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Performance Gains for Rotary Steerable Through Specialized Bit Design

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Abstract

This paper presents an updated "matched drilling system" approach that significantly improves directional control by selecting appropriate bit side cutting aggressiveness to the rotary steerable system (RSS). This reduces vibrations and makes directional control easier. By reducing the wasted drilling energy that is consumed in downhole vibrations, directional control and penetration rates on field studies of several runs in deepwater Brazil were improved.

The paper traces the application process of selecting bit features for a push-the-bit rotary steerable application by assessing active versus passive gauge cutters, geological conditions, anomalies, and objectives. The timeline for bit design, manufacture, and field application explains how an oil company was able to drill wells that previously had presented directional difficulties.

The findings of the paper are based on an evaluation of PDC rotary steerable bits by a directional company that ranked bit stability and dogleg generation as two key criteria for performance. The recommendation shows the bit design that performs best in the field conditions observed and the use of measurement-while-drilling mechanical measurements to improve the evaluation process.

Introduction

Rotary steerable systems (RSS) are a relatively new introduction to the drilling industry, but have contributed significantly to both drilling performance and hole quality improvements. These tools are now beginning to penetrate the lower-cost land market as the enhanced penetration rates produce significant rig cost savings. These drilling performance gains are due to the following reasons:

- corrections are made while the drillstring is rotating, there is no need for “slide” drilling as occurs with steerable mud motors
- as rotary steerable systems also do not require manual toolface orientation, more aggressive bit designs can be used to improve instantaneous penetration rates, and
- less circulation and reaming time is required on most wells as improved hole cleaning results from full-time drillstring rotation and better hole quality.

Directional companies supplying RSS tools have observed that elevated downhole vibrations began to occur with these drilling systems. Corresponding to the increase in vibrations, failures of bits and other downhole tools began to increase. Studies determined that these increased failure rates where due to:

- increasingly aggressive bit designs began to induce bottomhole assembly (BHA) whirl and related vibrations which damages the BHA and wastes drilling energy,
- the RSS and bit vendors began to lose control of the “drilling system” which consists the bit and RSS drive system as clients began to run virtually any RSS compatible bit design on any RSS and in any formation type,
- drillers began to “crowd” the bits on RSS when penetration rates decreased in harder stringers which caused the bits to become unstable and induce whirl vibrations into the drillstring,
- bit vendors did not have access to drilling mechanics data of MWD/LWD logging images to evaluate vibrations and hole quality, and
- the directional companies had failed to correlate dull bit grades showing vibration damage with downhole vibration issues.

Based on these observations, the directional company opened discussions with the clients and the bit vendors in Brazil on optimized bit designs for rotary steerable systems and analysis of drilling environment data. The results were a new understanding of bit applications and designs for rotary steerable systems based on three measurable criteria:

- bit performance in terms of penetration rates,
- bit steerability in terms of dogleg and RSS steering times, and
- bit stability in terms of vibrations and hole quality.

Theory

Many versions of rotary steerable systems are available and are classified into two basic categories relative to the method of deflection of the drill bit:

- "push-the-bit" systems exert a sideforce on the bit and
- "point-the-bit" systems utilize three points of contact to control the direction of the drill bit much like steerable motor systems.

These classifications are quite simplistic as the various RSS tools within the "push-the-bit" category operate very differently. A majority of these systems have non-rotating or slowly rotating parts in the annulus that control the operation of the tools. **Fig. 1**, the rotary steerable system in this paper is a push-the-bit system with no external stationary parts. The tool applies a side-force to control the bit direction, using mechanical pads near the bit that push against the borehole wall, while drilling. Drillstring rotation is supplied from surface while the hydraulic force to the pads is furnished by the mud flow.

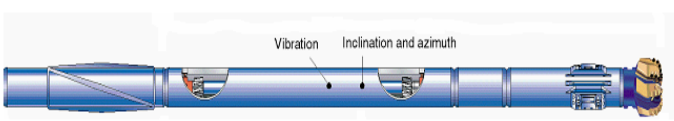

Fig. 1 Fully-rotating rotary steerable system used in this case study. Features no external non-rotating parts and provides automated directional control in vertical well applications.

Well Data Selection

When selecting drilling data, it is imperative that all data analyzed is as similar as possible to allow definitive comparison of the results. To improve the study results, only comparable wells and BHAs were selected which could be grouped as having the same characteristics. From the total of 25 bit runs, only 12 bit runs were selected for the case study based on the following criteria:

- Field / Formation – all wells under analysis were drilled in the same formation,
- Well profile – well profile can interfere in the RSS performance results, only horizontal sections drilled in the sandstone reservoir of Albacora Leste field were selected,
- BHA – has a great influence on all aspects of the drilling process and selecting wells with similar BHA minimizes external influences,
- Mud lubricity – mud properties plays a very important role when rotary torque, hole cleaning and BHA vibration are considered,
- Drilling events – eliminating extraneous drilling events that interfered with the drilling process and interpretation of the results.

Method of Drilling System Analysis

As previously mentioned, the objective of this case study is to verify the performance of RSS regarding the bit selection. This analysis consists of three main elements:

- Performance: rate of penetration and durability
- Steerability: dogleg severity (DLS) achieved by RSS setting, and the time percentage drilling per RSS setting
- Stability: stick-slip vibrations, downhole shocks and wellbore quality.

Some indicators are easily verified and measured, while others are more complex and require an in-depth analysis to extract the result. This is especially true in the stabilization elements, where measurements are not industry standardized and an understanding of mechanisms is necessary. These elements are combined with the bit evaluation and are extremely useful in the evaluation of the drilling system performance.

Bit Performance

This element is very straightforward but is far from the easiest indicator to understand . The drilling performance of any bit is related to its stability and steerability in the formations to be drilled. The use of surface sensors allowed measuring an average penetration rate (ROP) across each meter drilled. It is very important to clarify that bit stability is considered by the directional company as the main design concern of the bit.

Bit Stability

This element is important, as it will affect the other two elements. Today, bit stability improvement is becoming recognized for its importance in RSS applications. Depending on the bit company, different methods and techniques are employed to achieve the desired stabilization; however, stabilization is not the result of a single change in a bit design but the outcome of several design features in each bit.

Bit stability is also important for rotary steerable operations as it directly affects BHA reliability. Often the bit has a direct impact on a RSS failure due to the excessive vibration levels induced. Stability also affects the quality of the Formation Evaluation (FE) logs, especially when the bit has a tendency to generate high stick-slip vibrations. Stick-slip vibrations deteriorate the quality of the LWD image logs and have an undesirable effect on drilling performance by wasting drilling energy. The resulting borehole enlargement, often called washouts, affects logging measurements like bulk density, sonic travel times and formation resistivity and makes accurate interpretation more difficult.

Steerability

Steerability is often linked to well objectives and well tortuosity. RSS tools have to be capable of achieving the dog leg severity (DLS) as per the well plan to reach the well objectives. With a "push-the-bit" RSS, the predicted DLS is dependent on:

- the amount of force the pads apply to the formation to steer in the opposite direction,
- how often it pushes the formation,
- how competent is the formation being pushed,
- side-cutting ability of the bit, and
- the ability to maintain a constant toolface direction of the bit.

Proper bit selection controls the last two parameters and selection is based on both formation types to be drilled and the RSS type.

Additionally, in the case of the push-the-bit system, steerability is directly linked to tool reliability. This is because the mechanical pads are activated through hydraulic pistons in the tool. In addition, with most mechanical parts, increased usage reduces the life of the components. Maintaining a specific "toolface" setting, or "steering mode", requires higher mechanical wear than "non-steering" neutral mode. As the bit steerability is reduced, increased steering is required reducing the seal's life. The RSS may fail prematurely if an incorrect bit is selected. As vibrations reduce toolface control they increase, steering requirements due to lower dogleg severity achieved.

RSS Reliability (Service Quality)

As rotary steerable activity grows worldwide, RSS vendors focus on reliability of the complete drilling system to differentiate from other competitors. Beginning in June of 2003, RSS tool reliability began a sharp decline in Brazil. Shock related failures and failure to achieve directional objectives occurred with increasing frequency. As new fields opened to RSS applications, both the client and bit vendors began to change bit designs seeking to improve penetration rates without considering other factors. The RSS vendor realized a need to influence bit choice and control downhole vibrations through partnership and mutual understanding with the bit vendors and the clients. This partnership with the bit vendors improved understanding of the entire drilling system and not individual components singularly.

In September 2003, the RSS vendor implemented a service quality plan to recover RSS reliability in the deepwater market. The results of this plan are in **Fig. 2**. So successful was this plan, that RSS reliability exceeded all other RSS locations within six months. Part of this plan included controlling external factors that represent a menace to service quality results. These factors included bit design for the drilling system and controlling drilling mechanics related issues at the rigsite. Using downhole

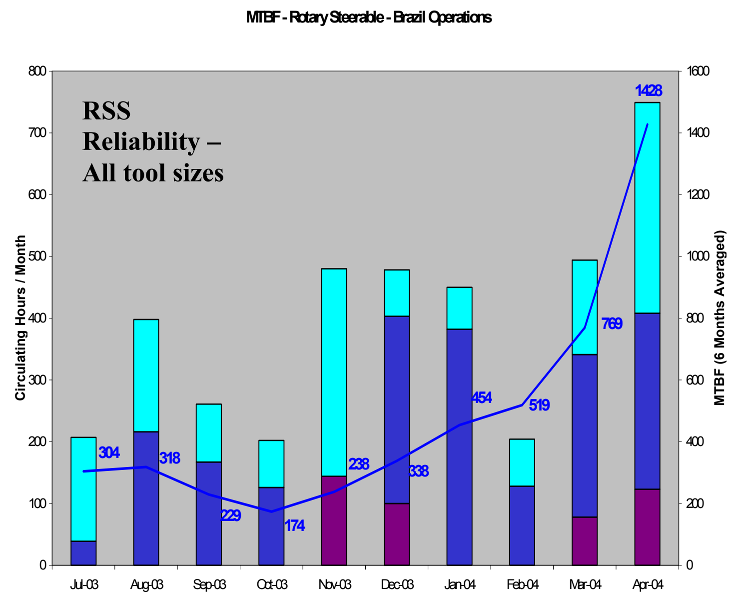

Fig. 2. Rotary steerable reliability measured by mean time between failure (MTBF) for Brazil. Bars are composite of all tool sizes.

measurements, vibration issues where detected early and mitigation procedures implemented. Mitigating the wasted drilling energy of vibrations, improved both the BHA reliability and the penetration rates that the customer wanted.

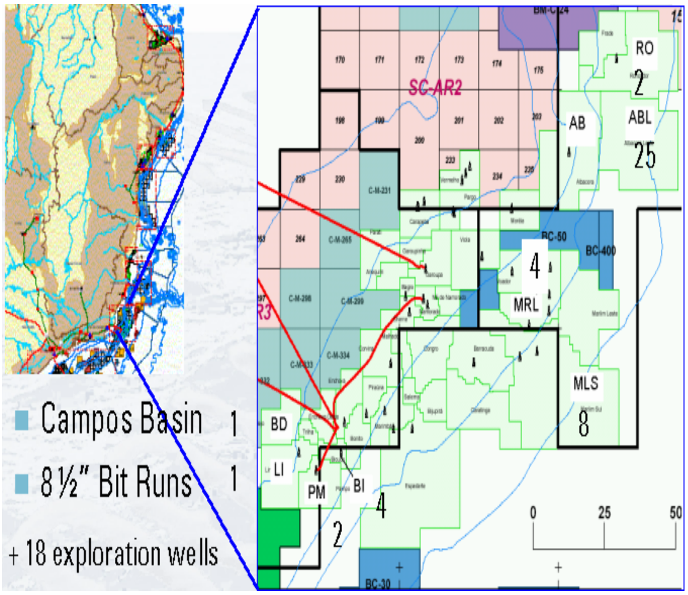

Fig. 3. 8 ½" PowerDrive runs distribution per production fields in Brazil. Numbers indicate number of RSS wells drilled in each field.

Albacora Leste Field

The Albacora Leste field was selected as the focus of our analysis as the majority of the RSS runs for 8-1/2" section were in this field. **Fig. 3** the Albacora Leste field (ABL) is located in the northeast portion of the Campos Basin, in the intermediate compartment that concentrates the majorities of all the discoveries in the deeper bathymetric contours of the Brazilian Campos Basin.

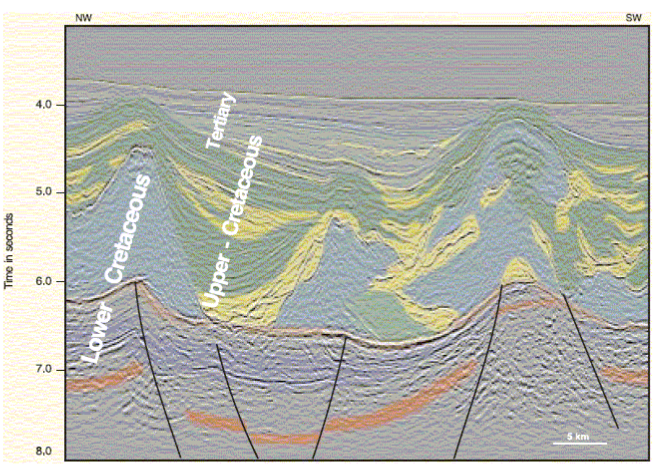

Fig. 4. Seismic section of Campos Basin intermediate compartment.

Fig. 4, the Albacora Leste field consists mainly of a marine turbidite depositional environment with an unconsolidated sandstone reservoir interbedded with calcilutites, calcarenites and shales. Wells are drilled horizontally or directionally through the reservoir for investigation, injection and production. RSS utilization in these types of wells improves dramatically the drilling performance and the well placement campaign in Brazil.

Historical Bit Performance

In the Albacora Leste field, the 13-3/8" casing is normally set in the Ubatuba Geribá formation at approximately 2,200 meters. A two-dimensional 8-1/2" pilot section is directionally drilled into and through the Ubatuba Geribá and the Miocene sands so the planned horizontal section can be properly positioned in the producing Miocene sands. The shales and marls of the Ubatuba Geribá have unconfined compressive strengths (UCS) between 2 and 4 kpsi. Typically, the total section length is 1,300-1,500 meters long. The Miocene sand reservoir (soft friable sand) ranges between 400 and 500m thick. The pilot section directional profile requires doglegs of approximately 4.0°/30 m while building from 25° to 80°.

In earlier wells, PDC bits were used to drill the section with a "push-the-bit" rotary steerable system (RSS). Lateral bit vibration and shocks were observed in earlier PDC runs. An opportunity was identified to increase ROP and improve bit stability to increase bit durability and the number of rerunable bits on subsequent wells.

Bit Development

Four main criteria were identified in order to optimize bit runs in Albacora Leste field: Bit stability and the associated durability, performance and steerability.[1,2,3] The main objective was to design a PDC bit that would be able to drill more than one pilot section while optimizing ROP and minimizing vibration and its associated shocks that could impact overall performance and induce rotary steerable system failures.

After identifying the opportunity to reduce drilling costs, local engineers from the bit supplier formed a design application review team (DART) to develop a new PDC bit design for this rotary steerable application. The DART is a cross-functional group of engineers that define performance objectives, review application information and determine solution requirements. **Fig. 5** shows the team members in the DART concept. This integrated, multi-functional team works to provide an improved design process by utilizing both application engineers and marketing personnel from the field in addition to research and design engineers to develop the proper bit for the application. This concept also includes personnel from the operator and/or directional company in a cooperative process to optimize the bit solution.

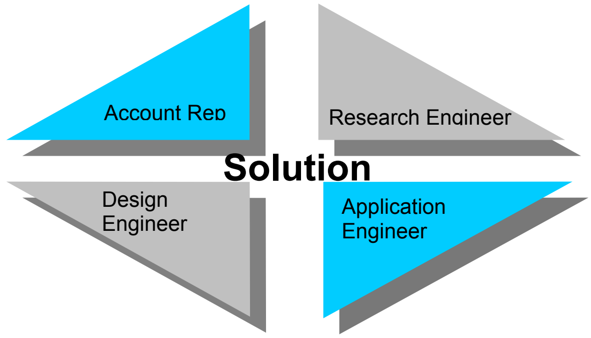

Fig. 5. DART – Design Application Review Team is a team based approach to solving design and application opportunities.

After several meetings, the DART team and local engineers designed an 8-1/2" matrix body PDC bit with 6 blades and 16mm cutters with special features to solve the application specific challenges. Core technology for the new design included new PDC cutters, stability analysis and optimized hydraulics using computational fluid dynamics (CFD).

Cutter Technology

The 8-1/2" 6-bladed PDC bit incorporates 16mm cutters that are a result of a comprehensive research program. They provide the proper diamond interface design, edge geometry and diamond table thickness. The main objective of the diamond interface design is to reduce residual stresses and increase cutter durability by reducing the tendency to fracture. Edge geometry plays a key role in cutter aggressiveness and durability. Diamond table thickness has an influence on cutter wear resistance and impact strength. This intensive research has led to a cutter that provides a new level of impact and abrasion resistance.

All cutters on the new design incorporate a patented polished finish that reduces the coefficient of friction on the diamond surface. This eliminates formation build-up on the cutter's edge.[4] This polished cutter feature was important to optimize penetration rates while drilling the plastic shales and marls encountered in the Ubatuba Geribá formation.

Hydraulics Optimization

The hydraulic optimization of the bit design was done with computational fluid dynamics (CFD) that simulates fluid flow in a computer model. CFD is a powerful tool that can determine where the flow is going and identify any issues. The CFD process starts by modeling the fluid passages between the bit and the formation with a computational mesh. Then, the program simulates the flow of drilling fluids and cuttings around the bit. Adjustments of nozzle tilt and angle are made in an iterative process, to maximize cuttings removal and reduce the bit's tendency to ball. Examination of fluid velocities assure the best balance between fluid flow and cutter cooling while reducing bit body erosion.

There are two main criteria for CFD analysis: particle residence time and flow balance. The particle residence time is a flow analysis that simulates formation particles generated from each cutter and tracking the individual particle's path. A bit is hydraulically efficient when the particles exit the junk slot and move up to the annulus in the least amount of time possible. The flow balance is achieved when the volume of cuttings generated by a specific junk slot is matched by the flow volume for that junk slot.

Bit Stability

According to offset PDC bit performances, high levels of shocks and torsional vibrations were observed in the previous 8-1/2" PDC runs. A stable bit design would be fundamental to optimize performance in the Albacora Leste field. Minimizing bit vibration would reduce cutter impact damage and result in longer runs. Penetration rates would also be higher because the cutters would keep their original edge geometry and continue to be efficient while drilling. Bit vibration is considered one of the main causes of PDC and BHA components failure.

The bit company's research and development group has spent extensive time testing new stability features to control lateral instability utilizing two main tools:

- Laboratory tests performed on a full scale downhole simulator and an atmospheric surface rig.
- Computational modeling to simulate the bit's dynamic behavior including a detailed interaction between the bit and various rock formations.[1]

During the product development process, stability was defined in two modes of vibration:

- Primary stability: defined as the tendency of a bit to drill smoothly.
- Secondary stability: a measure of how severely a bit vibrates when it is not stable.

Control of primary stability is by the cutter layout. This 8-1/2" 6-bladed PDC bit has a low imbalance spiral cutter layout. The main objective of this design is to layout the cutters so the total imbalance force (summation of side and torque imbalance) is as close to zero as possible (practically < 7% - total imbalance force/WOB). If the imbalance is low, the tendency to drill on-center and without lateral vibration is maximized. Spiral cutter layouts are generally more efficient and have increased cutter density relative to other cutter layouts.

Secondary stability plays a vital role in protecting the cutters when drilling in an unstable mode. This can be accomplished by using many additional bit features. These include: chordal drop management, a lateral movement mitigator (LMM), wear knots and backup cutters that are radially unaggressive and tangentially efficient (BRUTE).

Chordal drop is the maximum distance between the chord and a circle as shown in **Fig. 6.** This distance affects the severity of impacts during bit whirl. The new 8-1/2" design (bit type 4 in this study) has wider blades and gauge pads which minimizes the chordal drop. This reduces the severity of impacts while drilling in an unstable mode.

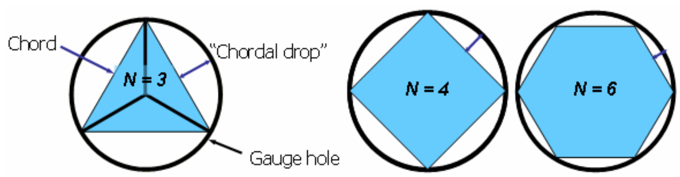

Fig. 6. Chordal drop is maximum distance between the chord and a circle.

Only the bit company's PDC bits utilize the lateral movement mitigator (LMM) feature. It is formed by building up the blade behind and around the gauge cutters as shown in **Fig. 7**. The objective is to provide a bearing surface that limits lateral motion when bits are experiencing lateral vibration.

This 8-1/2" 6-bladed PDC bit has brute cutters in the cone. The main objective of placing cutters in this area is to protect the cone surface from abrasion when utilizing a depth-of-cut control feature to reduce stick/slip vibrations while maintaining optimal penetration rate.

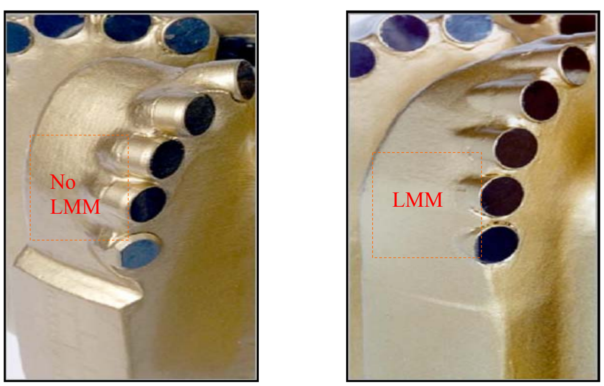

Fig. 7. Lateral movement mitigator (LMM) feature

Depth-of-Cut Control

The rotary steerable system does not use toolface control to deviate the wellbore like conventional motor assemblies. As with most drilling assemblies, the RSS can suffer from high levels of bit vibration and stick/slip while drilling in rotary mode. The bit company utilized another bit feature in order to control these vibrations. Cutters were underexposed in the cone area and a bearing was placed on the blade surfaces in the cone area that became active when target penetration rates were reached. Although generally utilized in motor steerable applications, this depth-of-cut (DOC) control technology and resulting rubbing area (bearing) has a stabilizing effect that helps counteract vibration caused by aggressive bits on rotary assemblies. This feature enables the bit to be aggressive as a standard PDC until a target depth of cut is attained. Once the target is reached, the rubbing area increases with increased depth of cut. This allows the bit to be efficient while drilling at low penetration rates and reduces high depths of cut and the associated stick/slip problems.

Laboratory Validation

Fig. 8 is a graph of WOB versus torque generated through laboratory testing for three types of 8-1/2" bits (standard PDC bit; DOC control PDC bit; and a roller cone bit). At low weight on bit, both PDC bits have similar weight to torque ratios. Once the WOB is above 8,000 lbs, the weight to torque ratio for the DOC control PDC bit is similar to the roller cone bit.

In directional wells, the actual WOB that effectively gets to the bit will often vary. (This is especially evident when running motor steerable bits in high angle wells.) For a change in WOB between 8000 - 12000 lbs, the roller cone bit shows a change in torque of approximately 150 ft-lb. For a standard PDC, the change in torque would be 750 ft-lb. The depth of cut control PDC bit has a torque differential of about 250 ft-lb. Even though the total torque is higher for the DOC control PDC bit when compared to the roller cone, the torque variation is similar. This change in torque is what causes tool face problems to occur when running motor steerable bits, especially when small diameter drill pipe is run with its associated pipe twist.

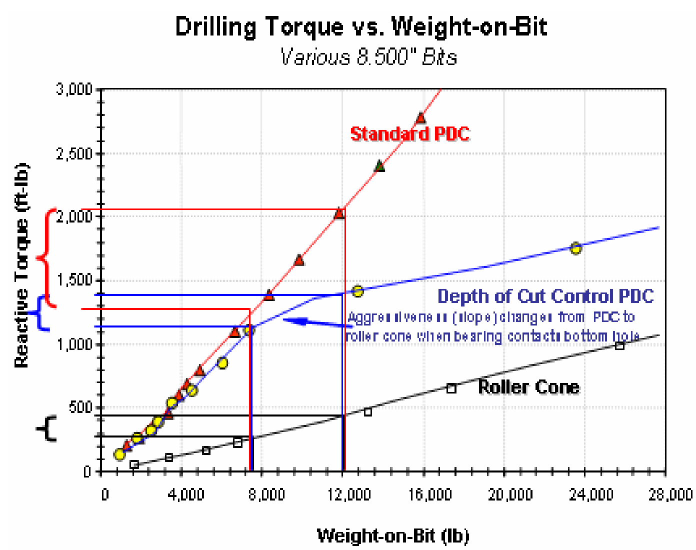

Fig. 8. Torque vs. Weight on Bit plot for 8-1/2" bits.

Once a target depth of cut is reached and the blades in the cone area begin to rub, bit stability is also improved. This controlled aggressiveness also helps reduce stick/slip vibrations in most applications including; motor steerable, rotary steerable and straight rotary drive systems.

Side Cutting Test

There have been numerous papers written on measuring the side cutting ability of bits and stabilizers. The drill bit company has also run many tests to measure the side cutting response of bits with various side loads for different sizes, gauge designs and rock types. A typical test setup is shown in **Fig. 9**. A side load is applied to a sliding bearing above the bit as it drills vertically. The lateral displacement measurement of the bit is for a given set of conditions and side load.

Fig. 9 – Side Cutting Test Setup

Fig. 10 shows a plot of side cutting angles versus side loads considering the same BHA configuration, same bit design and same lab test parameters. The plot shows that the side cutting angle is dependent on the formation hardness. Softer formations will require less side forces to achieve the same directional

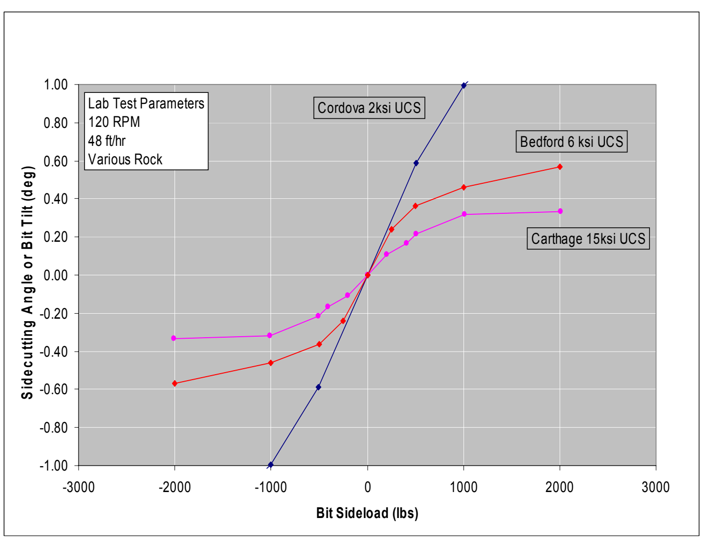

Fig. 10. Lab Test Results

changes. It is clear that for Cordova rock (UCS - 2 Kpsi) the slope is higher since it is the softest rock tested (i.e. easier to cut sideways).

Side Cutting Ability

One of the key issues when drilling with a push-the-bit rotary steerable system is the bit's side cutting ability. Push-the-bit rotary steerable systems apply a side load on a set of steering pads near the bit in the opposite direction they are intended to steer. Therefore, providing the required side cutting with the side forces available is a primary concern for "push-the-bit" RSS assemblies. However, the RSS tool requires a bit specifically designed for the application or one risks the bit becoming a vibration source that is detrimental to the electronic components and mechanical steering unit. Hole spiraling can also occur when highly aggressive side cutting bit designs are run with high side forces.[5] The key is to predict and provide the side cutting requirements of the bit for the system and application.

After a DART extensively analyzed the Albacora Leste application, they decided to specify a 2" gauge length with an active gauge feature in order to provide the required side cutting and associated BUR (Build Up Rate) for the RSS system. **Fig. 11** shows this aggressive gauge design. It incorporates PDC trimmers set above the gauge diameter and near the blade front. The aggressive gauge arrangement provides cutting elements to enable the necessary BUR requirements.

Fig. 11 - G12 gauge cutting feature

Case History Bits Selection

Four bit designs from three different bit vendors where used in this field study for comparison. Each bit is designed specifically for the RSS utilized in this field study. Before, this field study, the generally accepted practice considered that the main two characteristics for RSS applications where:

- should have aggressive cutter design to improve penetration rates, and

- lateral cutting ability and a short profile to improve dogleg severity.

Problems derived from torque generation did not appear to compromise RSS performance, as there was no need to control toolface as in conventional directional drilling sliding mode. Furthermore, modifying the bit body to allow more cutter exposure further increased bit aggressiveness. Local experience indicated that bit aggressiveness was often dramatically wasted if an unstable bit design produced undesired downhole vibration. The bit steerability is reduced by stick-slip and whirling vibrations as drilling energy becomes transformed into vibration energy.

Bit Type #1 – **Fig. 12,** this bit can be defined as a light set bit with short length. To improve stability and to give smoother torque, it incorporates spiral gauge design and back-rake angles are selected to minimize whirling. This PDC bit has 13mm cutters on face and gauge. Impregnated spherical cutters used in gauge for stabilization and gauge protection. Short taper, medium cone profile with 2.0 inch spiral gauge length and total face volume of 54.3in^3. Active gauge configuration is used to increase dogleg capability. This bit is the oldest design of the four, bit types in the study.

Fig. 12. 8-1/2" Bit type #1 for RSS study.

Bit Type #2 – Fig. 13, PDC bit composed of 16mm and 13mm cutters on the face. The gauge section and side action are composed of 13mm cutters. Short taper, shallow cone profile with 2.5in spiral gauge length and total face volume of 83in^3. Its high face volume is due to its blade's design, that sticks out of the body matrix leaving bit balance greatly dependant on cutting action. It also has a flat cone shape, thrusting to the gauges most of the lateral balancing action. This bit incorporates the first idea of the ideal bit for RSS: Aggressive design with improved side cutting capability. The bit stabilization is considered of secondary importance after drilling performance. However, due to vibration issues inherent to the type 2 bit, the vendor modified the bit design for RSS and is the type #3 below.

Fig. 13. 8-1/2" Bit type #2 for RSS study.

Bit Type #3 – **Fig. 14,** this bit is a redesign of bit type #2 but with some characteristics to reduce aggressiveness. This is also a PDC bit composed of 16mm and 13mm cutters on face but with increased back-rake configuration. Its profile is also a short taper, shallow cone with 2.5 inch spiral gauge length but with a face volume of 50.5in^3.

Fig. 14. 8-1/2" Bit type #3 for RSS study.

This bit has a slightly less aggressive design, with smaller face volume, higher back-rake on face cutters and different cutting structure layout for better stabilization. A special feature in its gauge allows better stabilization without eliminating the side cutting efficiency and coverage. Cutter layout is that every gauge section of each blade has a dual function of cutting and stabilizing.

Bit type 4 – **Fig . 15,** PDC bit composed of 16mm cutters on face and 13mm cutters on a straight blade gauge. Its profile is of a short taper, medium cone with 2.0 inch gauge length. This bit has a different design when compared to other bits developed for RSS applications. Its gauge is straight and with few side cutters. The stabilization on the gauge area is achieved by diamond-impregnated blades, which have a short length. This bit incorporates the depth-of-cut (DOC) control technology to manage reactive torque as described previously in the bit development section.

Fig. 15. 8-1/2" Bit type #4 for RSS study.

Performance Results

All the bit designs presented good drilling performance for the analyzed wells, **Fig. 16**. ROP ranged from 24 to 37 m/hr on bottom drilling performance.

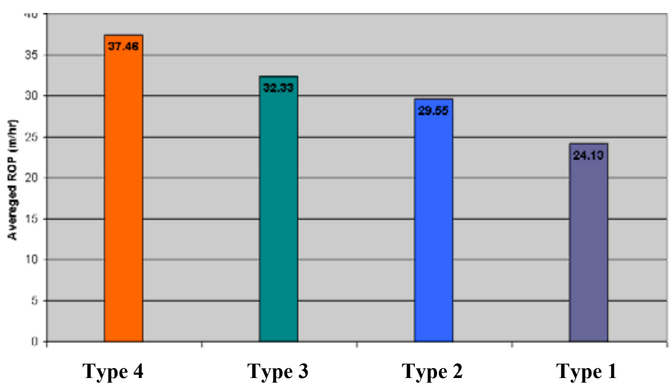

Fig. 16. Averaged penetration per bit types. (change labels and order of bits in chart to match bit types)

The type 4 design, with maximized stability design outperformed the other three designs. In addition, the less aggressive design of Type 3 outperformed its more aggressive type 2 predecessor design. This leads to a conclusion that bit aggressiveness and stability have to be understood. Bit aggressiveness alone does not guarantee improved drilling performance.

The best drilling performance is 55% better than the worst drilling performance. This is attributed to the fact that the type 1 bits have only 13mm size cutters. This bit had the slowest drilling performance through shales and shaly formations. For the Albacora Leste field in this study, it is reasonable to reduce daily drilling costs by 55% for the same RSS through the proper bit selection process. These cost savings will offset any differential in bit costs many times over to the operator and are additional savings beyond the penetration rate gains already realized with a rotary steerable system versus conventional steerable motors.

Steerability Results

The steerability measurement yields a very good idea of the ability of the RSS to steer in the desired direction when changing bit choice. As mentioned before, all the wells considered for the analyses are horizontal wells. Therefore, the achieved DLS is not to be interpreted as the maximum achievable DLS of the bit. It is more accurate to interpret as the mobility of the drilling system consisting of the RSS and the bit choice in each well.

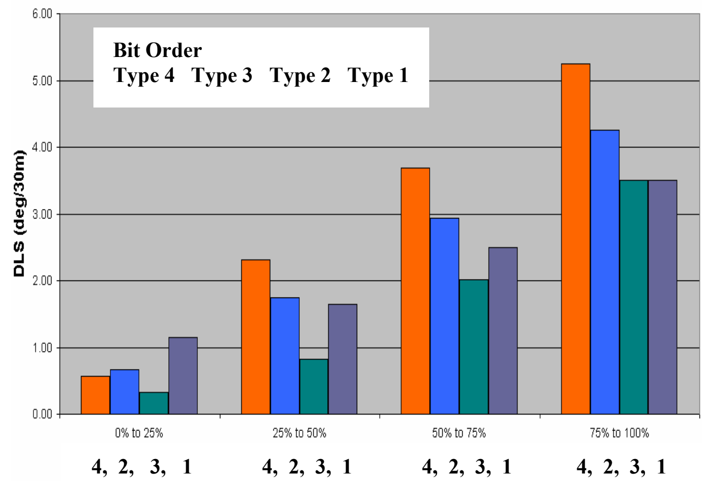

Fig. 17. Dogleg severity per RSS Setting per bit choice. The percentage of steering time is a direct function of the dogleg capability of the drilling system.

Fig. 17, bit type 4 that was, by conventional wisdom, apparently less aggressive on the side cutting features produced the best overall DLS performance. Additionally, bit type 3, which demonstrated a better ROP performance then its predecessor design type 2, is not able to provide the same DLS at lower tool settings. Also, note that the most aggressive side-cutting type 1 bit generates the best dogleg performance only at lower steering settings relative to the other bit designs. This indicates that bit steerability and dogleg generation are more than just a function of sidecutting and aggressive cutter design. Stability of the bit design has a large influence on the steerability of the bit design.

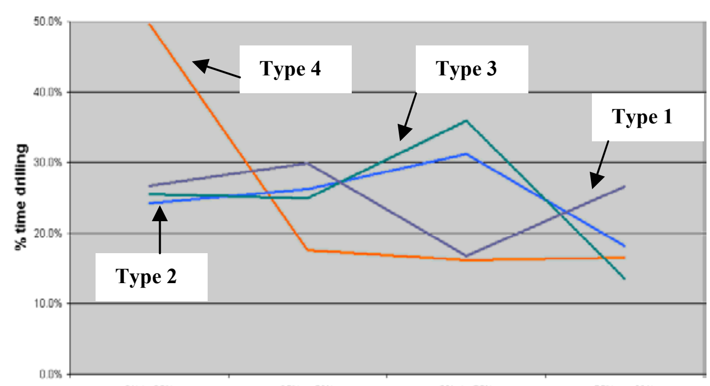

Fig. 18. Time percentage on drill setting per bit.

Another benefit of improved DLS, is the reduction in percentage of the time the RSS has to be biased, or in steering mode, to achieve the wellpath. Since the RSS is a mechanical tool, reducing the steering time, reduces the wear on the tool and improves the tool life in the well. For example, the difference in pad actuation, from neutral to steering mode, for the drillstring rotation speed of 100 rpm is 625% greater. This increased steering requirement leads to a reduction in seal life inside the pads of the RSS. **Fig. 18** shows how much bias setting was used in the analyzed wells for every bit studied. For percentage steering above 25%, the type 4 design reduces steering time requirements for the rotary steerable system (RSS) which agrees with the previous improvements in dogleg severity generation. The benefits to the RSS vendor are the cost of service reduction and the benefits to the customer are longer run times and reduced non-productive time due to tool failures.

ROP vs. DLS Plot

Another interesting way to interpret the results is to plot ROP vs. DLS in a Cartesian chart. This graph improves the evaluation of consistency of steerability performance by each bit design. The goal would be to have consistent bit performance in the upper right-most area of the chart, **Fig. 19**.

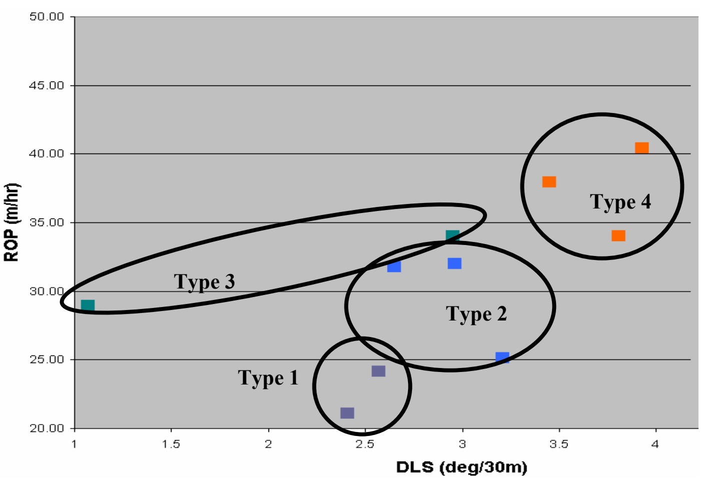

Fig. 19. Rate of penetration versus dogleg severity plot. Desired performance is the upper, right most portion of the plot.

The type 4 bit design presented the best drilling performance without compromising the drilling system steerability. All three wells plotted for bit type 4 fall within the same region of best ROP and DLS achievement. While the type 2 and type 3 bit designs are similar in response, they are basically centered in the plot, denoting an average performance and average DLS capability. However, the presence of a spread of the data points corresponds to its less predictable behavior due to its cutter aggressiveness. The type 1 bit is located lower on the plot, corresponding to the slowest penetration rates and less steerable performance overall. This bit design was the oldest design of the four types considered and suffered from bit balling in shale sections of the reservoir section. Newer hydraulic designs have since improved bit designs from this manufacturer.

Bit Stability Results

In order to evaluate the RSS/bit performance regarding the stability of the drilling system, drilling mechanics studies in conjunction with formation evaluation logs were performed. This improves interpretation of the BHA behavior while drilling through specific formations. Stick-slip vibrations are defined as the oscillation of the downhole BHA speed relative to the surface rotary speed. In the Stick-slip vibrations plots, **Figs. 20-22**, the severity classification are as follows:

- Peak to peak vibration < 50% RPM – Risk 0
- Peak to peak vibration <100% RPM – Risk 1
- Peak to peak vibration <150% RPM – Risk 2
- Peak to peak vibration >150% RPM – Risk 3.

Drillstring reliability and the ability of the rotary steerable to maintain constant steering modes are directly related to these vibrations. These vibration values were multiplied by ten to plot with the other drilling mechanics variables on similar scales. The Stick-slip and Rotary RPM values are listed on the left. All other values are listed on the right.

Stick-slip Vibration Plots

The following plots correlate the stick-slip variable transmitted in real-time to the different formations drilled by every specific bit. **Fig. 20** indicates the behavior of the drilling system when using the type 1 bit. It clearly shows that the BHA suffered stick-slip level 3 throughout most of the section, especially while drilling through shale and interbedded formations. The 13mm cutters perform poorly in shales and have a tendency of balling up. The system performed better while drilling through homogenous formation, but the stick-slip level is still undesired.

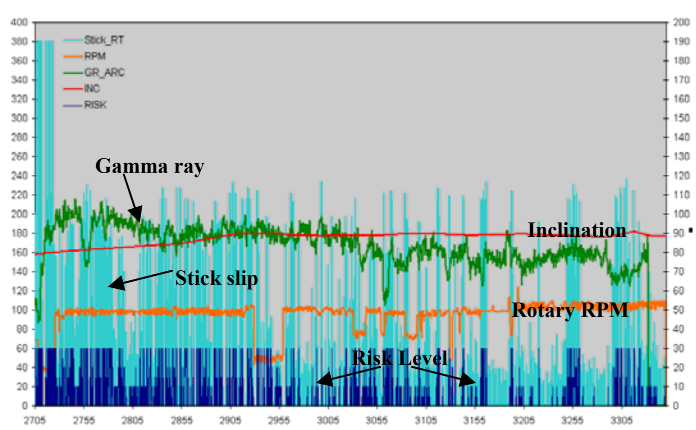

Fig. 20. Stick-slip vibration plot for bit type 1. Level 2 and 3 vibrations are undesirable for drillstring reliability and steering performance.

It is suspected that the aggressive configuration of the bit contributes to the stick-slip levels. The old conception of having aggressive side cutters can easily cause imbalance during drilling when crossing intercalated stringers such as the calcilutites and calcarenites encountered in Albacora Leste.

Fig. 21 is the vibration plot for the type 3 bit design. The stick-slip vibration level 3 for the majority of the well indicates the poor vibration characteristics of this bit design. The vibration problems with this revised version of the type 2 design, showed little or no improvement as a result of the design change.

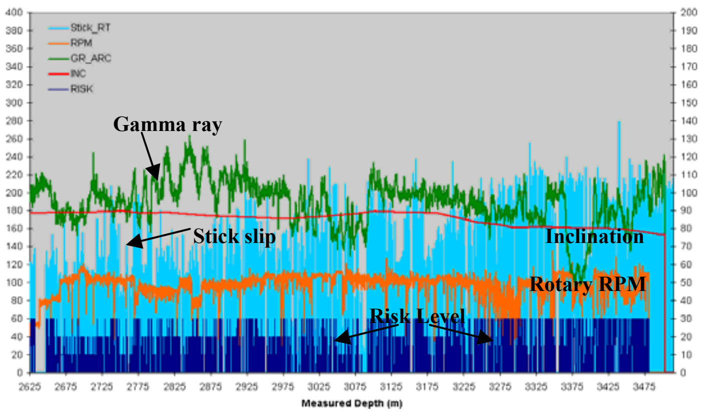

Fig. 21. Stick-slip vibration plot for bit type 3. Level 2 and 3 vibrations are undesirable for drillstring reliability and steering performance.

Under those drilling conditions, the BHA is submitted to extreme vibration that can lead to failure due to shocks as well as a reduction or loss of steering control by the rotary steerable system. Several reported cases of a RSS failure were later determined to be false when the drilling mechanics logs were analyzed. The RSS tool performed mechanically downhole but the steering direction was inconstant due to the stickslip variations downhole exceeding the tool's limits of 220 rpm. That is equivalent to the steering difficulty of conventional steering systems where it is hard to maintain the same toolface while drilling, leading to longer sliding requirements resulting in higher wellbore tortuosity.

Fig. 22 stick-slip vibrations plot displays the behavior of the drilling system combined with a type 4 bit type with depth-of-cut limiters. It is easy to verify that this bit generates much less stick-slip vibration than the previous mentioned bits. Although it still presents accentuated stick-slip in the shaly sands and intercalations, the severity is significantly improved. Note that the reduced stickslip vibration results in smoother surface rotary speeds.

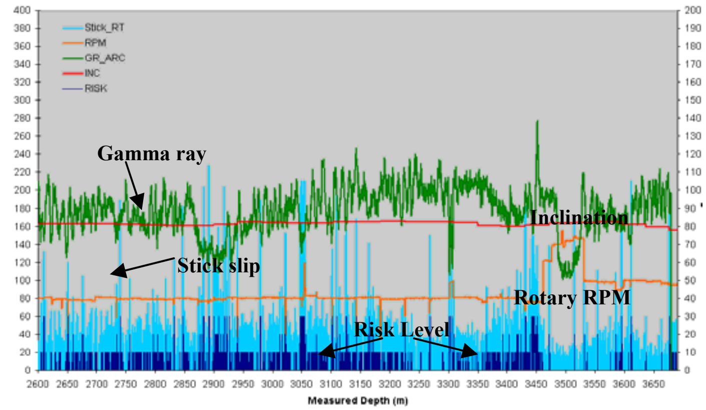

Fig. 22. Stick-slip vibration plot for bit type 4. Level 0 and 1 vibrations are manageable levels of shocks for improved drillstring reliability and steering performance.

This bit describes smoother drilling and generates much less vibration than the other three bit types. This bit has less aggressive side cutting action and is equipped with a few gauge protector cutters with high back-rake angles. The depth-of-cut technology allows the bit's blades to protrude on the back of the face cutters, especially in the cone area, thus absorbing the overload when drilling through intercalations where variable ROP and bit overload is experienced. That feature is interesting as it reduces the tendency of the bit cutters to penetrate too deeply in the formation causing excessive stick-slip vibrations.

While this bit is the least aggressive for sidecutting action, when compared to the other bits under analysis, it still presents better ROP and stability. When a bit generates too much vibration, a great portion of the drilling energy input to the system is dispersed in vibration and only part of the total input results in drilling ahead. This changes the conception that ROP improvements require an aggressive cutter design.

By analyzing these bit case histories and their actual output, it is obvious that aggressive side cutting designs do not necessarily equate to higher DLS or less steering requirements. Bit stability while drilling various formation types is a larger contributor to drilling system performance than normally considered.

Lateral Shock and ROP Consistency Plots

Another plot that was used to help understand the drilling mechanics events using the different bit types was the lateral shock / ROP plot. This plot utilizes drilling mechanics data acquired through the reservoir section of the selected wells from measurements while drilling (MWD) tools, **Fig. 23-25**.

This plot allows interpretation of the ROP changes in different formations and the correlation between shocks induced by formation changes and the bit selected. The Gamma Ray, Inclination, Shock Peaks and ROP values are all listed on the left vertical scale.

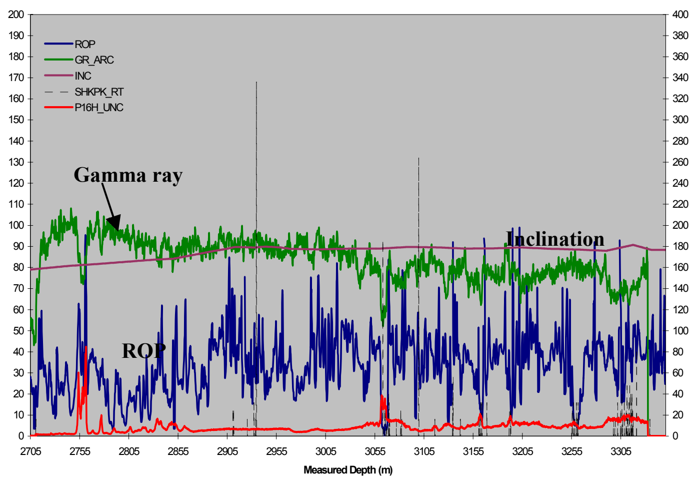

Fig. 23. Lateral shock and ROP plot for bit type #1. Indications of highly inconsistent penetration rates are undesirable. Lower levels for lateral shocks are desirable.

Fig. 23 is a typical example of bit performance for type 1 bits. From the plot, the bit ROP performance is lower in the shaly formations than in sandstone beds. Again, this is attributed to the 13mm cutting structure of this bit. Lateral shocks occurred while drilling through intercalated formations. That coincides with the increment of stick-slip, therefore vibration, while drilling through these intercalations.

Fig. 24 is a typical example of bit performance for type 2 bit designs. The drilling system drills very well through shale beds and shaly formation due to its aggressive cutter design. Yet, the ROP fluctuates quite a lot during the entire run as a function of formation changes. Generally drilling faster in more shaly formations and having lower ROP while drilling through the sandy reservoir section. Low levels of shocks were experienced during the run.

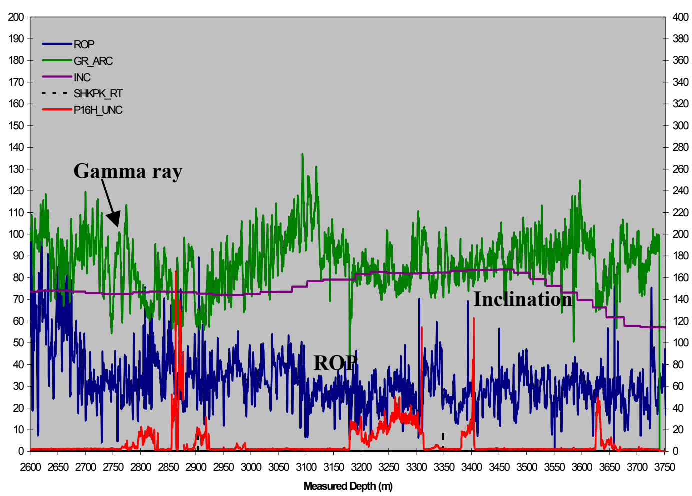

Fig. 24. Lateral shock and ROP plot for bit type #2. More consistent penetration rates are generally observed over type 1 bit designs. Very low levels for lateral shocks are highly desirable.

Fig. 25 is a typical example of bit type 4 performance in the 8 ½" horizontal section. This bit presents a smooth drilling pace, with good and steady ROP throughout the drilled interval. While some ROP reductions are observed while drilling through intercalations, no compromise of the overall performance of the system and no shocks were observed during the run.

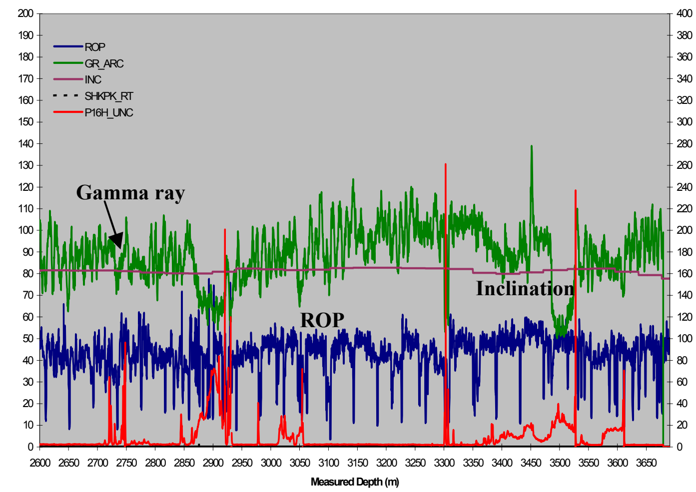

Fig. 25. Lateral shock and ROP plot for bit type #4 with depth of cut limiters. More consistent penetration rates are observed over all other bit designs. Very low lateral shocks are highly desirable.

Conclusions

1. Proper bit choice improves BHA and rotary steerable reliability by reducing bit induced vibration related failures. Reduced surface rotary speed variations and downhole shock levels are the result.

2. The steerability and dogleg generation by "push the bit" rotary steerable tools are affected by the bit's stability. Historically, bit stability was considered secondary in importance for RSS applications after cutter aggressivity and side-cutting ability.

3. Bit features such as chordal drop management, depth-of-cut control limiters and lateral movement mitigation improves the bit's ability to limit downhole vibrations by managing formation changes and drilling parameters.

4. Smoother and uniform boreholes improve the quality of logs as the pad-type logging tools have better borehole contact during the measurement.

5. The proper matching of the drilling system, RSS and bit, to the formations to be drilled, results in improved drilling, directional and BHA reliability performance that benefits the directional company, bit vendor and client. This design and selection process requires the sharing of data and open communication between all parties.

8 1/2" Bit Model	Performance (ROP) Highlights	Lowlights
BitType 1	Good performance while drilling through clean, more competent sands.	Very low performance drilling shaly sticky formating, balling up easily due to small cutter size. Due to bit generated BHA vibration, ROP is dissipated in shales.
Bit Type 2	Good performance due to its aggressive design. Very good ability to drill through shales.	Performance drops drastically when drilling through sands and carbonates due to amount of drilling energy being dissipated into vibration.
Bit Type 3	Good ability to drill through shales and sticky formations. Less aggressiveness from old bit version resulted on better energy transferring resulting in faster ROP (less stick-slip).	ROP highly dependant on formation. Lower performance observed while drilling through sandstone reservoir and stringers.
Bit Type 4	Good performance drilling through different formations resulting in a steady drilling pace. Surface drilling energy highly kept downhole.	Presents performance reduction tendency while drilling hard stringers. Difficulty on drilling through interbedded, competent formation.

Table 1. Bit drilling performance summary for the four bit types.

8 1/2" Bit Model	Steerability Highlights	Lowlights
Bit Type	Good DLS achievable in case needed due to its design. In low DLS wells can reduce BU seals wear (% setting) because of its DLS capability at low RSS settings.	Higher DLS only at high percentage settings, increasing BU wear. Low ROP on shales reduce DLS capability due to wellbore washout.
Bit Type	Its aggressive design helps on DLS achievement.	Bit aggressiveness DLS capability wasted when drilling sandstones and stringers due to erratic toolface and stick-slip related wellbore wash-out (pads support).
Bit Type	Its aggressive design helps on DLS achievement.	Tendency to drill at high percentage settings leading to excessive wear on BU seals. DLS reduced with reduced aggressiveness. Erratic toolface and wash-out contributing to DLS capability drop.
Bit Type	Good DLS ability at low settings. Tendency to drill at low RSS percentage settings. Low level of stick-slip contributes on DLS by keeping steady toolface, and ROP/stability result on higher DLS.	Reduced DLS at very low settings requiring aggressive changes to be done on higher settings, increasing BU wear.

Table 2. Bit steerability comparison summary.

8 1/2" Bit Model	Stability Highlights	Lowlights
BitType 1	Stable while drilling through consolidated sands, with low stick-slip level.	Generates high vibration level at shales, sticky, unconsolidated formation. Surface drilling energy (torque, RPM) dissipated into BHA vibration.
Bit Type 2	Long gauge design reduces hole spiraling tendency.	Very unstable with high levels of stick-slip, specially drilling through sands and stringers. Wellbore quality deterioration by bit vibration.
Bit Type 3	Long gauge design reduces hole spiraling tendency.	High stick-slip generation due to its aggressive design. Problem worsening while drilling through soft reservoir sands. Wellbore quality deterioration by bit vibration.
Bit Type 4	Very good stability on soft and hard formations due to its EZsteer design. Problems easily corrected through drilling practices showing good bit versatility.	Low drilling performance on hard stringers tends to create instability on thin intercalated formations.

Table 3. Bit stability comparison summary.

Comparison charts based on performance, steerability and stability accurately summarize the case history analysis presentation in this paper. **Fig. 26,** to visually rate each bit analysis, a three-axis plot was developed where each axis would represent the three properties investigated. Stability, Steerability and Performance were plotted together for every bit. The scale from 1 to 4 is the relative position that the bit achieved in the current analysis. Today, the type 2 bit design is banned from Brazil RSS operations, by the RSS company, because of its induced shock failure history.

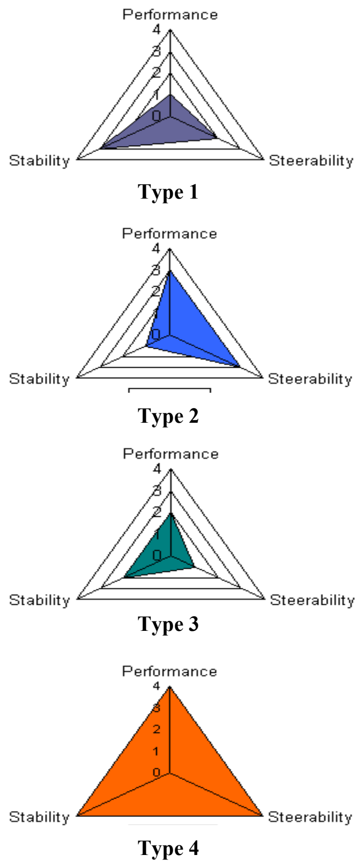

Fig. 26. Rotary steerable performance versus bit rating for each type bit design.

Acknowledgements

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Nomenclature

BHA = *bottomhole assembly*
BOP = *blowout preventer*
BUR = *buildup rate, (degrees/30m)*
CFD = *computational fluid dynamics*
DLS = *dogleg severity (degrees/30m)*
DOC = *depth of cut*
ECD = *equivalent circulation density*
EMW = *equivalent mud weight*
LWD = *logging while drilling*
MWD = *measurements while drilling*
MTBF = *mean time between failures (hours)*
OD = *outside diameter, inches*
PDC = *polycrystalline diamond cutter*
RKB = *rig floor kelly bushing elevation*
ROP = *drilling rate of penetration, meters per hour*
RPM = *revolutions per minute*
RSS = *rotary steerable systems*
TD = *total depth*
TVD = *true vertical depth*
WOB = *weight on bit*

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SI Metric Conversion Factors

m x 3.280 840 E+00 = ft
m^3 x 3.785 412 E+03 = USgal