



Continuous Improvement Through Optimized Drilling Performance, BP Northstar Alaska

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Abstract

The Northstar satellite oil field operated by BP Exploration (Alaska) Inc. is Alaska's first offshore development, located six miles offshore in the Beaufort Sea and ten miles from the Prudhoe Bay Unit. The field has been developed through the drilling of twenty-two "Big Bore" style wells, from an existing man-made gravel island.

One of the Northstar projects original goals was to complete each hole section in one bit run. This paper presents a technical evaluation of continuous improvement derived from drilling optimization engineering services and the utilization of downhole measurement tools to meet that objective. Conclusions are drawn from the experience gained by Schlumberger and BP personnel during the drilling of over 184,413 feet of borehole during the second and third drilling seasons (15 Rotary Steerable wells), and from post-analysis of the drilling mechanics data.

Introduction

The Northstar satellite oil field operated by BP Exploration (Alaska) Inc is Alaska's first offshore development, located six miles offshore in the Beaufort Sea and ten miles from the Prudhoe Bay Unit. The field has been developed through the drilling of twenty-two "Big Bore" (16", 12 1/4", 8 1/2" and 6 1/8") style wells, from an existing man-made gravel island.

The "Big Bore" well design involves the drilling of challenging 12 1/4" Intermediate hole tangent sections ranging in length from 6,000 to 12,500ft. Conventional motor assemblies were used to drill the 12 1/4" sections of the projects first eight wells (first season of drilling). The Schlumberger Rotary Steerable System (RSS) was introduced to drill these long sections at the start of the second season.

During the first drilling season (eight wells) damage to

Roller Cone and PDC bits was a factor that contributed to 12 1/4" sections requiring a minimum of two bit runs. This trend continued at the start of the second drilling season (early RSS wells) and attention was focused on the potential value of downhole stick-slip and shock measurements.

Real-time downhole stick-slip and shock measurements were introduced within the second drilling season, and used extensively to provide more information about the downhole drilling conditions. This allowed changes to be made to drilling practices and empowered rigsite personnel, allowing them to react to dangerous situations before serious bit or MWD / LWD tool damage occurred.

As the value of the drilling mechanics measurements became clear, their use increased until they were an integral part of the drilling process. At the start of the project only a basic shock risk value was used to indicate the level of downhole shocks. Stick-slip measurements were introduced, followed by more detailed lateral shock information, and finally multi axis Root Mean Square (RMS) shock measurements.

This project incorporates the following:

- Key Performance Indicators identified during the project.
- The presentation of the vibration / root cause analysis carried out during the Northstar project.
- Explanation of the development and utilization of a new technique to analyze stick-slip and shock data.
- Modifications to drilling procedures / practices implemented as a result of the vibration analysis.
- Direct comparison between drilling performance before and after the focus on downhole stick-slip and shock measurements. The benefits to the Client and SLB.

This project is not focused upon the physics of the drilling mechanics measurements, but solely upon how the measurements were utilized to bring benefit to the Client and Schlumberger

Root Cause Analysis

Careful analysis of vibration related incidents (both on the Northstar project and from other BP rigs drilling in Alaska) resulted in the following factors being identified as impacting vibrations and subsequently drilling performance.

- Drilling Parameters
- Wellbore Friction Factor
- Wellbore Inclination
- Wellbore Geometry
- Formations
- PDC Bit Design
- Drilling Procedures

The results of the analysis performed to identify the impact of each of these factors, are presented within this section. A number of these examples were presented to the client during the project to raise awareness of the importance of these factors.

Drilling Parameters

The key drilling parameters affecting vibrations are WOB and RPM's. It is often possible to find a stable drilling condition (without ROP dropping to an unacceptable level), through the careful modification of these drilling parameters. This is an on-going process as formations and boundary conditions change as the measured depth of the wellbore increases. Two examples are shown in figure 1 and 2.

(Fig. 1&2)

Wellbore Friction Factor

Stick-slip is not a phenomenon that is strictly associated with the drill bit. The condition and tortuosity of the wellbore, the type of formations being drilled and the lubricity of the drilling fluid have a significant influence on stick-slip and shocks. (Shocks can be generated as a result of the motion of the BHA when it is in a state of stick-slip).

Two Northstar examples are presented below to a) show the impact of drilling fluid lubricity and b) wellbore tortuosity, on stick-slip and shocks.

Note: Poor hole cleaning or cavings due to wellbore instability issues (breakouts and fractures) can also impact the wellbore friction factor as they load the wellbore with material. (Fig. 3,4,5,6)

Wellbore Inclination

Wellbore inclination is very important because it determines the point at which the collars above the last stabilizer lie against the wellbore.

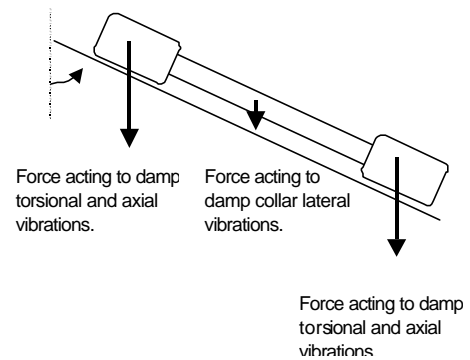
In directional wells the side forces (generated due to the weight of the drillstring) on the stabilizers, and hence

the associated friction, increase with the sine of the inclination. This causes a large frictional damping effect on both axial and torsional vibrations.

For Transverse (lateral) modes of vibration only the component of the drill collar weight normal to the BHA axis can act as a stabilizing force.

General trend from Northstar wells (there are exceptions) is that those with higher tangent angles have lower average section stick-slip.

(Fig. 7)



Northstar Trajectories vs Average 12 1/4" Section Stick-Slip

Well	12 1/4" Section Tangent Angle (degrees)	Average Section Stick-Slip (RPM)
NS07	33- 40	Not Present
NS06	40	48
NS12	37	42
NS16	26- 30	56
NS18	53-58	37
NS24	30-46	64
NS17	58-60	38
NS20	58-60	Not Available
NS19	39-41	34

Formations

The homogeneity (uniformity of the structure or composition), co-efficient of restitution, ultimate compressive strength, bed thickness and abrasiveness of formations has a significant impact upon the magnitude of stick-slip and drillstring vibrations. Trends can be identified from offset well data and formations rated in accordance with the risk of high stick-slip and drillstring vibrations.

The co-efficient of restitution is a property used to describe the amount of damping that takes place during a collision. For example, a golf ball has a high coefficient of restitution since not much energy is lost when impacted, and most of the energy is translated to the ball enabling it to take flight. An example of a low coefficient of restitution is a deflated basketball. When you drop the

ball it just goes plop. The ball absorbs all the energy. Sandstone's tend to have a high coefficient of friction and restitution, where as shales are lower. Therefore shales tend to damp vibrations, meaning that more energy has to be present to support sustained vibrations.

The ideal situation is to be drilling through large distances of homogenous rock. The drilling of conglomerated formations, formations which are intercalated (with layers of rock of differing UCS) or formations that contain boulders / nodules can significantly increase vibration levels. For example huge instabilities are created when a BHA drilling at 150ft/hr suddenly encounters a harder formation and the ROP drops to 15 ft/hr. During this period large amounts of energy can be transferred into vibrations.

Two examples are shown in figure 8, the first demonstrates the impact of inhomogeneous formations on vibration levels, and the second the impact on ROP. (Fig. 8)

Vibration Hazard Chart

Extensive analysis of offset well data enabled the generation of a "Vibration Hazard Chart", which visually displays the baseline level of Stick-Slip and Shocks that should be expected within the different formations. (During this project very similar RSS BHA designs were used to drill all of the 12 1/4" sections).

The "hazard chart" was one of the main deliverables from the project, and it is the presence of this kind of information that separated the project from a normal MWD / LWD service. A clear understanding of the normal (baseline) level of vibration in each of the formations was very powerful because it enabled Drillers', DD's and field engineers to identify when vibration levels were excessive and corrective action was required.

The "hazard chart" also proved to be a very valuable tool when discussing vibration issues with rigsite personnel such as Company Men and Drillers.

Formation	Stick-Slip	Shocks	
SV5	Low	High	
SV4	Low	Low	
SV2	High	Medium	
SV1	Medium	Low	
Upper Ugnu	Very High	Very High	Caution at Formation Top
Lower Ugnu	Medium	Med	
Schrader	High	Med	
Upper Colville	Medium	Low	Caution at Formation Top
Lower Colville	Medium	Med	Caution at Formation Top
HRZ	Low	High	Caution at Formation Top
Kuparuk	Low	High	Caution at Formation Top
Kuparuk C	Med	Low	Caution at Formation Top
Miluveach	Low	Low	Caution at Formation Top

Note: The tops of formations are often non-uniform areas that have been subjected to erosion, or are more heavily cemented. Generally shocks follow the same trend as stick-slip but this is not always the case, as can be seen within certain formations in the example Hazard Chart above.

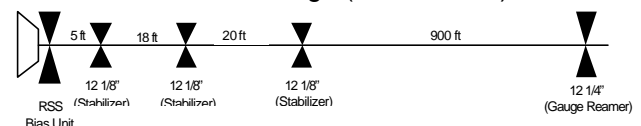
BHA Design

A BHA's susceptibility to vibrations is dependent upon its ratio of stiffness / mass. The higher this ratio, the higher the BHA's natural resonant frequencies and the less likely it is that drilling RPM's will coincide with the BHA resonant frequencies, increasing vibrations. For a uniform drill collar with fixed length, a larger OD will increase the mass as OD² but it will also increase the stiffness as OD⁴ and therefore result in a higher ratio of stiffness / mass. So larger collars (9", 8 1/4", 8" and 6 3/4") are less susceptible than smaller collars (4 3/4"). Stabilizers increase the stiffness of the BHA, since they restrict the movement of the BHA. The size of the stabilizers is important, the more under gauge they are, the less effective they are at reducing vibration levels.

$$\text{BHA's 1}^{\text{st}} \text{ Natural Frequency} = 4 \sqrt{\frac{\text{Stiffness}}{\text{Mass}}}$$

The RSS BHA design used for the 12 1/4" section remained very consistent throughout the project. The only significant change made was to the amount of HWDP run (dependent upon tangent angle inclination). A gauge reamer was used on all runs to wipe formations, and positioned within the HWDP.

Northstar 12 1/4" BHA Design (Locked BHA)



Drill Bit Design

PDC bits were used on the first two Northstar wells within the first bit run in the 12 ¼” section (a S986 HPX Smith Geodiamond PDC followed by a DS70 HFNPV). In both cases the bits were pulled prior to TD due to low ROP, the first having suffered significant impact / vibration damage and the second for a reason that could not be determined.

The next 4 wells (NS31 to NS14) used roller cone bits for the first bit-run of the 12 ¼”section, to drill from ~3200ft to 7000ft through the intercalations in the Upper SV sands and the Ugnu sand.

The Schlumberger RSS was introduced for the first time on NS08 and from this point onwards only PDC bits were used. The evolution of bit selection for the RSS runs was as follows:

- RS163HDNS
- RS141HDF+GNSV
- RS238HFGNS
- RSX238HFGNS (introduction of modified cutters)
- RSX238HF+GS (introduction of full cylinder cutters in nose of bit) – used for remained of project.

After damage to PDC bits on the first two all PDC bit run 12 ¼”sections (NS08 and NS15), bit selection stabilized with the RS238 PDC bit.

The first version of the 12 ¼” RS238 (the RS238HFGNS) was first used on NS07 and suffered significant damage and coring. The damage shown below resulted in the bit being pulled before reaching section TD.

RS238 HFGNS (First Version – A1), Used on NS07

12 ¼” RS238 A1 version
11 Angled Cylinder cutters in Cone of Bit



Grade: 8-4-WT-A-X-I-CR-PR



Bit vendor comments (NS07):

Good ROP, very little bit balling. Cored out in Kuparuk Sand. Dull condition indicates stick slip - flattened nose area, impact damage to cutters.(Broken and Chipped). Recommend proactive measures to avoid stick slip on next well and to add modified cutters to the RS238. Internal SLB study on going. Bit stopped 392ft short of TD.

The majority of the damage is believed to have occurred when the bit encountered hard stringers. To combat this problem the bit was re-designed – RSX238HF+GS. Reengineered cutters were added and the cutters within the cone of the bit where changed to a stronger Full Cylinder design. The re-designed RS238 bit is shown below and was run on all of the last seven wells.

RSX238 HF+GS
 (Second Version – A2)

12 ¼” RS238 A2 version
11 Full Cylinder cutters in Cone of Bit
 Increased Impact Resistance due to shape of cutter



Root Cause Analysis Conclusions

The three high angle wells (NS17, NS18 and NS20) all had low to average stick-slip in relation to the lower angle wells. This indicates that the high angle itself and/or the use of less HWDP may have lead to a reduction in stick-slip. In reality though the correlation was very weak, possibly indicating that the real key to success was the rig team reacting to increases in vibration levels by changing the drilling parameters (WOB and RPM) (especially the strategy for drilling hard stringers) and / or drilling fluid properties (addition of lubricants).

The redesign of the PDC bit (with the introduction of T-Rex and Full Cylinder cutters) in response to damage seen on NS07 and earlier wells, was an important step towards achieving the target of completing the hole sections in one run.

Stick-slip and four axis shock measurements proved very valuable when drilling hard stringers.

The worst stick-slip during the 12 ¼" section occurs within the Ugnu and when entering the tops of the Schrader Bluff and Kuparuk formations.

Communication between the DD's, MWD's, Rig-Crew, Company Men and Mud Engineers is essential, as is ensuring that the rig team understands the real time measurements.

Contour plots and plotting an overview of drilling mechanics measurements against formations can provide valuable visual indication of danger zones.

Reducing stick-slip did not directly result in increased rates of penetration.

Development of New Analysis Technique

During the project the graphical power of MATLAB was used to generate contour and histogram plots to aid the analysis of vibration data (in a new way) acquired while on bottom drilling, and allow the identification of dangerous RPM and WOB combinations. Both Stick-Slip and Vibration measurements were plotted against surface drilling parameters. The input data used for the analysis was depth based data (surface and downhole data) recorded by IDEAL in a ½ ft index.

Figure 9 is a color contour of stick-slip vs RPM and WOB. The plot provides a clear indication of the drilling parameters (RPM and WOB combinations) that resulted in high stick-slip. The histograms at the sides of the contour plot display the number of 1/2ft increments drilled at different RPM's / WOB's.

From Figure 9 it is possible to conclude that dangerous stick-slip occurred at lower RPM's with higher WOB's (as theory predicts) and that the majority of the time was spent drilling with RPM's > 120 and low to moderate levels of stick-slip (0-100). Possibly in the future this technique can be extended to analyzing time-based data.

Identification of KPI's

After the root cause analysis of the vibration related problems experienced during the first drilling season and at the start of the second drilling season, three key performance indicators were developed to help the team identify improvements based upon vibration related issues.

- Vibration Related Failures Per Hole Section. (Washouts, twist offs, PDC bit damage, downhole tool failures and uneven / excessive wear on tubulars)
- Drilling Performance. (Distance drilled per bit run, Days / 10K ft, Average on bottom ROP)
- Wellbore Tangent Section Tortuosity.

Key Factors Influencing KPI's

Identified from detailed root cause analysis: Vibration induced failures per hole section (See Appendix A for Northstar Examples). (Washouts, twist offs, downhole tool failures, drill bit failures, and uneven / excessive wear on tubulars)

- BHA whirl is the most dangerous form of vibration and will result in vibration-induced failures in a very short time period. [9]
- Sustained high levels of vibration will increase the rate of drillstring and top drive fatigue. (Fatigue is the most common failure mechanism experienced while drilling [9]).
- The risk of severe BHA vibration and buckling is dramatically increased when drilling with part or parts of the BHA in an oversized wellbore. (Washouts, ratholes, drilling out of casing). Monitor delta turbine RPM when drilling out of casing to provide a crude indication of stick-slip [10].
- High wellbore friction increases the risk of severe torsional vibrations. Track torque and drag information and drilling fluid lubricity. (When drilling with WBM high solids content reduces the effectiveness of lubricants.)
- Take into account the location of BHA components within the borehole. For example monitor vibration very carefully when reamers pass through lithology changes.
- BHA design (stabilizer placement) must take into account wellbore inclination. The highest risk occurs when running flexible (pendulum) assemblies at low inclinations. Extra vigilance is required upon rotary steerable jobs because RPM's are normally higher and RSS tools do not have the same vibration damping properties as mud motors.
- Bit bounce and high levels of stick-slip will chip PDC cutters and reduce the bits cutting efficiency.
- Drill bits can be severely impact damaged if drilling

parameters are not rapidly modified in response to sudden ROP changes (as occur when the bit encounters formation boundaries, cemented intervals, and stringers / nodules).

- Ensure the driller and DD are aware of approaching formation tops.
- Establish vibration limits (GO and NO GO) and utilize the alarm functionality on the IRCT display.
- Establish vibration baselines for each formation and carefully modify RPM and WOB if shock and stick-slip levels rise.

Drilling Performance. (Distance drilled per bit run, Days / 10K ft, Average on bottom ROP)

- Drill bits can be severely impact damaged if drilling parameters are not rapidly modified in response to sudden ROP changes (as occur when the bit encounters formation boundaries, cemented intervals, and stringers / nodules).
- Discuss strategies for drilling stringers / cemented intervals / nodules etc.. with the drill bit engineer.
- Bit bounce and high levels of stick-slip will chip PDC cutters and reduce the bits cutting efficiency.
- Minimizing vibrations transfers more energy to the drill bit, increasing drilling efficiency and ROP.

Wellbore Tortuosity.

- High levels of torsional vibrations and stick-slip reduce the efficiency of rotary steerable systems, making it harder for the DD to achieve the desired directional response. (Higher %settings are required to achieve the desired response).
- High wellbore tortuosity can increase stick-slip and torsional vibrations.

Modifications to Drilling Procedures and Practices

Modifications to drilling procedures / practices implemented as a result of this project:

- Red and Green lights for drillers on rig floor console, triggered based on real time torsional and lateral vibration measurements.
- Use of vibration hazard chart for look ahead.
- Strategy for drilling hard stringers. (Drillers reaction when a decrease in ROP and / or an increase in vibration levels is experienced)
- Strategy for going back on bottom.
- Monitor shocks even more closely when back-reaming (monitor vs time).
- Improved understanding in the planning stage of which types of wells are more likely to be impacted by vibration.
- Promote awareness that vibrations are usually an indication that there are other problems – in-efficient drilling.

- Understand how actions / events, especially within the surface hole, can have negative effects during later hole sections.
- Not re-running re-built bits for long sections

Actions to Address Drill String Vibrations				
Condition	RPM	WOB	Flowrate	Complete Action and Comments:
Stick / Slip or Torsional Vibration	Increase ↑	Decrease ↓	No Change	CAUTION: Take Care to monitor RT shock measurements to ensure lateral vibration is not initiated during this action!!! (Utilize delta turbine RPM when drilling out of casing)
BHA Whirl or Lateral Vibration	Stop Rotary & PU off bottom	Start Rotary @ 60 to 80 RPM	No Change	1. Stop the Rotary and PU off bottom. 2. Place the Bit Back on Bottom. 3. Slowly increase WOB to target drilling value. CAUTION: Take care not to initiate Stick / Slip!!! 4. Increase RPM to it's target drilling value.
Bit Bounce or Axial Vibrations	Increase or Decrease RPM in 10 units	No Change	No Change	Increase or Decrease RPM in increments of 10 rpms until vibration levels are minimized or maximum acceptable RPM is reached. CAUTION: Take care not to initiate other modes of vibration when altering the RPMs!!! In EXTREME cases PU off bottom and restart the bit in the following manner: 1. Set RPM between 60 & 80, 2. Place the bit back on bottom and 3. Slowly increase WOB to target drilling value.
Hard Streak or Stringer Strategy	Decrease ↓	No Change	No Change	1. Reduce Bit Rotary Speed to minimize bit impact damage 2. Maintain constant WOB, and 3. Maintain constant flowrate. CAUTION: take care not to induce torsional vibrations (Stick / Slip)!!!

Actions to Address Drill String Vibrations				
Condition	RPM	WOB	Flowrate	Complete Action and Comments:
Shutting Down for a Connection.	Reduce RPM to between 60 to 80.	Drill off to 50% of drilling WOB	Shut Down Pumps.	1. Reduce RPM to between 60 to 80, 2. Drill off to 50% of Drilling WOB, and 3. Stop Rotary and Lift Off Bottom. 4. Make the Connection.
Starting Up after a Connection.	Start the rotary between 60 and 80 RPM.	Slowly Increase WOB to target drilling value	Bring Pumps up gradually to drilling value	1. Start the rotary between 60 & 80 rpm, 2. Place the bit on bottom, 3. Slowly increase WOB to target drilling value, CAUTION: Take Care not to initiate Stick / Slip. 4. Increase RPM to the target drilling value.
Reaming Guidelines	Use low RPM	Use minimal WOB	No Change	1. Use minimal WOB while reaming. 2. Control reaming penetration rate to below 50% of the normal drilling penetration rate, 3. Ensure the bit torque does not exceed 50% of the normal drilling torque for that bit and formation. 4. Keep reaming speed below 35 fpm, and 5. Use low rpm to minimize vibration levels while monitoring RT shock measurements.
Bit Break-in Procedure	Start the RPM at half the target drilling rate	Begin drilling with low WOB <6K for 2 to 3 feet.	Target Drilling Flowrate	1. Start the RPM at half the target drilling rate, 2. Tag Bottom, 3. PU 1 foot off bottom & circulate for 5 minutes. 4. Begin Drilling with low WOB & drill 2 - 3 feet. (no more than 500 psi of bit diameter -- 6K WOB) 5. Increase the WOB to target drilling value, then 6. Increase the RPM. CAUTION: Take Care not to induce Stick Slip or Axial & Lateral Vibrations

Conclusion

Vibration Related Failures Per Hole Section. (Fig.10&11)

- The first version of the PDC bits did not have sufficient impact resistance (even when a stringer drilling strategy was utilized) to drill through the SV and Ugnu stringers and make it to TD.
- Average baseline vibration levels were manageable; failures (bit and downhole tool) correlate to short periods (in terms of the time to drill the section) of

extreme conditions of stick-slip (as in NS24) and lateral vibration (as in NS17). To achieve one bit run 12 ¼"sections with low days / 10K it is critical to quickly identify the onset of high vibrations and take remedial actions.

- Vibration failures in NS24 and NS17 indicated the importance of real-time vibration measurements and stringer drilling strategy (performance was not solely related to bit design).
- Important to understand the expected baseline vibration levels for each formation – very powerful because it allows rigsite personnel to identify abnormal conditions.
- It appears that the higher than normal average level of stick-slip seen on NS24 was due to the running of a re-built PDC bit.

Drilling Performance. (Fig. 12)

- Key step changes in performance were:
- Transition to drilling stringers in SV sands and Ugnu formation with PDC not Roller cone bits (PDC bits used for first bit run).
- Introduction of PD900 rotary steerable system.
- Identification that the RS238 PDC bit had the ability to provide the desired performance, identifying the bits weaknesses and re-designing the bit.
- Re-design of the RS238 resulted in a bit capable of making completing the 12 ¼"section (assuming good drilling practices).
- Highest average ROP's did not result in the best days / 10K (NS06 and NS12), due in part to vibration related issues. (Sections required 2 bit runs due to bit damage).
- Wells NS16, NS18, NS20 and NS19 indicated that with the following procedures / information, it is possible to repeatedly achieve a days / 10K ft of between 7 and 9.:
 - 1)Real-time vibration monitoring (with driller GO and NO GO lights),
 - 2)The use of a formation hazard chart and
 - 3)Good drilling practices: reaction to stringers / high vibration levels, and going on bottom,

Wellbore Tangent Section Tortuosity. (Fig. 13)

- No clear relationship between stick-slip and tangent section average tortuosity. Tangent section tortuosity was between 0.6-0.75 deg/100ft for the majority of the wells.
- Appears to be a correlation between max DLS in tangent section and on bottom ROP, with higher ROP 's resulting in tangent sections with higher maximum DLS.

Client Impact

- Ability to drill 12 ¼"sections in one bit run resulted in a reduction in Days per 10K (less time tripping).

- Reduction in rig equipment wear and tear (Drillpipe and topdrive fatigue).
- Lower charges for equipment damage (BHA components).
- Preparation for future ERD wells. Increased understanding and confidence results in a higher probability of success. More likely to consider even longer, more challenging 12 ¼"sections.
- Drilling engineers and rigsite personnel obtained excellent experience for future projects.
- Vibration contour plots (there is a possibility that this functionality maybe incorporated into future software to enable engineers to perform real-time analysis at the rigsite).
- Vibration analysis sheet for MWD / LWD engineers and FSM's.
- Formation hazard chart / baseline identification example.
- Benchmark for other jobs within Alaska.
- Input / feedback for Alan Clarke's Vibration TBT.
- Field testing Drilling Office BHA Vibration application.
- Exposure for field engineers (DD and MWD).

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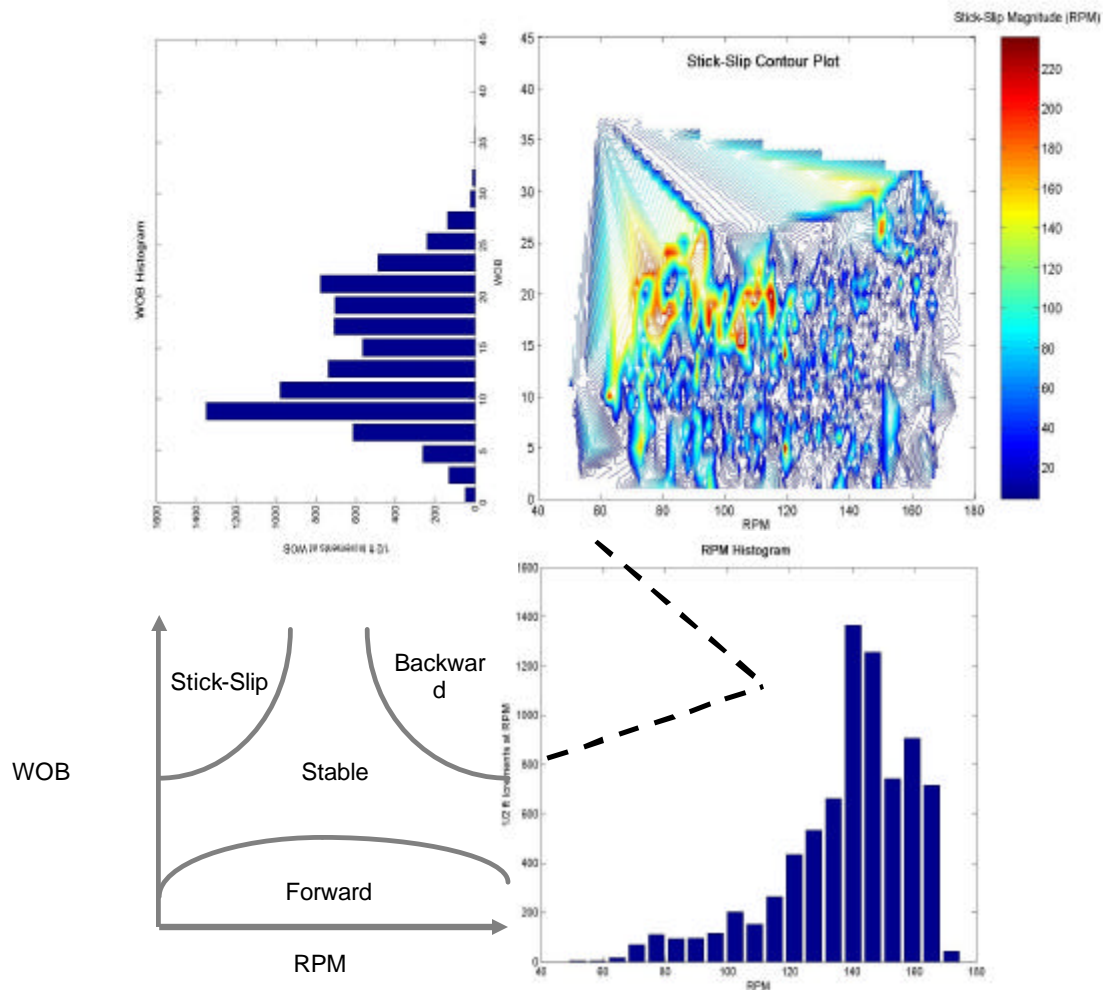
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(Fig. 1) A) RPM vs SWOB vs Stick-Slip: This example is from NS19 12 ¼"section (with PD900) and shows the impact of drilling parameters on stick-slip. At this stage in the project the rig team was actively responding to stick-slip and shock measurements by modifying drilling parameters.

RPM vs SWOB vs Lateral shocks: This example is from NS07 6 1/8"section and compares actual lateral shock data to the danger area predicted by BHAV vibration modeling software.

RPM vs SWOB vs Stick-Slip (Note: A guide to the interpretation of the plots below is contained in section "Modifications to Drilling Procedures and Practices")



Analysis Notes:

High stick slip was experienced when drilling with high WOB and low RPM, but as the histograms show, the driller and DD did not spend much time drilling with these dangerous parameters.

The 8300ft section was completed in 1 run and the PDC bit graded **1-0-WT-C-X-I-CT-TD**.

Some ROP was sacrificed by reducing the WOB whilst drilling certain formations, but this was made up for by the fact that section was completed in one run without any equipment failures.

The plot displayed is a stick-slip contour plot, constructed by cross plotting depth based (½ ft increment) SWOB and RPM data. The histogram plots indicate the distance drilled with different RPM's and WOB's.

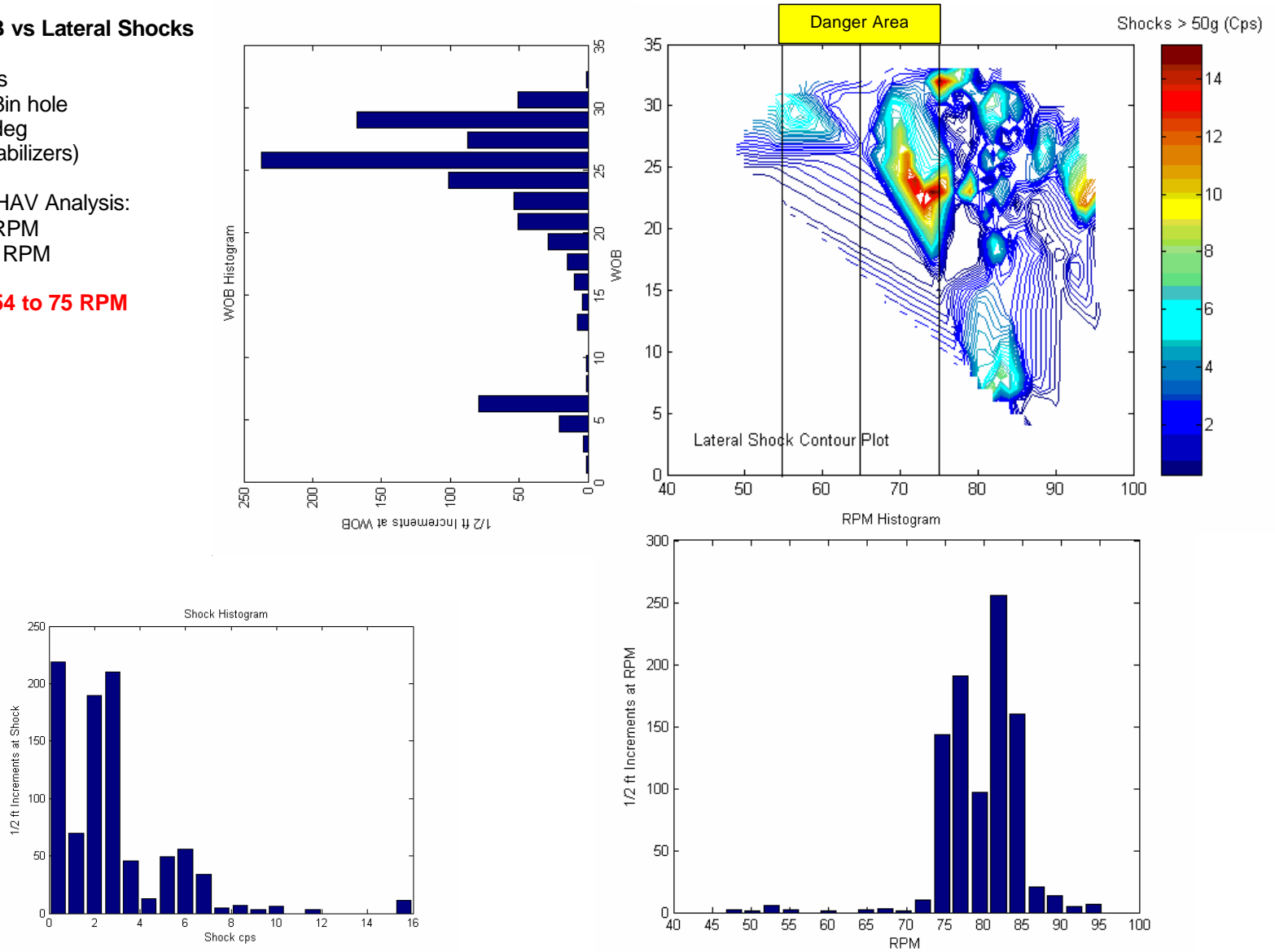
(Fig. 2)

RPM vs SWOB vs Lateral Shocks

Example Details
 Hole Size: 6 1/8in hole
 Inclination: 20 deg
 4 3/4" BHA (2 stabilizers)

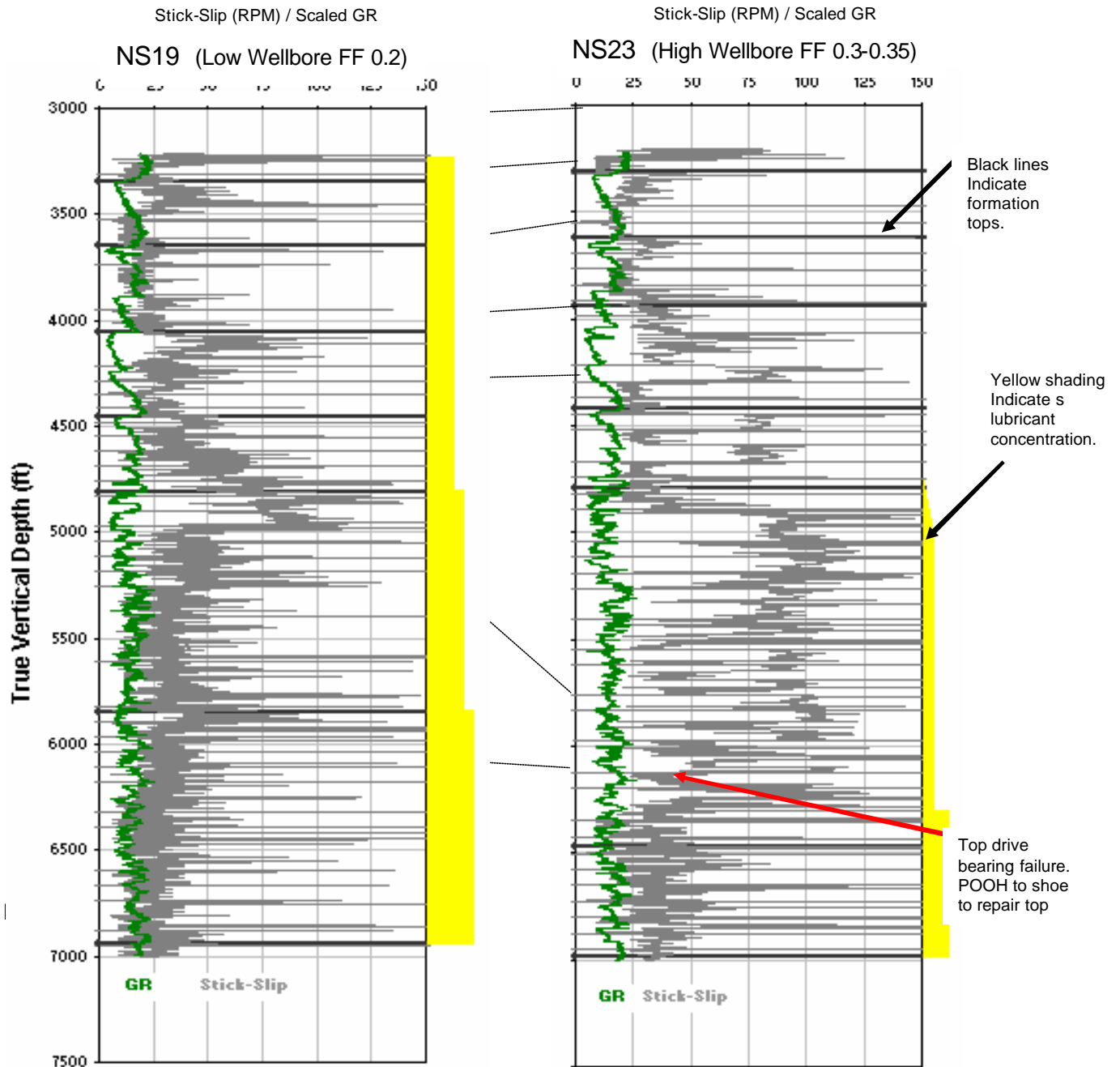
Results from BHAV Analysis:
 Mode 1 @ 64 RPM
 Mode 2 @ 219 RPM

Danger area: 54 to 75 RPM



Please Note: Vibration modeling is a valuable tool when trying to identify which BHA designs will be more susceptible to vibrations. However, field experience has shown that there are a lot of variables impacting drillstring vibration, not all of which are accounted for within the models. Results should be used qualitatively and not quantitatively.

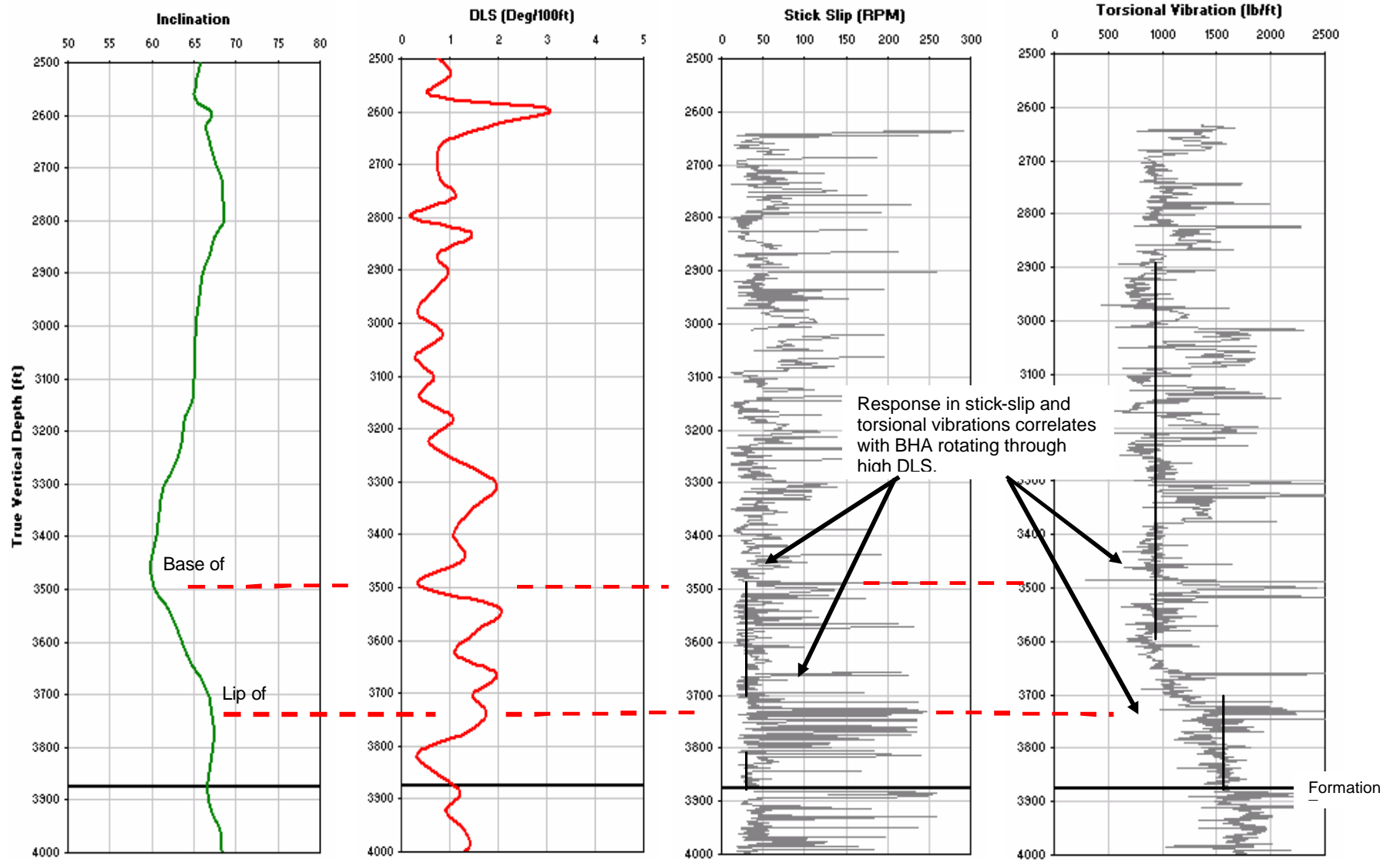
(Fig. 3) Drilling Fluid Lubricity



Same drillstring / BHA (with same PDC bit).
 Very similar well trajectories and tangent angles.
 Same formations.
 Directional drillers used the same WOB and RPM strategies.
 Similar hole cleaning (from APWD information
).

(Fig. 4) Wellbore Tortuosity

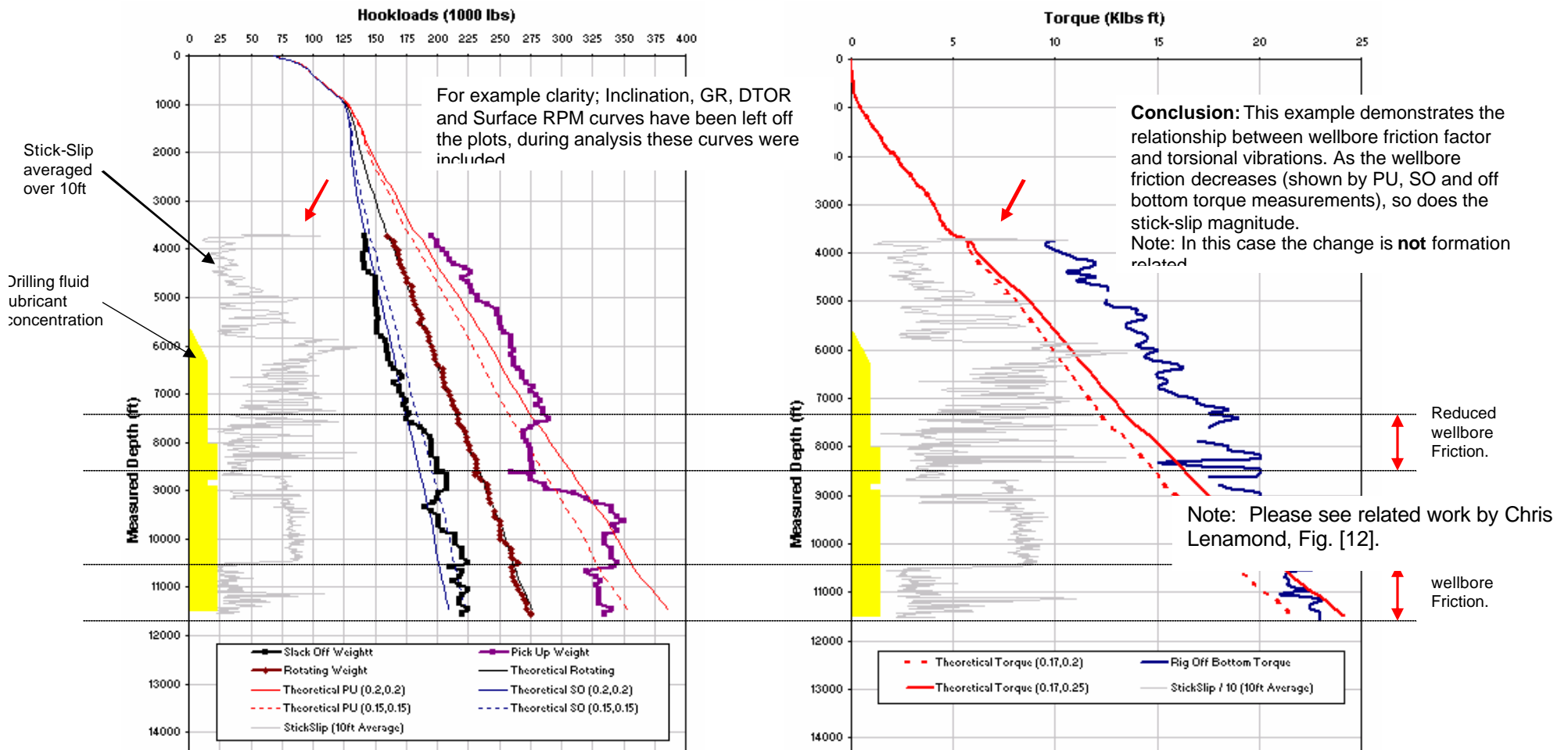
Note: Data from BP Borealis project well L-121.



Note: Stick-Slip returns to baseline after Bowl, but Torsional Vibration does not. Now have a new higher baseline

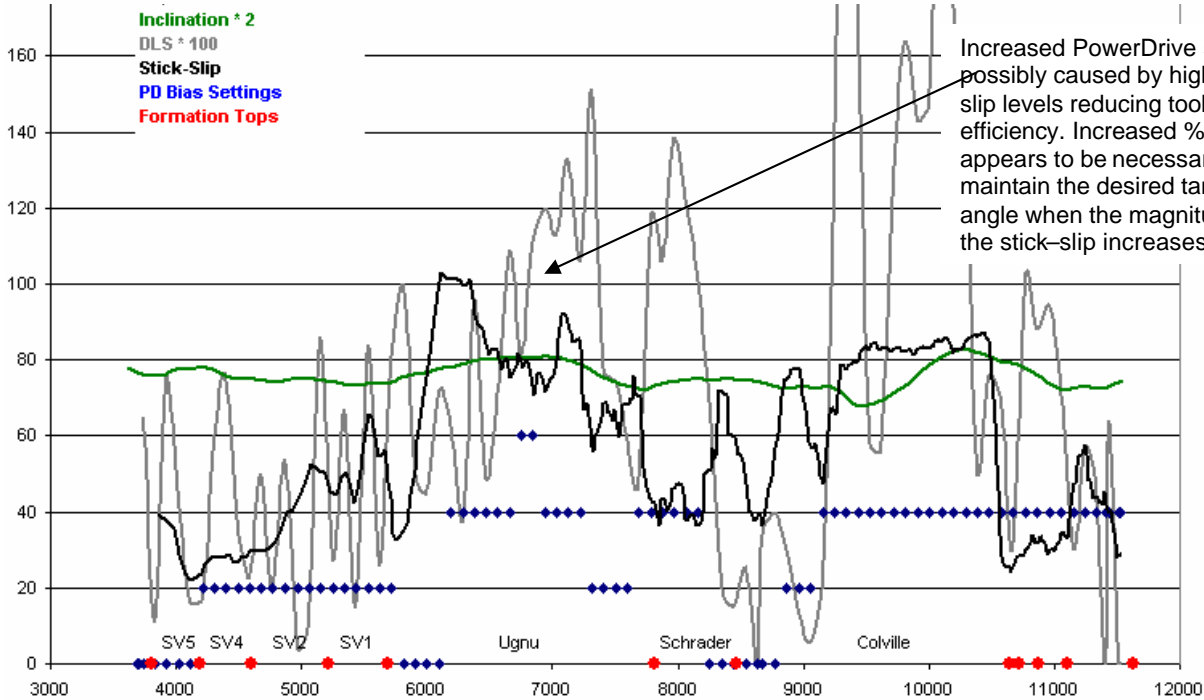
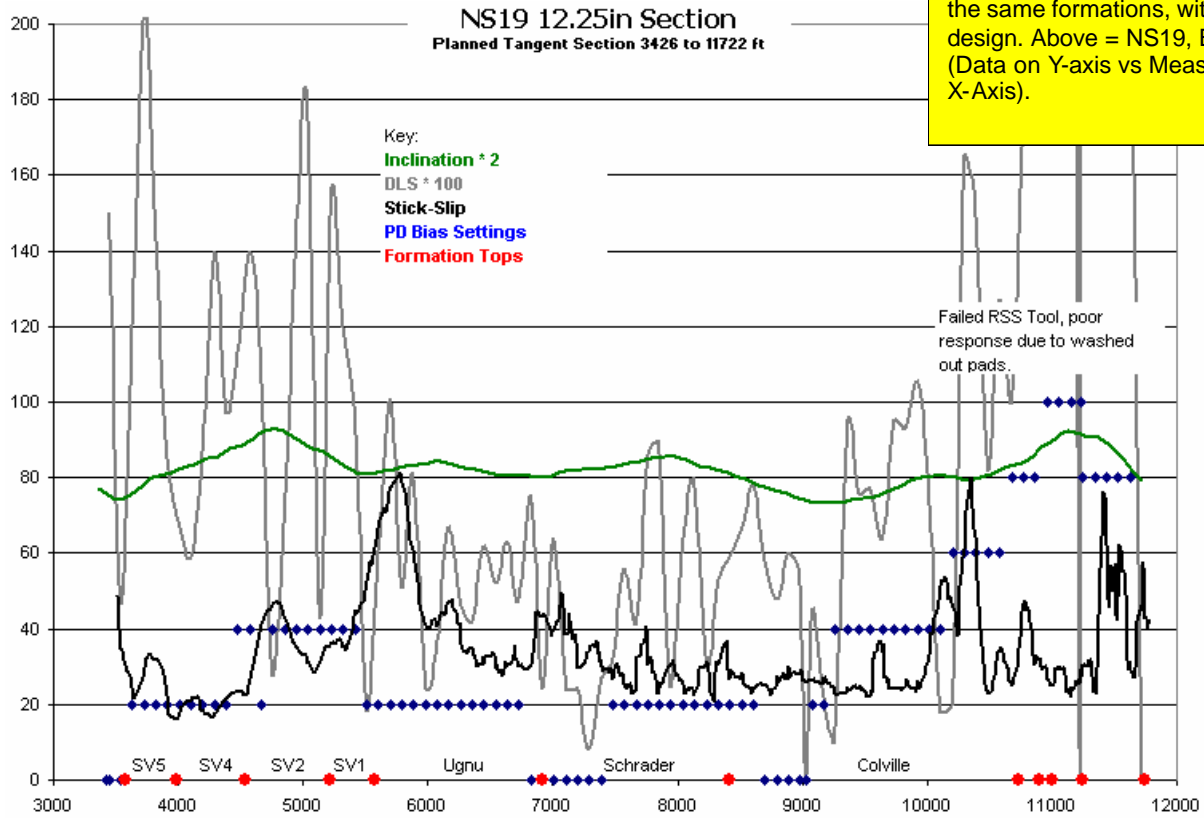
(Fig. 5) Wellbore Friction vs Stick-Slip and Torsional Vibrations

Comparison between Pick Up weight, Slack Off weight, Off Bottom Surface Torque, and stick-slip / torsional vibrations (vib_tor) can indicate if wellbore friction is influencing BHA torsional vibration. (Data from NS23 12 1/4" section).

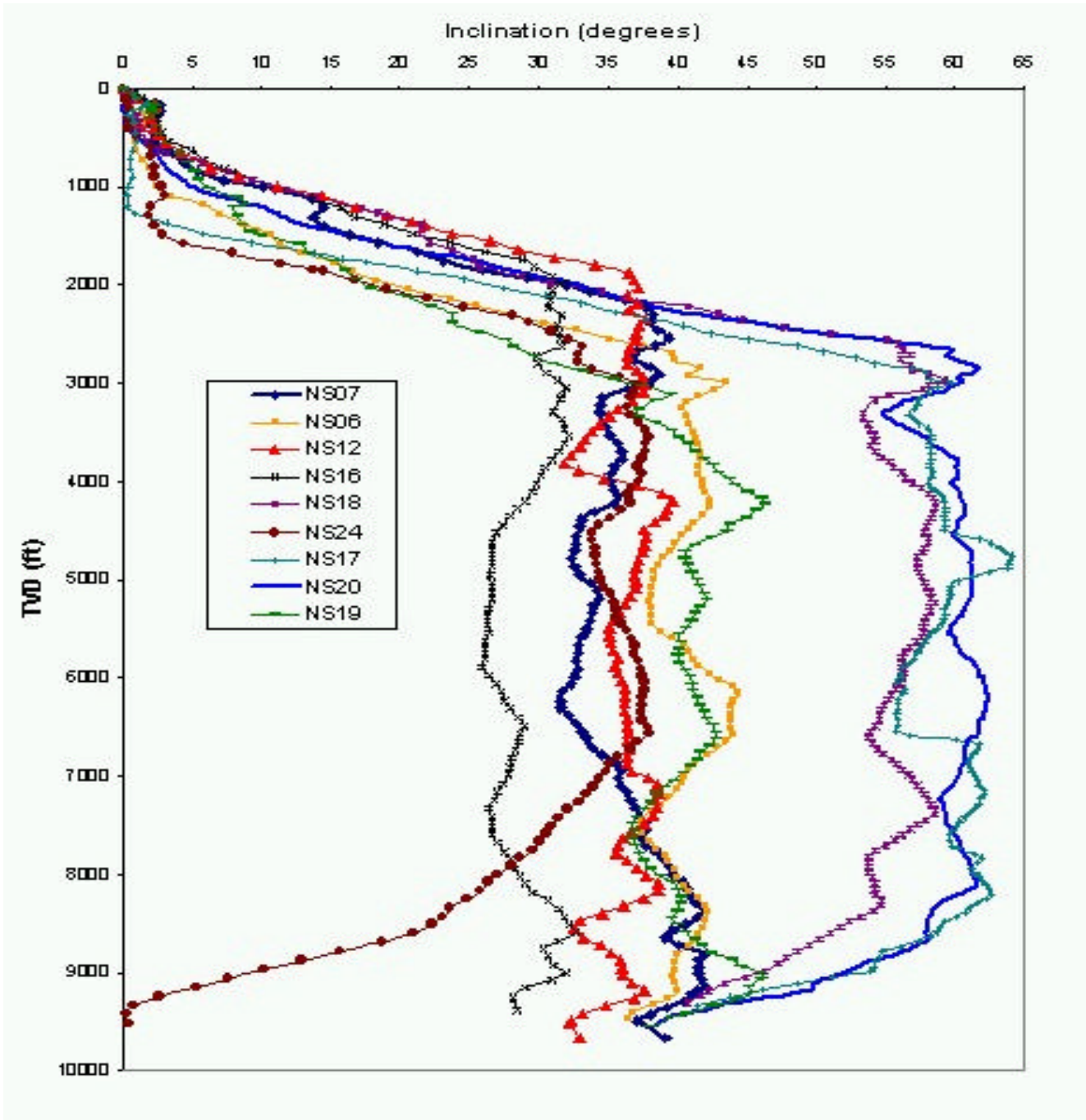


(Fig. 6) Tangent Section Tortuosity vs RSS Setting

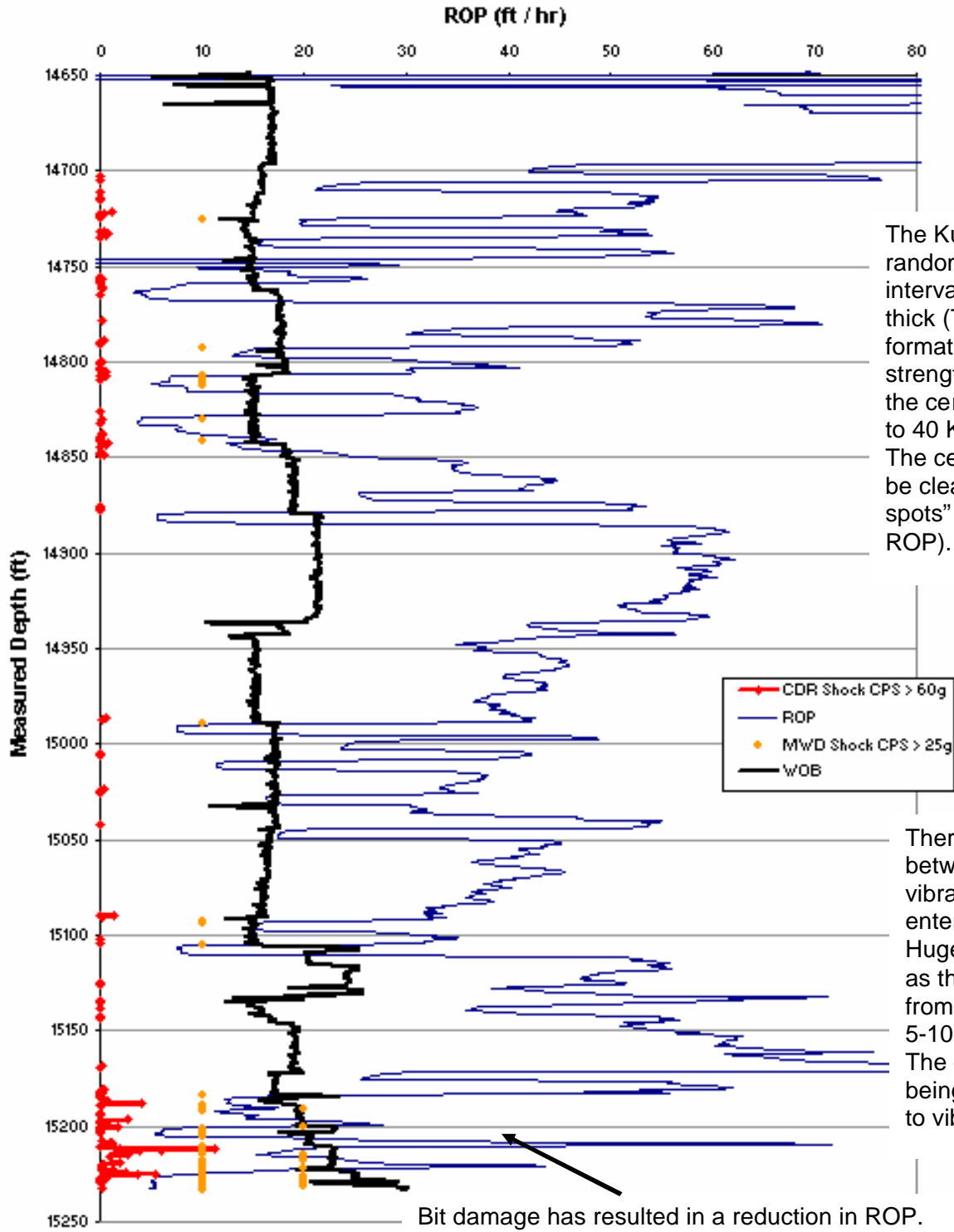
Note: The data presented is from two straight tangent 12 ¼" hole sections through the same formations, with the same BHA design. Above = NS19, Below = NS23. (Data on Y-axis vs Measured Depth (ft) on X-Axis).



(Fig. 7) Northstar Well Trajectories (to TD of 12 ¼" Section)



(Fig. 8)
Impact of Formation Non-Homogeneity on Vibrations (NS17 12 1/4" Section)

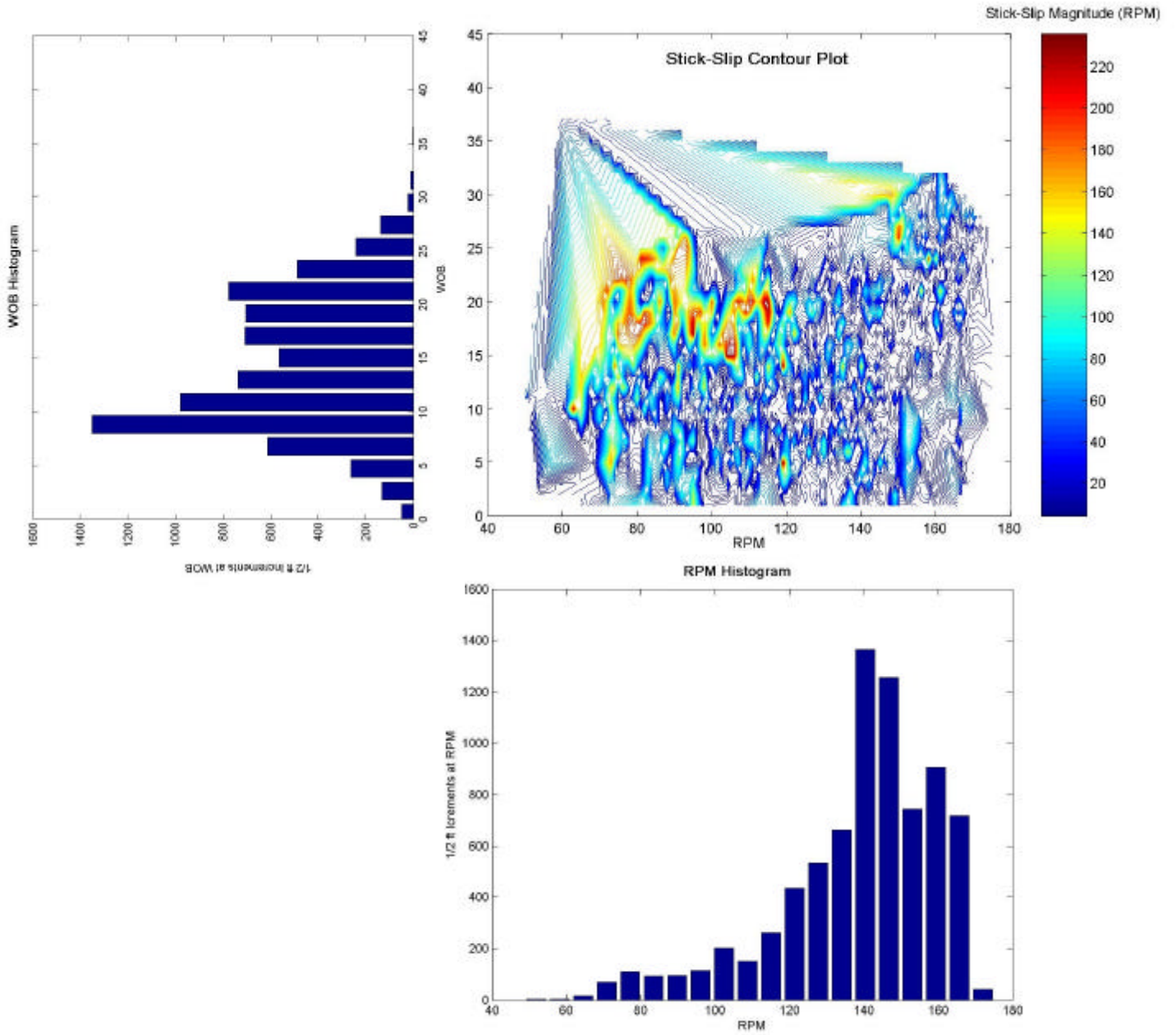


The Kuparuk sand contains randomly dispersed cemented intervals in the region of 2 ft thick (TVD). The normal formation has a compressive strength of around 10 KPSI, the cemented intervals are 30 to 40 KPSI. The cemented intervals can be clearly seen as the "slow spots" (areas of reduced ROP).

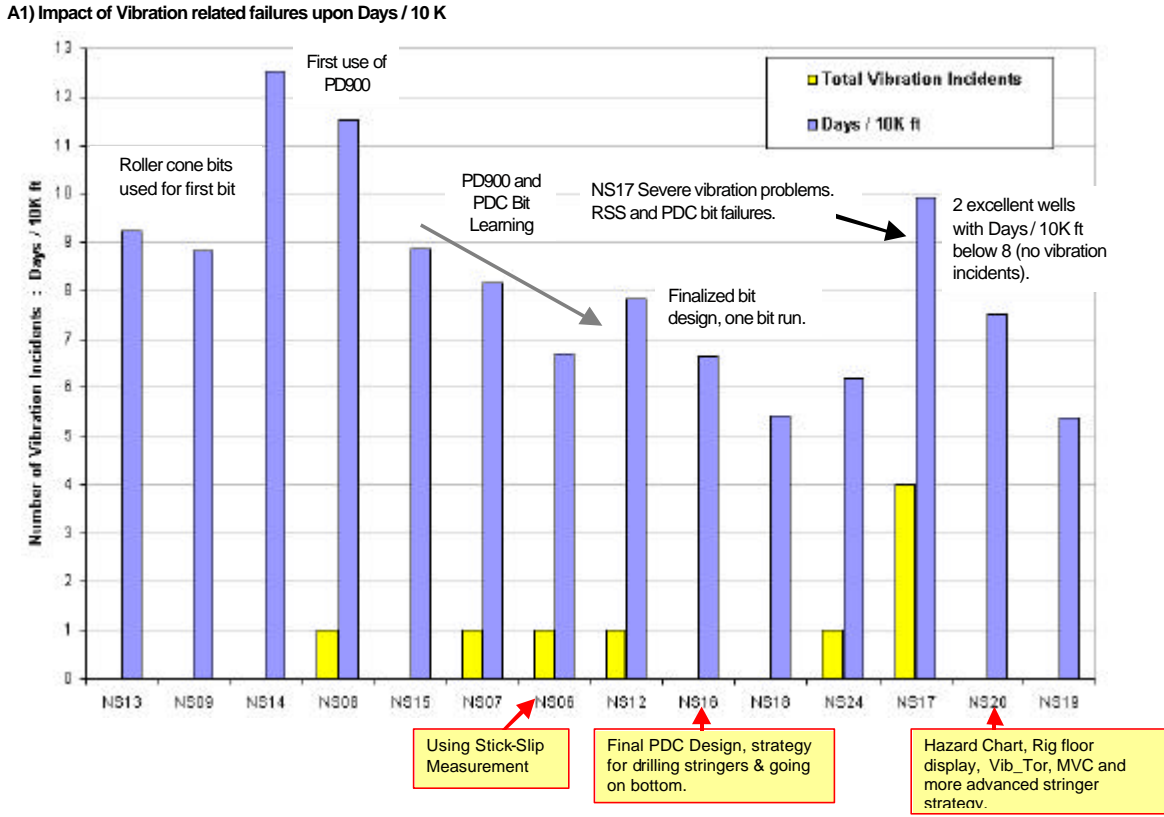
There is a clear relationship between the initiation of BHA vibration / shocks and the bit entering cemented intervals. Huge instabilities are created as the ROP drops quickly from 80 ft/hr down to around 5-10 ft/hr. The energy changes from being used to drill formation, to vibrating the BHA.

Bit damage has resulted in a reduction in ROP. WOB is increased in an attempt to make the bit drill. Increased WOB changes vibration mode (BHA driven into whirl). Downhole tools damaged due to high shock levels.

(Fig. 9)



(Fig. 10)



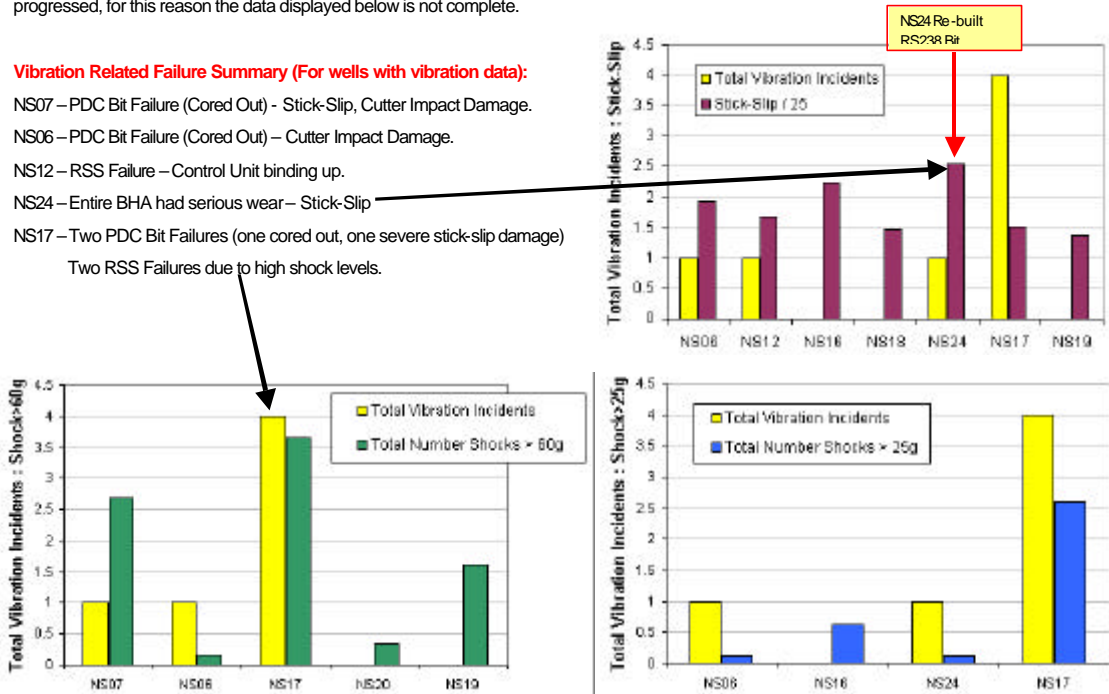
(Fig. 11)

A2) Vibration Related Failures vs Average Stick-Slip and Lateral Shocks

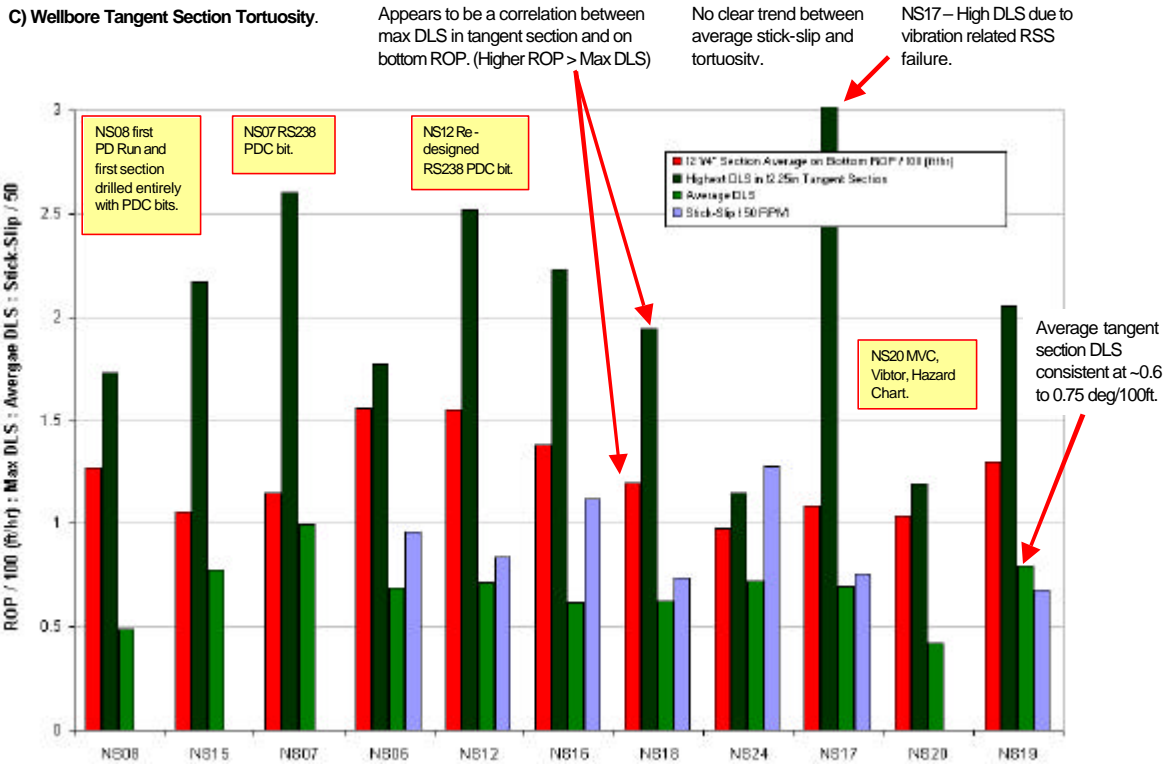
Note: The use of real-time vibration measurements increased and evolved as the project progressed, for this reason the data displayed below is not complete.

Vibration Related Failure Summary (For wells with vibration data):

- NS07 – PDC Bit Failure (Cored Out) - Stick-Slip, Cutter Impact Damage.
- NS06 – PDC Bit Failure (Cored Out) – Cutter Impact Damage.
- NS12 – RSS Failure – Control Unit binding up.
- NS24 – Entire BHA had serious wear – Stick-Slip
- NS17 – Two PDC Bit Failures (one cored out, one severe stick-slip damage)
Two RSS Failures due to high shock levels.



(Fig. 12)



(Fig. 13)

