Improved design processes allow bits to fit specific applications, set new drilling records

By Jerry Greenberg, contributing editor

DESIGNING A DRILL bit with the correct configuration and hydraulic performance for a specific application has everything to do with a well’s success. A wrong bit for the application can result in low rate of penetration (ROP), inefficient hole cleaning and expensive wells that sometimes won’t reach the operator’s geological objectives.

Today, bit companies use the latest software to model the bit based on lithology from offset wells and from lab tests on rock strength. Once data is input into the software, virtual wells can be drilled, using the resulting data to tweak the design and create the optimum bit for the specific application.

Since the introduction of rotary steerable systems (RSS), the industry appears to be divided regarding PDC bits and RSS. Varel International believes that each RSS requires a matching bit. Smith Technologies believes that the same bit can be used on either a push- or point-the-bit system. Both companies have produced bit designs for RSS that have resulted in highly efficient results. Following is a review of bit designs available in the industry.

HUGHES CHRISTENSEN

Hughes Christensen’s Quan tec premium PDC bit is produced with a new design process, newer abrasion-resistant cutters and bit designs matched to specific projects. Results include higher average ROP and greater stability and durability to reduce drilling costs. The bit’s diamond volume management (DVM) design also increases mechanical and hydraulic efficiency.

The company says its patented SmoothCut depth-of-cut control technology enables smoother, more stable drilling, resulting in reduced premature cutter wear, particularly through embedded formations. The bit integrates load-balancing cutting structures with chordal drop management and the company’s Lateral Movement Mitigator to reduce bit vibration and increase resistance to whirl. Thermally stable polycrystalline inserts provide maximum gauge-holding in the most abrasive drilling environments, according to the company.

Computational fluid dynamics (CFD) results in optimized bit hydraulics for maximum cuttings removal. CFD also optimizes the balance of fluid flow, cutter cooling and erosion resistance.

Case studies

Interbedded sandstones and shales, very high mud weights and overburden pressures led to high confining pressures in a Pinedale, Wyo., antiplane slimhole interval. Operators had been using five-bladed PDC bits from various bit companies for drilling at the bottom of S-type wells. One operator chose 6-in. Quan tec Q405 and Q505 bits, which drilled the slimhole interval 72 hr faster than the average offsets. This 35% reduction in drilling time resulted in $114,000 savings on a single well. Because the operator drills one well per month here, this meant nearly a $1.4 million saving over a year per rig.

An interval in the highly abrasive and hard sandstone Travis Peak formation in East Texas was typically drilled with 2-3 bits (six blade with backups) to drill out and proceed 600-900 ft into the formation, and one or two seven-blade bits to complete the Travis Peak interval. ROPs in the formation are significantly lower than higher intervals. The 8 ¾-in. Quan tec Q505HXX bit replaced 2-3 bits by drilling out and completing the Travis Peak interval at an ROP better than any of the offsets to that point.

The Travis Peak formation run typically begins at the top of the formation and becomes progressively more difficult to drill. Average footage drilled is about 1,400 ft. At that point, the bit dulls enough to slow ROP below an acceptable level, and a second bit is necessary to complete the formation. An 8 ¼-in. Quan tec Q507HX bit drilled the entire Travis Peak interval and into the Travis Peak/Cotton Valley transition zone, resulting in a 36% increase in footage with a 26% improvement in ROP.

Drilling a vertical hole in the production interval in the Uintah Basin in Utah encountered highly interbedded sandstones and shales with a broad range of rock strengths (5-25 ksi). This section of the 7 ⅞-in. production interval generally required 140 hr or more to complete, sometimes requiring 2-3 bits to reach TD. A Q506 bit drilled the interval in 106 hr, saving the operator 36 hr of rig time, a 25% reduction in time spent in the interval that translated into a savings of $38,500 on rig time per well.

REEDHYCALOG

ReedHycalog’s DuraDiamond diamond-impregnated bits are designed for hard and abrasive formations and those formations, such as chert, that cannot be sheared by PDC cutters. The bits will drill faster and farther, according to the company, than the most heavily set fixed cutter bits in those formations when used with downhole turbines or high-speed positive displacement motors (PDM).

The company provides a series of the DuraDiamond bits that incorporate advanced materials technology, hydraulics and performance-enhancing features. Surface-set diamond bits are manufactured in a single layer of natural diamonds set into a hard matrix on the bit’s working faces. With impregnated
Drill Bits

ReedHycalog’s DuraDiamond diamond-impregnated PDC bits are designed for hard and abrasive formations that cannot be sheared by PDC cutters. In Oman, the 8 ¾-in. DuraDiamond bit set five consecutive single-run footage world records during the past two years, according to the company.

As planned and then continued into the Barik formation. The bit drilled a total of 1,755 m in 318 rotating hr at an average ROP of 5.52 m/hr, setting a world record for an 8 3/8-in. impregnated bit, according to ReedHycalog. Previous runs in include:

- 1,678 m in 284.5 hr for a 5.9 m/hr average ROP on the SR-268 well.
- 1,779 m in 407 hr for a 4.37 m/hr average ROP in the SR-281 well;
- 1,885 m in the SR-286 well.

In the last well, the bit drilled the 9 5/8-in. casing shoe at a depth of 3,051 m and was pulled for a BOP test at 4,936 m after drilling 1,885 m in 415 hr for an average ROP of 4.54 m/hr. The bit drilled the planned formations through the Mabrouk, then continued through the Barik and into the Al Bashair formation. When the bit was pulled, only 389 m remained to be drilled in the section, allowing it to be drilled with only two bits rather than the typical three bits.

SMITH TECHNOLOGIES

Since the introduction of RSS, many have believed that different types of RSS – whether point- or push-the-bit – required its own bit design with specialized directional drilling features. However, Smith Technologies believes its IDEAS (Integrated Dynamic Engineering Analysis System) software has proven that the same bit can be run on many RSS in the same application. IDEAS was developed as a method of analyzing application-specific bit designs before they are run in the well.

For example, Smith’s 12 ¾-in. MDi616 bit was designed utilizing IDEAS software and run in the North Sea on three different rotary steerable systems as well as a directional mud motor, for a total of 37 runs during 2007 and 2008. “For this particular design, we ran on the order of 500 simulations,” said Chuck Muren, Smith vice president of engineering. “We take cutters that will be used on this bit and cut rock with them in a confined environment as the basis of understanding the bit-rock interaction.

“We model the entire drillstring from the bit to the drilling rig,” he continued, “and run simulated wells until we achieve the operator’s goals. The result is a custom design for the application.”

Well simulations with the MDi616 PDC bit for North Sea applications resulted in a stable and steerable bit that is compatible with many RSS and directional motors for many 12 ¼-in. North Sea intervals, according to the company. The bit’s versatility and durability allow it to drill in a variety of formations such as claystone and sandstone sequences, interbedded sand and limestone/chalk. Applying IDEAS to the design resulted in a 6-blade, 16-mm cutter design with
50 cutters and a steerable profile with a graduated back rake distribution. CFD resulted in improved hydraulics for cutting structure cooling and cleaning, as well as improved hole cleaning.

**Case studies**

The 37 North Sea runs included five on Schlumberger’s PowerDrive Xtra/X5 push-the-bit RSS, 22 on Baker Hughes INTEQ’s AutoTrak push-the-bit RSS, five on PathFinder’s PathMaker 3D point-the-bit RSS and five on PathFinder mud motors. The key to all of these runs is that the performance was achieved with the same bit design.

On the AutoTrak RSS, one well’s objective was to build hole inclination from 34° to 67°, and maintain azimuth between 351° and 7.51° through the target formation and to TD. The MDi616 averaged an ROP of 114 ft/hr, easily achieving the required dogleg section (DLS) of 3.57°/100 ft with minimal stick-slip and vibration and minimal torque fluctuation through the various formations. In another well, the bit achieved an average ROP of 113 ft/hr and met the DLS of 4.08°/100 ft.

With a well drilled with Schlumberger’s RSS, the goal was to build angle from 7°-10° to 90° through the objective. The same section was drilled twice, with the second run a sidetrack from the main wellbore. The bit was able to achieve more than 80 ft/hr to drill a cumulative total of 9,574 ft. The bit maintained directional control and resulted in a DLS of 3.8°/100 ft in the main wellbore and 4.25°/100 ft in the sidetrack.

The goal of another run, drilled with the PathFinder RSS, was to drill the entire 12 ¼-in. section in one bit run while building inclination from 23° to 36° and turning from 228° azimuth to 137° while maintaining a constant DLS of 2.7°/100 ft. The 1,804 ft section was drilled at an average ROP of more than 50 ft/hr, achieving the desired well path objectives and experiencing minimal stick-slip vibration and torque. The bit also showed excellent dull condition after drilling through a variety of formations.

In one other well, using a PathFinder motor, the goal was to maintain a vertical well profile while drilling through salt and shale formations to achieve TD in one bit run. The result was 2,985 ft drilled at an average ROP of more than 56 ft/hr, a 25% improvement in ROP compared with offset bit runs. Well verticality was maintained as required.

**SECURITY DBS DRILL BITS**

With the advances in PDC technology over the last few years, PDC bits are displacing roller cones in applications that were once thought to be drillable only by roller cones. A prime example is Henry Petroleum’s “Wolfberry” play in Ector, Upton and Midland counties in West Texas. At one point, these wells require 2-3 TCI bits (IADCs ranging from 527 to 617) to complete the production segment of the well.

Henry Petroleum and its drilling contractors have utilized PDC technology more often over the last 4-5 years to realize better drilling performance. The operator worked with Halliburton’s Security DBS Drill Bits to design a drilling program that has reduced the average drill time from 24 days to 14 days. A significant portion of this reduction can be credited to PDC technology.

Advances in PDC technology are attributed to improvements in cutter technology, enhanced bit body capabilities and improvements in the design process. Through this evolution, Security DBS has improved upon these areas and as a result has been able to reduce abrasion and erosion and improve durability.
Improvements in Security DBS cutter technology have resulted in a more abrasion-resistant and impact-resistant cutter. As mentioned, the bit body is also evolving and improving. The company uses CFD to improve bit hydraulics to reduce erosion and extend the life of the bit body. Its bit design capabilities are also improving by utilizing the DatCI (Design at the customer interface) design program, a 3D modeling software that allows engineers to design bits while interacting with a customer in his office if needed.

Henry Petroleum was drilling in West Texas in 2003 and heard about another operator’s success with Security DBS PDCs. The companies worked together and made the Wolfberry wells a research and development area.

Case studies

In 2003, Henry Petroleum’s Wolfberry well consisted of a 17 ¾-in. roller cone on surface to 400 ft, an 11-in. roller cone (IADC 537) to 4,800 ft, and 2-3 7 ¾-in. roller cones (IADC 527 to 617) to 10,300 ft. The well took 24 days to drill.

In 2004, the operator eliminated the three-string well and went to a two-string well, or a “Mud Well.” They began drilling surface with a 12 ¼-in. roller cone to 500 ft, then drilled with an 8 ¼-in. FM3755Z to 7,800 ft, and a 7 7/8-in. roller cone (IADC 547) to 10,300 ft. These wells were taking an average of 21 days.

In late 2005 to early 2006, Security DBS’ new 8 ¾-in. PDC, the FMH3753Z was run and increased footage drilled in the section from 7,800 ft to 8,800 ft. A 7 ½-in. roller cone (IADC 547) drilled to TD at 10,300 ft. These wells were taking an average of 19 days to drill.

In 2007, the 8 ¾-in. FMH3753Z with super premium cutters was introduced, once again increasing the footage drilled from 8,800 ft to 9,200 ft. This bit would occasionally TD the well, eliminating the need for a 7 ¾-in. bit. When the 8 ¾-in. FMH3753Z did not finish the well, a 7 ¾-in. roller cone (IADC547) was used to drill to 10,300 ft. The average time to drill these wells was 16.5 days.

Currently, Henry Petroleum is drilling a well in an average of 14 days. Not only is the 8 ¾-in. section being drilled with a PDC, the 7 ¾-in. section also is being drilled with the 7 ¾-in. FM3755Z with super premium cutters.

“By utilizing PDCs, we are shaving off eight days per well,” said Michael Rhoads, Henry Petroleum operations superintendent. “We are drilling more efficiently now than we were when we started. With eight days at $20,000 per day, we are saving about $160,000 per well.”

VAREL INTERNATIONAL

Varel’s Navigator series of bits are engineered for directional wells and custom-designed for a specific directional profile for a given application. The company’s philosophy on directional PDC bits is that the bit is the most important factor affecting directional drilling success and that each bit must be designed to match the rotary steerable system, the well’s directional goals and the formations to be drilled. A bit’s ability to achieve the wellbore objective relies on steerability and directional behavior.

Varel’s R&D engineers take into account the type of RSS and each system’s power and drilling characteristics. The design process also utilizes GeoScience, SPOT and CFD. GeoScience is Varel’s mechanical rock properties model. Information from GeoScience is fed into SPOT, its design software allowing for accurate model bit dynamics. Using single cutter tests and full-scale bit tests in the lab and field, SPOT ensures cutting structure optimization for specific applications. The CFD program examines the nozzle orientation for optimum bit and hole bottom cleaning.

For a point-the-bit RSS, the bit’s gauge length affects and influences the bit’s performance when it is in a hold or directional mode. The gauge is designed to have less torque and minimizes the potential for stick/slip issues when in the directional mode. In the hold mode, the gauge design complements the RSS by resulting in better wellbore quality and higher ROP, the company says.

In a push-the-bit RSS, additional matrix material in the shape of an O-ring is placed directly behind specific cutters to further enhance the directional capabilities of the bit. The additional material helps manage the torque generated by the RSS while maintaining orientation for increased ROP and reduced sliding.

“As a result of pairing the bit to the drilling system, Varel was able to achieve record runs for our customer,” said Bruno Cuillier, Varel Eastern Hemisphere PDC product manager. “It is imperative to success that we design a bit to the drilling system.

During the process,” he continued, “we identify as a first step the pertinent performance criteria which are going to drive all of the design characteristics. After our GeoScience study, the cutting structure is designed. We then simulate drilling in our SPOT software to ensure that the bit has been designed to meet the drilling objectives for ROP, durability, stability and steerability.”

Case studies

In one application, the company designed an 8 ½-in. VRT619GX bit to run on Schlumberger’s Vortex RSS in a well in Saudi Arabia. The bit entered at 5,524 ft with an incline of 20°. The bit drilled 3,621 ft to complete the section at 86° in 56.5 hr. The operator reported that this was a 44% increase in ROP compared with competitive runs in the same field.

Another run for the same operator utilizing the same RSS and bit type resulted in the best ROP for the field. The bit drilled 3,635 ft with an ROP of 58.63 ft/hr. Competitive runs in the same field were averaging ROPs around 40 ft/hr.