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Bit-Based Vibration Tool Records Downhole Vibrations & Improves Drilling Performance in Hard Carbonates

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Abstract

The Pearsall Shale play is emerging as another potential unconventional resource for the South Texas region. Geologically, the play lays several formations below the Eagle Ford Shale in the Lower Cretaceous and extends geographically from Maverick County near the Mexican border to Karnes County south east of San Antonio, Texas. To reach this shale zone, a deep vertical intermediate section is drilled through a hard carbonate sequence containing the Georgetown, McKnight, Edwards and Glen Rose formations. The production hole consists of a curve and a horizontal section through the Pearsall shale. A bit-based vibration tool was utilized to record downhole vibrations in the 9.875-in. intermediate hole section. The objective of the project was to measure, understand and mitigate vibrations at the bit and bottom hole assembly in an effort to improve drilling performance.

This paper discusses the successful application of a bit-based vibration tool to record drilling dynamics. The authors discuss the interpretation of drilling dysfunctions from both downhole and surface drilling data. Based on the field data recorded, changes in the bit design, bottom hole assembly and drilling parameters were implemented. Case histories will illustrate how these implemented changes led to significant reductions in vibrations levels, improved bit dull conditions and enhanced drilling performance. The operator saved significant amount of drilling time through the elimination of downhole vibrations and improved rate of penetration.

Introduction

The analysis reported in this study was conducted to identify which types of downhole vibrations occurred while drilling the intermediate section within the lower Cretaceous which led to drilling efficiencies and eventually damaged drill bits. Over the years, PDC bits have encroached widely into hard rock applications that were previously drilled exclusively by roller cone rock bits and diamond impregnated drill bits. Advancements in bit design and diamond cutter technology have allowed PDC bits to drill formations that were previously deemed as non-PDC drillable. As a result, operating parameters for PDC bits have shifted to higher WOB ranges and at reduced RPMs to enhance drilling performance in harder rock types.

Unfortunately though for PDC bits, higher WOB and lower RPMs initiate torsional instability that develops into stick-slip type vibration, refer to **Figure 1**. For this project, several bit designs were equipped with an in-bit vibration sensor to record downhole vibrations to gain a better understanding of these drilling dynamics. Once the bit was pulled to surface, the vibration data was downloaded and correlated with time based surface drilling data which was downloaded at five second data resolution.

This investigation revealed that stick-slip was the most common downhole vibration for the rotary BHA and was responsible for the damaged PDC bit. The lessons learned were implemented in sequential wells to improve drilling performance for this intermediate hole section.

Background and Drilling Challenges

The carbonate formations encountered in the lower Cretaceous presented various challenges for the operator drilling in Frio County within South Texas. **Figure 2** illustrates the location map for the wells drilled in the field of study. These project wells consist of a three casing string design (see **Figure 3**), with a lateral section in the Pearsall Shale formation. The surface section begins with a 14.75-in. surface hole to about 3,900 ft. TVD where the 10-3/4-in casing is set. Next, the challenging 9.875-in. intermediate section consists of a vertical hole with interval TD ending at about 10,750 ft. TVD where the 7-5/8-in casing is placed. Lastly, the production section is drilled in 6.75-in. hole with a build and horizontal interval to well TD at about 15,400 ft. MD.

For the intermediate section, unconfined compressive strengths were evaluated from offset wells in the area for the formations in the lower Cretaceous. Rock strength values averaged near 15,000 psi within the Georgetown limestone. Next the underlying Edwards formation also consists of a limestone with a harder UCS range within 15,000 psi to 20,000 psi. The following McKnight formation averages near 20,000 psi and contains both limestone and anhydrite. Finally, the Glenn Rose formation is composed of a thick limestone interval with a UCS range within 18,000 psi to 20,000 psi and lies above the Pearsall Shale pay zone. A stratigraphy table for the Pearsall Shale geology is shown in **Table 1**.

Prior to the project wells, an offset injector well was drilled with a 12.25-in vertical hole down to 8,409 ft. MD allowing a pre-well analysis. Although the injector well was constructed with a different casing design, it required five bit runs and 287 drilling hours to reach this depth. Multiple BHAs were tripped due to slow rate of penetration where the PDC bits exhibited impact damage indicative of downhole vibrations. For the project wells, the operator re-designed the casing string and reduced hole size from 12.25-in to 9.875-in. Also with the utilization of a bit-based vibration sensor, a better understanding of drilling dysfunctions could be attained by reviewing torsional and lateral vibrations data, then correlating this data with time and depth. From this correlation the operator would then be able to optimize the drilling BHA and select the proper bit design to maximize drilling efficiency through the various formations.

In-bit Vibration Sensor

A patented in-bit vibration sensor is installed in the shank of the bit as shown in **Figure 4**. The module resides directly inside the drill bit shank to capture the true dynamic dysfunctions at the bit. It can also be positioned in subs to be placed anywhere in the drillstring. The module is a drilling dysfunction identification tool. The device comprises of accelerometers in which axial, lateral, torsional vibrations are measured. Other additional measurements include RPM and temperature. Field-proven downhole algorithms convert raw g-RMS (root mean squared) values to understandable drilling dysfunctions such as: stick-slip, bit bounce and whirl. RPM is measured using several different accelerometers. The module is capable of recording data in two different operational modes: background and burst. The background data calculates and stores average values for axial and lateral accelerations, and maximum, minimum and average rotary speeds. Five second long samples of high frequency data, also known as "burst files", are stored at consistent intervals. For this project, all bursts taken were set to last five seconds and recorded every hour.

Downhole Vibrations: Identification and Mitigation

The three most common types of drilling dysfunctions are: stick-slip, whirl and bit bounce as illustrated in **Figure 5**. The module can measure each dysfunction. Each dysfunction can potentially cause damage to the drill bit and/or the BHA. The drilling dysfunctions are calculated in the background data by using a proven set of equations. The dysfunctions can also be seen in the burst files. Bit bounce (axial vibration), which is not typically known as a noteworthy cause of damage to PDC bits, is measured using the axial accelerometer. Whirl (lateral vibration) is known throughout the industry as a drilling dysfunction that is damaging to PDC bits. Whirl is measured by the tangential and radial accelerometer. Stick-slip (torsional vibration) is known across the industry as the most catastrophic drilling dysfunction that causes damage to the bit. It is also one of the most common types of dysfunctions when drilling with a PDC bit in today's industry due to increased bit life allowing bits to drill through multiple formations in a single run. The radial accelerometer in the module is used to calculate the severity of stick-slip seen at the bit. There are several different best practices used to mitigate stick-slip: monitoring surface torque and adjusting drilling parameters throughout a bit run, optimized BHA as well as motor selection (decouples the bit from the drillstring) and selecting the proper bit or bit design characteristics for the application. Stick-slip can be detected through monitoring surface torque. The ultimate solution for mitigating stick-slip is a stable system that allows the expansion of the stable operating zone. It is ideal to optimize the bit and the BHA design to allow more efficient drilling in high WOB and low RPM environments.

Surface MSE

Another drilling index included on this project was Surface MSE based on surface drilling parameters. The MSE formula is dependent on top drive RPM, surface WOB, ROP, surface torque and hole diameter. Unfortunately though for this analysis the surface MSE was calculated from five second data resolution. Hence, it is not a true representation of what the real time MSE signature would be at one second data resolution.

Case Study 1: Well A

For the first project well A, a 9.875-in PDC bit equipped with a vibration module was run featuring five blades and 19mm cutters. Drilling parameters consisted of 10-30 Klbs WOB and 75-100 top drive RPMs. This bit was run a on a pendulum rotary BHA without a downhole motor as illustrated in **Figure 6**. At the start of the run the stick-slip severity remained at low to moderate levels through the formations Midway, Escondido, Olmos and Taylor. In the Anacacho formation there were several incidents of stick-slip recorded.

Higher levels of stick-slip were not recorded until the Austin Chalk, Lower Eagleford and Buda formations were reached. Note how the surface torque variance closely matched the same signature profile of downhole RPM recorded by the vibration module as shown in **Figure 7**. High frequency burst plots captured stick-slip events (see **Figure 8**) and illustrated that at the higher RPM in the slip phase there is a higher risk for lateral vibration.

In the Georgetown formation, prolonged levels of stick-slip began with a reduction in instantaneous ROP to less than 50 ft/hr as 15 Klbs WOB was run. Rate of penetration improved with an increased WOB to 25 Klbs at 80 RPMs but stick-slip remained. Lateral vibrations remained low for this interval.

Drilling proceeds into the Edwards formation where ROP remained slow in this formation as the bit transitioned from severe stick-slip to moderate levels of vibration once past ~7,990 ft. MD. The intervals of moderate lateral vibrations appear to correlate when WOB is less than 15 Klbs as shown in **Figure 9**. Burst plots captured during this time period magnify the lateral vibrations recorded in high frequency, **Figure 10**.

Once in the McKnight formation the ROP never improved and the bit was pulled out of the hole at 8,603 ft. MD, see **Fig.**

11. The PDC bit was exposed to severe levels of stick-slip for over 40 hours of drilling time. Drilling past 8,300 ft. MD, WOB was increased to 20 Klbs and it slightly improved ROP but stick-slip still remained high. Overall the bit drilled 4,620 ft. in 114.5 hours for a final ROP of 40.3 ft/hr. The bit dull condition revealed several broken and sheared PDC cutters in the nose area of the bit's profile expanding outwards into the shoulder area. Within this same area there were several chipped PDC cutters and the bit was damaged beyond repair due to cutter pocket damage as shown in the photos, **Figure 12**.

For the next BHA as shown in **Figure 13**, a downhole motor (7-3/4", 7:8 ratio, 0.17 revolutions per gallon) was selected to help minimize stick-slip that was recorded from the vibration module in the previous bit run. This packed motor BHA generated ~90 RPMs at the bit and was coupled with a PDC design featuring six blades with 16mm cutters. Again this bit was equipped with a vibration module. Drilling in the Edwards formation, WOB was increased to ~30Klbs and instantaneous ROP improved to 50 ft/hr with low vibration levels. **Figure 14** combines the two time logs together at the bit trip and compares the drilling efficiencies for the bit runs.

In the Glenrose formation, instantaneous ROP remained at 50 ft/hr as the bit drilled with 25 Klbs and 60 top drive RPMs. Rate of penetration improved to 75 ft/hr when WOB reached 35 Klbs. Lateral and axial impacts were recorded at 9,400 ft. MD when WOB became erratic at below 20 Klbs. Refer to **Figure 15** for a summary of these events. Beyond 9,600 ft. MD, ROP remained at 50 ft/hr with low stick-slip severity at 25 Klbs WOB and 60 top drive RPMs. Significant lateral and axial impacts were observed tagging bottom near 10,125 ft. MD. These impacts could have damaged the bit as observed on blades four and five.

Upon reaching section TD at 10,550 ft. MD, the bit drilled 1,947 ft. in 52 hours for a final ROP of 37.4 ft/hr. The bit dull exhibited a lost PDC cutter on blade number four near the shoulder area of the bit's profile. There were also three broken PDC cutters located only on blades four and five in the shoulder as shown in the dull photos, **Figure 16**.

Case Study 2: Well B

On project well B, vibration levels were significantly reduced and ROP improved with the utilization of a downhole motor and a different PDC bit design. This change in BHA and bit design was based on the vibration data recovered from the in-bit vibration module run in well A. For the BHA, a downhole motor (8", 7:8 ratio, 5 stage, 0.15 revolutions per gallon) was selected generating ~90 RPMs at the bit in an effort to minimize stick-slip in the first BHA run in the hole. Again the PDC bit was equipped with a vibration module and the durable bit design consisted of six blades set with 16mm cutters.

Once on bottom drilling with the motor there were no stick-slip events recorded in the following formations: Anacacho, Austin Chalk, Eagle Ford and the Buda. In the Georgetown formation, instantaneous ROP ranged from 50-100 ft/hr with low levels of vibration. It was observed that moderate levels of stick-slip severity occurred when the top drive RPM reached ~93 rpms which exceeds the downhole motor RPM. Compared to the previous 11H well at these depths, there were prolonged levels of stick-slip with slow ROPs at less than 50 ft/hr.

Entering the Edwards formation the instantaneous ROP ranged within 50-100 ft/hr with low stick-slip severity. Moderate lateral vibrations were observed when WOB was reduced to 15 Klbs. Lateral stability was regained at 20 Klbs and within 50-60 top drive RPMs. The ROP achieved while drilling with a motor outperformed the previous 11H well drilled with a rotary BHA where ROPs were less than 25 ft/hr.

In the harder McKnight formation instantaneous ROP slowed down to 25 ft/hr though stick-slip severity remained low. Again it was observed that moderate levels of stick-slip severity occurred when the top drive RPM reached ~93 rpms, but this also correlates with spikes in differential pressure. Refer to **Figures 17 and 18** for a summary of these events. This optimized BHA drilled to the base of the McKnight formation and was pulled out of the hole for a wiper trip at 8,562 ft. MD. Overall the bit drilled 5,162 ft. in 93.5 hours for a final ROP of 55.2 ft/hr. This run outperformed the previous 11H well where the depth of 8,603 ft. MD was reached in 114.5 hours for an overall ROP of 40.3 ft/hr. Once out of the hole, the PDC bit exhibited minimum wear with only one chipped cutter as shown in the photos, **Figure 19**.

Once the first bit was pulled, another PDC bit with the same design features equipped with a vibration module was tripped in the hole on a new motor with the same specifications. Back on bottom in the base of the McKnight formation, top drive RPM was set within 50-60 RPMs and WOB was increase to ~20 Klbs with instantaneous ROPs at 50 ft/hr. Stick-slip severity remained in the moderate range as the minimum RPM value recorded from the vibration module approached near zero RPM. Refer to **Figure 20** for a summary of the events.

In the Glenrose formation, moderate stick-slip continued with higher severity levels that peaked when top drive RPM exceeded 90 rpms. Past 9,500 ft. MD, lateral vibrations increased from moderate to high levels with low WOB run below 20 Klbs. Moderate levels of stick-slip and lateral vibrations continued to section TD with ROPs maintained at 50 ft/hr. Overall the bit and motor drilled 1,910 ft. in 62 hours for a final ROP of 30.8 ft/hr.

The dull bit exhibited some broken and chipped PDC cutters on several blades located in the gauge area of the bit profile. There was not any significant wear present but the bit was repairable as shown in the photos, **Fig. 21**.

Results

Figure 22 illustrates the cumulative on bottom drilling hours versus measured depth for both project wells. The utilization of a downhole motor and a modified bit design on well B increased overall ROP by 37% to the base of the McKnight formation. Drilling to a depth of 8562 ft MD on well B saved 27.9 hours of rig time compared to well A. Finally, comparing project well B to the offset injector well saved an estimated 209.5 hours or 8.7 days to reach this similar depth as shown in **Figure 23**.

Conclusions

- Utilization of a bit-based vibration module allowed the operator to gain a better understanding of the drilling dynamics occurring downhole at the bit when drilling.
- Stick-slip on the rotary BHA was identified as the main limiter of drilling performance with sub-optimum ROPs and damaged PDC bits. Incorporation of a downhole motor and a durable PDC bit in the BHA eliminated stick-slip in the carbonate formations and enhanced ROP.
- For the rotary BHA, surface torque variance closely matched the same signature profile of downhole RPM recorded by the vibration module.
- Stick-slip events occurred with a rotary BHA in the following formations: Lower Eagleford, Buda, Georgetown, Edwards and McKnight.
- The aggressive PDC bit design featuring five blades and 19mm cutters run on the rotary BHA was exposed to severe levels of stick-slip for over 40 hours of drilling time once it entered the McKnight formation.
- Vibration levels were significantly reduced and ROP improved with the utilization of a downhole motor and a more durable PDC bit design consisting of six blades and 16mm cutters.
- Lateral vibrations increased when WOB fell below 10 to 15 Klbs within the Edwards and Glen Rose formations. Lateral vibrations also increased with WOB less than 15 Klbs.
- The bit-based vibration module also recorded incidents of lateral and axial impacts that damaged PDC bits.
- The utilization of a slow speed downhole motor in the BHA eliminated stick-slip within the following formations: Lower Eagleford, Buda, Georgetown, Edwards and McKnight.
- On the motor BHA, stick-slip severity reached moderate levels when greater than 93 top drive RPM was applied at the surface. The top drive RPMs exceeded the downhole motor RPMs which exacerbated stick-slip in the BHA.
- Better dull conditions were attained with more durable PDC bit designs consisting of six blades and 16mm PDC cutters.

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Nomenclature

BHA = *Bottomhole assembly*
MD = *Measured Depth*
MSE = *Mechanical Specific Energy*
PDC = *Polycrystalline Diamond Compact*
ROP = *Rate of Penetration*
RPM = *Rotations per Minute*
TD = *Total Depth*
TVD = *Total Vertical Depth*
UCS = *Unconfined Compressive Strength*
WOB = *Weight on Bit*

References

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4. Patusek, Paul, Sullivan, Eric and Harris, Tommy, “Development and Utilization of a Bit-based Data Acquisition System in Hard Rock PDC Applications,” presented at the SPE, IADC Drilling Conference, Amsterdam, Feb. 20-22, 2007

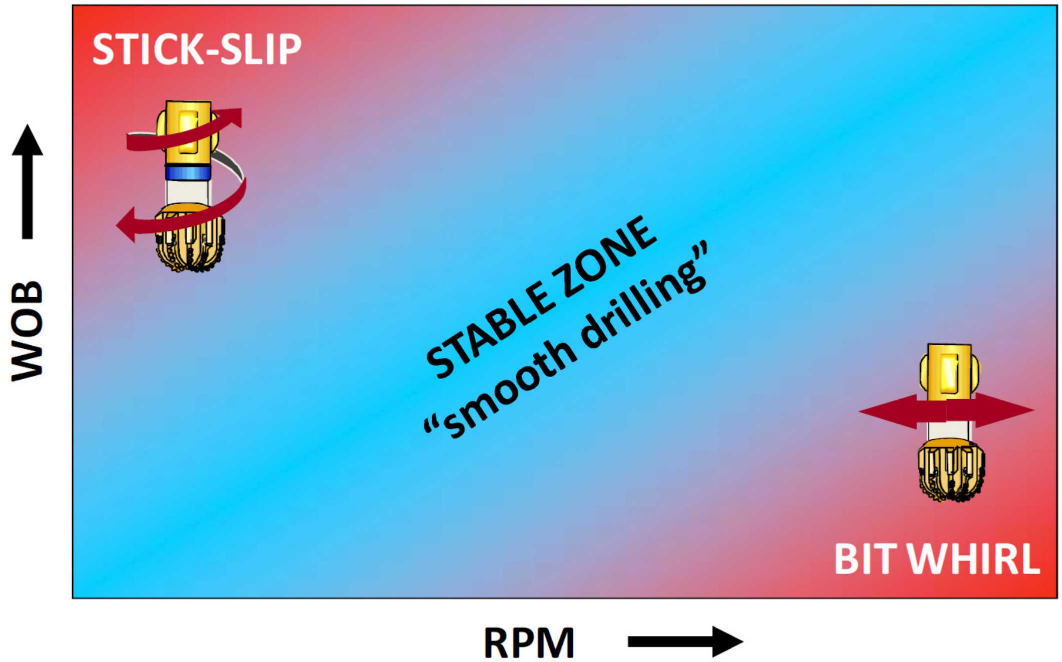

Figure 1: Stability Map of Drilling Dysfunctions for PDC Bits

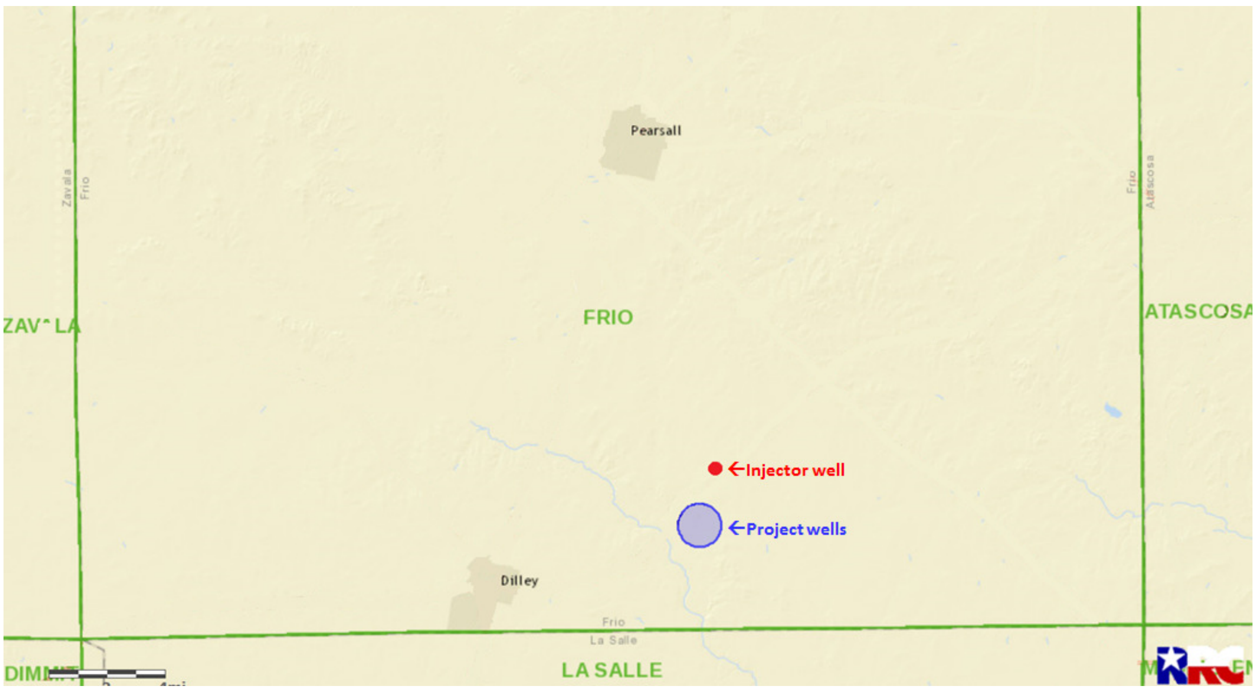

Figure 2: Area Map for Field of Study

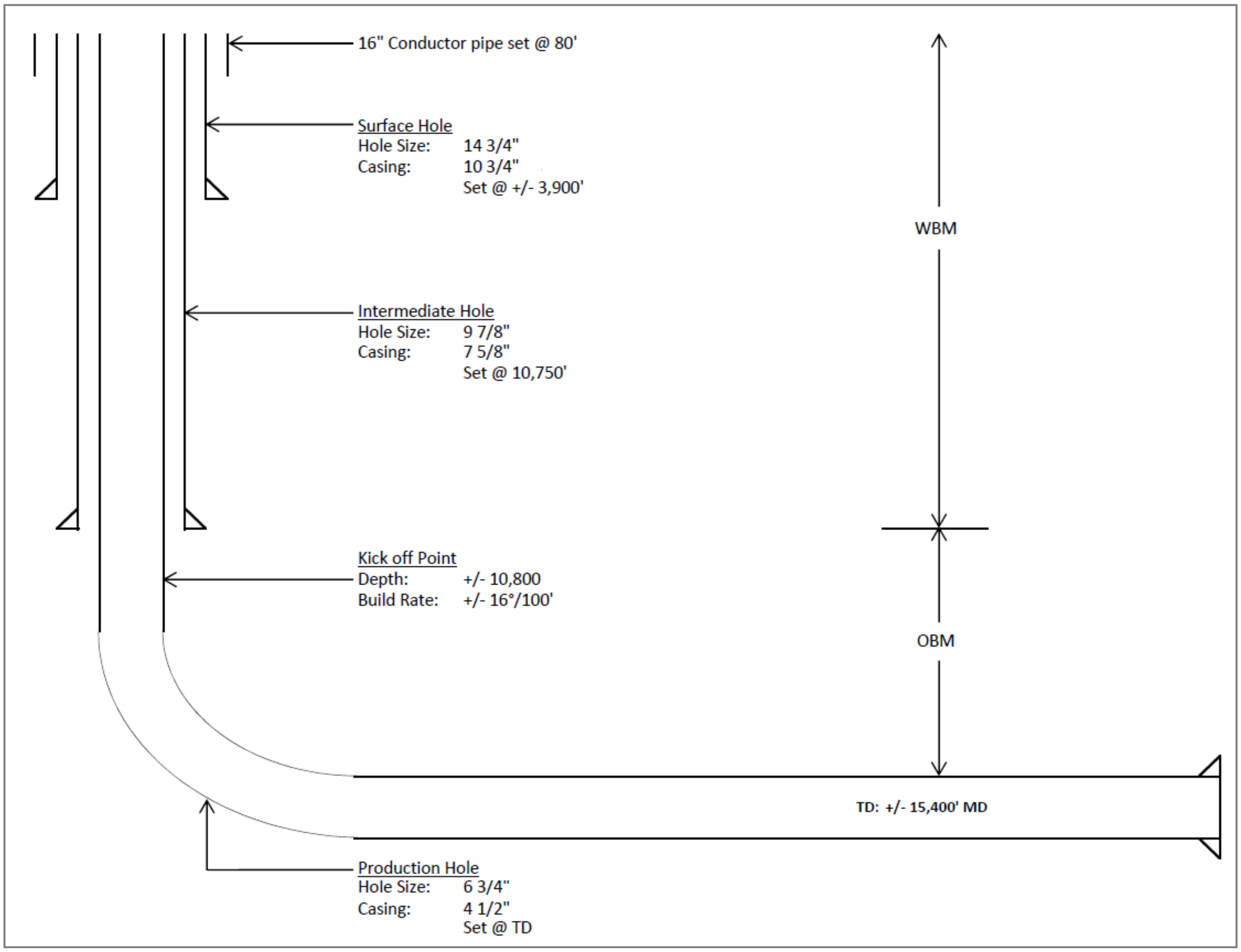

Figure 3: Casing Design for Project Wells A and B

System	Series	Formation	Lithology	Unconfined Rock Strength (psi)
Cretaceous	Gulfian	Anacacho	limestone	5,000
		Austin Chalk	limestone	8,000
		Eagle Ford	shale / limestone	5,000
	Comanchean	Buda	limestone	12,000
		Del Rio	shale	3,000
		Georgetown	**limestone**	**15,000**
		Edwards	**limestone**	**15,000-20,000**
		McKnight	**anhydrite / limestone**	**20,000**
		Glenn Rose	**limestone**	**18,000-20,000**
		Pearsall	shale	15,000

Table 1: Stratigraphy Table and Unconfined Rock Strengths

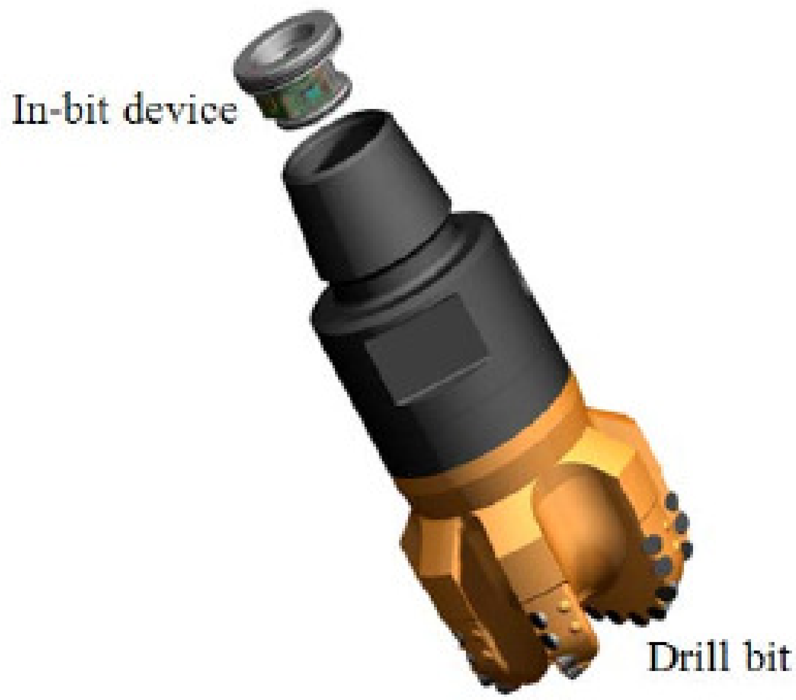

Figure 4: In-Bit Vibration Sensor Location inside the Drill Bit

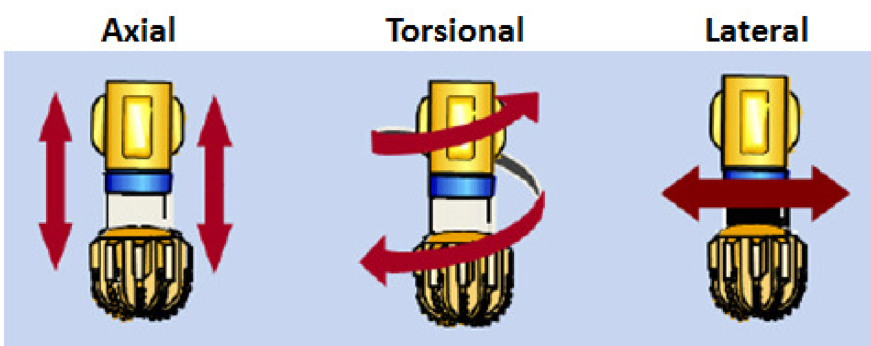

Figure 5: Types of Vibrations: Axial, Torsional and Lateral

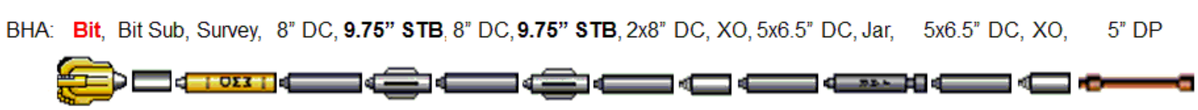

Figure 6: Well A - Pendulum Rotary BHA for 9.875-in Intermediate

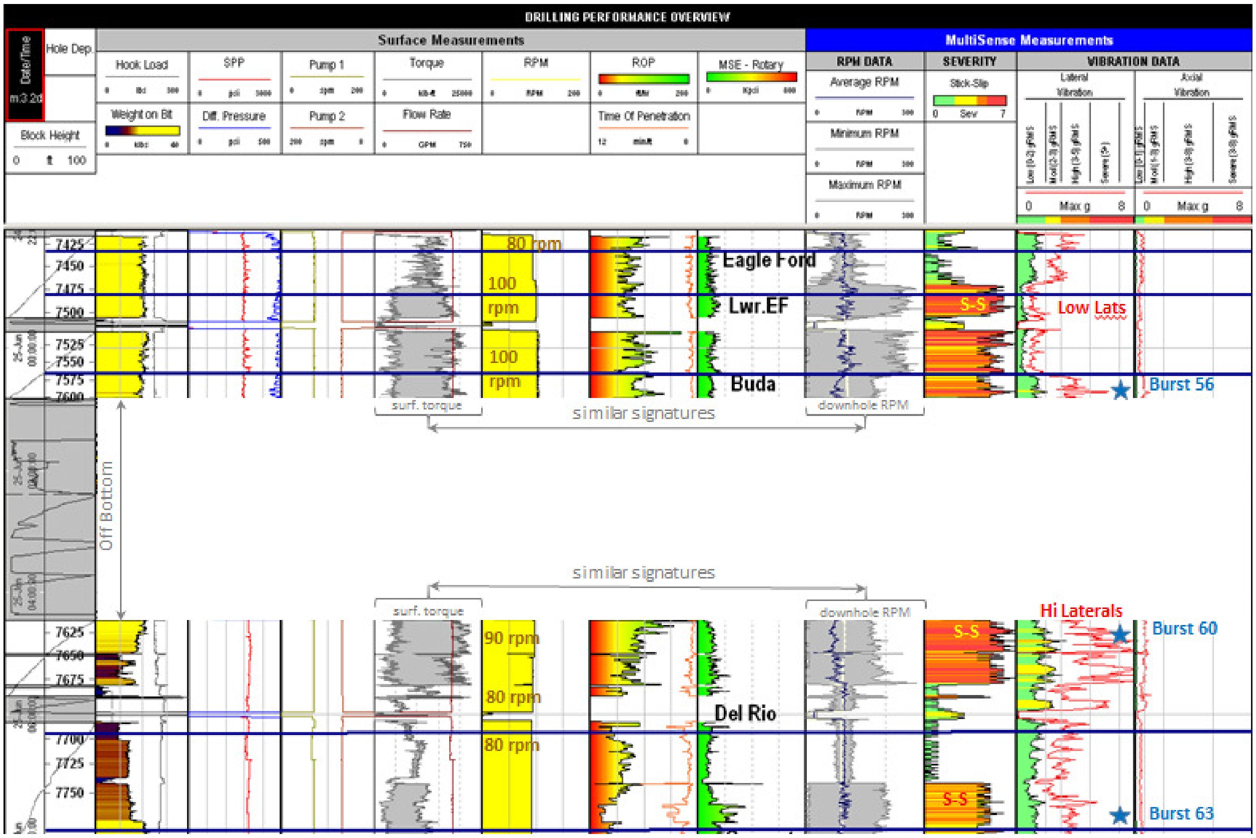

Figure 7: Well A – Stick-Slip Coupled with Lateral Vibrations

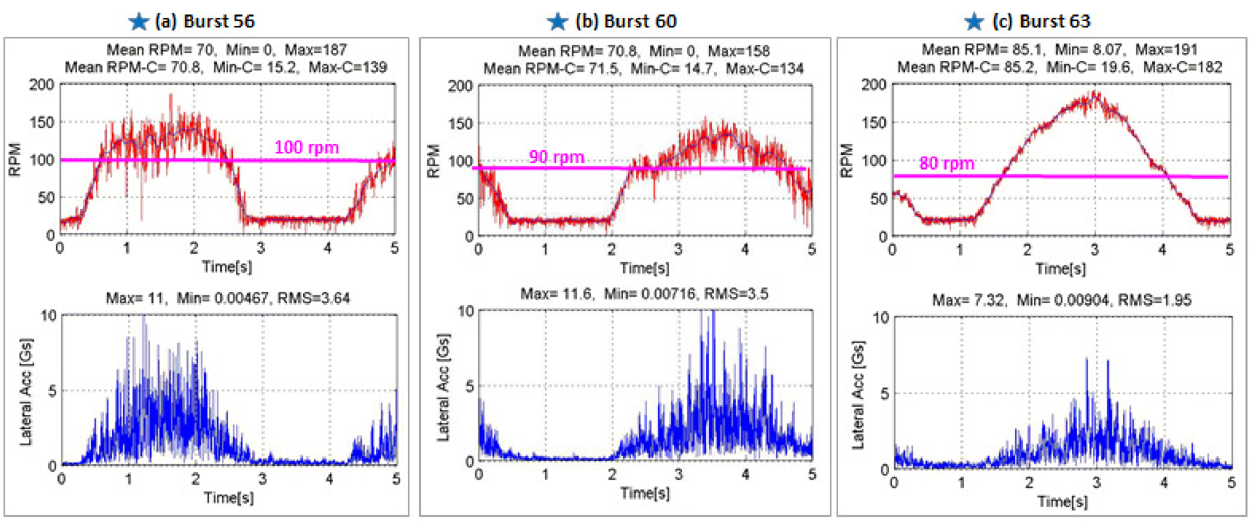

Figure 8: Well A – Burst Plots within Stick-Slip Events

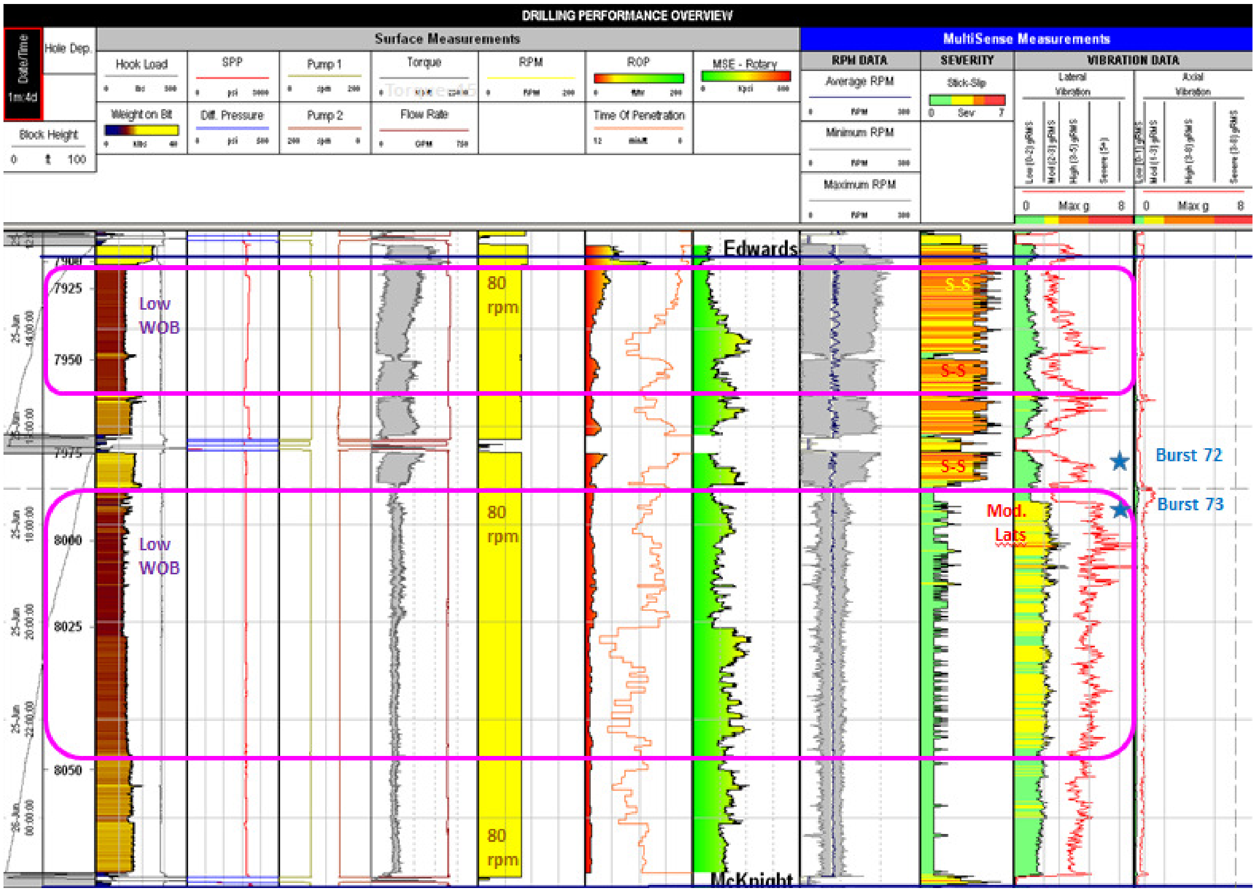

Figure 9: Well A – Stick-Slip to Whirl

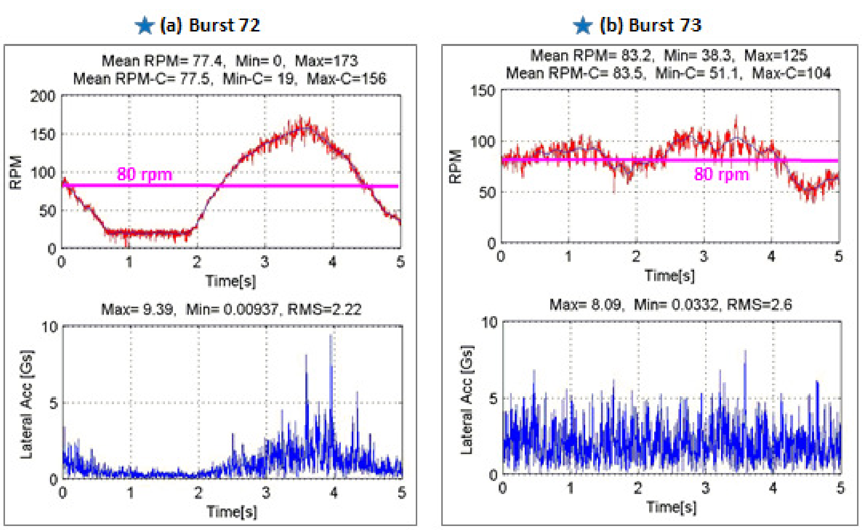

Figure 10: Well A – Burst Plots in Stick-Slip (a) and Whirl (b)

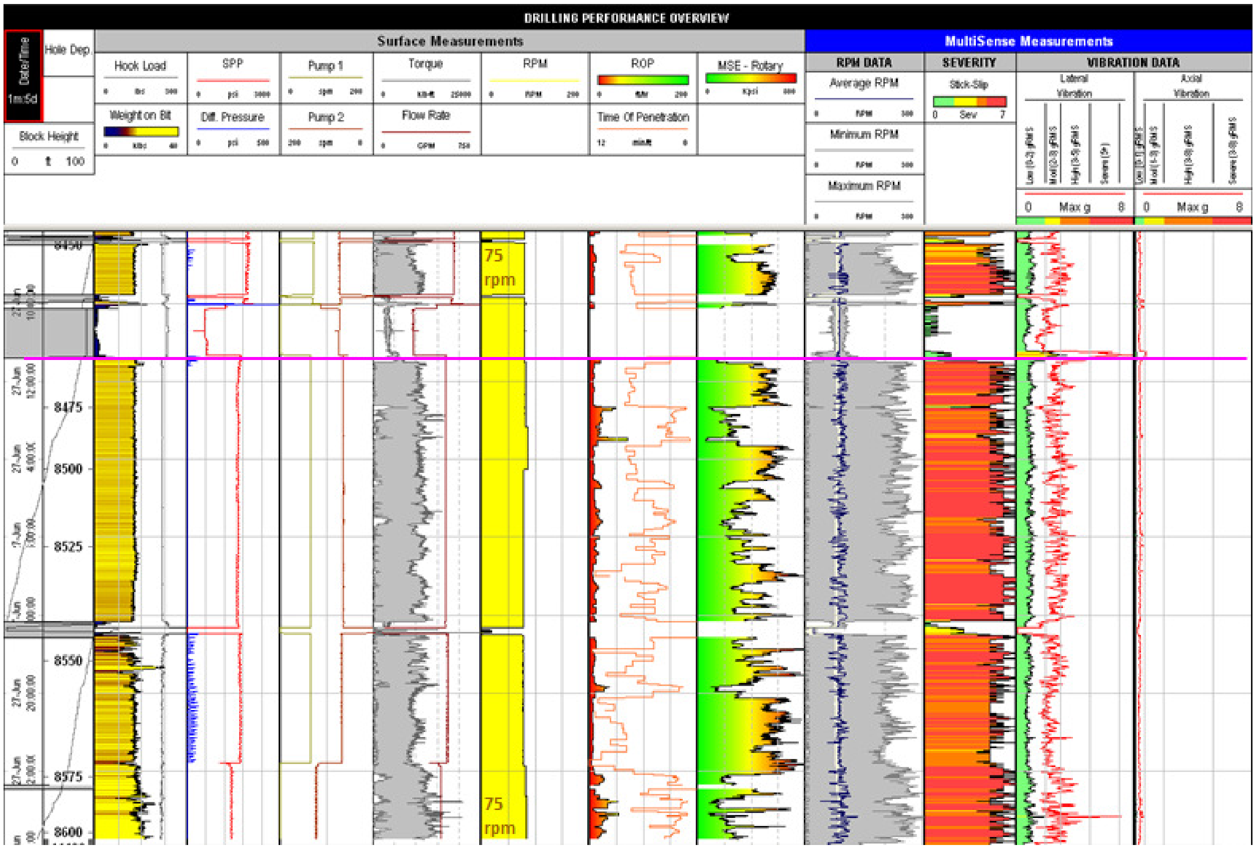

Figure 11: Well A – Stick-Slip and Pull Out of the Hole

Figure 12: Well A – First 9.875-in PDC Bit with Five Blades and 19mm Cutters

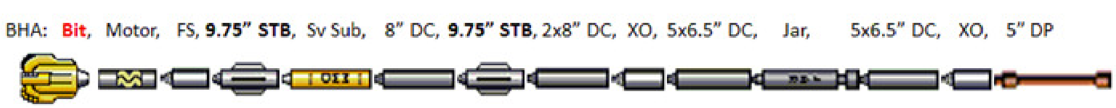

Figure 13: Well A – Packed Motor BHA for 9.875-in Intermediate

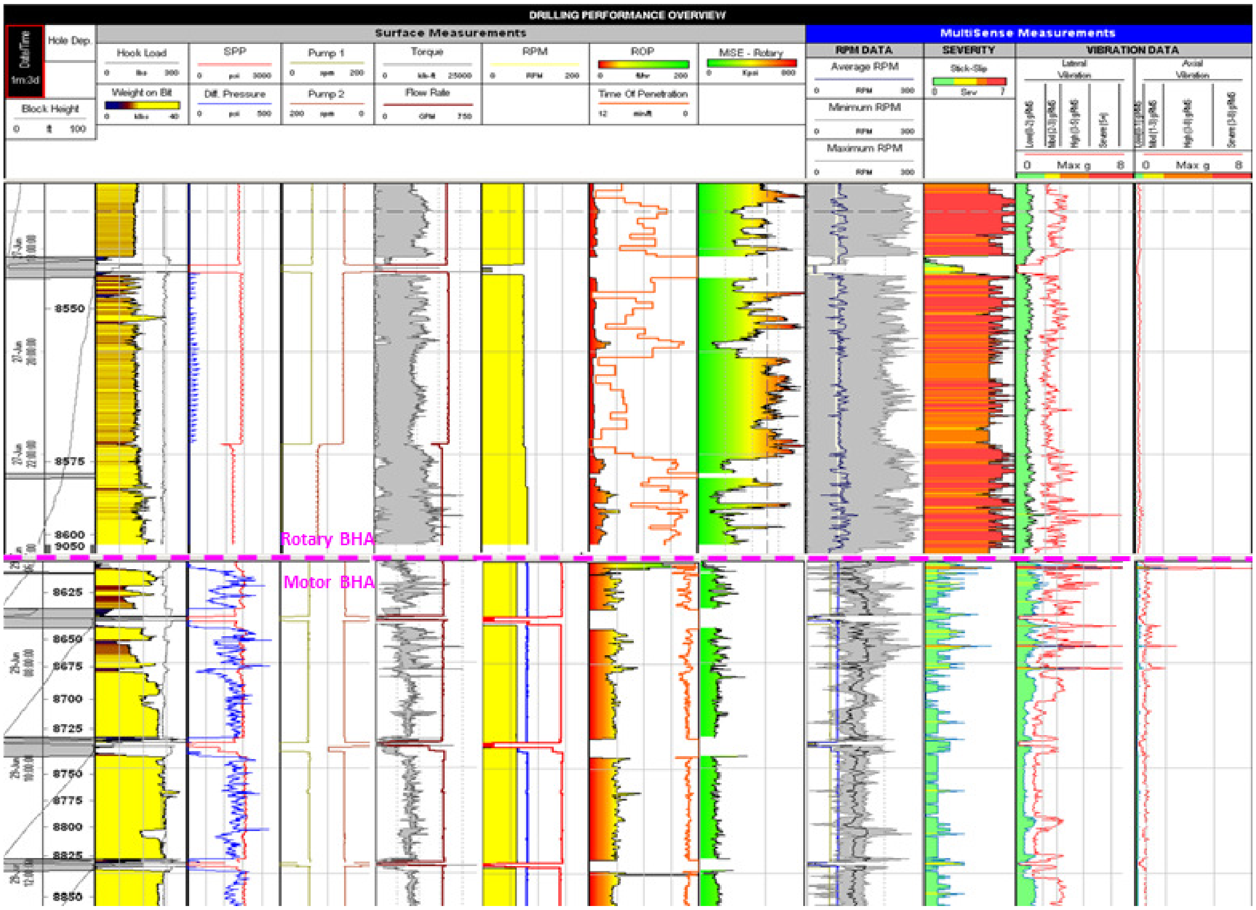

Figure 14: Well A – BHA Change from Rotary to Motor

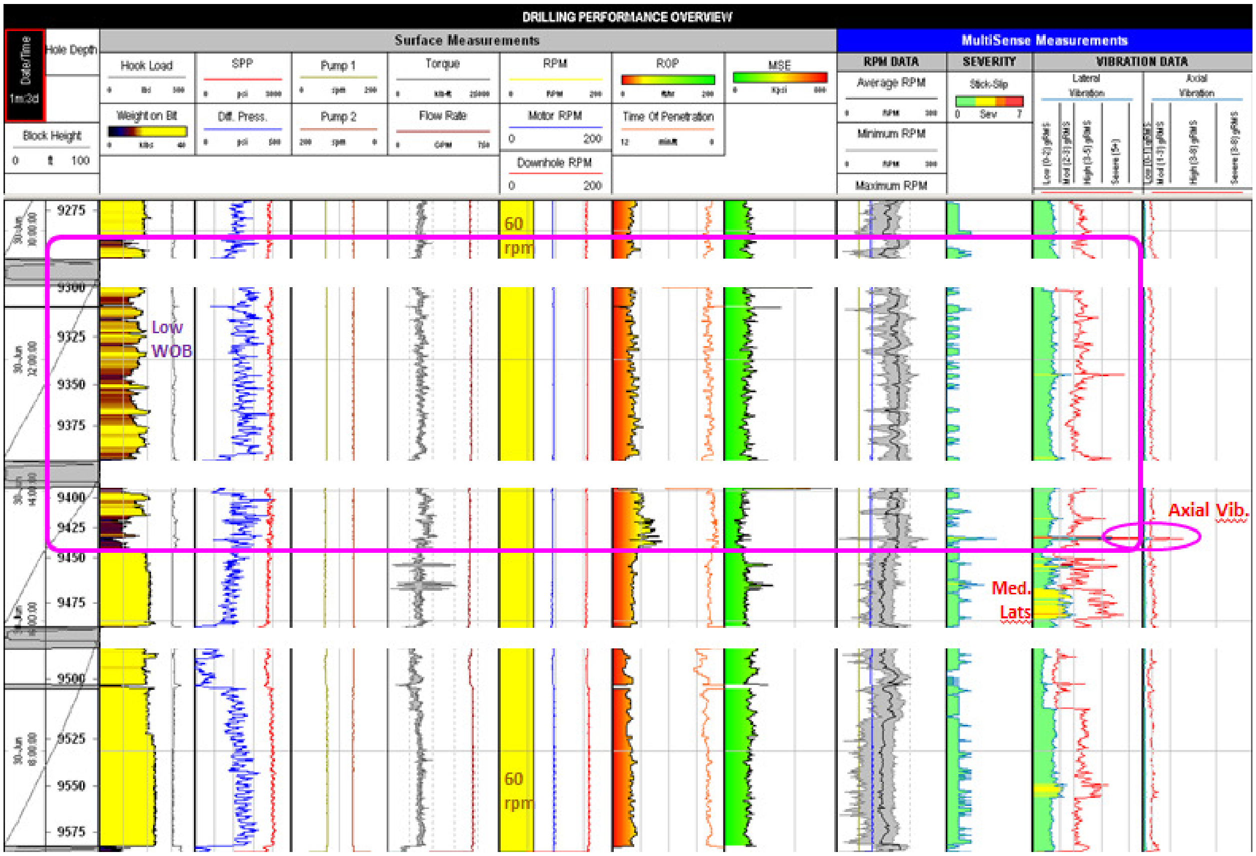

Figure 15: Well A – Lateral Impacts

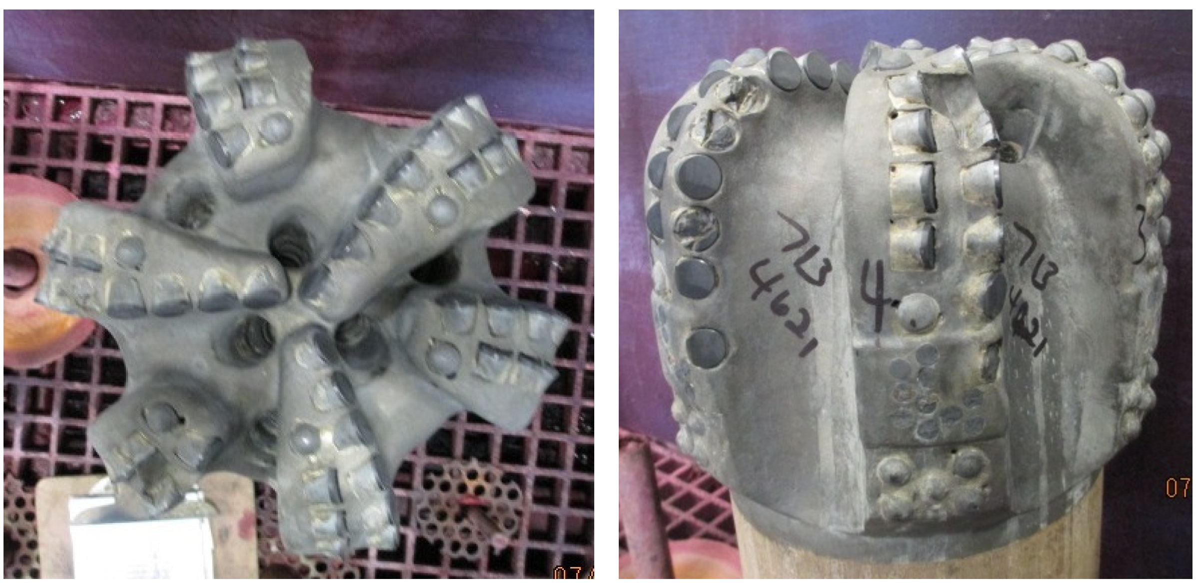

Figure 16: Well A – Second 9.875-in PDC Bit with Six Blades and 16mm Cutters

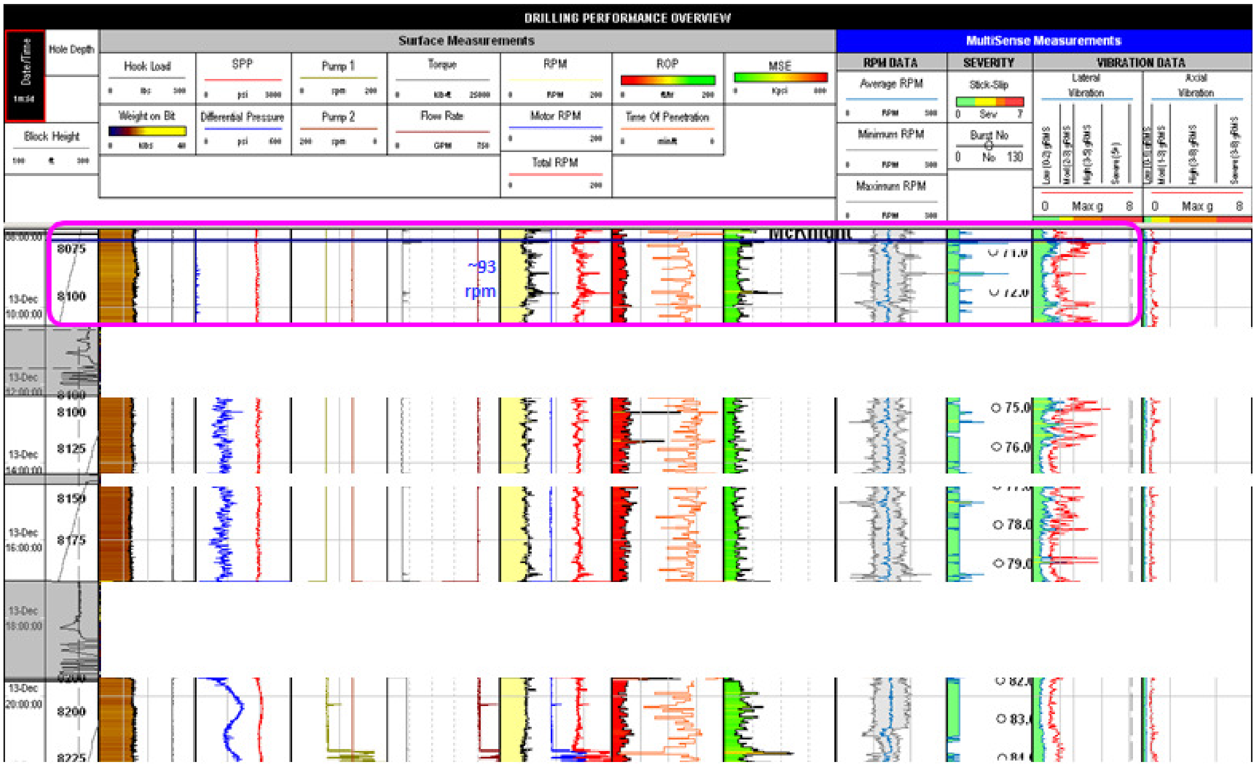

Figure 17: Well B – Low Stick-Slip in McKnight Formation

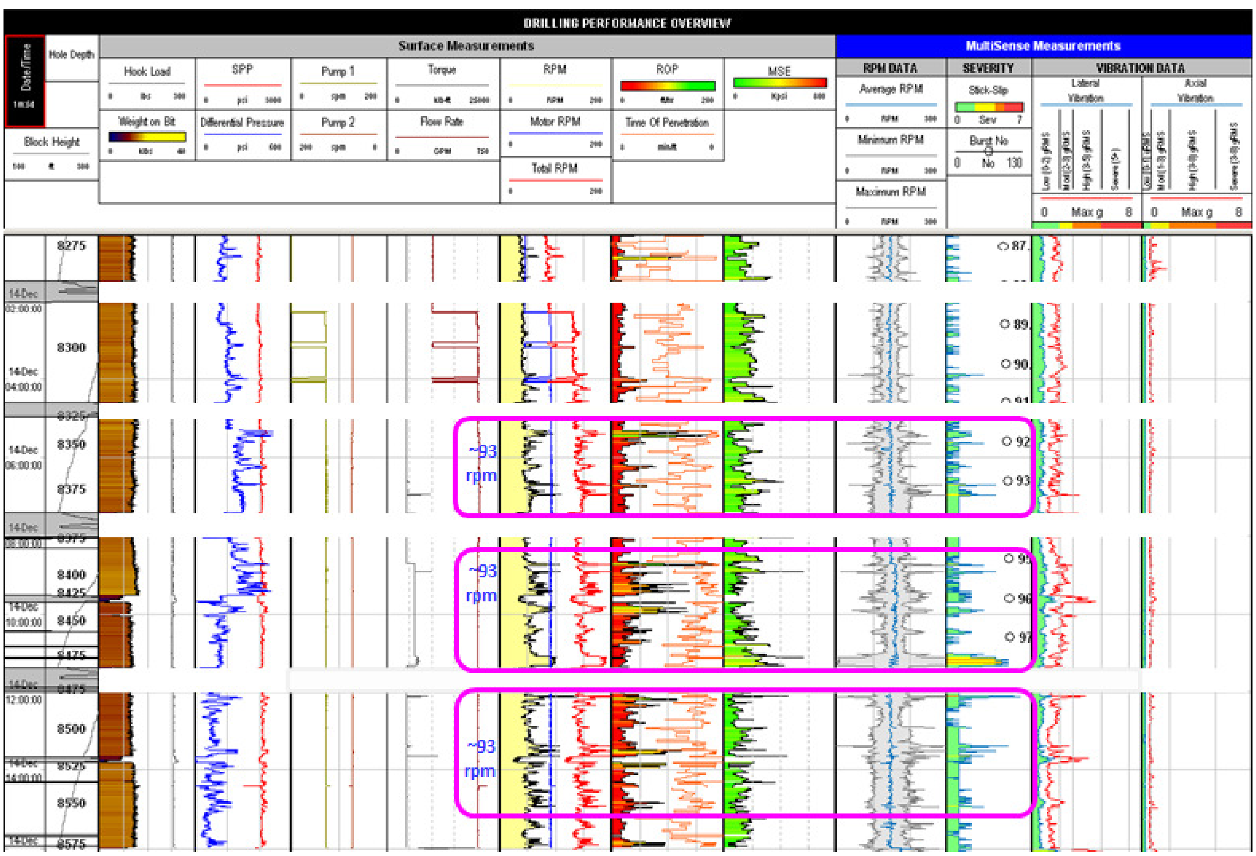

Figure 18: Well B – Pull Out of the Hole in McKnight Formation

Figure 19: Well B – First 9.875-in PDC Bit with Six Blades and 16mm Cutters

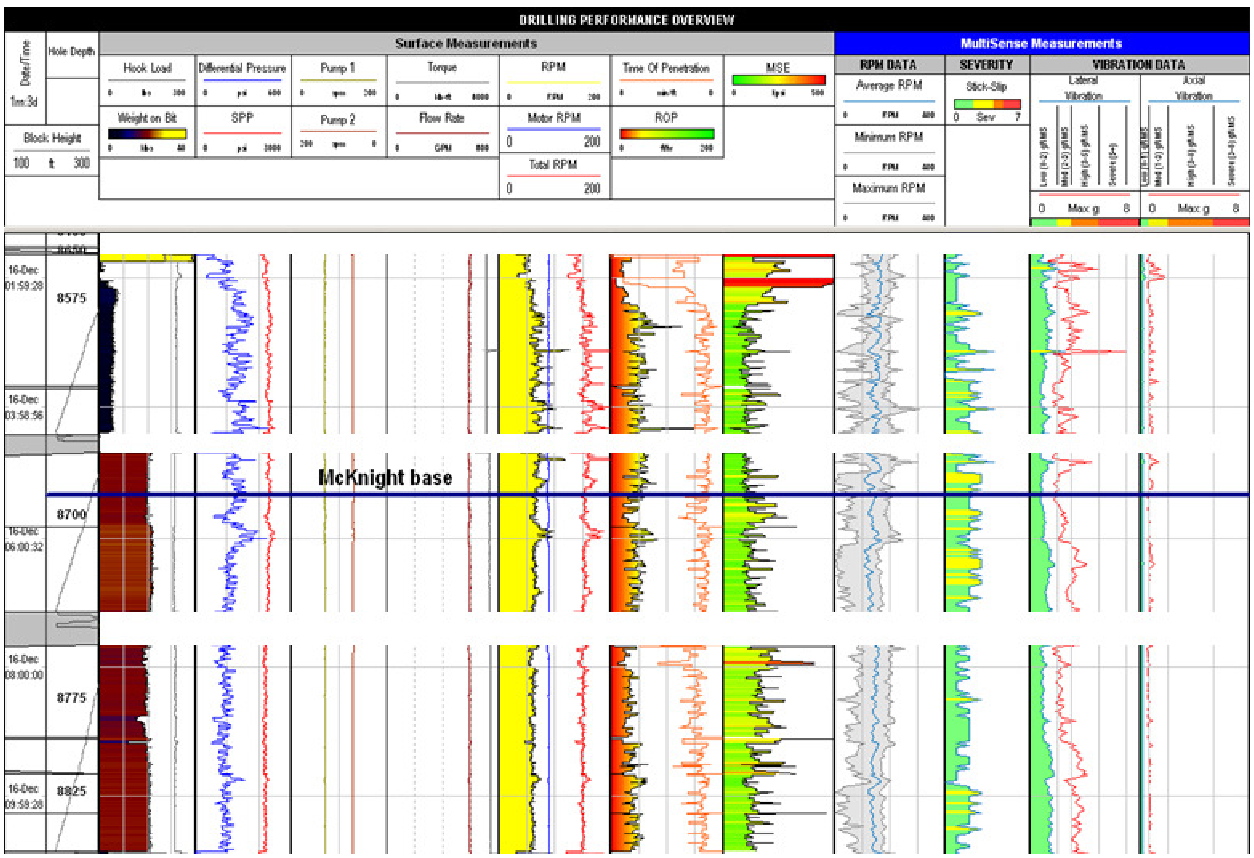

Figure 20: Well B – Back on Bottom Drilling Base of McKnight Formation

Figure 21: Well B – Second 9.875-in PDC Bit with Six Blades and 16mm Cutters

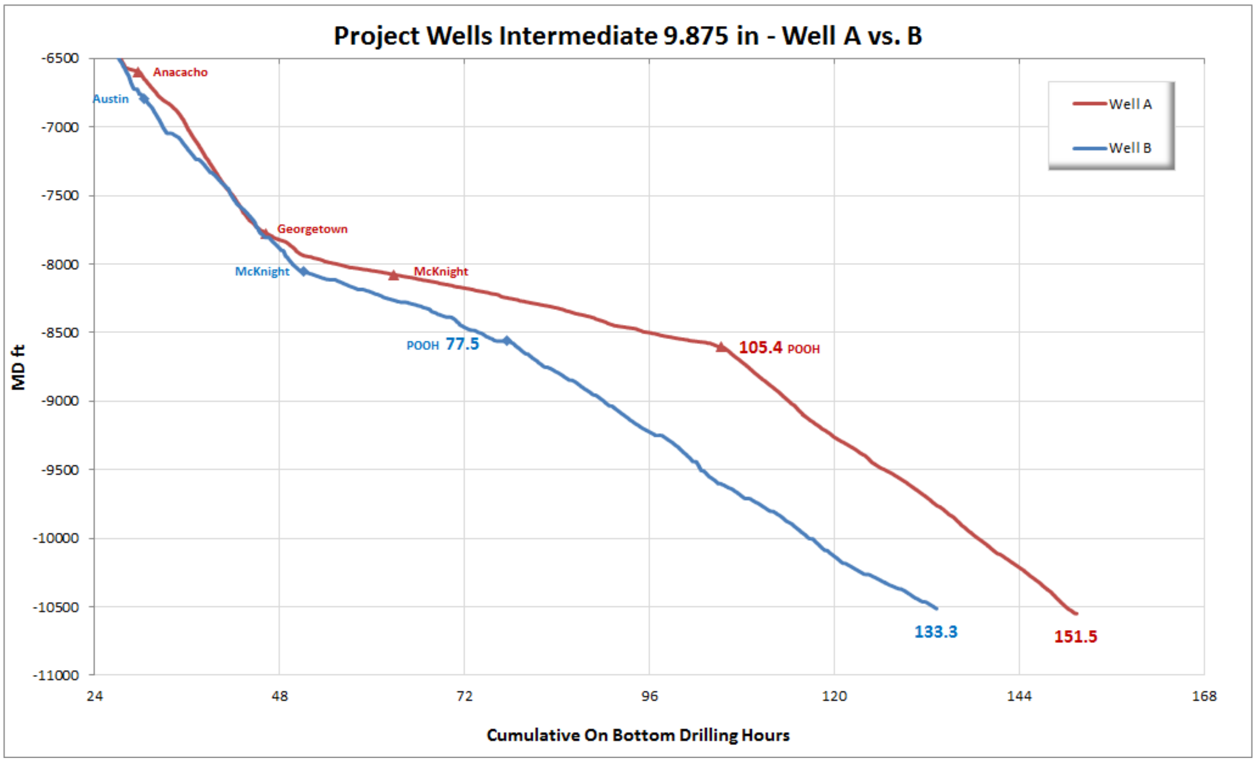

Figure 22: Cumulative Drilling Hours vs. Measured Depth – Project Well A vs. B

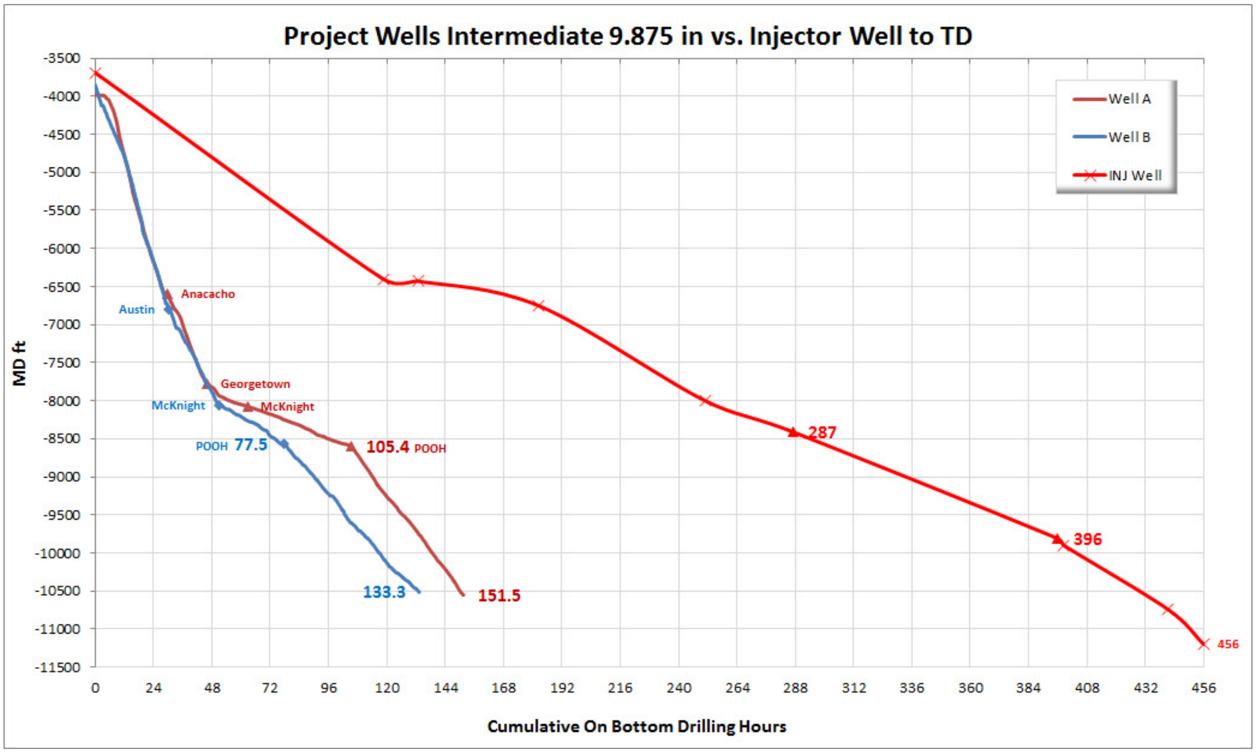

Figure 23: Cumulative Drilling Hours vs. Measured Depth – Project Wells A vs. B vs. Injector Well