Reduce Torsional Vibration and Improve Drilling Operations

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Abstract

Torsional vibration can be very damaging to drill string components during downhole drilling operations. Reducing torsional vibration as a result of monitoring and implementing corrective actions can be very useful in drilling optimization. While downhole vibrations cannot be totally eradicated, if properly monitored and kept to a minimum, they are harmless. A software package was used during drilling operations on two wells off the East Coast of Trinidad. Results showed that severe slip stick vibrations were occurring and having major impact on downhole equipment such as bit, Measurement While Drilling (MWD) tools and motor. The computer program provides real time display of the magnitude of torsional vibration by utilizing Fourier Spectral Analysis on the data from drilling sensors.

This paper will look at the results from these two wells and show that there are benefits from monitoring and reducing torsional vibrations. These include:

- *reduction of the frequency of drill string/Bottom Hole Assembly (BHA) failures;*
- *reduction in trip time and fishing time;*
- *increase in drilling rate and bit life*

Keywords: Torsional vibration, drilling operations

1. *Introduction*

Identification and control of drill string vibrations has become an area of considerable interest over the past 10 to 15 years. This is because drill string failures have increased tremendously during that time and have become a serious problem resulting in substantial financial losses. The financial impact of such failures can be significant both in terms of cost of replacing damaged components and extended operation time caused by unplanned events. Increasing drilling costs and the use of more complex and expensive downhole tools make vibration monitoring and control a key in drilling optimization. A number of oil companies have become aware of the benefits of controlling vibration and have implemented programs to raise awareness and create control strategies (Kriesels et al, 1999).

High levels of vibration during the drilling process frequently occur. A combination of technologies and methodologies can be useful in reduction of downhole vibration (Gabriel et al, 1997). High unacceptable levels of vibration can result in drill string failure, premature bit failure, poor directional tendency, hole enlargement, stalling of the top drive or rotary table, MWD tool failure and Stabilizer / tool joint wear. Torsional or “slip stick” vibrations are often regarded as one of most damaging modes of vibration (Omajuva et al). This paper looks at the problem of stick slip during drilling by identifying and determining the magnitude of drill string torsional vibration using a computer program and monitoring data from drilling sensors. The detailed Fourier spectral analysis of this data provides a real time display of the magnitude of torsional vibrations (Kt) in the drill string. This value is the amplitude of the highest resonant frequency detected in the torque signal expressed as a percentage of the maximum torsional output of the rotary system.

2. Vibration Background

A drill string can vibrate in three modes, laterally, axially and torsionally. Axial vibration is motion along the drill string axis, lateral vibration is a side to side motion of the drill string and torsional vibration is a twisting or motion causing varying levels of torque in the drill string.

Slip stick or stick slip is the non uniform rotation of the drill string caused by resistance to motion traditionally regarded as resistance by the formation to the cutting action of the bit. Research has shown that slip stick may occur at any point in the drill string where the resistance is sufficiently high to impede rotation. Slip stick is the primary mechanism for the creation of torsional vibration within drill string. These occur in the range of up to 1 Hz. A rule of thumb is that the period of vibration is 2 seconds per 1000m for 5" drill pipe.

The rotation of the drill string is impeded to a level close to or above the energy level being imparted to drill string by the rotary drive. The subsequent increase in torque applied by the motor to overcome this resistance, causes greater twisting to the drill pipe section and storage of the energy. Once the resistance to rotation is overcome, the stored energy in the drill pipe is transferred to the BHA and it accelerates to speeds of 3 to 15 times the current rotary speed.

The repeated acceleration and deceleration of the drill string components has a number of detrimental effects (Abbassian, 1994). When the BHA is accelerated forward, if the stored energy in the drill string is sufficient, it twists the drill string from the bit upward past its neutral position. When the drill string tries to return to equilibrium the bit, BHA and part of the drill pipe then rotate backwards. Fig. 1 shows the cycle of the slip stick phenomenon highlighting the changes of the drill string during the torsional vibration occurrence. Fatigued of the drill pipe and BHA connections are increased and because of this increase and reduction in torque, the life span of the drill pipe is reduced and additional fatigue cracks can develop into washouts.

In extreme circumstances, connections are backed off incurring the costly expense of fishing or sidetracking around the obstacle. The behavior also causes impact and abrasion damage to stabilizers and bits, especially PDC bits because they are highly susceptible to damage when rotated backwards. Damage to the rotary drive is may occur from the high cycling torque.

3. System Layout and Software Program

A software package was used on trial during drilling operations on two wells off the East Coast of Trinidad. Figure 2 shows the hardware layout of the torsional vibration monitoring program. The diagram shows data from rig sensors are passed through a filter board and the output signal for display and recording of Kt magnitude is obtained.

The computer program was used to analyze the magnitude of torsional vibrations using Fourier analysis.

Torque is a complex waveform created by cumulative resistance to rotation of the entire drill string. By analyzing the power input to the rotary drive, and using fourier analysis, the torque signal could be broken down into its constituent components, and repetitive cycling waves and respective frequencies identified. These cyclic frequencies indicate the presence of torsional vibration. Thus the program uses fourier analysis to breakdown the torque signal and provides a frequency domain spectrum of the amount of energy contained within the sinusoidal oscillation of the torque signal. These sinusoidal oscillations in the torque are caused by torsional vibrations. This is shown in Figure 3.

The determination of these frequencies and their magnitude (Kt) allows the driller to correct the problem by varying the associated drilling parameters of Revolutions per Minute (RPM) and/or Weight on Bit (WOB).
The resulting benefits can bring substantial cost savings to a drilling program by reducing BHA and tubular failures, reducing bit damage and increasing bit life, decreasing the number of bit trips, reducing tool failures and determining optimum rotational speed

When a predetermined threshold of torsional magnitude is exceeded a data file is created. The program then creates an event listing of these data files. The listing contains file name, start and end times and depths of event files. This event listing is useful in determining the amount of torsional vibration for each bit run.

Two database files are stored for each bit run. One gives a catalogue of event files showing File Name, Date, Start and Stop Times, Start and Stop Depths. The other keeps a record of Date, Time, Cycles/Min., Kt Values and Bit Depth.

These files can be used to determine the duration of each event file, the footage made for the duration of each event file, the duration of torsional vibration for the bit run, whether the vibration is at the bit or BHA and the amount of times torsional vibration had exceeded the threshold

Also included in the software package is a playback facility which allows the playback of each event file. This system helps in the analysis of event recording files and printing playback charts which show stick slip occurrences and torsional vibration. The torsional vibration system is shown in Figure 4. It shows the playback facility, Kt levels on drillers display and the real time monitoring of torque levels.

Figure 5 shows a typical playback chart with four traces color-coded as: green – hook load (HL); light blue – stand pipe pressure (SPP); deep blue – revolutions per minute (RPM). Torque is normally black but when the torsional vibration limit is exceeded it changes to red. The positions of the zero baselines for these 4 parameters are indicated on the figure and were chosen so as to minimize overlap of their traces.

Each division on the playback chart is equivalent to 10 seconds on the x-axis and 10% of the baseline values on the y-axis. These baseline values are set for normal drilling using the driller's gauges on the rig floor.

Additional information that was required for this vibration analysis was obtained from Mudlogging (SDL) data. ASCII data such as rate of penetration, weight on bit, surface RPM were captured in excel format from SDL Log Drawing System. Some MWD data (gamma and resistivity) were also obtained from the SDL logs. Bit data was obtained from the bit record report (Mudlogging Report).

Selecting a threshold value for Kt is pretty much subjective and as a result depends on the operator's discretion and foresight. At the start of drilling, Kt levels would be monitored for some time to determine a trend for normal drilling. In this case Kt was averaging 0 to 2.5. Thus 0 to 3 was taken as normal drilling for this field and the threshold set at Kt = 3. Above this value the program would be triggered into creating and storing data files. Once this threshold had been established, it was used for all the bit runs. While this threshold value would vary from field to field and country to country, generally regardless of field or country harmful drilling would be in the range 3 to 8.

4. Field Trial

Drilling wells in Trinidad have resulted in increased drilling cost due to unscheduled events such as downhole tool failures. These include motor failure, bit failure and MWD failure. Most wells drilled in Trinidad have been drilled without real time downhole vibration measurement tools used with MWD tools. This is so because of high cost associated with using the downhole vibration measurement tools.

The torsional vibration-monitoring program was used during the drilling operations of two wells off the East coast of Trinidad as a trial. The field contains both oil and gas and consists of interbedded formations of sandstone and claystone. There were numerous downhole tool and bit problems on most of these wells.

The objective of drilling both wells was to penetrate the oil leg and drill lateral sections for a total length of about 2000 ft. To achieve the well objectives, both wells were drilled from the same slot of the platform utilizing twin monobore wellhead technology.

Seven bit runs were made in drilling Well 1. The software program was used for bit runs 2, 3, 4 and 6 but not for bit runs 1, 5 and 7. Nine bit runs were used to drill Well 2. The software program was used for bit runs 2, 3, 4, 5, 7 and 8 but was not used for bit runs 1, 6 and 9. Torsional vibration was very evident while drilling both wells. Many stick slip occurrences were recorded on bit runs 2, 3, 4 and 6 of Well 1 and bit runs 2, 3, 4, 5, 7 and 8 of Well 2. An event file analysis was done for each bit run. The following discussion focuses mainly on bit run 2 of Well 1but also includes examples from bit run 3 of Well 1 and bit run 2 of Well 2.

4.1 Motor Failure - Well 1 Bit Run 2

During bit run 2 of well 1, a Polycrystalline Diamond Compact (PDC) bit was used to drill the 12 ¼" hole section from 4030 ft to 4846 ft. The section was drilled in 7.0 bit hours at an average rate of penetration of 117 ft/hr. A total of 34 data files were created for this bit run including the period of drilling cement. There were 13 periods of torsional vibration over 5 minutes, 7 periods of torsional vibration while rotating off bottom and 24 stick slip occurrences. Total torsional vibration time was 3 hrs and 47 minutes equivalent to 54.3 % of the total drilling hours for this bit run. Figure 6 shows the periods for Kt values of 5 and greater, the depths at which they occurred and the length of time in minutes for which they were sustained. There were 6 periods of torsional vibration with Kt levels between 7 and 9 which was equivalent to 2500 ft lbs and 4500 ft lbs respectively. Each of these lasted for more than 10 minutes. At depths of 3925 ft and 4363 ft the Kt values were 9 and 7 respectively and each lasted for 23 minutes. At 4658 ft the Kt value was 9 and lasted for 28 minutes. This data clearly shows that there were significant levels of damaging torsional vibration that adversely affected the downhole motor that eventually failed during this bit run.

4.2 Reduction of ROP's - Well 1 Bit Run 2

When stick slip occurs the bit stops rotating and the Rate of Penetration (ROP) decreases. Figure 7 shows some of the depths at which stick slip occurred for this bit run and the rates of penetration before and after it occurred. ROPs decreased by more than 50% at the depths 4359 ft, 4367 ft, 4389 ft, 4710 ft. Kt values for these depths ranged from 6.7 to 8.6.

4.3 MWD Decoding Problems - Well 1 Bit Run 3

Decoding problems and MWD tool failures seem to persist on every well drilled in this field. Decoding problems are associated with temporary loss of gamma ray and resistivity data. Both of these are important in the determination of lithology, pore pressure and hydrocarbon bearing zones.

During bit run 3 Well 1, a PDC bit was used to drill the 12 ¼" hole section from 4846 ft to 10,319 ft. There were several instances of MWD decoding problems. These were correlated with stick slip occurrences and a few are shown in Figures 8 and 9. Figure 8 shows loss of gamma ray and resistivity data on a MWD log while Figure 9 is a playback chart of these same stick slip occurrences.

Stick slip occurred at 5294 ft with consequent loss of MWD data between 5300 ft and 5330 ft. Torsional vibration was controlled at 5327 ft by briefly increasing the RPM, Figure 10. This resulted in restoration of MWD data between 5340ft and 5360ft. The loss of signal again between 5370 ft and 5390 ft prompted a further adjustment to the RPM. The MWD data collection was then restored beyond 5390 ft.

4.4 MWD Failure - Well 2 Bit Run 2

During bit run 2, Well 2 a PDC LA330BG bit was used to drill the 12 ¼" hole section from 4020 ft to 8404 ft. This bit run started with MWD decoding problems and as torsional vibration persisted and was not controlled, MWD failure occurred. Figure 11 shows loss of MWD data at several depths starting at 6210 ft while a playback chart for the depth 6254 ft is shown in Figure 12. It is clear that stick slip was occurring at the same interval MWD decoding problems were being experienced. An attempt to correct this problem was made at 6913 ft by reducing the RPM which decreased the torque, Figure 13. However it appeared that this corrective action was implemented too late and stick slip continued at the other depths as indicated by the loss of MWD data shown in Figure 11 and eventually MWD failure.

4.5 Torsional Vibration Reduction - Well 1 Bit Run 3

At about a depth of 4979 ft the play back chart was similar to that of Figure 9 and showed rapid fluctuations in torque as high as 15% above the baseline value. As soon as the RPM was increased torsional vibration began to stabilize and a reduction in torque was realized.

There are instances where it is necessary to reduce the RPM in order to decrease torsional vibration (Figure 13). At a depth of 6913 ft erratic fluctuations in torque were occurring with values reaching 20% above the baseline value. In this case the reduction in torque and torsional vibration were achieved by decreasing the RPM.

This emphasizes that monitoring torsional vibration can allow the driller to make simple adjustments to rotary speed and/or weight on bit to effectively control torsional vibration. This was accomplished by monitoring the rig floor gauge together with advice from engineers analyzing torsional vibration.

4.6 Dogleg Severity

Dogleg is a deviation in the borehole of the well and is created to build angles in inclined holes. The recommended dogleg for drilling both wells was 2.5 degrees per 100 ft. Figures 14 and 15 show plots of Measured Depth vs Dogleg for both wells. Substantial torsional vibration levels were occurring where dogleg exceeded the recommended limit. The evidence for this is the number of data files that were created and the number of stick slip occurrences. For Well 1 dogleg was above the recommended limit while drilling through the interval 7125 ft to 8180 ft and 9075 ft to 10,800 ft. During this period 18 torsional vibration data files were created and there were 6 stick slip occurrences. For Well 2, in the regions 8500 ft to 10,400 ft, where the recommended dogleg was exceeded, and 60 torsional vibration data files were created.

4.7 Bit Correlation

For both wells more torsional vibration was obtained when PDC bits were used as opposed to rock bits. PDC bits were used for bit runs 2 & 3 of well 1 and bit run 2 of well 2. For bit run 2 there were 31 stick slip occurrences while drilling 816 ft (Figure 16).For bit run 3 there were 37 during the drilled interval of 5473 ft. When a Tricone bit was used there were 5 stick slip occurrences and the footage made was 1425ft.

For well 2 stick slip occurred 36 times during bit run 2 when a PDC was used (Figure 17). The footage made for this bit run was 4384 ft. For this same well when a Rock bit was being used there were 12 stick slip occurrences during the drilled interval of 2025 ft. During the bit run for this well when a Devil Drill bit was used there were 24 stick slip occurrences and the footage made was 2659 ft. It is interesting to note that PDC bits use shearing action while rock bits use compression as the means of cutting the encountered formation.

4.8 Lithology

High torsional vibration and stick slip occurrences were generally observed in the sandstone sections, while lower levels of torsional vibration were evident in claystone beds. For well 1 bit run 3, there were 31 occurrences of stick slip in sandstone sections as opposed to 6 in claystone. For all bit runs the majority of the stick slip occurrences were observed in sandstone (Fig 18).

5. *Summary*

1. The computer program was used
   - To determine the optimum RPM for each bit run.
   - In the reduction of BHA and tubular failures.
   - In the reduction of bit damage and increase bit life.
   - To confirm the hypothesis that severe stick slip vibrations were occurring and having a major impact on downhole equipment such as bit, MWD and motor, especially while drilling abrasive sands.
   - To identify instances when Kt values were greater than 3 during the drilling of both wells.
2. The Playback facility of the computer program allowed detailed analysis of historical drilling data, which was used to help avoid problems in subsequent bit runs.
3. The data obtained from monitoring torsional vibration can be used for interpretations related to lithology, bit wear and drill string/borehole interactions.
4. A thruster was used during bit runs 2 and 3 of Well 1. This tool operates in a sense to minimize axial vibration. However, many stick slip occurrences were evident in both bit run # 2 and bit run #3, which led to motor failure and MWD decoding problems. This indicates that MWD decoding problems, motor failure for bit run #2 and bit run #3 were as a result of torsional vibration and not axial vibration as was previously believed.
5. PDC bits use the mechanism of shearing rock dislocation. For both wells, it appears that more torsional vibrations were obtained when PDC bits were used as opposed to rock bits as evident by the number of major stick slip occurrences
6. Frequency of Stick slip is dependent on
   (a) Type of formation (often in abrasive sands)

(b) Type of bit (higher frequency with PDC bits)
(c) Type of BHA
(d) Possibly amount of doglegs

7. Stick slip was reduced by either increasing rotary speed and reducing weight on bit OR decreasing rotary speed and increasing weight on bit.
8. Previous experience has shown that torsional vibration tends to increase in severity above 30 degrees. It was noticeable that an increase in the severity of torsional vibration occurred when dogleg was above the recommended 2.5 degree/100 ft. This sudden increase in inclination increased the friction between the wellbore and drill pipe.
9. The periods where the bit stopped rotating were identified. These ranged from 1 second to 40 seconds. Maximum instantaneous RPM were several times higher than the average surface rotary speed.
10. The ROP's were significantly reduced after the occurrence of stick slip.
11. Drilling efficiency can be increased by monitoring and analyzing drill string torsional vibrations. This can then be used to determine optimum drilling parameters as the well is being drilled. This can result in reduction in the frequency of drill string failures, the amount of time spent tripping and/or fishing and an increase in both bit life and penetration rate.
12. The overall success of this system is dependent on the willingness of the rig crew to make the required corrections when necessary.

6.0 Nomenclature

BHA --- Bottom Hole Assembly
BP --- British Petroleum
HL --- Hook Load
Kt --- magnitude of Torsional vibration in the drill string
LDS --- Log Drawing System
LWD --- Logging While Drilling
MD --- Measured Depth
MWD --- Measurement While Drilling
PC --- Personal Computer
PDC --- Polycrystalline Diamond Compact
POOH --- Pull Out Of Hole
ROP --- Rate of Penetration
RPM --- Revolutions Per Minute
SDL --- Surface Data Logging
SPM --- Strokes per Minute
SPP --- Stand Pipe Pressure
TD --- Total Depth
TRQ --- Torque
WOB --- Weight On Bit
Devil Drill Run --- Clean Out Assembly using a bit called devil drill
Hydra Thruster --- Tool used on the BHA to cushion axial vibration and stabilize Downhole WOB

7.0 References

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Mudlogging End of Well Report for Wells 1 and 2 (ASCII Data, Bit run Information, End of Well Logs and Geology reports)

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1	2	3	4	5
Bit RPM Normal	Bit RPM Decreases	Bit RPM Increases	Bit RPM Decreases	Bit Stops
Bit TRQ Normal	Bit TRQ Increases	Bit TRQ Decreases	Bit TRQ Increases	Bit TRQ increases
Surface RPM Normal	Surface RPM Decreases	Surface RPM Increases	Surface RPM Decreases	Surface RPM Increases
Surface TRQ Normal	Surface Torque Increases	Surface TRQ Decreases	Surface TRQ Increases	Surface TRQ Decreases
Cycle then repeats from step 3				

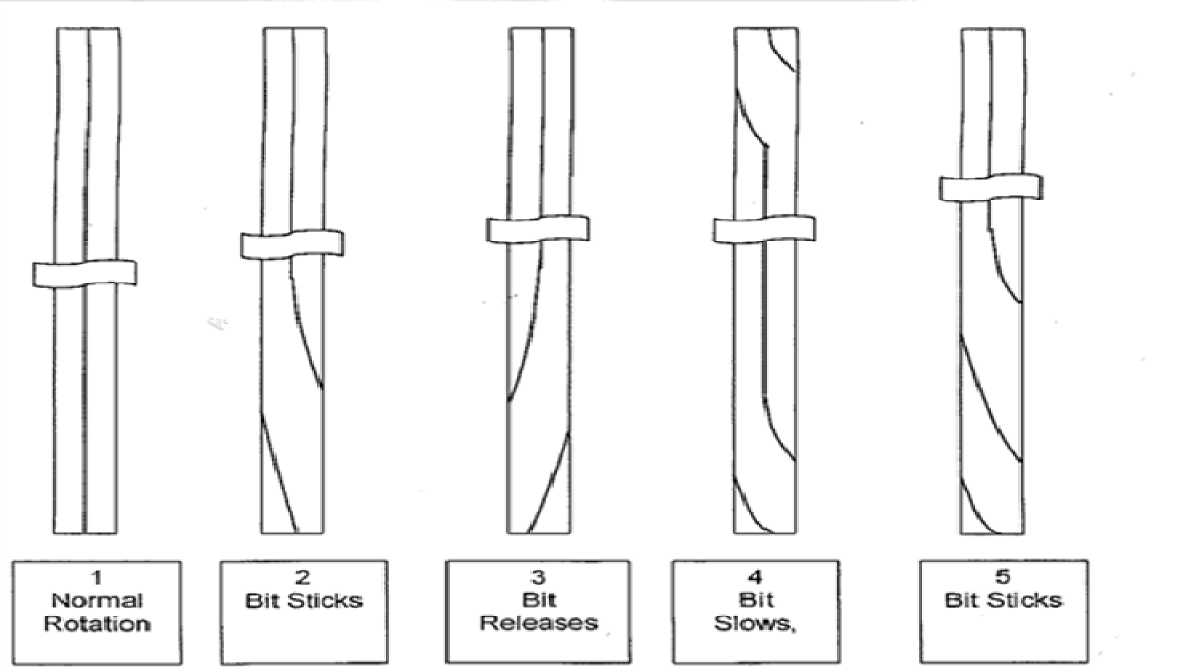

Figure 1 – Drill String Slip Stick Cycle

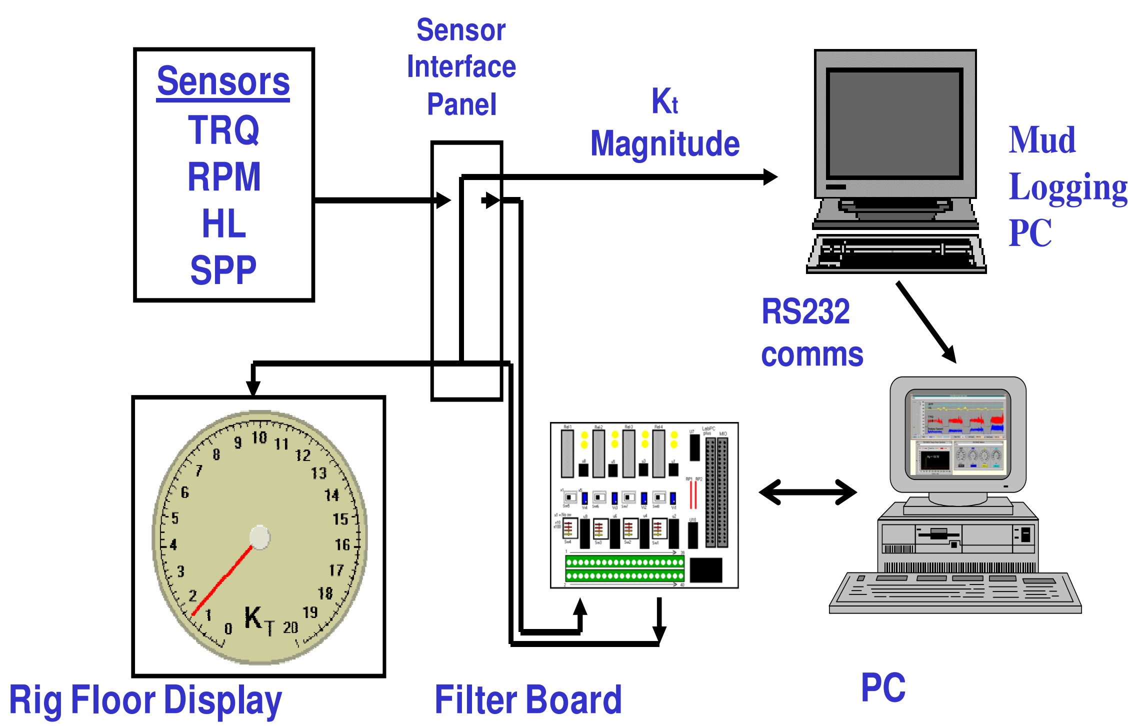

Figure 2 – System Layout: Mud logging Unit

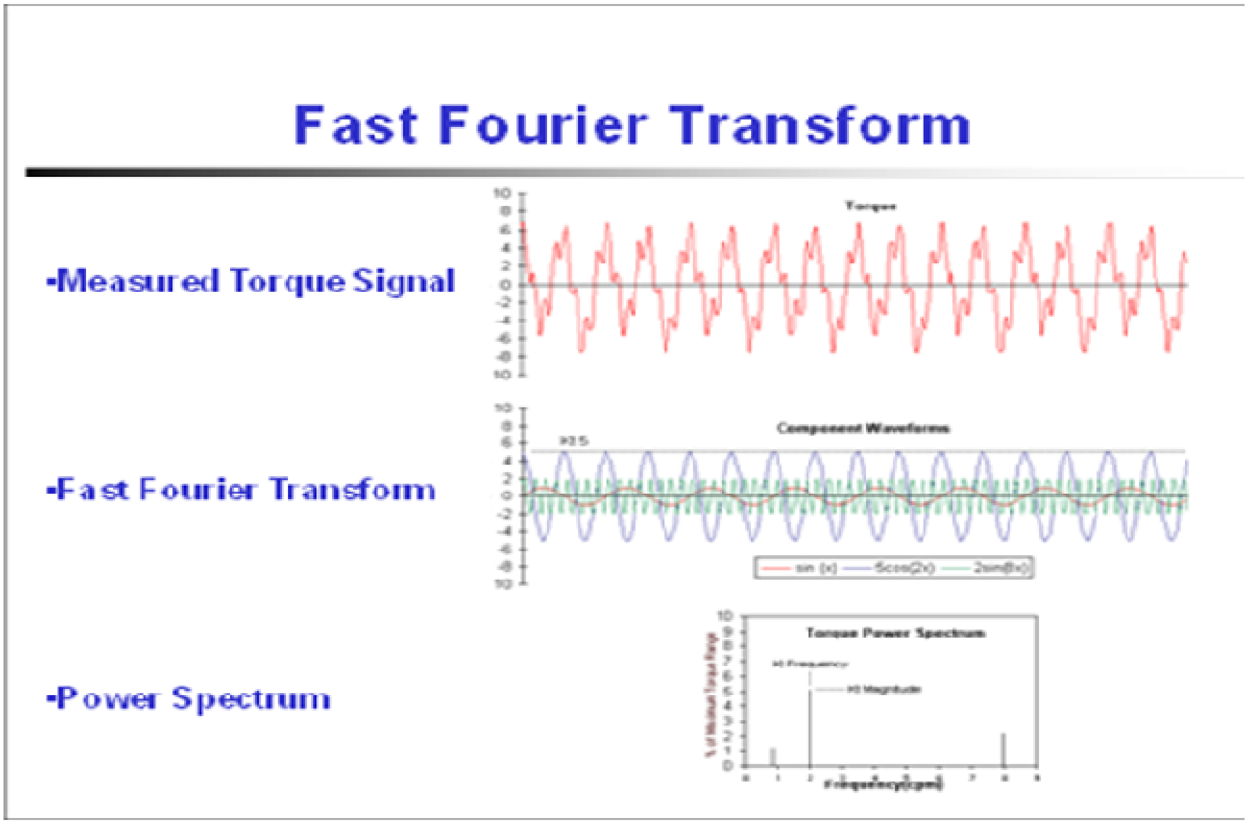

Figure 3 – Fast Fourier Transform quantifying torsional vibration

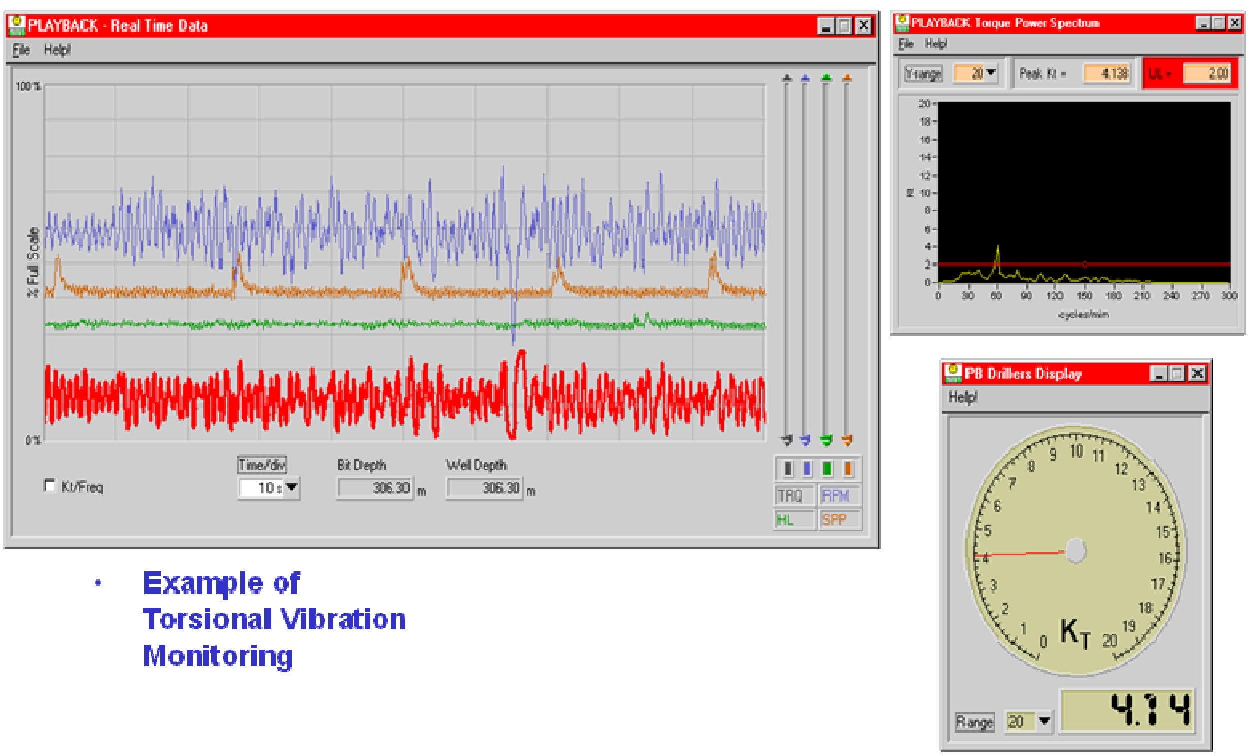

Figure 4 – Torsional Vibration Monitoring Output Screens

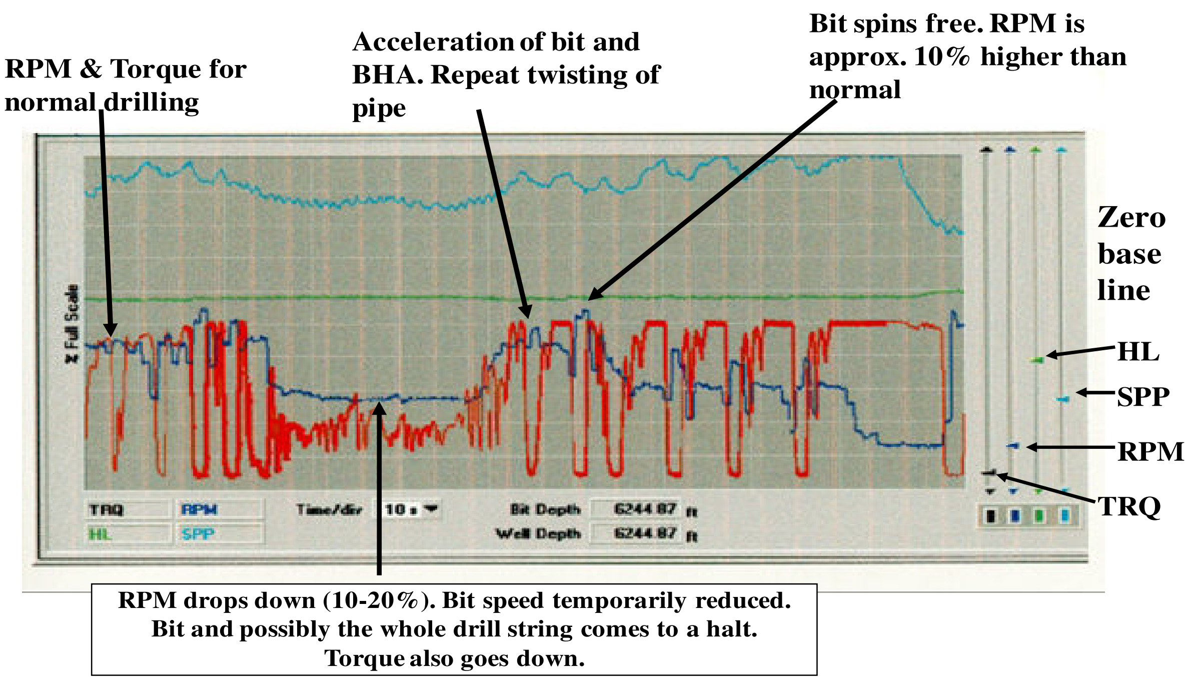

Figure 5 – Playback for Well 1 Bit Run 3 - Depth 6244 ft

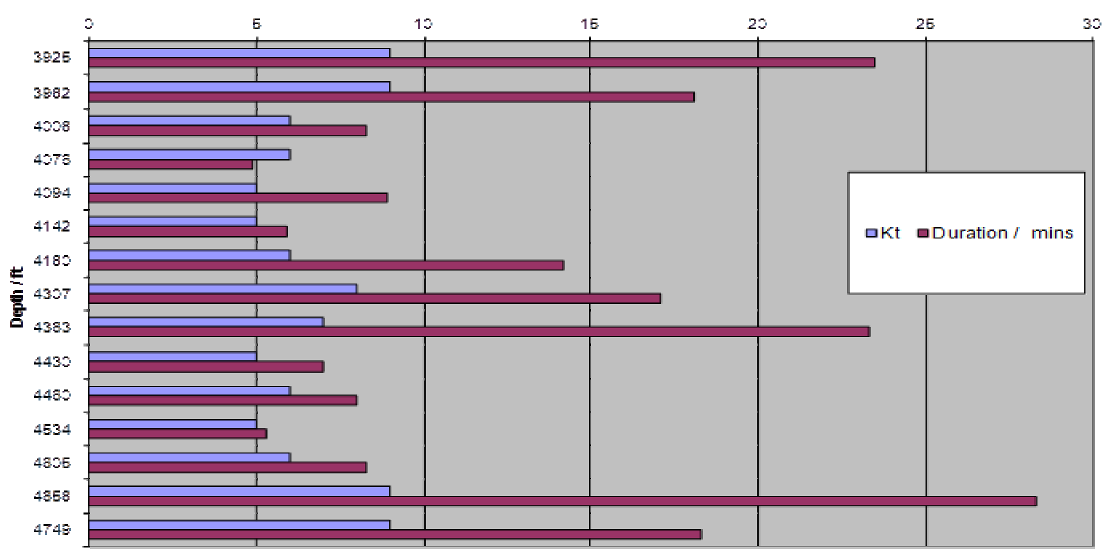

Figure 6 – Well 1 Bit Run 2 – Kt and Duration

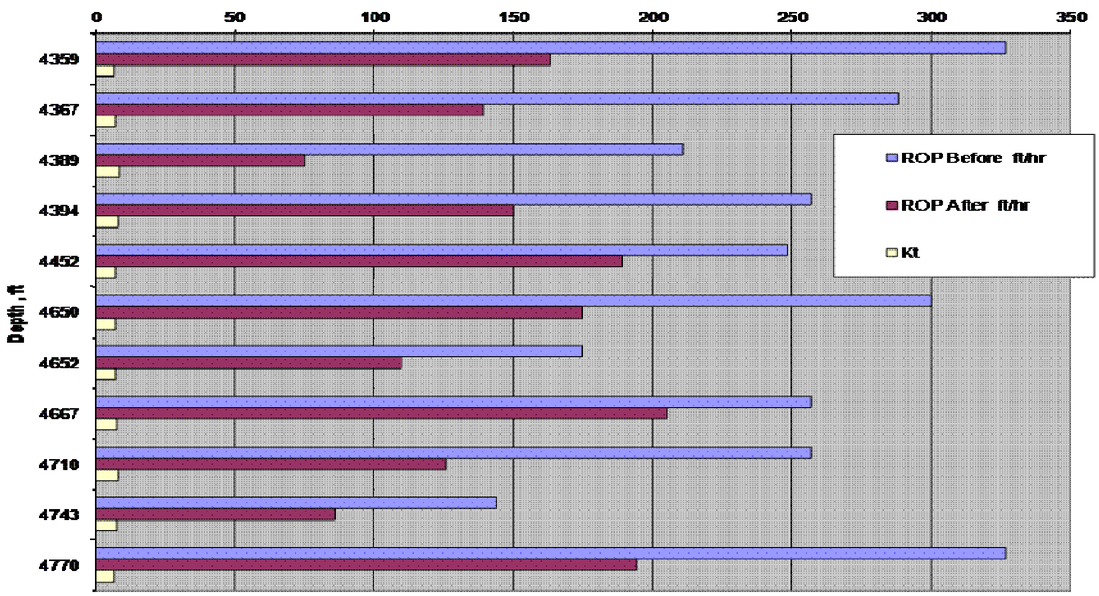

Figure 7 – Well 1 Bit Run 2 – Rate of Penetration

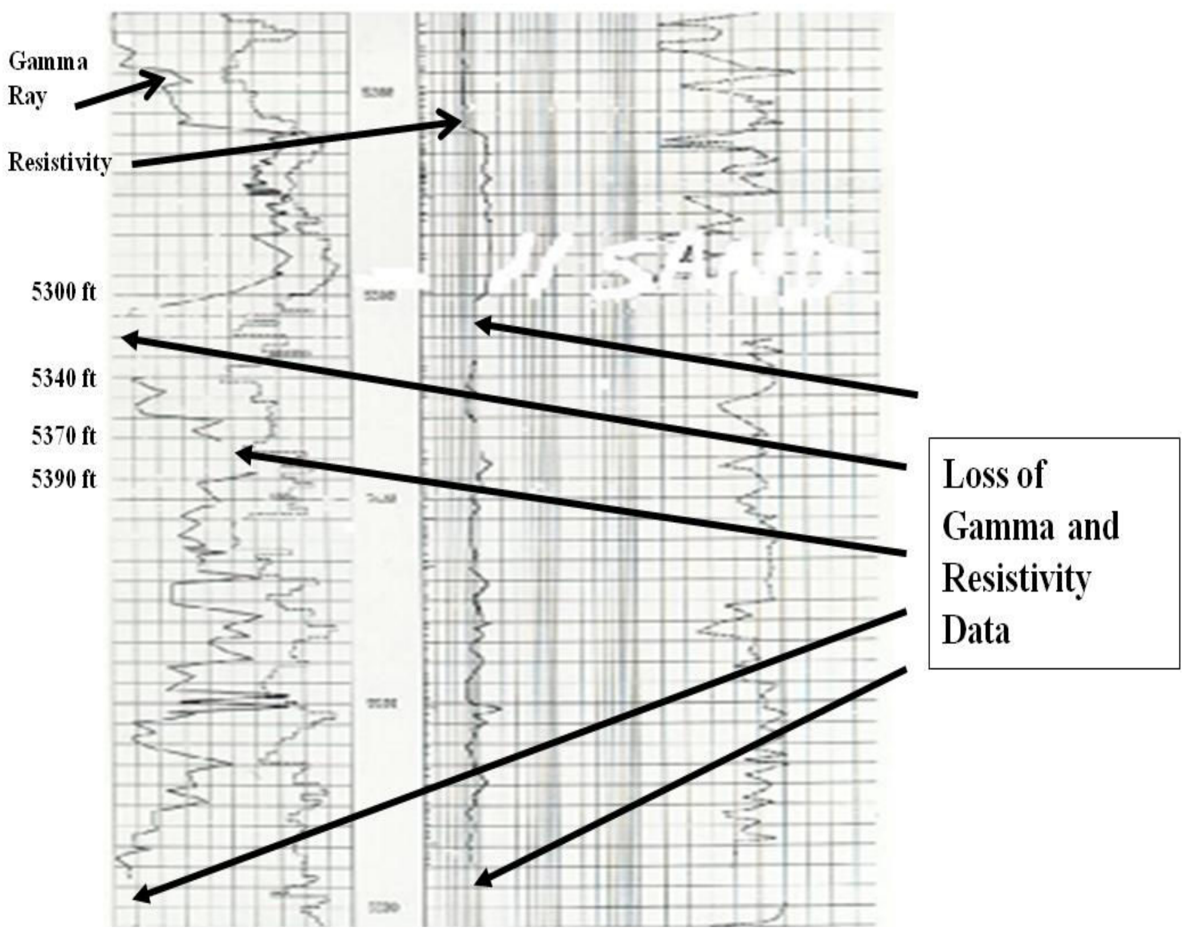

Figure 8 – MWD log – Well 1 Bit Run 3

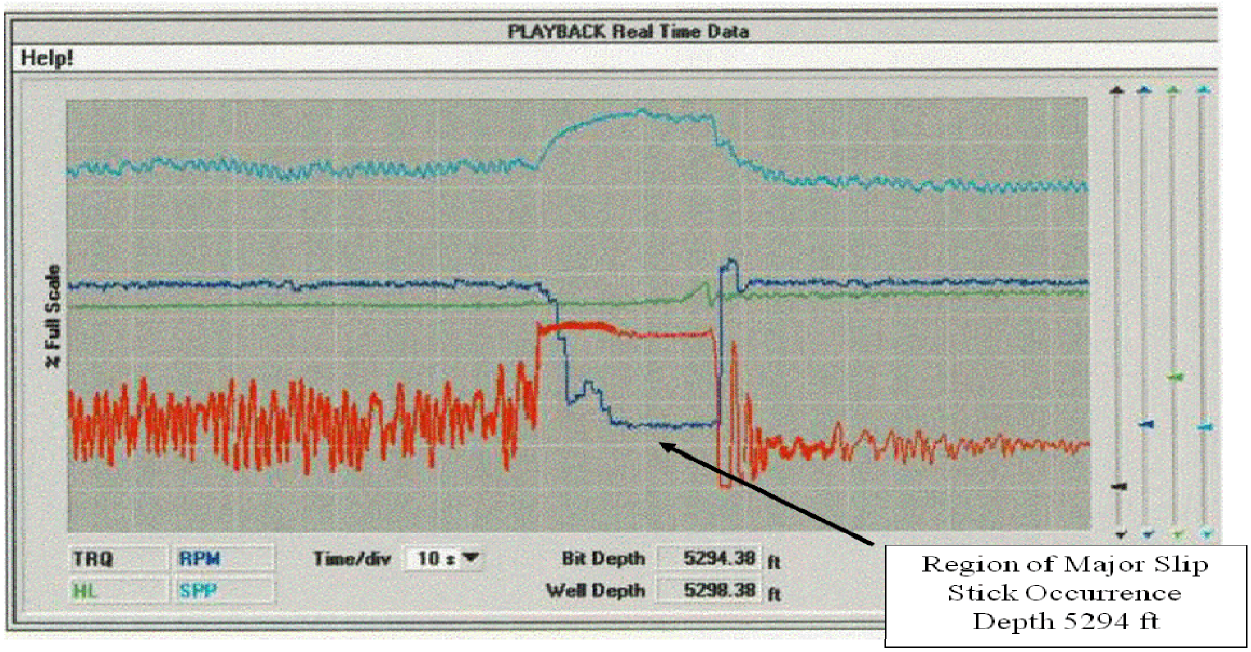

Figure 9 – Playback for Well 1 Bit Run 3 - Depth 5294 ft

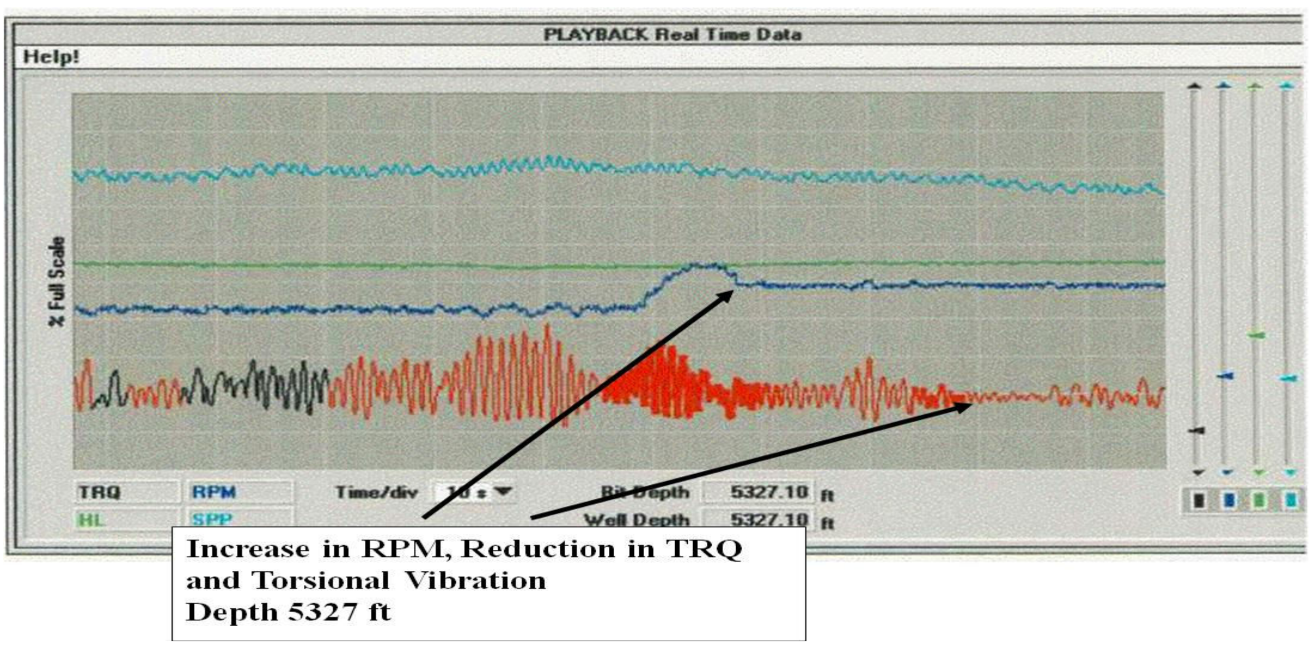

Figure 10 – Playback for Well 1 Bit Run 3 – Torsional Vibration Reductions

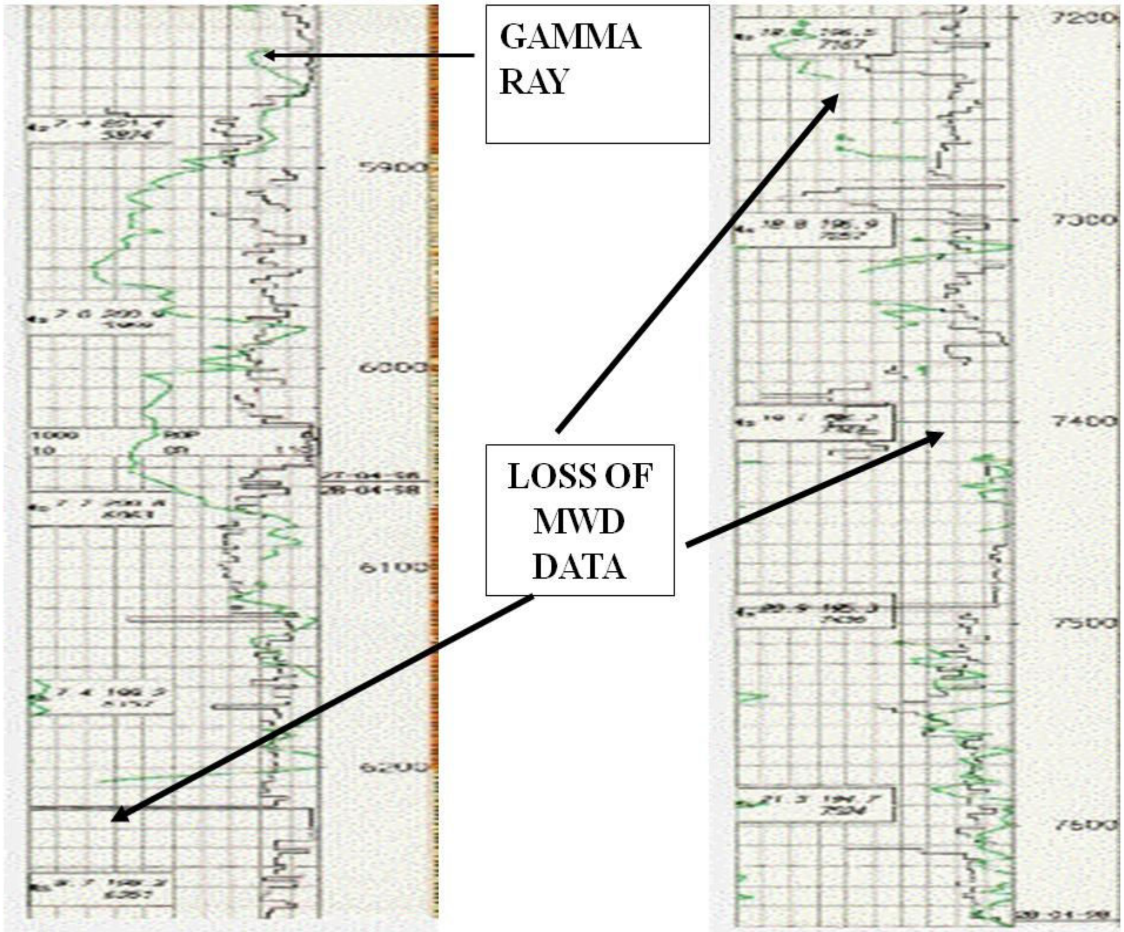

Figure 11 – Mud log – Well 2 Bit Run 2

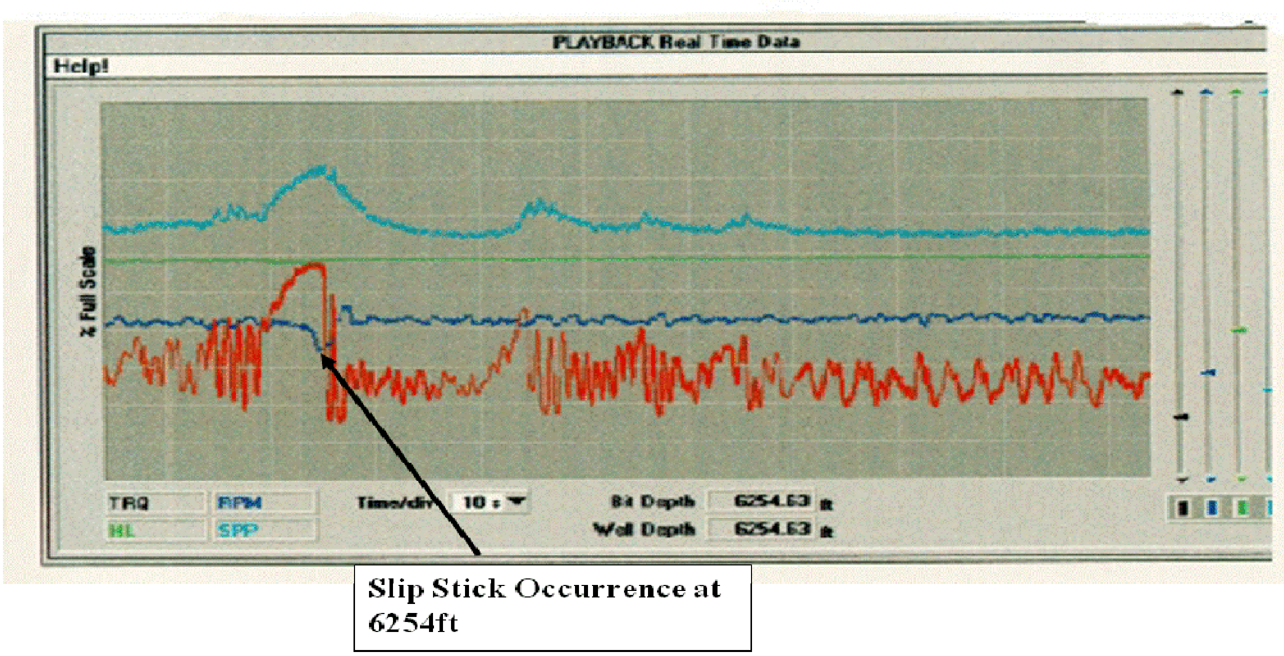

Figure 12 – Playback for Well 2 Bit Run 2 – Depth 6254 ft

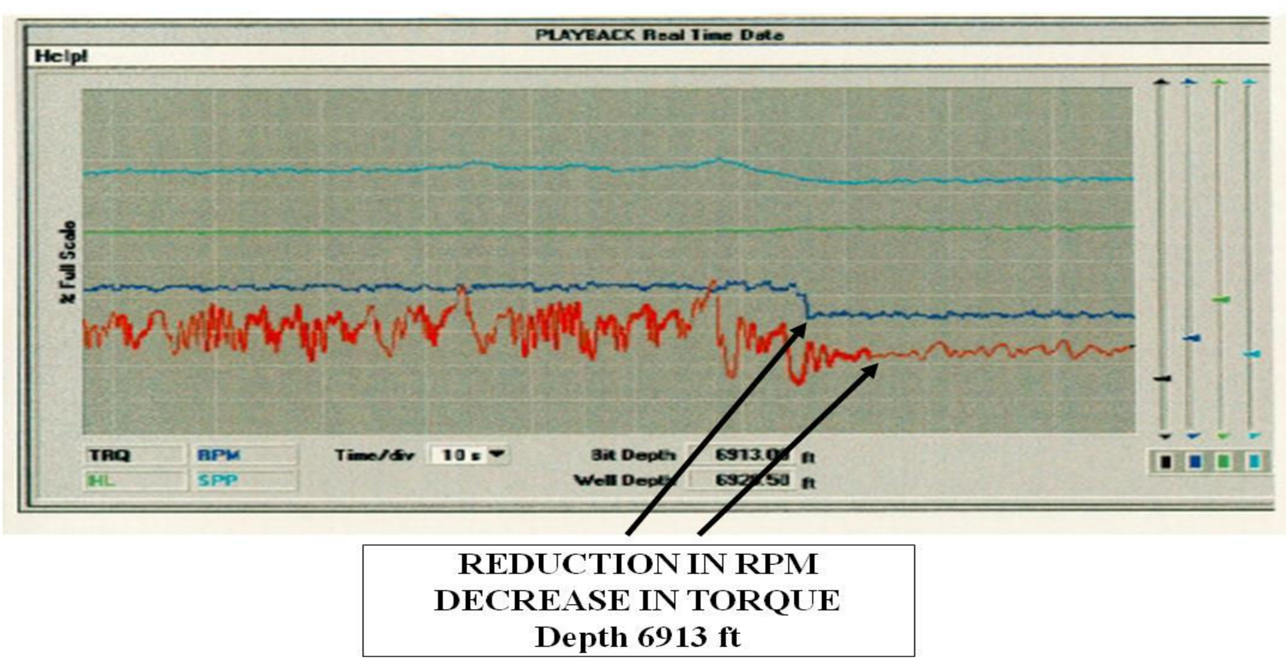

Figure 13 – Playback for Well 2 Bit Run 2 – Torsional Vibration Reduction

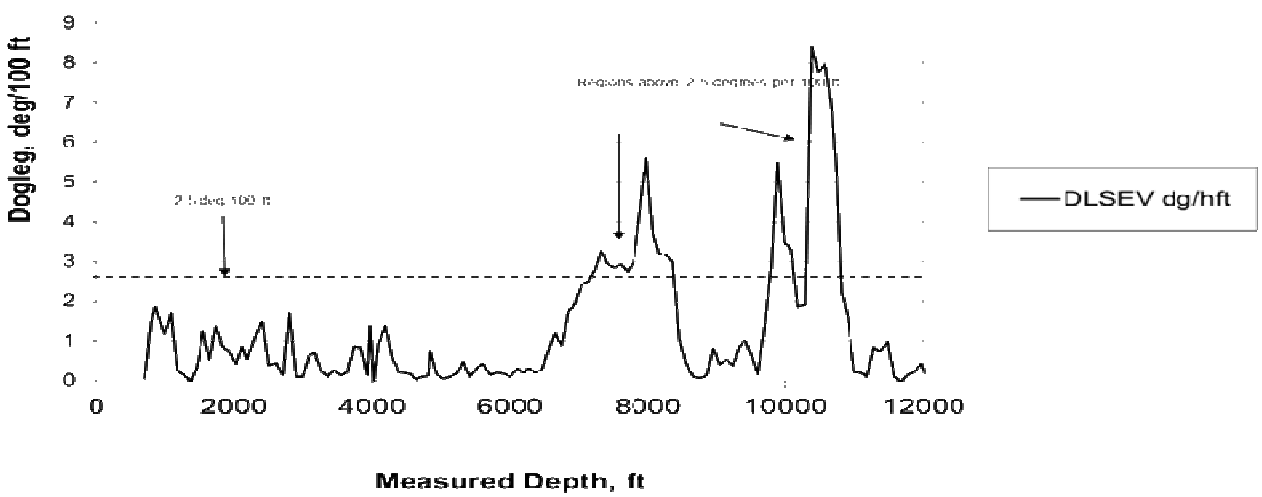

Figure 14 - Well 1 – Dogleg & Torsional Vibration

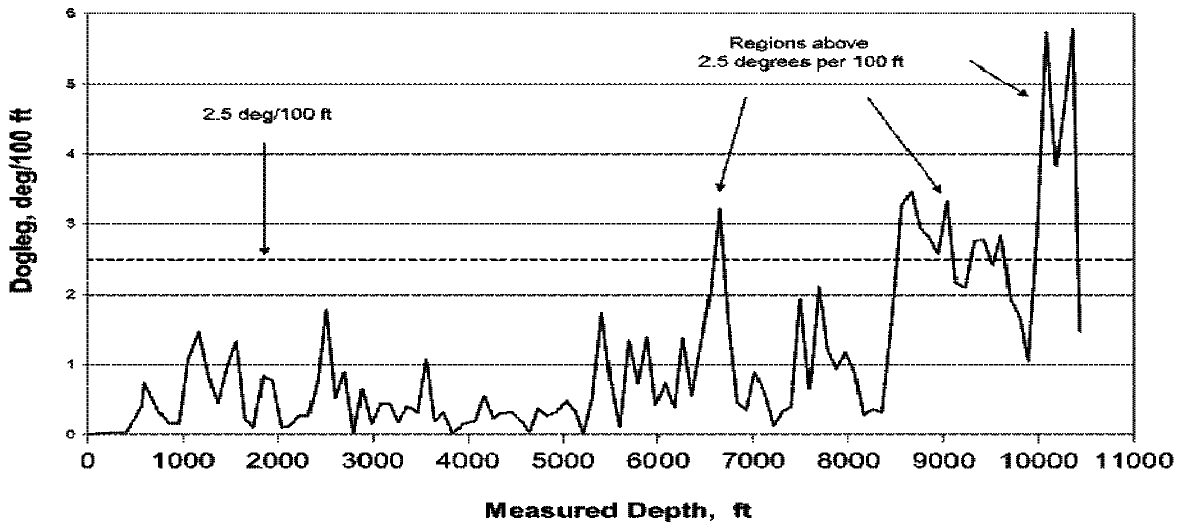

Figure 15 - Well 2 – Dogleg & Torsional Vibration

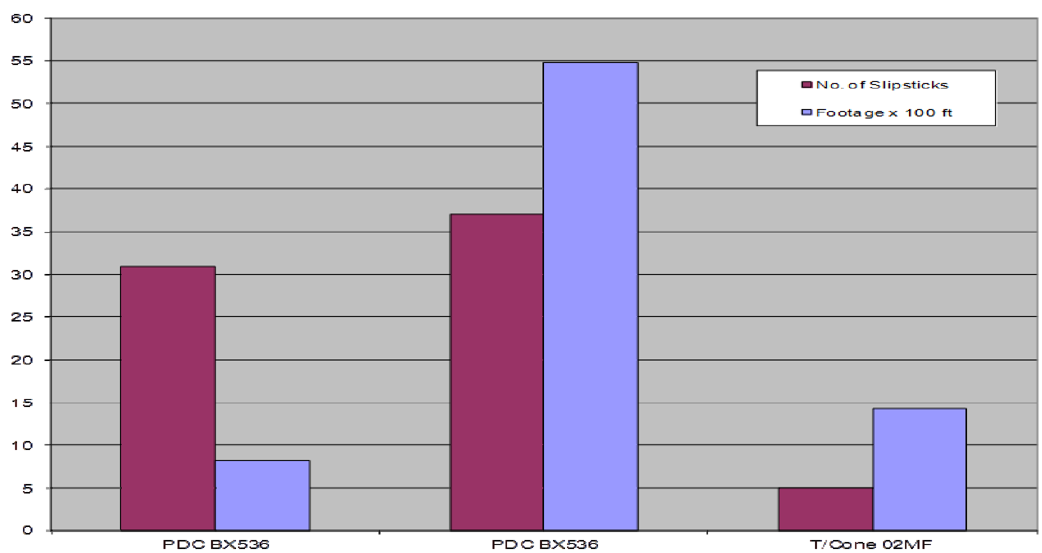

Figure 16 - Well 1 – PDC vs. Rock Bit

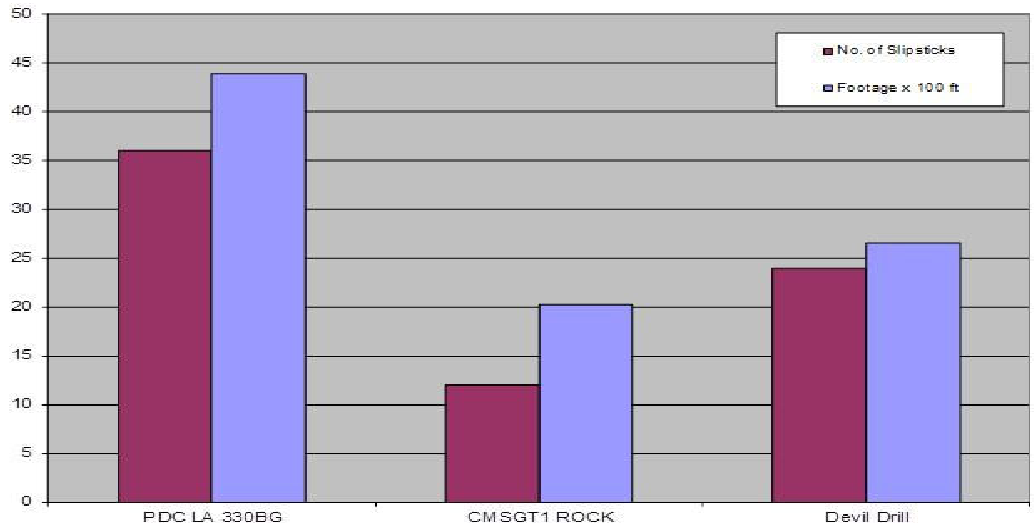

Figure 17 - Well 2 – PDC vs. Rock Bit

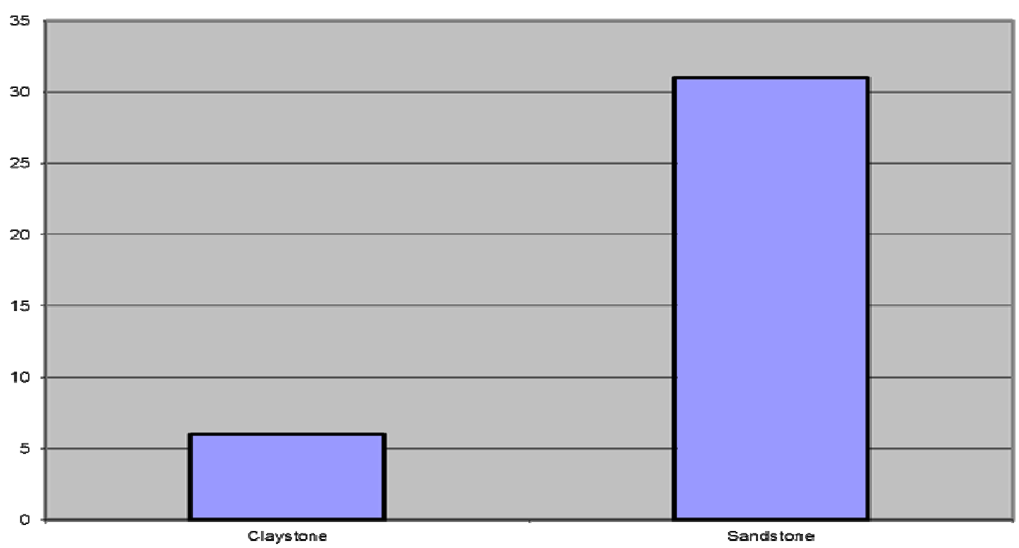

Figure 18 - Well 1 Bit Run 3 – Slip Stick Frequency