Where Do We Go From Here?

In September 2008 Hart’s E&P hosted a roundtable in conjunction with the 2008 Society of Petroleum Engineers Annual Technical Conference and Exhibition. The discussion provided an insightful glimpse of the future for rotary steerable systems.

A panel of industry experts convened in Denver, Colo., to discuss rotary steerable systems (RSS) and their role in future well construction. Participants included (in alphabetical order) Guillermo Capacho, Halliburton, Sperry Drilling Services; John Dick, Baker Hughes INTEQ; Mike Pfister, PathFinder division of Smith International; and Mike Williams, Schlumberger Drilling & Measurements.

**F&P:** What are the top three technical, application, environmental, or market challenges and/or frontiers facing rotary steerable systems?

**Williams:** We have to stop looking at individual tool reliability and start looking at system reliability. How far we can go with reliability is one of our biggest challenges, and we can go a long way to improve it. Are we going to reach positive displacement motor reliability? Probably not, but I believe we can get reasonably close.

Secondly, we must address ways to make RSS more cost-effective. For me this means how much faster can we drill? We also hear from our clients that they’d like to see low-cost RSS. Several companies have tried to make a low-cost system by taking functionality out. To be honest, the market that would be addressed by such a system has higher specification than some of the traditional high-tier markets. So we really have to look at finding a more cost-effective way to add more functionality or reduce cost without reducing functionality — and that’s not going to be easy. Lastly is dogleg capability; not just the highest number we can get but consistency in dogleg capability. A whole new world opens up if we can produce higher doglegs, consistently, stand after stand after stand.

**Pfister:** We face the challenge of addressing a broader spectrum of the market. The deepwater and offshore markets were prevalent when RSS were first introduced, but now we’re getting into land markets. The North American rig count is overwhelmingly land. So the challenge is not only building low-cost tools but to build tools that can adapt to the land drilling environment. By and large, a majority of land rigs do not have the horsepower or capability that even the early-generation offshore rigs had when RSS were first introduced. We need tools that can perform at lower fluid flow rates and lower rig horsepower in order to adapt to the land market.

In addition, besides the cost of the tool system, we must also consider the repair and maintenance time required to turn the tools around. We need to find ways to simplify the systems so they can compete in the land market. As for the emerging markets, the new shale plays, like the Haynesville and Marcellus, are going to turn out to be a huge market for RSS.

**Capacho:** Those points are very valid, but I’d like to elaborate on the issue of reliability. There is a trend that we’re tracking. It has two components — people and environment. Every day, the RSS are asked to tackle...
deeper, hotter challenges, and we have to develop the technology to handle that. But we also have to keep the basics right, and this means training and best practices. Industry statistics show that more than 70% of the people have less than two years experience. These are the crews that are going to have to face these challenging wells. To address this, we need to focus on training, and developing remote controls. We need to make maximum use of real-time remote operations centers to concentrate our expertise.

A second challenge is the cost of material and technology. Today’s growing economies are taking a lot of material out of the market and driving up the price. The final challenge is getting more value into the equation. We are developing more economical tools, but the trick is differentiating the commodity from the technology — the advanced technology that adds greater value.

Dick: My colleagues have covered the most important points, but we’re always going to hear the low-cost argument. If it’s half the present cost, there will still be those who want more for less. In time, we think those people will see the value they get from the proper application of the technology and will shift their focus from the tool price to its effect on their total operational costs. Well construction is becoming more complicated as operators strive to develop tighter targets and improve recoverability. Removing tool functionality is regressive. We need to find ways to improve efficiency while making a strong effort to reduce our costs without removing functionality.

Also, performing operations from remote centers is one way to get costs down, both for the service company and the operator. The advantages are clear. Less HSE [health, safety and environment], less need for experienced people at the rig site, more concentration of expertise, faster decision time, and reduced drilling risk — these are indirect ways we can reduce operating costs and show value.

E&P: Are complementary technologies, such as bit design, drilling fluids, logging while drilling/measurement while drilling (LWD/MWD) measurements, real-time telemetry, and drillstring design leading or limiting the exploitation of RSS solutions? If so, what hurdles remain to be overcome?
Dick: It depends. Things like higher-speed telemetry will have a positive effect. With more relevant data, remote centers, faster decisions and feedback, not having to slow down to downlink — these will enable us to get to total depth more quickly. In general, we must always focus on the total system, taking a holistic approach,

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Modeling software helps optimize BHA design

In today’s digital oilfield environment, each component of the bottomhole assembly (BHA) including the drillbit can be modeled, tested, and optimized before ever being manufactured. Utilization of this methodology is especially beneficial in the rotary steerable market, where mismatched tools can cause vibration and can be detrimental to performance and to electronic components.

Varel drillbit designers have moved into this digital environment using bridgeable technologies that have the capability to analyze specific rock mechanics, BHA configuration characteristics, and energies required for the planned well profile and then are able to model and optimize the drillbit to meet application requirements.

Previous drillbit optimization methods focused mainly on cutting structure configuration utilizing a constant BHA model. However, with rotary steerable system applications, drillbit designers are required to examine conditions that may affect stability, bit steerability, and hole quality. In addition, it is imperative to take into account the effect of the side forces on the gauge needed to create a required well path, thus matching the specific bit properties to a specific drive.

Each application is scrutinized to develop precise algorithm-based cutting structure and gauge configurations. This transition of viewing each component of the system as a variable, rather than a constant, is an evolution in drillbit design.

Field runs indicate that the latest evolution in optimization is creating a significant value for operators. In one extended-reach application for a major operator in the Middle East, a six-bladed rotary steerable bit was optimized for a specific drive system. The matched system completed a record run of more than 5,300 ft, reaching total depth and saving the operator an estimated six days off the AFE. The operator attributed this success to proper planning and selection of tools.

Contributed by Varel International
because each component of the drilling job can affect the ultimate outcome.

**Pfister:** The general answer to the question is each component plays a role in making RSS work, particularly on the bit side. Early in the game, we realized just how critical the bit is in getting the rotary steerable to function properly, and I know that the support we’ve been getting from the bit manufacturers has been excellent. We have a better understanding of the harmonics downhole and the role and the effect each component has in the final result.

One area where we’re lacking is on the drilling fluids side. If you look at the integration of drilling fluids and how they work in well construction it’s not where it needs to be. The hurdles that remain are largely in improving the way we work together. The bit companies, the fluids companies, the drilling contractors, and the drilling service companies all need to be focused on the same goal. For example, to adapt to the land market we’re running motor-assisted systems because we can’t get the horsepower we need from the rig. This puts more stress on the rig hydraulics, so all of these things need to come together so we can expand the business to where its advantages can be realized by everyone across the board.

**Williams:** I agree. The rig itself is one of the biggest limits we see today. Such things as solids control must be addressed, for example. Already, we can create more cuttings faster than many rig shakers can handle. It’s a considerable problem. I’d estimate that on 20% to 30% of our jobs, we’re forced to control our penetration rates to accommodate solids control limitations. This impediment intensifies as you try to penetrate the lower end of the rig market — the land business — where many rigs simply cannot keep up.

**Capacho:** I believe that complementary technologies are vital. We cannot focus only on RSS; we have to see the entire system. Look-ahead capacity will play a critical role. We’re not talking about the wells we drill today; we’re talking about the deeper, hotter, tougher wells we’ll be asked to drill tomorrow. The uncertainties are growing.

**Certified directional PDC bits efficiently achieve well objectives, improve performance, and reduce risk**

The historical approach to designing and marketing directional PDC bits has been to incorporate a set of features into a particular design and promote them as essential for improving directional performance. This created a perception that each type of rotary steerable system or steerable motor bottomhole assembly (BHA) required its own precise bit design with a highly specialized set of directional features.

Smith Bits has taken a unique approach to solving the expanding directional application challenge by developing its Integrated Dynamic Engineering Analysis System (IDEAS). IDEAS is a time-based 4-D modeling tool that accurately predicts a drilling system’s performance and behavior using finite element analysis and laboratory-derived drilling mechanics data that accurately characterizes the attributes of the total drilling system. The comprehensive analytical capability and field-proven accuracy of the IDEAS process have enabled Smith Bits to take a novel approach to designing bits for directional applications. Instead of offering a “directional line” of PDC bits with specialized directional features, Smith Bits uses the IDEAS process to evaluate individual directional applications and recommend the best bit for the specific situation.

IDEAS bit designs are developed and performance is confirmed using the same highly sophisticated simulation process to accurately model the total directional drilling system, including all BHA components. Because of the truly dynamic nature of the simulation model and the holistic approach of incorporating all system elements into the analysis, PDC bits can now be certified as being dynamically stable and directionally responsive across a range of demanding directional applications. Additionally, with IDEAS, all the different types of rotary steerable systems can be accurately modeled individually.

IDEAS has been used to analyze conventional directional bit designs and confirmed that in many cases the range of special directional features previously incorporated into the design served as only as a “crutch” that allowed a basically unstable bit to drill acceptably in a specific directional application. However, when the unbalanced design was used with a slightly altered BHA or in a different application, its unstable character caused performance issues requiring a new or significantly modified bit to again compensate for the design’s inherent instability.

IDEAS has changed the industry’s perception by proving a single PDC bit design can provide exceptional performance when used with different types of directional drilling systems provided it’s engineered to remain dynamically stable.

In multiple North Sea applications, Smith’s 12 ¼-in. MD616 successfully met the operators’ directional and drilling performance objectives on three different rotary steerable systems/PDM. This achievement confirms IDEAS modeling accuracy in developing a bit capable of delivering superior performance across a wide range of drive systems and directional requirements.
As an example, to improve bit design, we need to be able to look ahead to understand the conditions, and this means more sensors at the bit to better describe the drilling environment. This, in turn, will require improved telemetry to get the relevant information to surface in a timely way. We will have to improve our ability to not only capture the data but to be able to use it intelligently to improve our operational and engineering decisions. We have to use the information effectively to improve reliability. Total depth as soon as possible is what we all want, but to get there, you have to see the entire system.

**Williams:** While we’re talking about telemetry, in my view the critical capability is not in getting data uphole so much as it is the ability to efficiently downlink. My son talks about James Bond and his ability to drill down through the bottom of a boat using a remote drill system and some sort of joystick control, but with the increased need to control the bottomhole assembly and increases in telemetry rates from surface to bit these kinds of ideas may not be so far-fetched.

**F&P:** What will be the impact of wired drillpipe on rotary steerable drilling?

**Dick:** I think right now, we’re drowning in data. Unless we can use the data we’re receiving in an operational time frame, it’s not going to help us improve well construction efficiency. We really need to address the wired drillpipe issue in its entirety. It has the ability to change the way we do our business, but we need to learn how to handle the data and turn it into useful information. Perhaps we should hire some MicroSoft people who can look at the problem from a different perspective to help us address this issue. I have spoken with a drillpipe representative who told me there are about 4,500 rigs working worldwide today but only four strings of wired drillpipe. We’re getting data from downhole now. The data we need immediately we get through telemetry; the rest is recorded in memory for later analysis. The first company that figures out how to effectively use all that data in real time will have a huge competitive advantage, but we’re not there yet.

**Capacho:** The potential is there, but we will require more commitment from the users. High-speed, high-bandwidth telemetry is a cultural change. The speed is there, but there are gaps in the technology when it comes to using it effectively. For instance, I don’t think the reliability is there yet. There are so many pieces that can fail; there is the cost of the drillpipe. There are many potential problems, and the cost of trying to figure them out is a major factor.

**Williams:** Part of the problem is this: When I look at the amount of data we send with mud pulse today, and the rate is still climbing, we’re already at the point with some clients that there is too much. When I ask, “What are you going to send when you get wired drillpipe?” I’m told “seismic,” because that’s the stock answer, but after that it becomes much more vague because really we don’t know. Wired
Front-end engineering optimizes bit design for rotary steerable drilling

With the introduction of new Direction by Design software, Security DBS Drill Bits, a product service line of Halliburton, provides the first technical and scientific tool that quantifies the effects of even slight design changes on the ability of a bit to drill a deviated well — before the bit is built.

In a front-end approach to design engineering, Security DBS applies accumulated knowledge through a proven bit design platform that provides the ability to “model, measure, and optimize” a design before the bit is ever run. Part of this Drilling by Design service platform, Direction by Design software provides advanced bit design engineering to optimize directional performance for the specific drilling system used.

Where previous kinematics models represented bit motion by axial penetration rate, rotational speed, and lateral penetration rate or side cutting, the software meshes specific bit design features and formation characteristics in three dimensions, and simultaneously uses bit rotation, axial penetration, tilting motion, and formation properties to simulate the bit/formation interaction.

In terms of directional bit design, this enables designers to predict side force required, walk force, and speed in azimuth direction for a specific bit design in a given drilling application. In addition, bit torque variance during directional drilling is calculated to account for different bit behaviors during kick-off, build, and hold drilling modes.

The software’s new cutter/rock interaction model enables directional drill bits to be designed with optimum bit walk characteristics for drilling a specific wellbore profile with a specific drilling system. As a result, PDC bit designs can be optimized and sent to the field with directional performance attributes already known before the bit is ever run in hole.

Contributed by Security DBS Drill Bits/Halliburton
data that ordinarily would be too much for a human to assimilate in real time.

**F&P: How does rotary steerable drilling technology impact completion options?**

**Capacho:** As you drill deeper and deeper, torque and drag factor into the ability to complete the well. We address this with hole quality. The controls over hole enlargement, over doglegs, are going to be very important. If people continue trying to drill with motors, extended sections especially are going to be affected by lack of directional control.

**Williams:** I agree. People argue about the relative merits of push-the-bit or point-the-bit. The real truth is all rotary steerable systems give better hole quality than motors. The differences between each rotary steerable system are tiny compared to the differences between RSS and motors. One point I’d make is that most RSS drill gauge holes, or close to it, and most motors don’t. So there have actually been some people who have had more problems getting casing down when the hole has been drilled with a rotary steerable system, just because it is gauge rather than vastly over gauge. So you have to look at it from the perspective of understanding what you get with rotary steerable systems. The hole quality is infinitely better but it is gauge.

When considering extended reach wells, the critical factor is how you control your micro-doglegs at the top of the hole, because these will have the greatest effect on your ability to get the completion all the way to the bottom of the hole. For example, in most extended-reach wells, the key enabling factor in reaching TD is how we control the doglegs at the top of the hole. Once we got down to the pay zone, we are typically geosteering anyway to stay within the pay and higher tortuosity here has much less of an effect on the ability to reach TD. The ability of RSS to drill high-quality top holes, of 26-in. and 30-in. diameter, is therefore going to become more prevalent going forward.

**Pfister:** Hole quality is a key factor. Earlier in my career, I worked for a different company and we used the in-gauge hole attribute to attack RSS. We said, “If you use RSS, you’ll have trouble getting your liners to TD.” Nowadays, I don’t say that anymore. I agree with Mike and Guillermo.

**Dick:** The rotary steerable system enables the well to be placed in the reservoir’s “sweet spot” to maximize completion effectiveness. Over the life of the reservoir, this is a major factor that determines the well’s profitability.

**Williams:** Yes. Where you perforate and where you fracture is a significant component of the well’s ultimate profitability. The ability to place the well in the optimum spot is the deciding factor governing the effectiveness of subsequent completion and stimulation steps.

**Capacho:** Yes, at the end of the day, it’s about production, it’s not about making hole. More and more, we’re seeing the ability to run hole enlargement tools under-reamers or bicenter bits with RSS helps with the completion installation.

**F&P: What future do you foresee for RSS? Where do we go from here?**

**Pfister:** Guillermo touched on a point earlier I’d like to address, and that is rig site supervision. We’re so lacking in competent personnel to be able to keep up with the demand. So I think we’re going to see RSS that are simpler to operate. Just like computers have become a useful tool for everyone, we’re going to see more remote operations centers to allow more effective use of our experienced personnel. The second thing is that we’re going to see a lot more sensors in the RSS. We’re going to have the ability to compress more data and get it uphole more efficiently to enhance our ability to manage drilling operations.

We’re going to record more and more data at the bit and that’s going to affect the design of tomorrow’s RSS.

**Capacho:** My experience is whoever is using RSS today finds it very hard to go back. I predict massive growth of the RSS market. We’re going to see more remote control, more sensors, alarms, and alerts. In addition, the screens will be easier to understand and use. At my company we’re trying to reduce the input of the human factor. We’re addressing developments to provide better precision. These include adding gyro capacity and ranging technology.

**Williams:** I agree, and to take it one step farther: We’re going to see the ability to enter a whole well plan into the RSS and let the tool drill the well, with intervention only to address unforeseen occurrences, and even these will be minimized through the use of better downhole sensors. But the biggest challenge will be to proliferate RSS technology throughout the industry and to convince the masses of land operators to see the value of RSS. To do this will require improved technology and better answers. I don’t think that improving drilling efficiency alone will do. As we all said at the outset, it must be a total approach. We are experiencing 40% to 50% annual growth rates so far, but that will stop if we don’t make improvements that add value and make RSS easier to run and maintain.