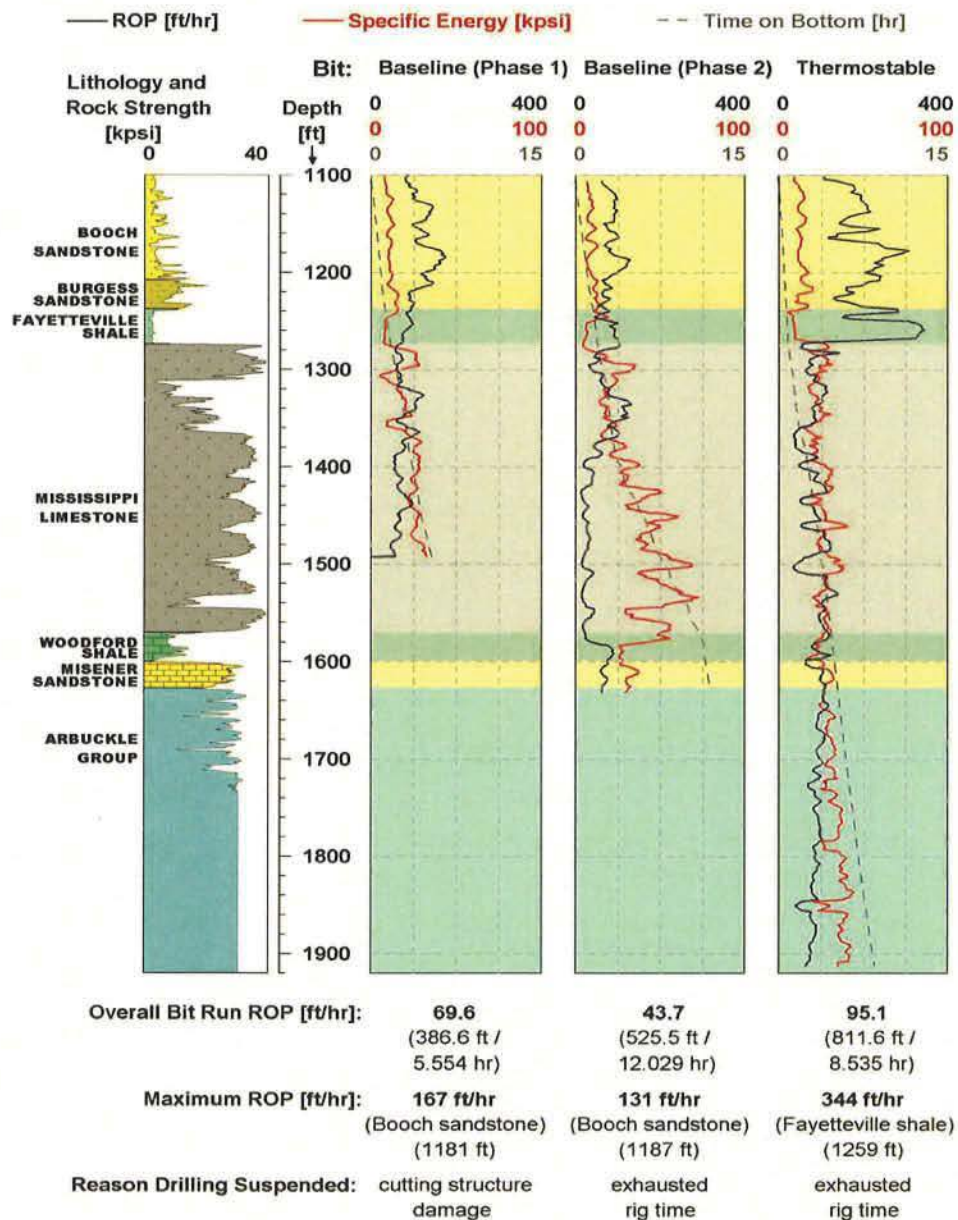


Figure 14 - Specific energy chart comparing thermostable PDC bit with baseline bit