Innovative, application-specific drill bit designs prove value, help operators set drilling records

By Jerry Greenberg, contributing editor

A WELL IS successful as a result of a drill bit with the correct configuration and hydraulic performance for the particular application. Designing the wrong elements can lead to low penetration rates, inefficient hydraulics for hole cleaning, and wellbores that may not reach the operator’s objective.

It is not entirely the responsibility of the bit designer to come up with the optimal bit design for the application. Rather, it is a collaborative effort between the bit company and operator. Armed with as much data as possible about the lithology from offset wells and rock strength data, the bit designer utilizes software (mostly proprietary) to design the bit for the application.

“Different bit vendors have different approaches when it comes to being willing to customize designs for a specific application, and even how they go about doing that,” said Mark Dykstra, senior staff well engineer for Shell. “Some have very formal application review process where they review the well from top to bottom, talk about each hole section, the expected challenges, rock trends, and work with them to come up with what they would propose as appropriate technologies considering directional requirements, hole quality concerns, hole cleaning concerns and, obviously, ROP goals.

“Other companies are a little less formal in their approach.”

Either way, Mr Dykstra noted, the role of the operator is to set up the challenge.

Each bit company has their own design, not only software and tools but also philosophies. “Based on my experience, some of them have a different understanding of what drives performance in a given application,” Mr Dykstra said.

“At the end of the day, performance is what talks, so all of the bells and whistles and fancy pictures the vendors can show you are nice, but ultimately the performance that is delivered in the field is what makes the difference.

“Our goal is to drill as many top-performing wells as we possibly can,” he continued. “It is paramount that we are delivering the lowest cost per barrel didn’t go into the details of trying to provide what the operator wanted. “They didn’t put forth as much effort (as the other companies) to try to use their (bit) design.”

Being open to trying new bits is reason for the company’s success in the Barnett in terms of continually increasing ROP.

“A bit company may come to us and say the last bit we ran did this and this and now we can get higher ROP,” Mr Rose said. “We wouldn’t be reluctant to try a new bit, but the decision would be from a combination of our engineers, superintendents and supervisors.

“Engineering addresses the problems we encounter, and they also are talking with the bit companies, but first hand is our supervisor on location,” he continued. “That’s where a decision can be made because they are the people actually running the bit. But engineering has a lot to do with the decision.”

“If they all thought it would benefit us to try a new design, it probably would be implemented on the next program or next well,” he said. “If Chesapeake sees the possible advantage, we’ve never been reluctant to try something that might enhance the drilling operation.”

Following is a review of several of the latest bit designs.

HEDGEHOG BIT FOR INTERBEDDED FORMATIONS

Hughes Christensen’s new HedgeHog bit features an aggressive, balling-resistant cutting structure, optimized hydraulics and advanced matrix material for drilling in interbedded formations. The bit’s interrupted cutting structure allows shale to flow between the posts to enable cutting elements to drill more efficiently. Its post-over-blade design adds 25% more diamond volume than same-size standard impregnated bits, resulting in significantly extended bit life.

Additionally, overlapped posts are staggered to increase drilling efficiency and eliminate an uncut bottom.

The bit’s unique ported design directs impact force at areas where balling occurs, maximizing hydraulic energy to the hole bottom and bit face. Deep junk
slots enhance ROP by optimizing cutting evacuation and limiting hole swabbing during trips.

Three new diamond matrix types include matrices for predominantly non-abrasive formations, interbedded formation drilling and abrasive formations. Configuration flexibility allows for a choice of three cone styles: most aggressive, aggressive and durable, and most durable.

The company recently set a record in Venezuela with a 12 ½-in. HH35G079Y impregnated bit run in west Venezuela field. This also was the longest 12 ¼-in. three runs, the longest footage for this impregnated bit by drilling 1,955 ft in three runs, the longest footage for this field. This also was the longest 12 ½-in. impregnated bit run in west Venezuela and saved the operator $169,350.

The HedgeHog bit replaced nine PDC and TCI bits during this first successful impregnated run in the field. The bit was dull graded 5-7-WF-A-X-1-NO-PR, indicating the abrasiveness of the Misoa formation. It comprises hard shale and abrasive sandstone and siltstone stringers with uncompressive strength values ranging from 6 kpsi to 23 kpsi, leading to slow drilling and rapid bit wear. The impregnated technology ran on turbine with significantly low WOB and high RPM, especially in abrasive intervals. The bit showed very good ROP response to low WOB and high RPM. The design eliminated nine trips required by the two offsets.

On the first run, the BHA had to be pulled out of the hole to change the turbine. After inspecting the bit, the drilling team decided to drill the remaining section to TD despite the advanced wear on the shoulder area. On the second run, the BHA had to be pulled because of a top-drive problem. Finally, on the last run, the BHA had to be pulled for high torque with the applied WOB, which affected the ROP.

Despite not drilling to TD, the drilling performance and dull condition of the bit proved the operator chose the right technology with the correct parameters. The operator continued to drill this well using a TCI bit because of a formation change.

INDEXES-BASED TOOLS

Subtle differences between bit designs, not apparent to the eye, can lead to significant changes in bit performance. NOV ReedHycalog says that the key to selecting the right bit is modeling bit performance according to four fundamental indexes:

- Rate of penetration – how fast the bit will drill for a given weight on bit;
- Stability – how resistant the bit is to lateral vibration;
- Durability – how resistant the bit is to abrasive wear;
- Steerability – how responsive the bit is to applied RSS side forces.

ReedHycalog embarked on mathematical modeling of bit performance 15 years ago, verifying the models in the laboratory and the field. In 2007, the INDEX application optimization system was released, enabling users to prioritize the four indexes according to the application, the drive system and directional requirements. The model then enables bit selection optimized for specific application requirements.

The software incorporates logic regarding tool operation and trajectory requirements and assesses each drill bit based on its steerability index, bit length, profile and gauge geometry.

In one case, two visually similar six-bladed, 13-mm cutter bits were compared in a rotary steerable application in the Middle East. Design 1 performed well but suffered from occasional vibration damage. Lateral stability and sidecutting capability were required to match the RSS. The indexes-based selection tool recommended Design 2.

On the first run, the bit drilled 4,473 ft in 71 hrs for an average ROP of 63 ft/hr compared with an average ROP of 47 ft/hr for Design 1. Design 2 drilled the interval in a single run, achieving all directional and performance objectives: a maximum dogleg of over 67°/100 ft was achieved with no lateral shocks observed and a 75% reduction in stick-slip. The run was longer, and significantly faster, than the average offsets.

The company also has re-engineered its RockForce bit, for slim-hole applications. The bearing system uses advanced machining and lubrication technologies, among others.

A field study of 149 6 ¼-in. 537 type bits in Oklahoma on directional and rotary applications showed R30A RockForce bits delivered a superior seal effective rate, 94% compared with 85% for the next best, and superior KRev reliability, 800 KRev life versus 528 KRev for the next best.

Another field study of 46 4 ¾-in. 517 bits in South Texas in directional motor applications at 200-plus RPM showed that R22A RockForce inserts delivered 79% more average hours and 80% more average KRevs than the next best.

GEO-PILOT BITS

Halliburton’s Security DBS line of Geo-Pilot bits was designed for Sperry Drilling Services’ point-the-bit rotary steerable systems. Its extended gauge matches the requirement of the RSS to provide optimal steerability, low vibration and hole quality. The bit uses Security DBS’ FM3000 bit design platform for precise characterization of the cutter rock interface.

Drilling by Design services use patented proprietary software to match bits to the drilling system and formation. A suite of software tools is used to predict rock strength and geology from well logs and create 3D bit designs.

The Direction by Design software provides bit design engineering to optimize directional performance for the specific drilling system used. The software determines the effects of bit geometry parameters on steerability and bit walk rate, and calculates bit torque variance.

NOV ReedHycalog’s RockForce bearing system features advanced machining techniques and lubrication technology for better performance.
DRILLING CONTRACTOR

Drill Bits

during directional drilling to account for different behaviors during kick-off, build and hold drilling modes.

For a MWD, LWD and directional drilling contract with BGTT in Trinidad, Security DBS used its design tools, in combination with Sperry Applied Drilling Technology services, and recommended a program of Geo-Pilot extended-gauge PDC bits. The bits were designed for 16-in., 12 1/4-in. and 8 1/2-in. hole sizes with the extended-gauge configurations to eliminate hole spiraling and minimize wellbore tortuosity while maximizing ROP and directional control. The bits also incorporated proprietary Z3 cutters that, according to the company, offer 20 times the abrasion resistance of industry-standard cutters.

The 16-in. FMF3663Z bit drilled 3,101 ft in 50.7 hrs in the well, completing the tophole section at an average ROP of 61 ft/hr. In the 12 1/4-in. section, the FMF3653Z bit drilled 4,635 ft at a record 102.5 ft/hr, after which the 8 1/2-in. FMF3653Z bit drilled 1,352 ft at 57.5 ft/hr to TD the well at 11,850 ft.

Horizontal Drilling Records

A company established in Canada in fall 2008 offers PDC drill bits to operators exploring in the western Canadian market. Shear Bits has set several records while working with major E&P companies in this market, including ConocoPhillips, Petro-Canada, EOG and Devon. The company has expansion plans in the US as well.

All of the company’s bits are designed with a multi-tiered approach toward hydraulic optimization. All waterways and junk slots are contoured to minimize dead spots in the flowfield, all nozzles are interchangeable, junk slots are oversized and most designs include multiple nozzles per blade layouts. The company’s proprietary tertiary gauge technology ensures durability through three-point diamond coverage.

In addition to having three PDC cutters per blade, each pad is formed from tungsten carbide for additional wear resistance. The final PDC cutter of the tertiary gauge package is positioned to allow the bit to effectively backream through tight spots.

The company’s design technology is not simulation-driven but application driven, according to Tim Beaton, one of the company’s owners. “When one observes the spectrum of different drilling fluids, borehole pressures, temperatures, BHA components, and, most importantly, formation changes, and the amount of variables that are in constant flux, it can clearly be seen that computer simulations can only do so much.”

Having said that, Mr Beaton notes that there are analytical tools that can help a design engineer produce a successful drill bit. The company’s design system is built around a 3D model of each bit, which includes proprietary cutter positioning algorithms. The focus is on understanding the geometric interaction between the PDC cutters and the rock.

“Rather than attempting to predict the performance of the bit while drilling,” he explained, “we focus on creating design geometry that has been engineered to produce the desired performance result. The most important step in (our) design process comes after the preliminary design has been completed and the initial bits have been tested.”

At this point in the process, a detailed review of the condition of the dulls is performed. That information is used to drive the development of the next bit to be run in the application. “As new PDC cutters are developed and new geometries are created,” Mr Beaton said, “the bit design technology is modified to match the variables to the target application, thus the company’s application-driven technology. Each portion of the development cycle is focused on the downhole performance of the bit, and not on a computer simulation.”

The company has four PDC bit lines, each with specific technology to maximize performance in a given application. The vertical series bits have an advanced cutting structure for high ROP with less WOB than conventional designs. Each bit is designed to maximize ROP potential by maximizing the depth of cut that the bit can achieve without blade rubbing.

The directional series provides consistent toolface control without sacrificing ROP potential with bits that are steerable when sliding and fast when rotating. The bit profile design is a proprietary geometry that equates to a very short overall length while maintaining excellent diamond volume on the shoulder of the bit.

By adding additional rows of PDC cutters on each blade, the multi-row series bit designs can be tailored to provide the characteristics to perform in complex intervals.

The horizontal series bits are fitted with specialized gauge pads to maximize circumferential borehole contact while maintaining a short overall length. The targeted PDC cutting structure drills ahead without aggressive side cutting, limiting dropping tendency. “We currently do not know of any other drill bit company that has developed a line of drill bits to specifically target horizontal applications,” Mr Beaton said. “All other companies use bits developed for directional applications to drill horizontal sections.

“This approach is functional,” he continued, “but any time a bit is designed to drill in two different types of applications, the drilling performance of the bit is always compromised in at least one, and most frequently, in both of the applications. To date, half of the record runs that we have had with our drill bits have been in horizontal applications.”

In one such well in Canada, the company was able to significantly increase ROP in a section of the well that typically experienced low ROP but was drilled in one bit run. Shear Bits used its 6 1/4-in.
SH513 and 6 ¼-in. SH513D PDC drill bits, the latter featuring a double row of cutters. The application in question is a 600m-700m horizontal leg in the Swan Hills field in Alberta through a formation of the same name.

The formation is predominantly dolomite with compressive strength in the range of 15-20 kpsi. The section has historically been drilled with bits designed for generic directional work, resulting in relatively low ROP. While the section is typically drilled in one run, the best ROP recorded in the area was 12 m/hr. After analyzing the application and due to a short time line, the company developed two horizontal series designs simultaneously so it could test both concepts quickly.

The run with the 6 ¼-in. SH513 drilled 644 m in 31.3 hrs for an ROP of 20.6 m/hr, a 166% increase compared with the fastest offset run. The 6 ¼-in. SH513D drilled a longer leg, 689 m, and still managed an ROP of 19.7 m/hr, much faster than the next-best offset run.

Both bits came out with only minor wear to the cutting structure (dulls graded 0.2 and 1.2 respectively).

OUTLAW BITS

Smith Bits’ Outlaw PDC bit, optimized through its proprietary IDEAS bit design and simulation process, set numerous
Anadarko Basin drilling records in the tough carbonate, shale and sandstone formations typically found in the region.

The 7 7/8-in. Mi616 six-blade bit features 26 face cutters and six gauge cutters to balance durability for longer bit runs and aggressiveness for faster ROP. Three standard series 60N nozzles are positioned to effectively clean the hole. The bit also features an 8.88-sq-in. junk slot area.

In 2008, the bit set six drilling records in the Anadarko Basin for footage drilled and ROP. In one application, XTO Energy’s Corwin B 5-29 well in Major County, Okla., was drilled with an Mi616MNSPX bit, achieving an ROP of 92 ft/hr, the highest of five offset wells.

In another record well, Kingfisher Resources’ Branham Trust 1-34 well in Dewey County set a footage record of 9,590 ft for a 7 7/8-in. drill-out PDC bit. The footage record was 27% farther than the best offset run, achieving an ROP of 51 ft/hr, the highest of five offset wells.

In the Ghawar field in Saudi Arabia, a 16-in. Shamal Typhoon six-nozzle bit drilled 2,344 ft of hole, setting a field record ROP of 90.15 ft/hr, 54.6% better than the five-well offset average of 58.32 ft/hr. Another record was set with the well when the bit finished the hole section at a per foot cost of $31, compared with $41/ft for the five-well offset average. A hole section drilled in the field earlier with a 16-in. Shamal Typhoon held the previous record with an ROP of 76.19 ft/hr and a per foot cost of $33.

Smith’s latest roller cone drill bit, Shamal Typhoon, was developed for the challenges of the Middle East’s larger-diameter drilling applications. The design incorporates the traditional Shamal features along with a new “Typhoon” hydraulics configuration for more effective cleaning of large-diameter holes. The IDEAS software ensures that Shamal Typhoon’s hydraulics, insert geometries and the latest carbide technology are integrated to achieve optimal performance.

The bit uses computational fluid dynamics (CFD) analysis techniques to evaluate fluid flow and ensure that flow is optimized to clean the cones, remove cuttings more efficiently and ensure that the cutting structure is always drilling virgin formation. The Typhoon hydraulics configuration is currently available for bits with ODs of 16 in. and larger. It uses three vector extended (VE) and three dome jet (J3) nozzles to provide the optimum hydraulic solution for the specific application.

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This study included three competitor products, one standard Shamal bit and two Shamal Typhoon bits. The 16-in. Shamal Typhoon bit set the record in rotary drilling mode from the Wasia formation to mid-Thamama in one run (shoe-to-shoe).

BITS FOR UBD

In February 2009, Varel International debuted its A-Force roller cone bits, a line of sealed journal bearing jet air
Varel International’s new A-Force line of roller cone bits is designed and built specifically for underbalanced applications. The bits include material improvements such as a new grease formulation that is stable at increased operating temperatures. A more wear-resistant hardmetal inlay was incorporated onto the journal surface of the bits. The series also uses redesigned head forgings, resulting in a drill bit with increased speed, longevity and steerability.

All A-Force bits include an updated sealed journal bearing system designed with new technology that improves management of bearing heat for use with high drilling loads. The bits incorporate the company’s patented high energy tumbled (HET) processed carbide inserts and are equipped with cutting structures and carbide grades specific to underbalanced applications.

The bits include a heat shield disc deployed between the seal and the inner bearing that acts as a thermal insulator to protect the seal from excessive thermal energy, lowering the operating temperature for the seal and extending seal life. The bits also are equipped with a conical seal gland that positions the seal in such a way that it can better handle pressure fluctuations and still maintain a preferred sealing location and interface.

This is especially important with the high internal bearing pressures that can be experienced in air, foam and mist drilling. The A-Force series bits also incorporate a more robust and tightly tolerated journal bearing capable of supporting increased levels of weight on bit.

In one directional application in Canadian County, Okla., an operator needed to drill through a shale section while maintaining a high rate of penetration. Based on local offsets and lithologies, Varel recommended using an 8 ¾-in. VM613PG Navigator bit for the section. The bit successfully drilled to the planned TD of 17,400 ft after which the operator continued to drill ahead for 500 ft while building a 10° horizontal bend and an 8° vertical bend.

The bit met all objectives, drilling a total of 4,676 ft in 206 hrs with an average ROP of 22.7 ft/hr. This performance saved the operator an additional run and trip.

In an application in the Barnett Shale, a major operator challenged Varel to provide a drill bit where stability was a major issue. The company recommended a six-bladed 7 ¾-in. VM619H Navigator PDC bit for the application. The bit successfully drilled 4,531 ft to reach a TD of 9,885 ft in 45.25 hrs with a ROP of 100.13 ft/hr. The operator realized a saving of almost a full day of rig time, about $50,000 for this area.