

On the Cutting Edge

Improved materials and innovative designs are expanding applications for all types of rotary bits and modifying how they are used to drill wells. Operators and drilling contractors are taking full advantage of the latest bit technologies and new techniques to construct more cost-effective wells.

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Drilling through subsurface strata to find hydrocarbons requires a bit run on drillpipe or coiled tubing and rotated by surface rig equipment or downhole motors and turbines. Selecting the best bit for a particular application is one of the challenges faced by oil companies and drilling contractors when planning a well.

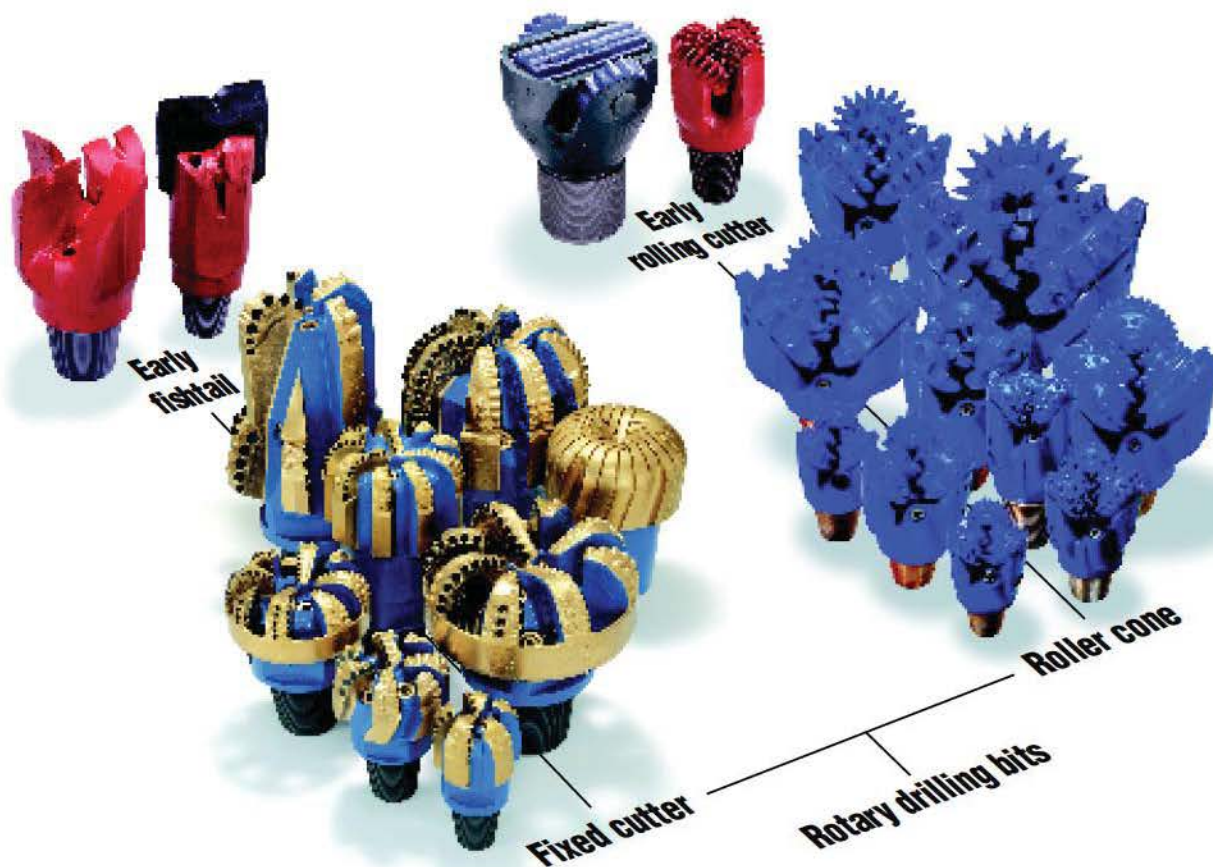
A basic tool of drilling engineers, the rotary bit—broadly classified as either fixed cutter or roller cone—is designed and manufactured for different formations and a wide range of conditions. Those who purchase and use bits must understand the differences between various types and designs ([next page](#)).

Fixed-cutter, or drag, bits have integral blades that turn together. Steel-blade drag bits, also called fishtail bits because of their characteristic shapes, date back to rotary drilling before 1900 and cut soft formations like plows making furrows in soil. Modern fixed-cutter bits with surface diamonds also plow formations; bits with diamonds suspended in matrix blades grind rocks; and those with man-made polycrystalline diamond compact (PDC) cutters shear like a lathe.

Roller-cone bits have metal cones that rotate independently as a bit turns on bottom. Each cone has cutting structures—hard-faced steel teeth or tungsten-carbide inserts—that wedge and crush, or gouge and tear like chisels or shovels, depending on formation hardness. Roller-cone bits led to deeper drilling and are often referred to as rock bits because they could drill harder formations than early drag bits.

Drilling bits constitute just a fraction—one to five percent—of total well costs, but are a critical component of well-construction economics. The time required to drill a well is related directly to how fast bits drill and how long they last before becoming dull. On a cost-per-foot basis, investing in the right bit significantly reduces cost by decreasing drilling time and the number of trips in and out of a well. For shallow land-rig operations, less expensive standard rock bits might be appropriate. Even though they cost more, advanced roller-cone or PDC bits with a better rate of penetration (ROP) and longer life may be the most economic choice offshore and in deep wells where rig rates and trip cost to replace bits are high. Regardless of the application, the purchase price of optimized bits is returned many times over.

The first roller-cone bit with three cones was patented by Howard Hughes in 1909. C. E. Reed developed rock bits with replaceable twin disks and four rolling cutters in 1916 and 1917. These first stages in the evolution of bits extended rotary drilling beyond the depth and durability limits of steel-blade bits. Since then, developments have alternated between cone-bearing and cutting-structure improvements. These advances include intermeshing cones with harder metals welded on steel teeth, antifriction roller bearings with roller balls to hold—retain—cones in place, tungsten-carbide inserts, self-lubricating sealed roller bearings and friction journal bearings.



This trend continues today with new bearing and seal designs, better cone-retention systems, improved cemented carbides and diamond-composite edges with higher wear resistance that offer superior performance and reliability, especially in problematic hard formations, and high-speed drilling with downhole motors or turbines. Combining individual elements and advances into bit solutions for specific applications improves drilling performance and extends bit life by increasing the load-carrying capacity and durability of roller-cone bits.

Fixed-cutter bits have also evolved beyond early fishtail and drag designs, driven by integration of natural diamond and synthetic PDC composites as cutting edges. Fixed-cutter bits have no moving parts, only cutting surfaces to wear out, and can drill fast for long periods in some applications. Natural diamonds were first used in about 1910 for specialized coring bits that cut doughnut-shaped holes and retrieved concentric columns of rock, or core, in special sleeves or tubes for formation evaluation. Full-hole diamond bits were introduced in the early 1920s. Based on General Electric technology that allowed synthetic diamonds to be bonded on tungsten carbide, the first PDC bits became commercial in the early 1970s.

Developments in fixed-cutter bits are a result of improved materials and manufacturing coupled with better understanding of bit stability and fluid dynamics. Advanced cutting structures and designs minimize unstable downhole motion, or vibrations, to allow faster, more aggressive drilling. Cutting elements are also matched to specific formations or drilling conditions. A new generation of PDC bits has evolved to meet complex directional-drilling demands, and enhanced diamond-impregnated bits are finding new applications.

Bit hydraulic and cutting-structure advances yield better designs for both roller-cone and fixed-cutter bits. Full-scale testing and computer modeling improve our understanding of relationships between fluid flow, bit cleaning and cuttings removal to further enhance drilling-bit performance. Computational fluid dynamics (CFD) computer simulations, like those used to develop automobile, aircraft and marine-vessel shapes, allow designers to optimize roller-cone and fixed-cutter hydraulics for higher ROP.

Advanced design software now correlates lithology and rock strength with various bit types to help operators choose an appropriate bit.

Expanded databases record and track drilling performance and results to aid in roller-cone or fixed-cutter bit selection and provide a basis for continued improvements and future developments.

As design and manufacturing improve, traditional boundaries between roller-cone and fixed-cutter bits blur. Research and development results in better reliability, advanced composite designs, improved hydraulics and greater stability across all bit types. While this provides drillers with more capabilities, it also makes the complex job of bit selection more challenging.

Drilling bits and new downhole tools in combination with service-provider expertise save operators time and money. This article reviews roller-cone, fixed-cutter PDC and diamond bits, and the latest advances, including a full range of designs, materials and manufacturing methods that significantly improve drilling performance and help drillers customize bits for each formation or application. Research, testing and developments in bit hydraulics, gathering data downhole at the bit, bit optimization and case studies about specific drilling solutions are also discussed.

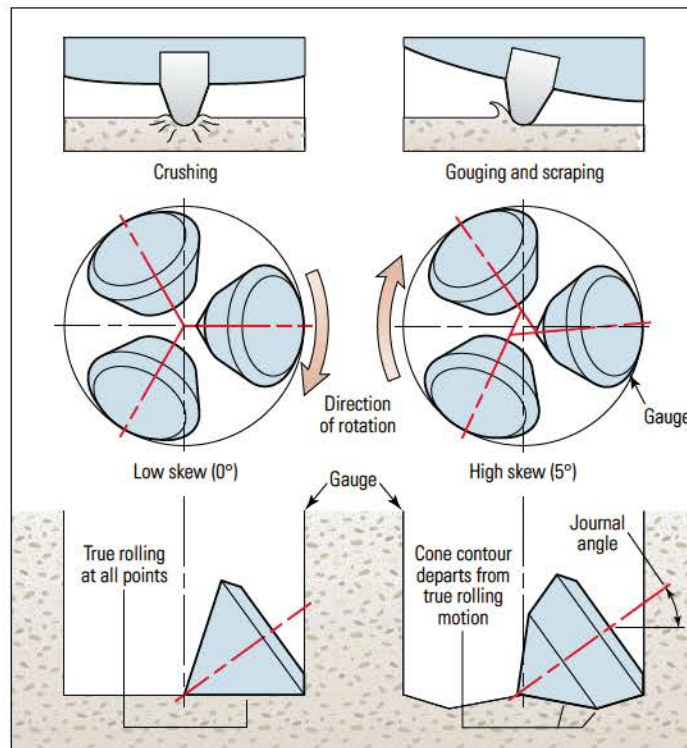
Roller-Cone Technology

In the 1800s, drilling with cable-tool rigs and percussion bits was slow and limited to shallow depths. Fishtail bits and rotary rigs with continuous circulation to remove cuttings were improvements, but steel-blade bits worked best in soft formations and even then wore out quickly. Cutting structures on cones that rotate independently to roll across the bottom of a hole as the bit turns caught on quickly in the 1900s. These bits lasted longer and could drill deeper. However, the first bits with rolling cones lacked durability and reliability—pins and screws held early versions together—but were superior to blade bits. Simple bearings with steel bushings, or liners, were used to reduce friction.

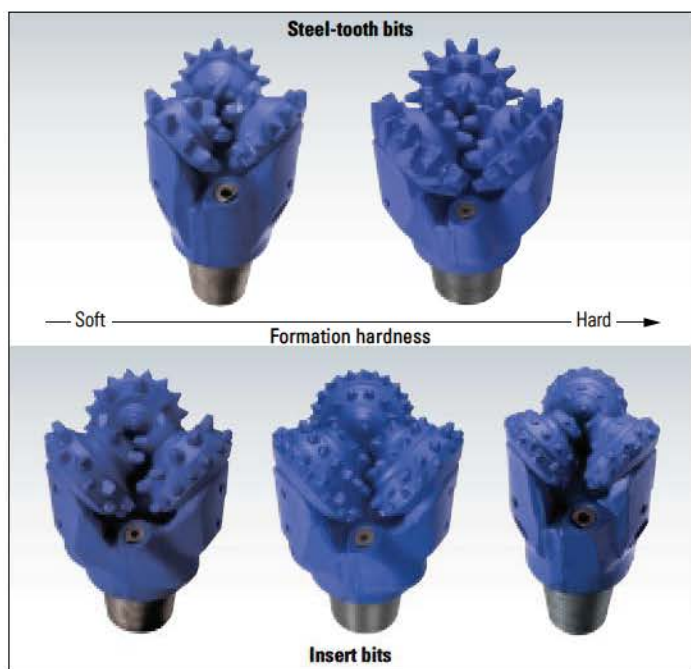
Initial improvements involved cutting structures. In the early 1930s, intermeshing cones were developed. By leaving space on adjacent cones, cutters can be longer and provide additional cleaning action in soft formations. Prior to that, teeth had to be short enough to miss each other as the cones turned. About the same time, manufacturers began heat-treating steel and welding harder metal on steel teeth to drill formations with high compressive strengths.

There are two types of roller-cone cutting structures: steel teeth machined, cast or integrally forged with wear-resistant carbide composite edges, and tungsten-carbide inserts formed separately and pressed into precisely drilled holes on the cone surfaces. Steel-tooth and insert bits are available to drill soft, medium hard and hard formations (below). Steel-tooth bits are used in soft formations with low compressive strengths as well as medium-hard to hard formations with higher compressive strengths. Insert bits drill formations ranging from soft and medium-hard, to hard semi-abrasive and hard abrasive.

Cutting structures that crush or cause compressive failure of hard rock are blunt, short to prevent cutter breakage, and closely spaced. Soft formations allow sharp, long teeth to penetrate and remove material by gouging and scraping. Each cutting action is used to varying degrees depending on the formation. Cutters tend to gouge and scrape more as cones depart from true rolling motion. A balance between rock failure mechanisms is achieved



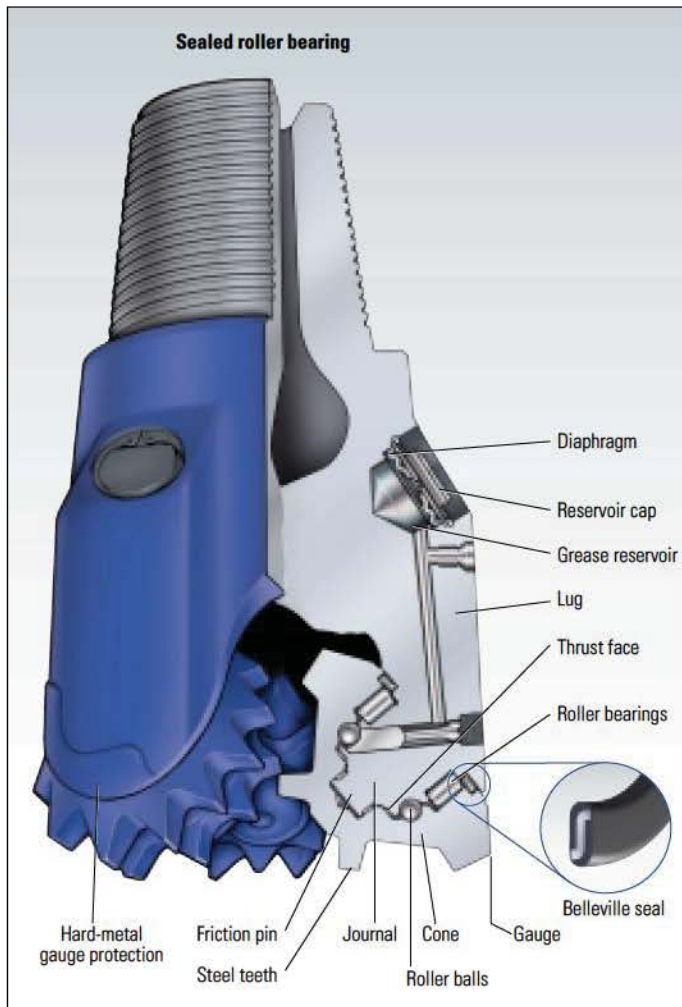
▶ **Roller-cone drilling actions.** Roller-cone bits remove rock by gouging and scraping or by crushing. Rolling cones impart a crushing action. As cones depart from a true rolling motion, cutting structures gouge and scrape more. Skew angle, or offset, and cone shape cause cones to periodically stop rotating as the bit turns. As a result, cutting structures slide on the bottom of a hole and scrape the formation. Offset angles vary from 5° for soft formations to zero in hard formations. Bits for soft formations use longer cutting structures with cone-offset angles that reduce true rolling motion. Short cutters on cones that roll more generate crushing action in hard formations.



by adjusting journal angle, cone shape and offset to control how cones roll (above). Journals are shafts, or axle-like structures, about which cones turn. Offset, or skew angle, is a measure of how much journals are shifted so that the axis of each cone does not intersect at the center of a bit.

As cutting structures improved and bits drilled more aggressively, bearing life became a limiting factor. In the mid-1930s, antifriction roller bearings were developed (next page, top). Bit runs improved from 6 or 8 hours to between 20 and 25 hours with a corresponding increase in footage drilled and decrease in cost. Fluid nozzles were first used in 1950 to improve bit and hole cleaning, and increase penetration rates by jetting mud on the bottom of a hole to dislodge cuttings held down by hydrostatic pressure. Tungsten-carbide inserts, introduced in 1951, were a boon to hard-rock drilling. Carbide inserts—with only a small sacrifice in toughness—were

◀ **Steel-tooth and insert cutting structures.** Steel teeth are cast, forged or machined from the same metal as the cones (top). Tungsten-carbide hard-facing is welded on steel teeth to improve durability. Intermeshing cones allow longer cutting structures and provide additional cleaning action. In soft formations, wide cutter spacing also promotes bit cleaning. Sintered tungsten-carbide inserts are cast separately and mechanically pressed to a tight interference fit in slightly smaller holes on cone surfaces (bottom). Inserts capped with more abrasion-resistant PDC layers also are available.



harder and more wear-resistant than the best steel and could drill long intervals before wearing out.

For the first time, cutting structures outlasted bearings. However, mud and solids damage bearings, especially in critical applications. Although a special grease was used to lubricate bearing components and extend bit life, fatigue and wear of roller-bearing surfaces and tracks, or races, on lugs and cones limited bearing durability, so a new approach was needed for insert bits. In the 1960s, seals were added to keep grease in bearings and prevent fluids or solids from entering. Grease reservoirs in each lug provide continuous lubrication. A diaphragm-compensation system equalizes pressure across the seals. Open, or unsealed, roller bearings cooled and lubricated by drilling fluids are still used in steel-tooth bits for low-cost drilling.

Today, less porous cemented carbides are made by combining fine tungsten-carbide particles in a cobalt matrix and sintering at high temperatures in a

1. Sintering is the heating of powdered metals until a binder-metal constituent melts, causing densification and shrinkage while maintaining preform shape.

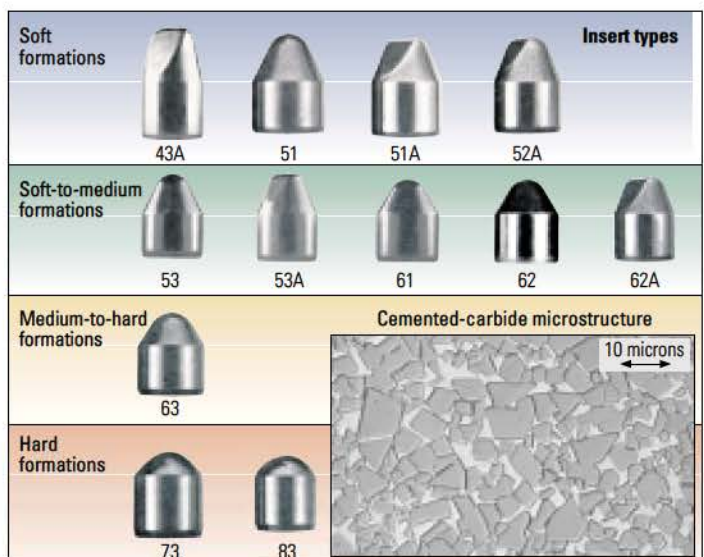
< Antifriction bearings. Bits with three cones, the most common roller-cone design, bear little resemblance to early rolling-cutter bits. Roller bearings carry most of the loads, and ball bearings inserted through a hole in the journal hold cones in place. A thrust face and friction pin carry nose loads and stabilize the bearings. Seals keep grease inside bearings, and prevent mud and solids from entering. The first rubber-bonded seals were energized by an internal metal ring, or belleville spring. Later, round and radial elastomer seals were used. Grease reservoirs in the lugs ensure lubrication. There is no pressure differential across the seals, and hydrostatic pressure is transferred through a diaphragm to equalize pressure between the bearings and borehole.

vacuum or hydrogen atmosphere.¹ Cobalt content and grain size are varied to generate a dozen standard cemented-carbide grades. These metal composites combine hardness to limit deformation with toughness to resist cracking.

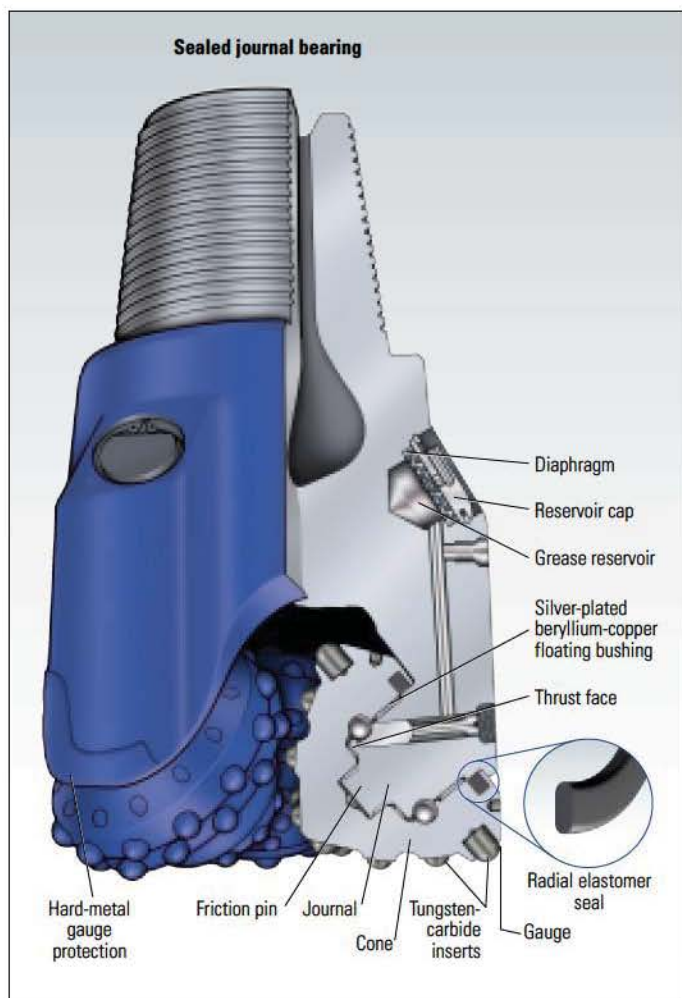
Small grain sizes and low cobalt content increase hardness and wear resistance at the expense of toughness. Large grains and high cobalt levels reduce hardness and wear resistance, but increase toughness. The right grade must be selected—too soft leads to premature wear, too hard increases insert breakage under severe loads. The results are wear- and erosion-resistant inserts for hard formations, and strong inserts for soft formations (below).

Better cutting structures and aggressive drilling in deep, hard rocks require more bit weight and better bearings. Journal, or friction, bearings without rollers and using O-ring seals compressed more than 15% were introduced in the late 1960s and early 1970s, ushering in a new era in roller-cone performance.

Journal bearings are more durable and handle higher weights than roller bearings because loads are distributed over a larger area—both journal and



^ Insert variety. Insert durability depends on advances in powder metallurgy that eliminate defects, optimize binder chemistry and achieve a precise relationship between hardness and toughness for each application. Less porous cemented carbides are fused onto steel teeth or sintered into wear- and erosion-resistant inserts for hard formations or stronger inserts for soft formations. Careful process control ensures precise material properties and grain sizes, and a high-temperature, isostatic pressing step eliminates cemented-carbide pore defects (insert).



< **Friction bearings.** Bearings without antifriction rollers are durable and handle high weights because loads are distributed over a larger bearing area. These journal bearings are used in bit sizes up to 12½ in. Floating beryllium-copper bushings dissipate heat and reduce relative velocities between journals and cones. Silver plating acts as a solid lubricant to further reduce friction and wear. Radial elastomer seals are used because they require less compression than round seals and do not generate as much heat.

Roller-cone bit bodies were initially cast or forged in one piece with cones and sometimes companion blades attached. With the emergence of three-cone designs, manufacturers began producing individual lug and cone units that were subsequently assembled and welded together. This paved the way for six decades of increasingly precise manufacturing processes (below). Tighter tolerances for forging, machining, heat-treating, sintering, grinding, welding and powder metallurgy are the foundations of today's cadre of high-performance roller-cone bits. Reed pioneered grinding bearing surfaces in one setup to provide consistent shapes, and eliminate eccentricities.

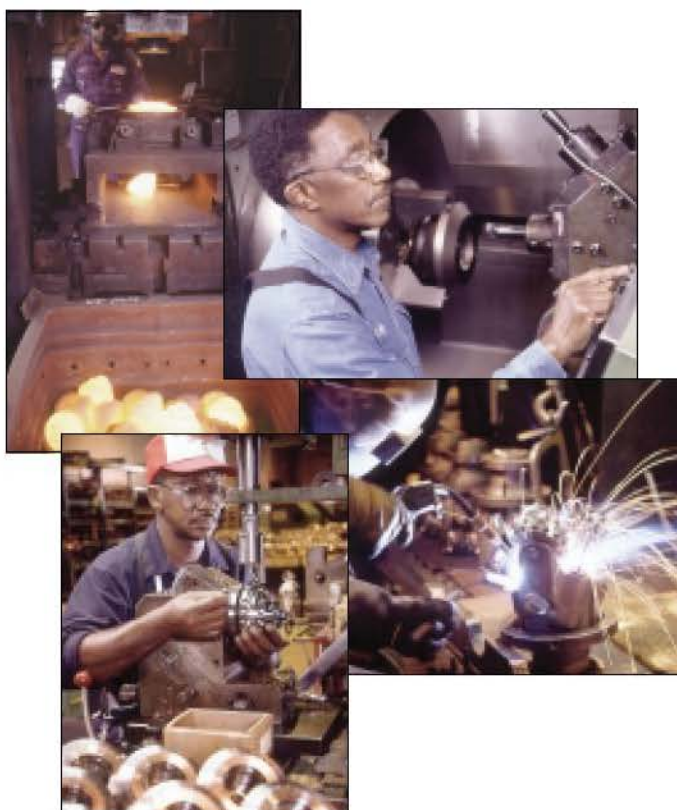
Reed also developed patented methods for finishing bearings that improve surface finishes, concentricity and dimensional control. Cassette fixtures provide a repeatable method for holding parts in a machine.⁴ A holder, or cassette, fits in a lathe to position parts securely and accurately. Larger parts are machined by static turning—a moving lathe contours stationary parts.⁵ Static turning is now a standard in roller-cone bit manufacturing. Similarly, robotic welding provides near-final shape alloy inlays unobtainable by manual welding.

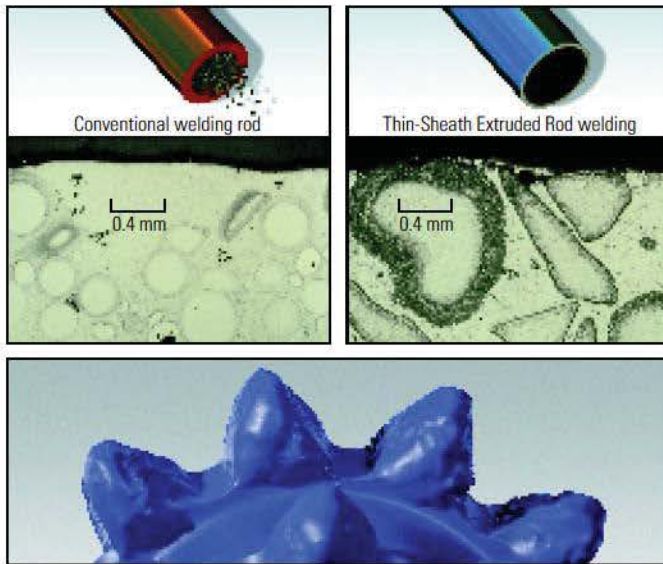
Advances in powder metallurgy fabrication have translated into improved performance of premium hard metal for steel-tooth bits. Welded overlays for bit teeth evolved using manual welding with composite rods made from steel and carbide powders. This arduous application process limits consistency and performance of steel-tooth bits. The Armor Clad composite rod developed by

interior cone surfaces—rather than just the rollers (above). The first journal bits drilled as much hole as three to five standard roller-bearing bits, but were more expensive. Net savings came from increased footage per bit and fewer trips to replace bits.

In the early 1970s, Reed Tool Company, now Reed-Hycalog, developed a floating beryllium-copper bushing with better load-carrying capacity, ductility and wear resistance with high thermal conductivity to dissipate heat.² Compared with conventional friction bearings, this floating bushing rotates between journal and cone surfaces to provide four surfaces and twice the sliding area, which reduces relative velocities and decreases wear. Floating bushings are also silver-plated to reduce friction and wear. At about the same time, Reed patented an oval seal with a cross section that is greater radially than axially.³ Radial seals require less than 10% compression to seal effectively, which reduces wear. A lower interface pressure also reduces friction and heat, so seals run cooler. Today, many bit designs use seals that are based on this radial concept.

> **Manufacturing roller-cone bits.** Steel-tooth cones and cutters are forged from hot-rolled steel billets (top left). Heat treatment hardens bearing cavities. These cone shapes are shaped by machining profiles and a rough bore followed by complex detailed milling of individual teeth (top right). Tungsten carbide is manually welded on each tooth to improve wear resistance. For insert bits, cemented-carbide inserts are sintered and interference fit on cone surfaces by pressing them into slightly smaller precision-drilled holes (bottom left). Lugs and cones are assembled and welded together (bottom right).





◀ Premium steel-tooth hard-facing. Heat degradation from standard high-temperature welding and slower application with thick-tube rods cause high porosity, cracking and inconsistent properties (*top left*). Conventional welded hard-metal overlays leave spherical tungsten-carbide particles exposed to erosion (*middle left*). Lower temperature welding and rapid deposition with a Thin Sheath Extruded Rod (TSER) minimizes dilution in steel teeth (*top right*). A premixed, multiphase blend of tungsten carbide and powdered steel provides greater abrasion resistance. Large spherical particles and plate-like structures overlap to reduce matrix erosion (*middle right*). This Armor Clad hard metal has exceptionally low porosity and crack defects, so teeth stay sharper longer, increasing penetration rates and bit life (*bottom*).

Reed-Hycalog doubles the weld application rate while reducing heat degradation of carbide particles (*above*).⁶

The patented powder metal cutter (PMC) process combines powder-metal and traditional forging technologies to produce bits with advanced

cutter geometry and features. This manufacturing method, which involves rapid, solid-state densification of final-shape cones and teeth, eliminates many conventional bit-design constraints and provides advanced material options that improve cutting-structure integrity (*below*). Teeth with a consistent hard-metal thickness for improved wear resistance are a primary advantage of the proprietary PMC technology.

This process is well suited for automation, and manual welding operations are eliminated. Unlike manually welded premium hard metal, carbide volume and microstructure are identical on each tooth of every cone. This process provides flexibility for innovation in several aspects of roller-cone design. Final-shape capability allows economic manufacturing of complex cutting structures—aggressive shapes, locations and orientations—

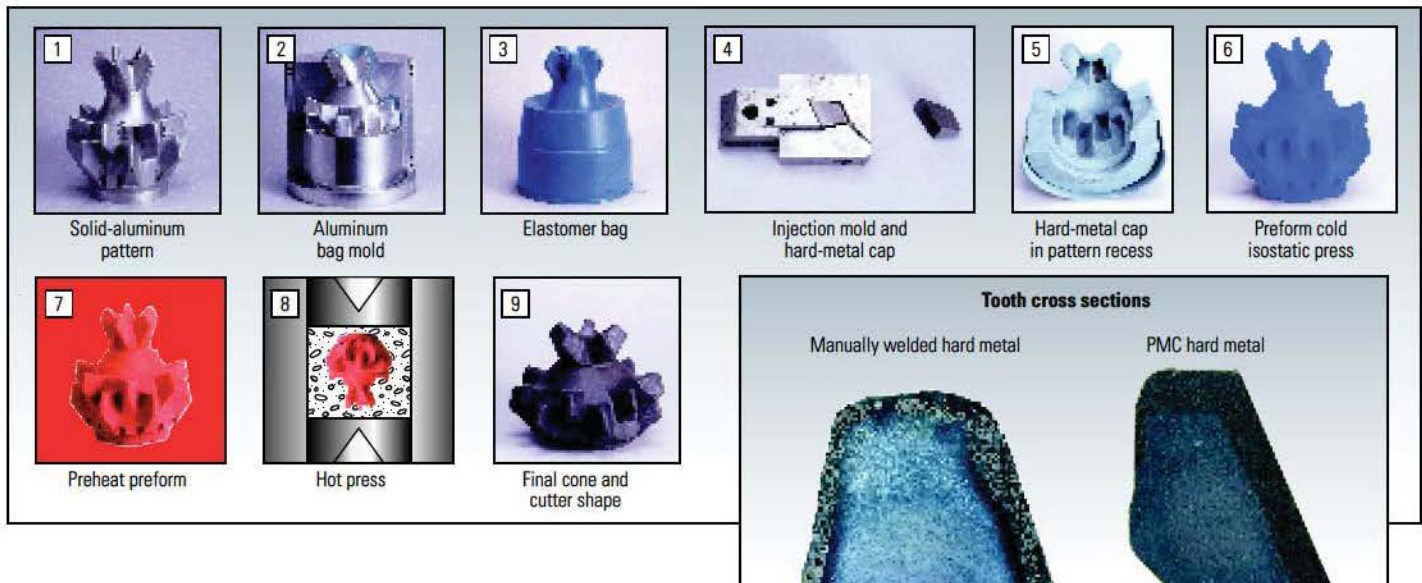
2. Mayo TH: "Drill Bit Bearings," U.S. Patent 3,721,307 (March 20, 1973).

3. Murdoch HW and Schumacher PW Jr: "Drill Bit Seals," U.S. Patent 3,765,495 (October 16, 1973).

4. Gaither PI and Tucker III JR: "Method and Apparatus for Machining a Workpiece," U.S. Patent 4,599,921 (July 15, 1986).

5. Gaither PI and Klappenbach SW: "Method of Making Lug Journal for Roller Cutter Drill Bits," U.S. Patent 4,982,496 (January 8, 1991).

6. Smith RC: "Hardfacing Material for Rolling Cutter Drill Bits," U.S. Patent 5,740,872 (April 21, 1998).



▲ Powder-metal cutter (PMC) technology. A patented process combines powder metal and traditional forging technologies to produce lower cost bits with advanced cutter geometry and features. A final cone and cutter geometry is expanded to account for a two-step densification process. A solid pattern and two-part mold are machined from aluminum to make an elastomer bag that replicates the pattern exactly.

Locations and thickness of wear-resistant material for teeth are also expanded to make steel molds. A mixture of tungsten carbide and cobalt pellets, steel powder and binder is injected into the molds to produce hard-metal tooth caps. The flexible bag is placed in an aluminum support, and caps are inserted into recesses corresponding to teeth. A solid mandrel and cap form the bit bore and allow access to fill the bag with steel powder. Vibration packs the powder to about a 60% solid in the shape of the pattern. Cold isostatic pressing densifies the powder to about 80% solid with a uniform size reduction of 14%. These preforms can be handled, heated and manipulated during final deformation, but will shatter if dropped.

Cone and cutter densification to 100% solid and final shape begins by uniformly preheating preforms in an inert atmosphere close to forging temperature. Preforms are transferred to a preheated die and surrounded by hot graphite powder. This transfer takes less than 30 seconds to prevent oxidation and minimize heat loss. A hydraulic press consolidates preforms to final shape and full density in less than one minute.

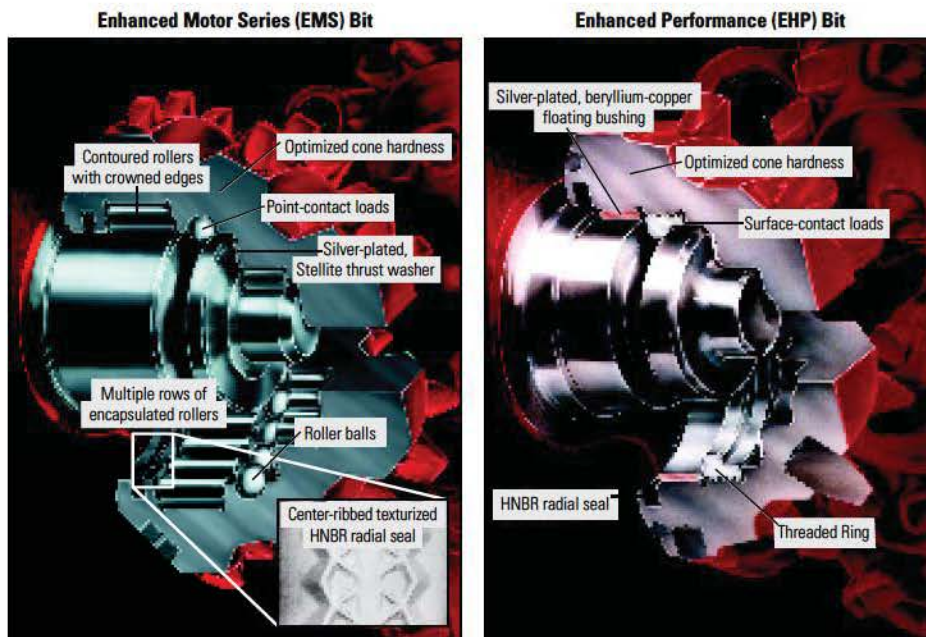
After blast cleaning, bearings are machined, surface-hardened by heat treatment and precision-ground by conventional means. Carbon content and microstructure are the same in each cone and tooth, thereby eliminating manual welding (*bottom right*).

that are not feasible in conventional machining operations. Recent PMC advances include improved hard-metal formulations and full-coverage hard metal.⁷

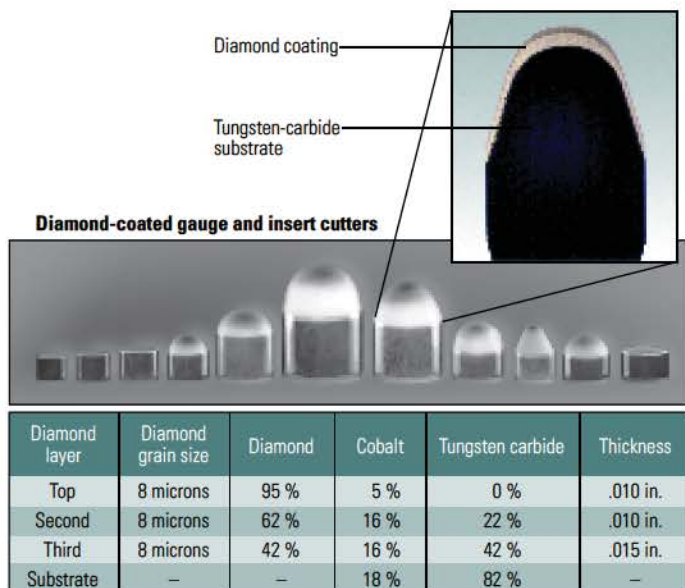
Shaped inserts with diamond-composite coatings have revolutionized cutting-structure performance in many roller-cone bit applications. Diamond technology provides resistance to thermal cracking and wear for cutting edges as well as rock-facing gauge surfaces. Diamond-enhanced inserts use graded polycrystalline diamond layers on cemented-carbide substrates (below). The surface layer of almost pure diamond that cuts rock is optimized for abrasion, temperature and impact wear in roller-cone applications. Differences in thermal expansion and elasticity between cemented-carbide substrates and diamond composites result in compatibility strains that are reduced by graded intermediate layers.

Reed-Hycalog coated inserts are fabricated under license using a patented high-temperature, high-pressure process similar to the one used in making fixed-cutter PDC elements (see "Fixed-Cutter Technology," page 45).⁸ Fortunately, development of durable PDC inserts for roller-cone bits coincided with the increase in aggressive directional drilling using downhole motors.

The latest bearing designs and ongoing advances in hydraulics also expand roller-cone bit capabilities and further improved drilling



Advanced bearing designs. Enhanced Motor Series (EMS) roller-bearing bits are durable at high penetration rates in high-speed turbine and motor drilling, particularly directional applications (left). For longer bit life, multiple rows of rollers increase durability, and center-ribbed texturized seals reduce friction. Contoured roller edges minimize contact stresses and reduce metal flaking. Rollers are encapsulated in the cone to maximize journal diameter and reduce contact stresses. Hydrogenated Nitrile Butadiene Rubber (HNBR) seals provide abrasion resistance and withstand temperatures greater than 300°F [150°C]. Texturized seals trap grease and reduce friction; a center rib keeps contaminants out (insert). Enhanced Performance (EHP) bits feature patented Threaded Ring bearings with more inward-loading capacity than ball bearings to reduce failures and lost cones (right). Threaded Ring bearings provide better cone retention in the event of seal failure. There is less axial play, which reduces pressure fluctuation across seals and limits particle migration. A silver-plated Stellite thrust washer carries axial loads and reduces heat friction at the thrust face.

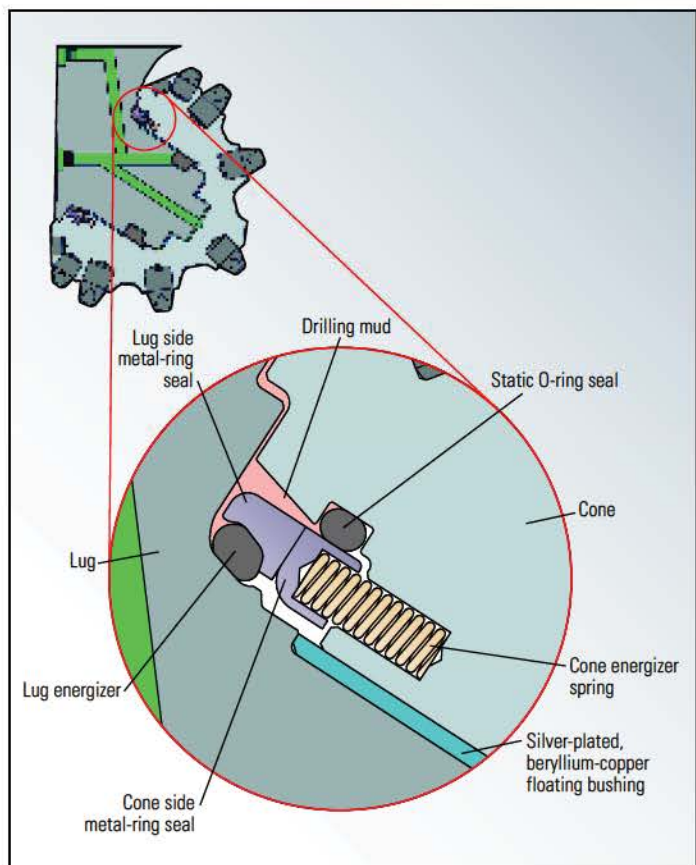


Shaped PDC inserts. Diamond coatings on cemented-carbide substrates improve roller-cone insert abrasion, impact and thermal properties (top). Dome-shaped gauge inserts use a uniform diamond layer, while round-top insert coatings grade from thick on top to thin on the edges (middle). A surface PDC layer of almost pure diamond and one or two intermediate layers of diamond, tungsten carbide and cobalt mixtures are sintered, causing the binder to adhere firmly to the carbide base (bottom). Intermediate layers are optimized to minimize strains between diamond and tungsten carbide caused by the difference in expansion between diamond and carbide.

performance. A new generation of premium Enhanced Motor Series (EMS) and Enhanced Performance (EHP) bits combine improved materials and manufacturing with advanced designs. These new designs balance cutting-structure improvements, which increase penetration rate, with bearing and seals that improve bit durability and life (above).

The Threaded Ring bearing introduced by Reed-Hycalog provides superior cone retention in the event of seal failure.⁹ This solid-steel, silver-plated ring is made in two halves so it can be installed on the journal. Aggressive cutting action causes high loads on bearings. The bushing-like structure offers greater inward-loading capacity than ball bearings for longer bearing life, especially in directional drilling. Reduced clearances decrease axial play, minimize pressure

7. Sreshta HA and Drake EF: "Hardmetal Facing for Rolling Cutter Drill Bit," U.S. Patent 5,653,299 (August 5, 1997).
- Sreshta HA and Drake EF: "Hardmetal Facing for Earth Boring Drill Bit," U.S. Patent 5,988,302 (November 23, 1999).
- Drake EF and Sreshta HA: "Rock Bit Hardmetal Overlay and Process of Manufacture," U.S. Patent 5,967,248 (October 19, 1999).
- Drake EF and Sreshta HA: "Rock Bit Hardmetal Overlay and Process of Manufacture," U.S. Patent 6,045,750 (April 4, 2000).
8. Hall HT Jr and Hall DR: "Carbide/Metal Composite Material and a Process Therefor," U.S. Patent 5,304,342 (April 19, 1994).
9. Pearce DE: "A New Rock Bit Bearing Provides Superior Cone Retention," paper IADC/SPE 19909, presented at the IADC/SPE Drilling Conference, Houston, Texas, USA, February 27-March 2, 1990.
- Murdoch HW and Schumacher PW Jr: "Drill Bit," U.S. Patent 3,971,600 (July 27, 1976).
- Pearce DE and Walter JC: "Means for Mounting a Roller Cutter on a Drill Bit," U.S. Patent 4,991,671 (February 12, 1991).



▲ Metal-face seals. Metal seals show promise for extending and improving bit durability and life. Lubricated stainless steel generates less sliding friction and heat than elastomers on steel and also has better resistance to heat or chemical attack.

fluctuations across seals and limit particle migration into the bearing to extend seal life. The hardness of silver-plated Stellite washers also improves handling of thrust loads and reduces friction in the thrust-face area of bearings.¹⁰

Increased use of downhole motors and turbines subjects bits to high-speed rotation and sliding velocities that cause seals to fail early. Research indicated that a texturized seal could resist wear and retain grease under these conditions.¹¹ This self-lubricating seal holds grease in the texturized area, which reduces friction and provides longer seal life. Metal seals are also used in high-temperature and high-speed drilling, and in environments with severe abrasives, fines or harsh chemicals (above).¹²

10. Stellite is a family of cobalt-based superalloys.

Singh RK, Nixon MS and Daly JE: "Rolling Cutter Drill Bits," U.S. Patent 5,725,313 (March 10, 1998).

Griffin ND: "Methods of Treating Preform Elements Including Polycrystalline Diamond Bonded to a Substrate," U.S. Patent 6,056,911 (May 2, 2000).

11. Carter MW, Daly JE and Van Nederveen H: "A New Sealed Bearing Rock Bit for High-Speed Drilling," paper SPE 14385, presented at the 60th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 22-25, 1985.

Daly JE and Kotch RJ: "Roller Cutter Drill Bit Having a Texturized Seal Member," U.S. Patent 4,619,534 (October 28, 1986).

12. Daly JE, Pearce DE and Wick TA: "Different Stiffness Energizers for MF Seals," U.S. Patent 875,861 (March 2, 1999).

Pearce DE: "Face Seal Having Strain Induced Face Geometry," U.S. Patent 6,109,376 (August 29, 2000).

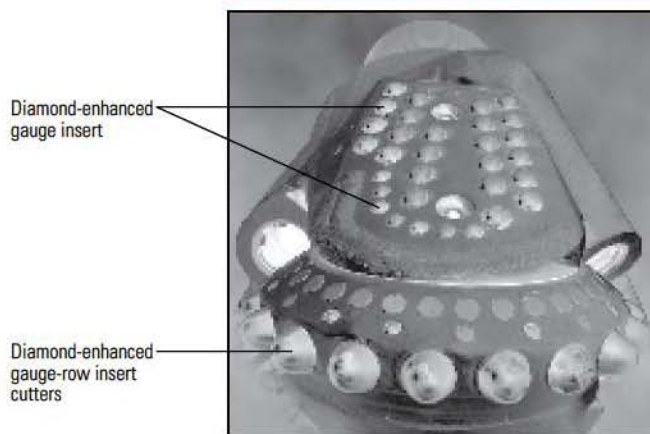
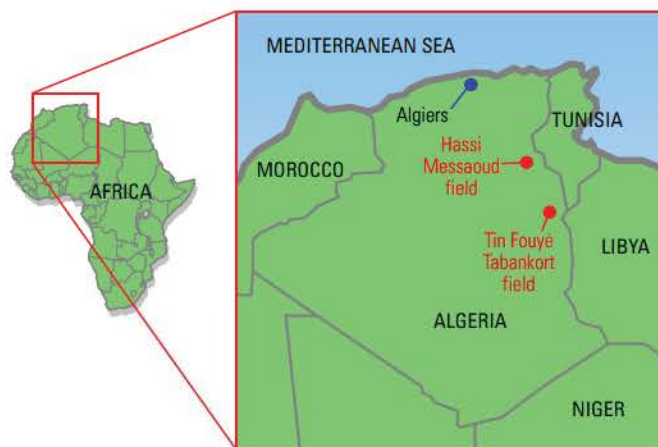
Besson A, Rabourdin JL, Huon W and Cazenave F: "How to Design Rock Bits to Drill Ultraabrasive Quartzitic Sandstone in Horizontal Wells, Algeria," paper SPE/IADC 52878, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 9-11, 1999.

Optimizing Roller-Cone Performance

A five-well drilling program for TotalFinaElf in Tin Fouyé Tabankort (TFT) field located in eastern Algeria illustrates improvements that are attainable using new materials and designs (below).¹³ The TFT field produces from a gas reservoir at a depth of about 2000 m [6560 ft] in an Ordovician sandstone. The company planned to drill horizontal wells with a reach of about 600 m [1970 ft] as part of a two-year infill program. Offset data indicated extremely low penetration rates and footage for all bit types. To reduce cost, the operator, working with two bit manufacturers, evaluated formation characteristics, historical drilling performance and dull-bit data for both roller-cone and fixed-cutter bits.

The sandstone consisted of angular interlocking quartz grains with 5 to 10% porosity. Poor performance in the offset well and a high level of bit wear suggested an ultra-abrasive, possibly extremely hard formation. Diamond-enhanced inserts are too friable for drilling some ultrahard rock, but analysis determined that this zone was medium-hard to hard.

Abrasiveness was greater than any previously ranked quartz sandstone. Sliding any material, including diamond, on this formation generates excessive wear, a critical factor in bit selection for this horizontal drilling application, which reaffirmed that a properly designed roller-cone bit could drill more efficiently than a fixed-cutter bit.



▲ Optimized roller-cone bits. Horizontal drilling performance in a medium-hard, ultra-abrasive sandstone of Tin Fouyé Tabankort (TFT) field in Algeria (top) was improved by using EHP bits with Threaded Ring bearings, 0° offset angle, and diamond-enhanced gauge, heel and center-row inserts, and gauge pads (bottom). Shaped PDC, or diamond-coated inserts, are relatively new on roller-cone bits, but results are impressive. In environments that seriously damage tungsten carbide, diamond-capped inserts remain virtually intact. Bits run longer and drill more footage, which means fewer trips to replace bits and reduced drilling costs.

In offset wells, both roller-cone and fixed-cutter bits—PDC and diamond-impregnated designs—experienced short run times, low footages per bit and heavy wear from abrasion and heat. The horizontal section of an offset well required 25 insert bits and more than 500 hours to drill. Because this formation could be crushed, roller-cone features were chosen to reduce sliding. Larger and stronger gauge pads were used to stabilize bits laterally. Exposed surfaces were enhanced with diamond as were gauge pads, heel, first intermediate row and center inserts. Cone offset angle was reduced or eliminated to minimize sliding and generate more crushing action. Irregular insert arrangements further enhanced crushing and combated friction from inserts sliding in grooves, or tracks.

In the first well, eleven 8½-in. insert bits with 2° offset drilled the horizontal section in 215 hours. Penetration rates increased to 2.8 m/hr [9 ft/hr] from 1.25 m/hr [4 ft/hr] in an adjacent well. Bearing performance was not a limiting factor. EHP bits were selected based on proven performance in severe drilling conditions and for the cone retention advantages of the

Threaded Ring bearing. Diamond-enhanced inserts showed limited wear, but gauge pads still experienced heavy wear. Based on these results, cone offset was reduced to 0°, the gauge-pad area with added diamond insert was increased significantly, and diamond-insert coverage was increased on the intermediate cutter row.

Average penetration rate increased to 3.5 m/hr [11 ft/hr] in the second well, which required nine bits and 176 hours to drill the horizontal drainhole. Drilling time decreased to 123 hours with only six bits in the third well, and penetration rate improved again to 4.8 m/hr [16 ft/hr]. By the fifth well, six bits drilled 637 m [2090 ft] in 121.5 hours at 5.3 m/hr [17 ft/hr]. Compared with the adjacent well, average penetration rate and footage drilled per well improved more than 400%, and trip time was reduced drastically. Total savings per well was more than \$1 million.

Advanced Roller-Cone Hydraulics

Bit hydraulics involves four basic functions: loosen cuttings, clean cones and cutters, cool the bit and transport cuttings out of the hole to avoid regrinding.¹⁴ However, conventional nozzle placement

directs mud flow straight down and does not clean the cones or hole prior to cutting structures contacting the formation. As a result, rock chips remain on bottom and can build up on cones or pack between cutting structures in a phenomenon called bit balling that prevents full penetration of undisturbed formation. Hydraulic designs, therefore, influence roller-cone performance and optimal penetration rates significantly.

The relationship between penetration rate, bit cleaning and cuttings removal was first recognized in laboratory tests on full-size bits. Before settling into steady-state performance, bits drill slightly faster as the teeth or inserts first begin cutting to full depth, gradually slowing as cuttings pack around the cutters and reduce formation penetration. These observations led to a series of tests that studied the effects of varying nozzle direction and location. In the first test, nozzle angle focused flow directly on the cutters. Penetration improved significantly, demonstrating the importance of fluid redirection for cleaning bits and preventing balling.

To optimize bit performance, various nozzle extensions and orientations were tested (below).

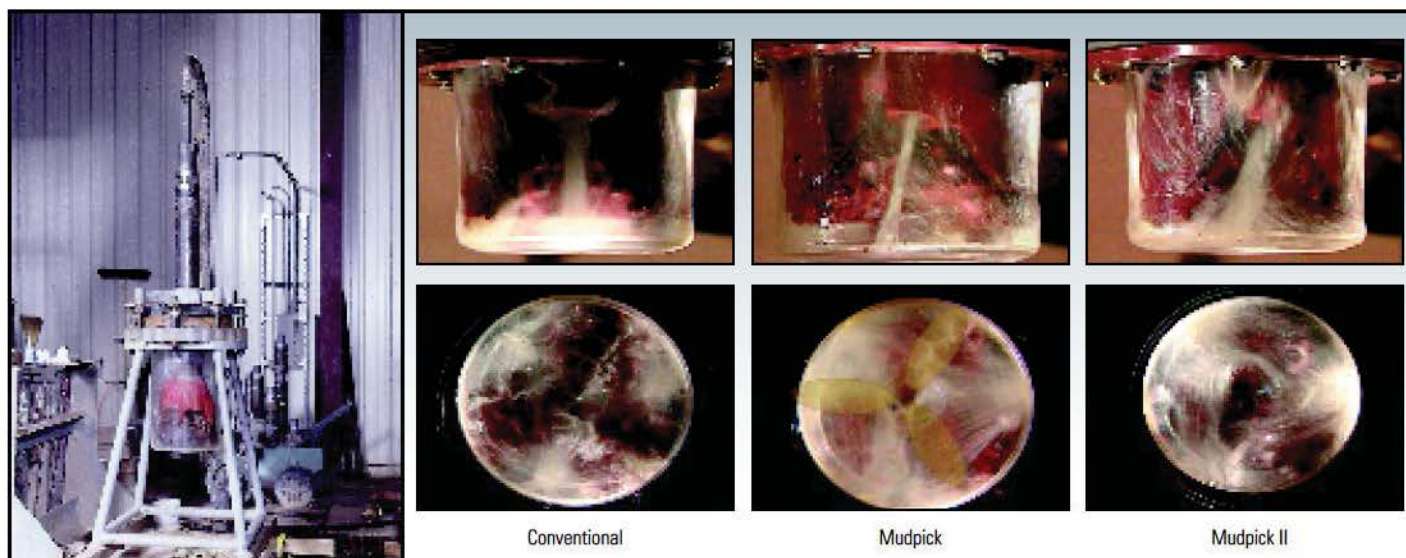
14. Doiron HH and Deane JD: "Effects of Hydraulic Parameter Cleaning on Rate of Penetration of Soft Formation Insert Bits," paper SPE 11058, presented at the 57th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 26-29, 1982.
15. Slaughter RH Jr: "Development, Laboratory, and Field Test Results of a New Hydraulic Design for Roller Cone Rock Bits," paper SPE 14220, presented at the 60th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 22-25, 1985.

Childers JS and Pastusek PE: "Drill Bit Having Angled Nozzles for Improved Bit and Well Bore Cleaning," U.S. Patent 4,546,837 (October 15, 1985).

Moffitt SR and McGehee DY: "Performance Comparison of Rolling Cutter Bits with Alternative Nozzle Configurations," paper SPE/IADC 18630, presented at the SPE/IADC Drilling Conference, New Orleans, Louisiana, USA, February 28-March 3, 1989.

16. Moffitt SR, Pearce DE and Ivie CR: "New Roller Cone Bits with Unique Nozzle Designs Reduce Drilling Costs," paper IADC/SPE 23871, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 18-21, 1992.

Ivie CR and Pearce DE: "Hydraulic Action for Rotary Drill Bits," U.S. Patent 5,096,005 (March 17, 1992).



Advanced bit hydraulics. Cutting action is most effective when rock chips are removed immediately. Fluid flow around and under bits can be observed in the Reed-Hycalog Flow-Visualization Chamber (far left). Conventional hydraulics focus flow on the bottom or bottom corner of a hole (left). Fluid disperses radially 360°, and much of the mud hydraulic energy is lost up the annulus. The remaining flow meets in stagnant areas of confluence that coincide with the zones where cutters contact rock, which reduces flow velocity and hole-cleaning efficiency as well as penetration. Mudpick hydraulic designs use precisely angled and slightly extended nozzles to clean cutters and formation before they interact and move stagnant flow areas away from cutting zones (right). Mudpick II hydraulics maximize penetration efficiency for insert bits (far right). Fluid flow cleans gauge and inner-row inserts, and sweeps under the cutters to scour the hole bottom. Flow under the cutters is maximized to ensure efficient chip removal.

Partially extended nozzles were directed at leading edges of cones between outside gauge and intermediate cutter rows to clean the bit and hole bottom prior to cutting structure contact with the formation. This patented Mudpick technology improved penetration rates by more than 20% in laboratory tests, providing consistently higher penetration rates than conventional straight-nozzle designs.¹⁵ Nozzle extensions are forged as integral parts of the lug to avoid separate add-on extensions.

Research and full-scale testing continued, varying nozzle location and direction. Jets were

directed toward the gauge cutters so that high-velocity mud cleans the cones before making a smooth direction change and sweeping across the formation under the cones. The Mudpick II hydraulic design eliminates areas of stagnant fluid and improves penetration rates by more than 45% over conventional bits in soft to medium-hard formations.¹⁶

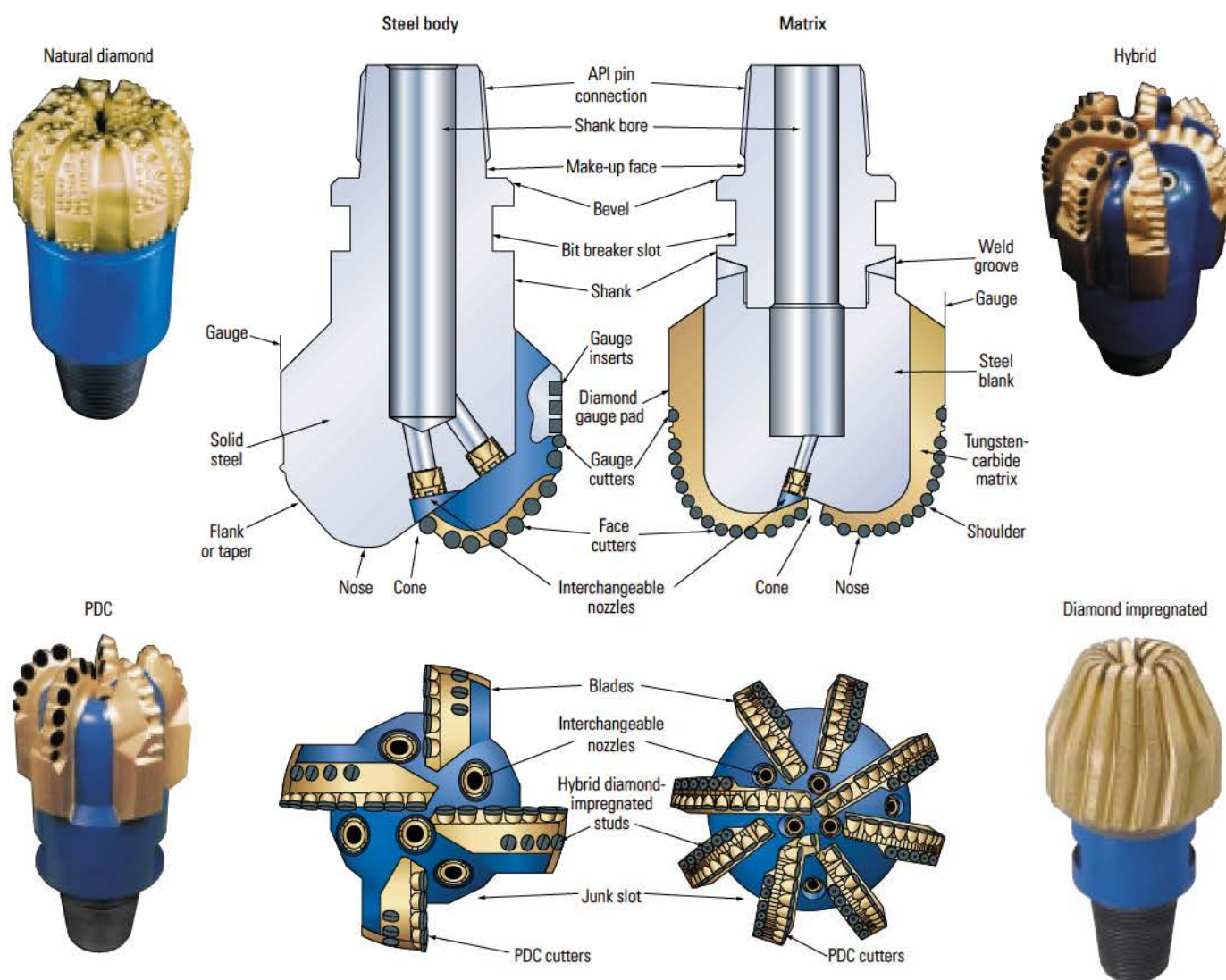
In formations where bit life is limited by cutting-structure failure, advanced hydraulic designs allow shorter, durable cutting structures to be used without sacrificing penetration. Many intervals can now be completed by a single bit.

Choice of Mudpick or Mudpick II hydraulics depends on formation type. Mudpick designs are used for soft-formation, steel-tooth bits. Mudpick II hydraulics are standard on premium EHP insert bits. Current research is targeting additional improvement in cuttings removal to avoid regrinding.

Fixed-Cutter Technology

Modern fixed-cutter bits are descendants of steel-blade drag bits and natural-diamond coring bits. There are two types of fixed-cutter bits: steel and matrix (below). These bits, classified as

Fixed-Cutter Bit Types



^ Steel and matrix fixed-cutter bits. Steel stock is machined on computer numerically controlled (CNC) lathes to make steel bit bodies (left). Steel bits withstand impact or torsion loads better, and are preferred for soft formations and larger hole sizes. A powder-metallurgy process is used to sinter matrix bits (right). Matrix bits, which last longer and can be manufactured in complex shapes, are preferred in high solid-content drilling mud, with high pump rates and hydraulic horsepower, and for wells requiring long bit runs. Natural-diamond (upper left) and diamond-impregnated (lower right) bits drill medium-hard and extremely hard formations that are moderately to extremely abrasive. Diamonds are set on surface or dispersed in the tungsten-carbide matrix on and near blade surfaces. PDC (lower left) bits drill soft to hard formations with low to high abrasiveness. Hybrid (upper right) bits have diamond-impregnated studs that share loads with primary PDC cutting elements.

natural diamond, synthetic polycrystalline diamond compact (PDC), hybrid and diamond impregnated, have no moving parts or bearings, only blades. In 1953, Hycalog began manufacturing full-hole bits using surface-set natural diamonds. PDC bits became commercial in 1973; improved hybrid designs combined PDC and diamond-coated cutters. Impregnated bits have diamonds on and near the surface of the blades. Natural diamonds are mounted on steel-body bits or preset in mold pockets before sintering tungsten-carbide matrix bits. PDC inserts can be mounted on both steel and matrix bits.

Making steel bits in one piece eliminates welding, and design details can be machined to exact tolerances. Cutting structures are mounted by interference fit in slightly smaller precision holes drilled by computer numerically controlled (CNC) mills that also cut the main bore, blades, junk slots or waterways, PDC and gauge-insert pockets, nozzle holes and threads. Steel is softer than tungsten carbide, but hard metals can be applied to critical areas. Tungsten carbide is more brittle than steel, but has greater resistance to erosion. Tungsten-carbide powders and

a binding alloy are placed in a mold with a steel core, or blank, and sintered to produce matrix bits. Carbide particles bind together and form a bond between the inner steel blank and outer tungsten-carbide shell, or crown.

The energy needed to drill a formation is determined by cutting action. Of the basic rock-removal mechanisms, shear is most efficient because the tensile strength of rocks is typically less than the compressive strength (below). PDC bits drill fast by shearing, which requires less energy than high loads that cause compression failure of formations. Natural-diamond and diamond-impregnated bits drill slowly by plowing and grinding, respectively, which both require high bit weight and torque. Fixed-cutter bits cost more, but drill faster and last longer than roller-cone bits in some hard and abrasive formations.

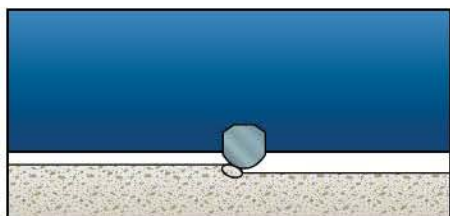
Diamond, the hardest material known to man, is almost pure crystalline carbon. It is 10 times harder than steel, 2 times harder and 10 times more wear-resistant than tungsten carbide, and 20 times stronger in compression than granite, with the lowest coefficient of friction and highest thermal conductivity of any known material.

Natural-diamond bits use industrial-grade—not gem-quality—naturally occurring stones that are crushed and processed to produce specific sizes and regular, rounded shapes. Penetration rates are relatively low—about 20 ft/hr [6 m/hr] maximum—but a properly designed diamond bit can drill for up to six days at 15,000 ft [4572 m] in medium-hard to hard formations.

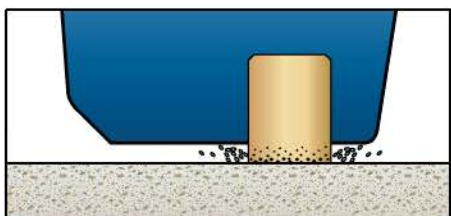
When diamond bits were first introduced, tiny grit-like diamonds were used. Diamonds were set in tungsten-carbide blades during sintering, but the blades tended to wear away too fast, lose diamond grit and stop drilling. This led to conventional diamond bits with larger stones set in specific patterns. However, when surface-set natural diamonds are lost from the matrix or become polished, no sharp, hard elements are left to grind formations. Penetration rates go down, and ring-wear failures occur.

At first, application of natural-diamond bits was not well understood, and designs were based on intuition. Today, diamond bits and diamond sizes are matched to formation hardness. Bits for softer formations use large diamonds to produce a plowing action. Small diamonds produce more of a grinding action and are used to drill hard formations.

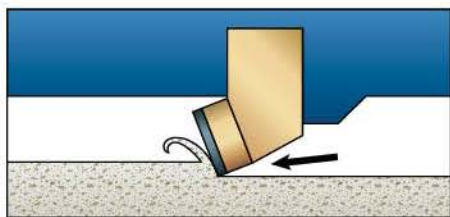
Natural diamonds form deep in the earth under intense heat and extreme pressure for thousands of years. In the early 1970s, General Electric developed a sintering process to make synthetic diamonds. Thin circular layers of alternating carbon graphite and cobalt are stacked in small cans and pressed to 2 million psi [13,733 MPa] followed by resistive heating to 2732°F [1500°C] for five minutes. Molten cobalt, acting as a catalyst and solvent, dissolves graphite and deposits monocrystalline diamond grit which conglomerates and bonds together to form a polycrystalline diamond layer, or table. Individual crystals, like natural diamonds, cleave if impact loads are applied in the correct direction, but bonded polycrystalline diamonds do not have cleavage planes and are more impact-resistant.



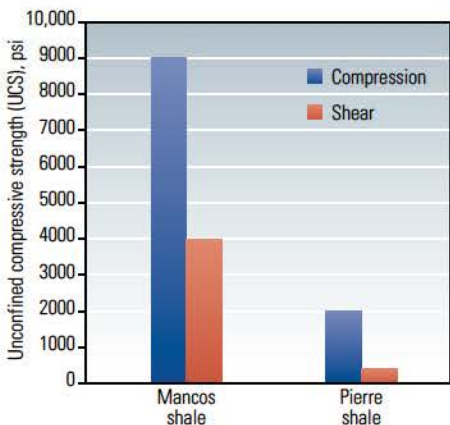
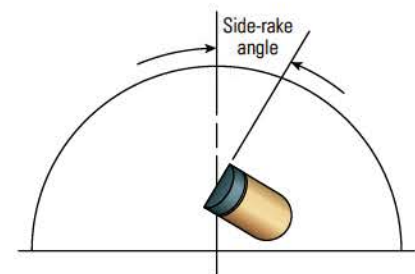
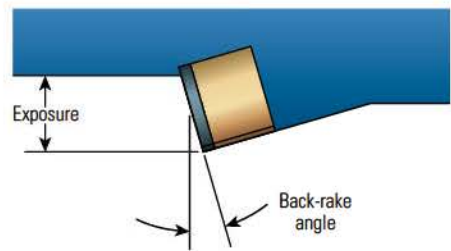
Natural-diamond bit—plowing



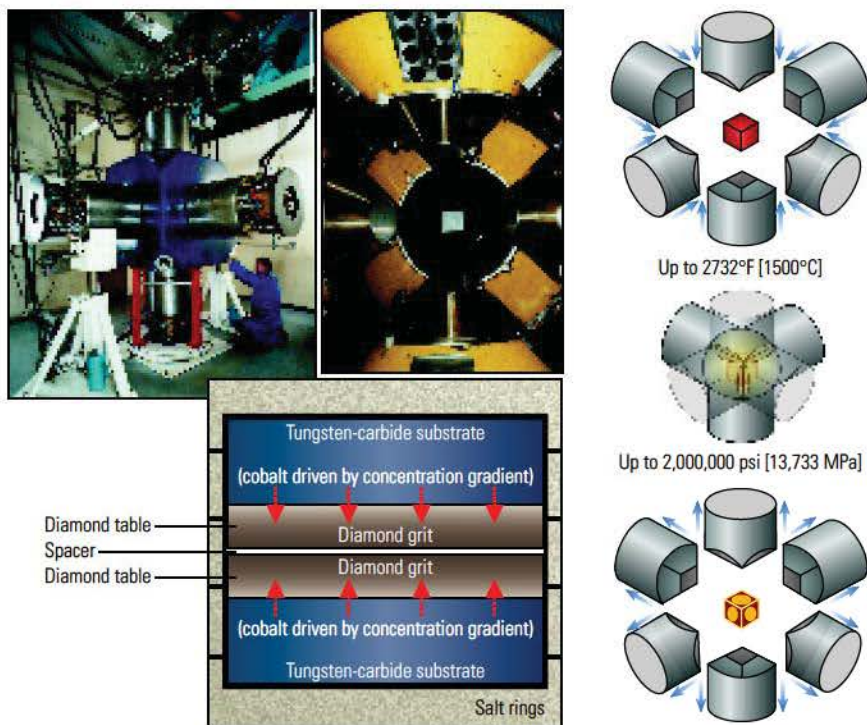
Diamond-impregnated bit—grinding



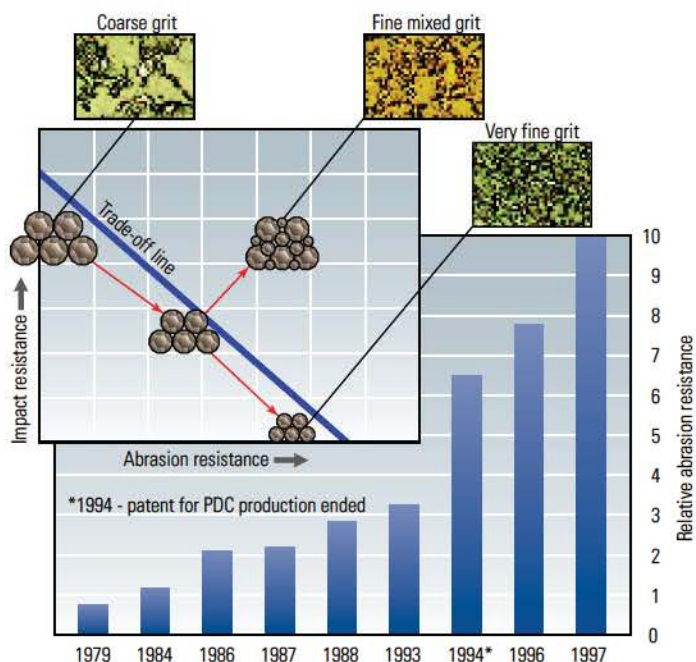
PDC bit—shearing



Fixed-cutter drilling actions. Natural-diamond bits are drag-type bits that drill by plowing (top left). Diamond-impregnated bits grind formations like a grinding wheel or sandpaper (top right). PDC bits drill fast by shearing formations much like a lathe (middle left). As a general rule, it is easier to remove rock by shear (bottom left). Back-rake and side-rake angles and cutter exposure define how aggressively PDC cutters will contact formations (middle and bottom right).



▲ Polycrystalline diamond synthesis. Reed-Hycalog manufactures PDC cutters using two proprietary cubic diamond presses with six independently controlled anvils arranged in opposing pairs that apply ultrahigh pressures and temperatures to achieve diamond-to-diamond bonding (*left*). PDC cutters consist of a bonded layer of synthetic diamond particles, or diamond table, on a thicker tungsten-carbide substrate (*middle*). These cutting structures are used as is or bonded onto longer tungsten-carbide posts to facilitate attachment and provide more cutter exposure. Manufacturing PDC cutters requires precise control of pressure and temperature (*right*). State-of-the-art equipment and in-house synthesis capabilities establish PDC specifications, improve process control and expedite product development.



▲ Synthetic diamond microstructure. Today, PDC components are more durable in both impact and abrasion resistance than in the past (*bottom*). Optimization of diamond particle distribution and thermal processing has improved diamond quality. In the past, the inverse relationship between PDC impact resistance and abrasion resistance required manufacturers and users to make compromises. Today, cutters classified as Top Right-hand Corner (TRC) are manufactured using improved diamond synthesis to mix diamond grit sizes that optimize both impact and abrasion resistance (*top*).

Reed-Hycalog uses outside suppliers, but also produces PDC cutters for research and bit manufacturing with two in-house cubic diamond presses (*left*). This approach helps establish PDC specifications rather than having to evaluate and accept only standard products. PDC cutters consist of synthetic-diamond disks and thicker cemented-carbide substrates. Cobalt forms a bond with the substrate to create integral compacts that are often bonded to longer cemented-carbide posts for mounting.

Cobalt expands more than diamond when heated. At 1292°F [700°C], this expansion breaks cobalt and diamond bonds, so PDC cutters must remain below this temperature to avoid failure. To help overcome this limitation, thermally stable polycrystalline (TSP) diamonds are produced by treating new synthetic diamonds with acid to leach out cobalt. TSP cutters are stable to 2100°F [1150°C], but are held in place mechanically because they cannot be bonded directly to supports. Silicon, which reacts with diamond particles to form silicon carbide, can be used in place of cobalt. Silicon carbide binds diamond particles and has a much lower thermal expansion coefficient than cobalt. This TSP form is stable to more than 1150°C, but is also difficult to bond.

PDC cutters are more impact-resistant than natural diamonds and extremely effective in hard, moderately abrasive rock. Abrasion resistance improved significantly after 1994 because of accelerated materials development, but compromise was still required because of the inverse relationship between impact and abrasion properties. Impact and abrasion resistance depend primarily on diamond grain size and processing. Larger grains make diamond compacts more impact-resistant, but less abrasion-resistant. Smaller grains increase abrasion resistance, but reduce impact resistance. Reed-Hycalog optimizes diamond cutting structures by mixing diamond-grit sizes to provide better resistance to both abrasion and impact (*left*).

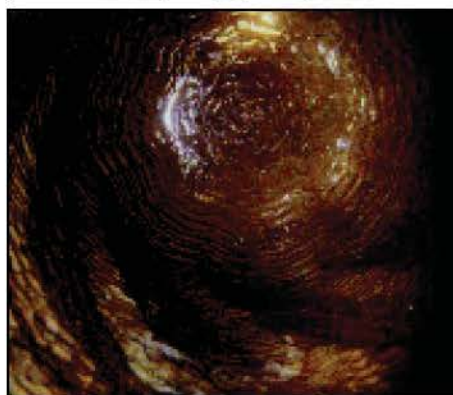
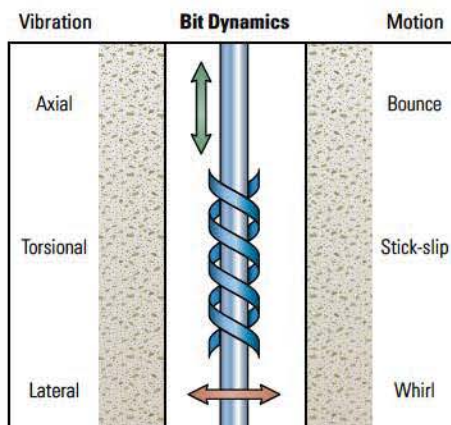
PDC performance is also limited by diamond-table thickness, which is a function of cobalt diffusion from the tungsten-carbide substrate into the diamond layer, and by stresses induced by tungsten-carbide thermal expansion and shrinkage. High residual stress and unsintered diamond grit as a result of incomplete cobalt sweep during PDC synthesis lead to delamination, flaking and cracking of diamond tables that shorten cutter life and end bit runs prematurely. Advanced ASTRA cutters use nonplanar interface (NPI) designs to overcome some limitations inherent in conventional cutters

with flat planar interfaces between diamond table and substrate (below).¹⁷ Diamond-table thickness and residual stresses have always been a PDC weakness, but processing improvements and NPI geometry increase diamond volume and reduce stresses in modern cutters.

NPI geometry reduces residual stress from carbide shrinkage and provides a mechanical lock at diamond-carbide interfaces to increase impact resistance. Additional surface area for bonding and cobalt diffusion allows diamond volumes to be increased 25 to 40%. Severe impacts cause cutters to chip, especially when PDC cutters are new, and all the bit weight and cutting force are directed at the corner tip. As cutters wear, forces are spread along the worn edge, reducing the stresses and risk of damage. TuffEdge cutters have a slight bevel that reduces stress concentrations as cutting edges make contact and begin to cut.

PDC bit stability is important in overall drilling performance. Understanding dynamics and design features that help overcome destructive downhole bit motions is an important aspect in designing and selecting PDC bits. A stable bit increases penetration rate and hole quality, lasts longer, reduces damage to other downhole equipment and improves directional steering by smoothing torque responses.

Downhole, PDC bits move in extremely chaotic fashion that includes lateral, axial and torsional vibrations acting alone and in combination. Downhole vibrations reduce bit life by damaging individual PDC cutters, interfere with directional control and logging-while-drilling (LWD) telemetry by causing torque fluctuations,



^ Downhole vibrations. PDC bit dynamics involve three primary vibration modes—axial, torsional and lateral—that result, respectively, from bit bounce, stick-slip and whirl motions (top left). Whirl is any regular motion characterized by the bit rotating about a point other than its geometric center. Backward whirl, in which the center of rotation moves around the hole counter to the direction of bit rotation, reduces bit performance, damages PDC cutters and produces predictable lobed bottomhole patterns (top right). The lobes generally progress downhole in a spiral sidewall pattern (bottom left), not to be confused with a spiral hole where the centerline forms a corkscrew shape. A stable bit makes concentric circular cuts (bottom right). Stick-slip is the tendency for a bit to slow or stop, torque up and then accelerate as it spins free. Bounce occurs when bits chatter up and down on bottom. Downhole bit motions occur alone and in combination.



^ Advanced cutters. The performance of PDC cutters is enhanced not only by better impact- and abrasion-resistant diamond material, but also by geometry. A nonplanar surface provides a mechanical lock between the diamond table and tungsten-carbide substrate, and more surface area for cobalt diffusion (left). This improves stress profiles relative to planar PDC cutters, increases impact resistance and allows substantially increased diamond volumes. Improvements in impact toughness also contribute to better abrasion resistance by reducing subtle microchipping of diamond tables. However, it is not a simple matter of just increasing diamond volume. Thicker diamond tables have less resistance to abrasion, so both abrasion and impact wear characteristics must be optimized. Beveled cutters reduce initial stress concentrations at PDC edges (upper right).

17. Matthias TR, Griffin ND and Fuller JM: "Elements Faced with Superhard Material," U.S. Patent 5,590,728 (January 7, 1997).
18. Brett JF, Warren TM and Behr SM: "Bit Whirl: A New Theory of PDC Bit Failure," paper SPE 19571, presented at the 64th SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 8-11, 1989.
Brett JF: "The Genesis of Bit-Induced Torsional Drilling Vibrations," paper SPE/IADC 21943, presented at the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 11-14, 1991.
Langeveld CJ: "PDC Bit Dynamics," paper IADC/SPE 23867, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 18-21, 1992.
Kyllingstad A and Halsey GW: "A Study of Stick-Slip Motion of the Bit," paper SPE 16659, presented at the 62nd SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, September 27-30, 1987; also in *SPE Drilling and Engineering* 3, no. 4 (December 1988): 369-373.
Warren TM and Oster JH: "Torsional Resonance of Drill Collars with PDC Bits in Hard Rock," paper SPE 49204, presented at the 73rd SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27-30, 1998.
19. Sinor LA, Powers JR and Warren TM: "The Effect of PDC Cutter Density, Back Rake, Size, and Speed on Performance," paper IADC/SPE 39306, presented at the IADC/SPE Drilling Conference, Dallas, Texas, USA, March 3-6, 1998.

and reduce borehole quality by creating out-of-gauge irregular holes. Downhole lateral, axial and torsional vibrations represent whirl, bit bounce and stick-slip motions, respectively (previous page, top).¹⁸

When PDC cutters grab the bottom of a hole asymmetrically, the instantaneous center of rotation shifts to that spot, and the bit tries to rotate about a point other than its geometric center. This creates backward motion, or whirl, as the center of bit rotation moves around the hole counter to the direction of bit rotation. This results in multilobe patterns on the bottom of a hole instead of the concentric circular cuts of a stable bit. Lateral vibrations and high-impact loads on the back of PDC cutters reduce bit life and may cause catastrophic bit failure. Less destructive forward whirl occurs when the instantaneous center of rotation moves in the same direction as bit rotation.

Stable bit designs reduce lateral motion by adjusting cutter type, size, density, orientation and location so cutters track each other or do not bite as deep.¹⁹ Cutter back-rake controls how aggressively cutters engage formations and can be used to reduce vibrations, but high angles also limit depth of cut and penetration rate. In addition to strengthening new PDC cutter edges, TuffEdge cutters with a beveled leading edge reduce bit aggressiveness, which also increases stability. DiamondBack PDC cutters behind primary cutters on the same blade and at the same depth of cut offer stability benefits from tracking and increased diamond volume on bit shoulders, which allows shorter, more stable profiles.

Bit profile and gauge structure or configuration act to maintain stability. In laboratory tests, profiles that are flat or have deep inner cones reduce bit vibrations. Spiraled gauge pads reduce the capability of a bit to penetrate laterally, or gouge, into borehole walls by increasing circumferential contact. Beveled gauge pads limit side-cutting aggressiveness and reduce the tendency of bits to

grab the borehole wall and cause instability. Asymmetric blade positions break up regular, lobed hole patterns. Spiral blades contribute additional asymmetry by breaking up the single line of cutter contact so that a bit is less likely to uniformly bite laterally into formations and establish a point of rotation other than the center of the bit.

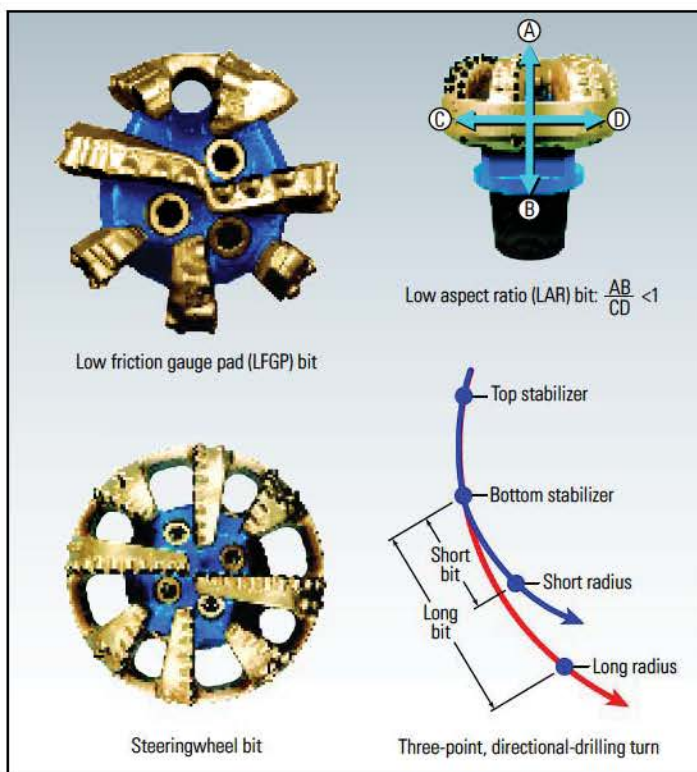
Downhole environments produce many forces on drilling bits. Balancing bits by designing blades and cutters that minimize out-of-balance forces has long been touted as a stability feature. Although variations, such as formation anisotropy and hardness, tend to negate balanced cutting structures, force balancing does at least mitigate bit-induced lateral vibrations. In many applications, bits with one or more standard stability features reduce bit dynamics and provide acceptable performance. However, if vibrations are severe and significantly impact drilling results, other measures are required.

One technique is to install a large low-friction

gauge pad (LFGP) on one side of the bit and arrange PDC cutters so that out-of-balance forces are directed toward the pad. The LFGP antiwhirl design was developed by Amoco Research to minimize lateral vibrations.²⁰ A drawback is that unbalanced forces and directions are difficult to predict. Stability of a LFGP bit can also be compromised by large side-acting forces like those experienced during directional drilling.

Reed-Hycalog uses a larger LFGP pad with no cutting elements to compensate for this uncertainty. Because antiwhirl bits lack side-cutting capability, bottomhole assemblies should minimize side forces for optimal performance. In addition to standard stability features and antiwhirl LFGP bits, design concepts like continuous gauge pad, tracking and hybrid cutters are used to promote bit stability.

Steeringwheel bits utilize a 360°, continuous gauge pad to centralize the bit and maintain lateral stability (below).²¹ By providing full-hole



▲ Stability and directional drilling. Standard antiwhirl bits use large low-friction gauge pad (LFGP) designs (top left). PDC cutters are arranged so that an out-of-balance force is directed toward this bearing pad. Steeringwheel bits go beyond the LFGP concept by providing a 360° continuous gauge ring (bottom left). This feature centralizes the bit and restricts lateral movements by preventing outer cutters from biting into the formation, which reduces whirl and increases cutting structure life. These bits drill smooth in-gauge holes, have less torque fluctuation and have more predictable weight transfer. The smooth torque response of Steeringwheel bits in combination with low aspect ratio (LAR) and short cutting profile makes these designs particularly well suited for directional drilling (right, top and bottom).

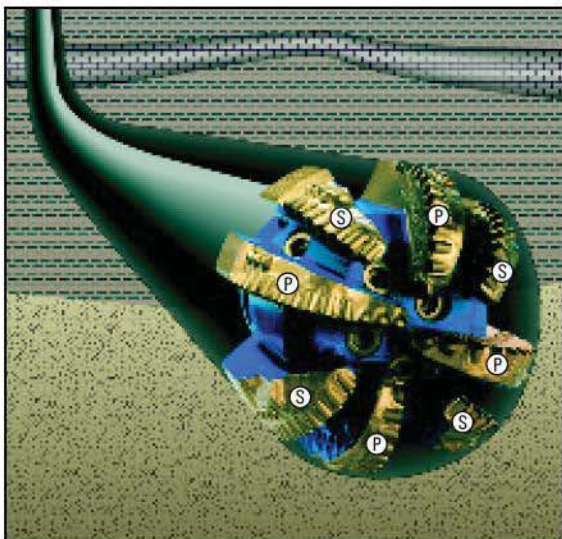
20. Warren TM, Brett JF and Sinor LA: "Development of a Whirl-Resistant Bit," paper SPE 19572, presented at the 64th SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 8-11, 1989.

Sinor LA, Brett JF, Warren TM and Behr SM: "Field Testing of Low-Friction Gauge PDC Bits," paper SPE 20416, presented at the 65th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 23-26, 1990.

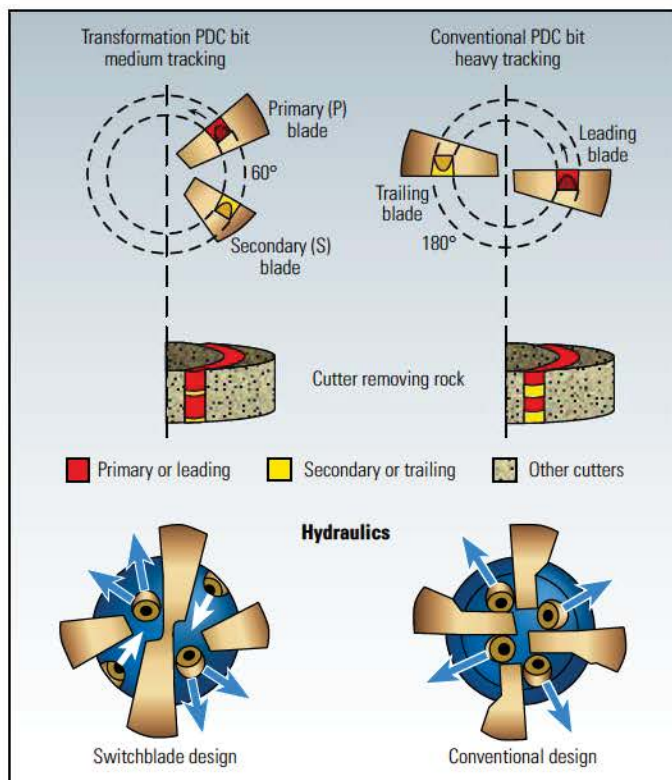
21. Caraway D, Hayward J, Taylor MR, Roberts TS, Taylor S and Watson GR: "Rotary Drill Bits," U.S. Patent 5,904,213 (May 18, 1999).

Caraway D, Hayward J, Taylor MR, Roberts TS, Taylor S and Watson GR: "Rotary Drill Bits," U.S. Patent 5,967,246 (October 19, 1999).

Caraway D, Hayward J, Taylor MR, Roberts TS, Taylor S and Watson GR: "Rotary Drill Bits," U.S. Patent 6,092,613 (July 25, 2000).



Tracking and improved hydraulics. Conventional PDC bit blades generally share rock removal equally. To effectively drill interbedded soft and hard formations, Transformation bits have paired primary (P) and secondary (S) blades (*left*). Variable spacing between tracking cutters on adjacent blades allows cutters on the primary blades to remove more rock than cutters in the same track on secondary blades (*top right*). This allows bits to drill fast in soft formations and reduces cutter loads in harder rocks. Tracking cutters also reduce downhole vibrations. Conventional PDC bit hydraulics channel flow outward from the center (*bottom right*). Much of this flow is inefficient and contributes little to clean and cool cutters. Transformation and Steeringwheel bits use advanced Switchblade cross-flow hydraulic designs that make efficient use of fluid by directing flow from secondary blades inward to maximize flow across the primary blades (*bottom right*).



gauge contact, the bit is less likely to move into the borehole wall, which reduces lateral vibrations, increases cutting structure life and improves borehole quality. These bits generate minimal reactive torque and torque fluctuations, and drill smooth boreholes to facilitate sliding and weight transfer that are essential to control directional orientation.

Steeringwheel bits combine roller-cone directional performance with high PDC penetration rates and meet all the requirements for directional and horizontal wells, including low aspect ratios (LAR), smooth torque response and stable antiwhirl performance. A short bit is easier to turn than a long bit. LAR bits have an aspect ratio—bit length divided by diameter—less than

one and can build, drop or turn angle more easily. Designed primarily for directional steering applications, Steeringwheel bits have a short gauge and flat profile that meet the LAR requirement.

PDC cutters that follow, or track, each other tend to ride in grooves created by the leading cutters, which acts to restore stability. However, deep tracking decreases cutting efficiency and reduces penetration rates by up to 66%. Transformation bits use dual-blade arrangements with moderate tracking to balance stability and penetration rate (*above*). Cutters on primary blades remove about 80% of the rock. Cutters on secondary blades remove less material and do not reduce penetration rates like extra cutters on the blades of heavy-set conventional bits. When

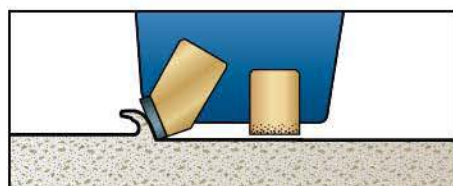
Transformation bits encounter hard formations, the secondary blades become more important. Tracking cutters reduce loads on primary cutters and improve bit stability for longer life.

Steeringwheel and Transformation bits offer additional stability over LFGP designs. Both Steeringwheel and Transformation bits use advanced hydraulics. A patented cross-flow design employs an inboard nozzle directed at each primary blade and an outboard nozzle in front of each secondary blade.²² Fluid exits the outer nozzles, cleaning and cooling only cutters on secondary blades before flowing inward. High-velocity flow from the inner nozzles creates a pressure drop, or venturi effect, that draws flow from the outer nozzles across the bit through the reduced space between

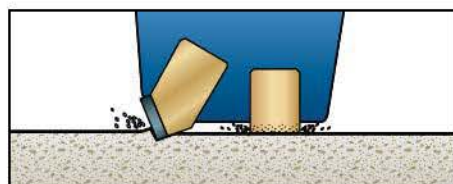
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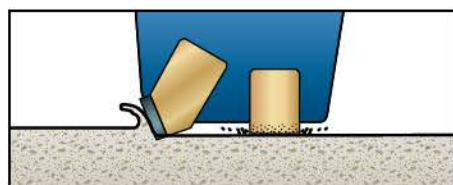
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New hybrid bit



Hard formation



Soft formation

▲ Hybrid cutting elements. Combining PDC technology and natural-diamond-impregnated inserts helps protect PDC cutters from abrasive wear and damage caused by downhole vibrations to increase durability and extend bit life. When hybrid bits are new, diamond-impregnated inserts do not make contact with the formation, and the bit performs like conventional PDC bits to ensure maximum penetration rates (*top*). As PDC cutters wear down in hard formations, diamond inserts engage the formation and take an increasing share of the load, which minimizes PDC damage (*middle*). In softer rocks, more efficient PDC cutters again take most of the load, and cutting efficiency remains high (*bottom*).

blades. Primary blades get flow from both inner and outer nozzles. These Switchblade designs distribute hydraulic energy more efficiently to improve bit cleaning, cooling and penetration rates.²³

Hybrid bits combine PDC and natural-diamond technology.²⁴ Separate diamond-impregnated tungsten-carbide cutting elements are placed behind the main PDC cutters. Each impregnated cutter serves as a load-sharing partner for a specific PDC cutter in high-wear regions of the bit. These secondary cutters protect the PDC cutters in severe drilling conditions and reduce wear in hard, abrasive formations (*above*).²⁵ Hybrid designs improve bit stability by preventing excessively deep cuts, which minimizes lateral and torsional vibrations from whirl and stick-slip. Diamond-impregnated cutters also bear most of the impact from backward bit motion associated with whirl.

Up and down axial vibration, or bit bounce, causes variations in cutting depth that translate

into excessive torque. Impregnated cutters limit formation penetration and smooth out rapid torque fluctuations. Impregnated cutters are set lower than PDC cutters, so as bit weight increases, they contact the formation and decrease torque response relative to bit weight, a particularly important factor in directional drilling applications. Side loads that are applied to bits when drilling with steerable downhole motors expose PDC gauge cutters to impact damage. To maintain effective gauge, Reed-Hycalog PDC bits use impregnated studs for additional gauge protection.

Directional Drilling and Special Bits

PDC bits play an important role in directional drilling and are key components of advanced systems that drill horizontal drainholes and extended-reach wells with complex profiles. Bit configurations, cutting structures, hydraulic designs and gauge protection are areas where technological advances have improved directional performance. Application-specific technology is required to meet the challenges of drilling directional wells.

For optimal bit performance, torque fluctuations must be minimized during directional drilling. Variable torque on steerable motors decreases steerability and inhibits directional control. For rotary assemblies, torque generated by stick-slip at the bit produces harmful torsional

vibrations. Increasing cutter angles, decreasing cutter size and using hybrid diamond-impregnated backup cutters reduce torque. Hybrid technology also reduces torque fluctuations. Beveled TuffEdge cutters are used to minimize PDC damage. Bits for directional and horizontal drilling use small PDC cutters, flat profiles and short overall bit lengths. Increasing contact points on a PDC bit by increasing the number of blades, cutters and gauge pads also reduces torque fluctuations.

Bits are available for rotary steerable systems that drill horizontal and extended-reach wells. Push-the-bit technology like PowerDrive rotary steerable systems makes directional adjustments from surface while rotary drilling. Instead of using a steerable motor to tilt or point the bit, a force generated by the tool deflects the bit in the required direction.²⁶ Independent of torque, bit trajectory is controlled by downhole valves and pads. These systems have less drag, transfer weight to bits more effectively and achieve higher penetration rates. Continuous pipe rotation improves hole cleaning and reduces wellbore tortuosity, which means fewer wiper trips and lower rig costs. Rotary steerable systems allow use of aggressive bits and offer opportunities to optimize bits.

Specific PDC bit features maximize rotary steerable system performance.²⁷ Bits for these systems require low aspect ratios and active gauge, or aggressive gauge cutting structure (*below*).

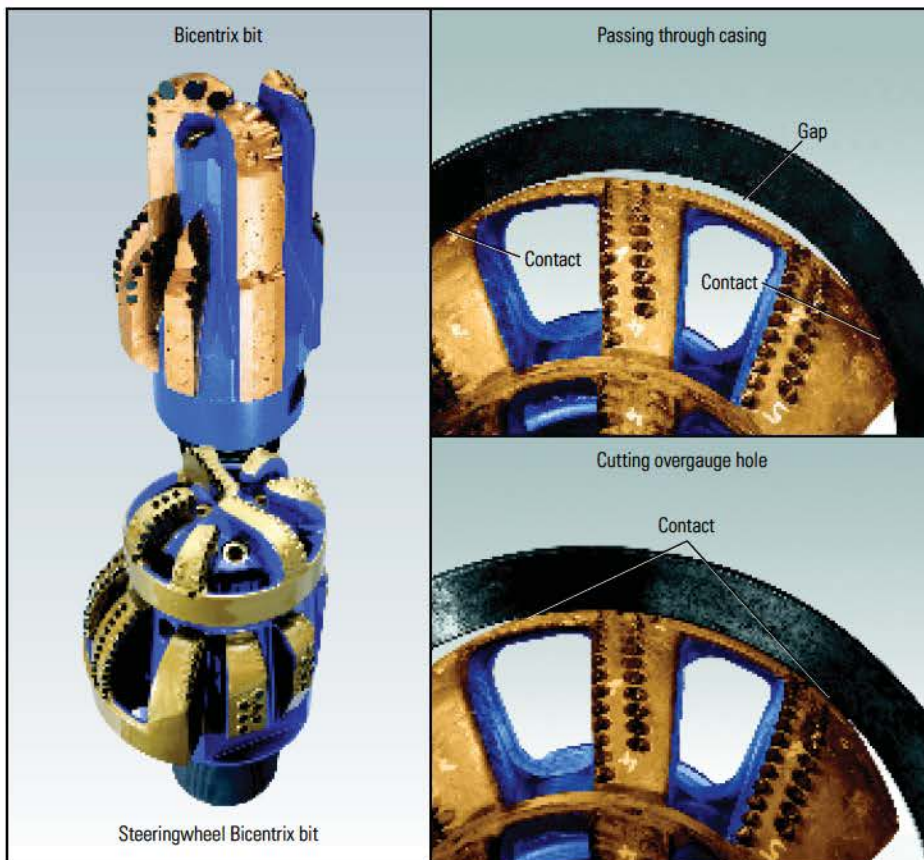


Conventional gauge



Active gauge

▲ Active gauge. Steerable rotary bits require aggressive cutting structures on the gauge. To achieve required well trajectories, a bit must cut into the side of the hole as rotary steerable tools apply lateral force to point the bit in the proper direction. In contrast to conventional gauge protection (*left*), active gauges have reduced bit diameters, full-round PDC gauge cutters with aggressive back-rake angles along the entire gauge length and tungsten-carbide hybrid studs that control the depth of lateral cut (*right*). A maximum number of exposed cutters increases side-cutting capability and improves bit durability. Smaller bit diameters reduce friction and improve fluid flow in the gauge region for better cooling and cleaning.



◀ Eccentric bits. Bicentrix bits have an enlarged structure, or reamer, on one side to drill larger holes below casing (*top left*). Without rotation, asymmetry allows the bit to pass through a smaller diameter. Steeringwheel Bicentrix bits are designed to drill out cement and continue drilling in directional applications (*bottom left*). The reamer section shape prevents cutters from contacting casing while drilling out cementing equipment (*top right*). Cutters on the reamer then rotate with the bit to cut an overgauge hole (*bottom right*).

Diamond-Impregnated Bits

Selecting bits for extremely hard, abrasive formations involves compromise. PDC bits drill fast, but do not last long in abrasive conditions; roller-cone bits drill more slowly, but may wear out quickly and produce undergauge holes. Natural-diamond bits have better penetration rates and last longer, but selection has been limited, especially for interbedded formations where soft stringers plug the bit face and degrade drilling performance. In the past 10 years, diamond-impregnated bits have come full circle and there has been a revival of sorts. With better matrix and diamond material and new manufacturing techniques, wear resistance has improved significantly. Impregnated bits can be designed to drill soft or hard, abrasive formations. Downhole turbines and motors have also improved and stay in the hole longer to take advantage of the long life of impregnated bits.

Early diamond-impregnated bits, which date back to the 1800s, drilled slowly and were primarily a last resort when formations were too hard, abrasive or deep for roller-cone, PDC or surface-set natural-diamond bits. Diamond grit is now suspended in the tungsten-carbide matrix of bit blades for vastly improved wear resistance. Instead of individual cutters, the entire bit face contains cutting elements set as deep as hydraulic water courses. Diamonds grind hard formations, and blade edges shear soft formations like PDC bits. Penetration rate is gradually reduced as blade edges become rounded. The matrix abrades away to continually expose new sharp diamonds. Bit life is a function of diamond-impregnated volume that can be placed on the bit face. Taller blades, therefore, last longer.

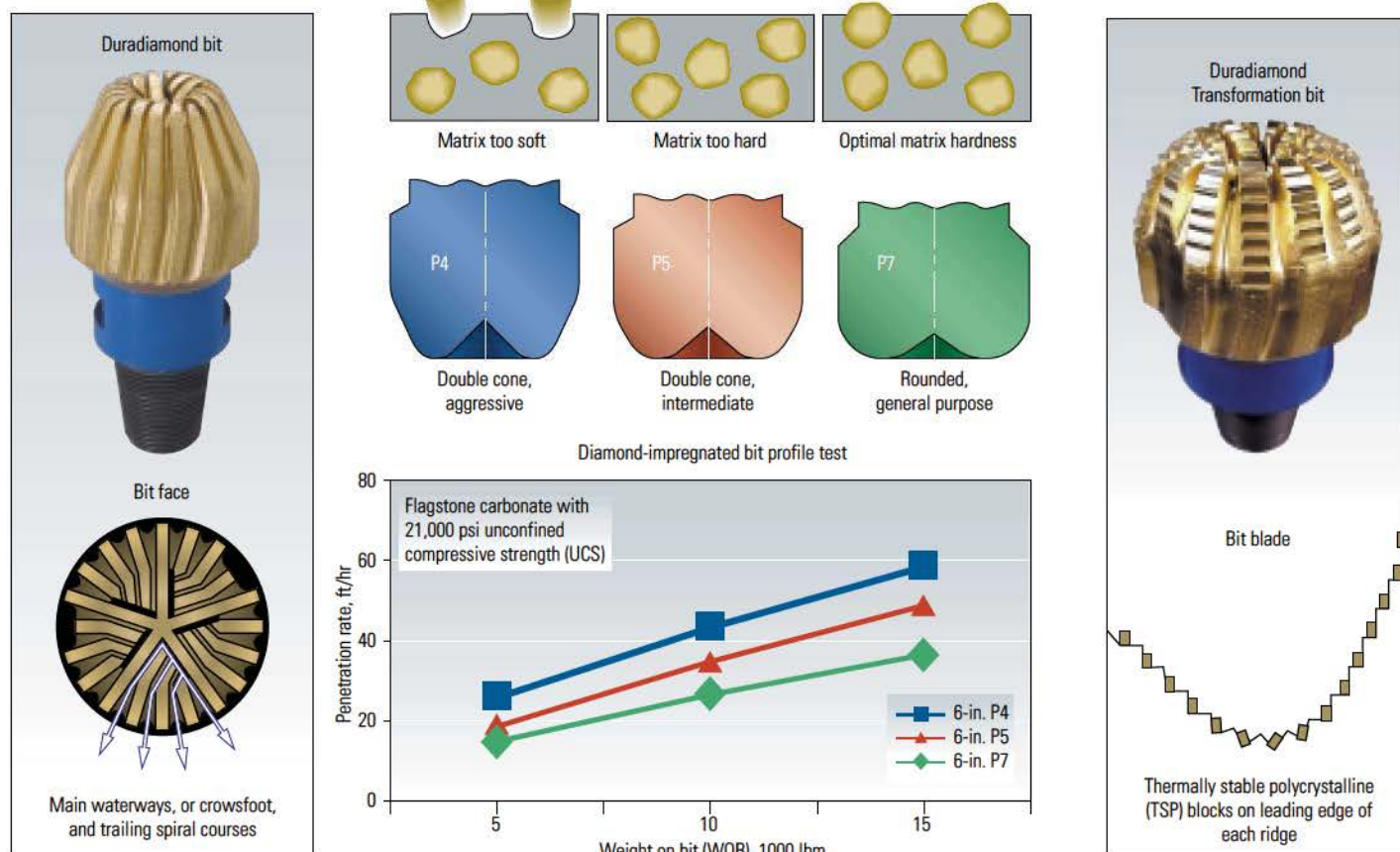
In the past, diamond-impregnated bits were limited to drilling hard and abrasive formations with high-speed turbines. Over the past few

Conventional PDC bits lack significant side-cutting capability. Traditional gauge-protection elements like tungsten carbide or diamond-impregnated inserts, thermally stable polycrystalline (TSP) diamond tiles and preflattened PDC cutters are used only to maintain bit diameter and drill full-size holes. The active-gauge concept, first developed for North Sea applications, features full-round PDC cutters with hybrid tungsten-carbide dome-shaped studs directly behind them for protection and a reduced gauge diameter with insert protection removed to increase cutter exposure.

High gauge-cutter densities and low back-rake angles on active-gauge designs provide aggressive side-cutting capability and improve steerability. Active-gauge point contacts—cutters and hybrid studs—reduce gauge-pad friction, drag and bit torque. Smaller gauge diameters improve fluid flow around the bit, which aids in cooling and cleaning the gauge pad and cutters. Active gauge is used on both steel and matrix bits. This technique provides adequate gauge protection, but steel bits require erosion-resistant hard-metal facing due to improved flow across the pads.

Experience is a critical element in providing drilling-bit solutions for directional drilling. The Schlumberger focus on directional drilling is embodied in the PowerSteering concept, a unique combination of technology and experience. In demanding directional-drilling applications, the PowerSteering process provides for specification of the proper bit, modification of existing bits or design of a custom bit.

Sometimes there is a need to enlarge existing boreholes or drill oversized holes below casing, especially to improve cement jobs or complete wells in formations that swell or cave. In the past, mechanical underreamers that expanded to cut a larger hole diameter were used. Today, asymmetric bits are available for these applications. Bicentrix bits pass through a smaller diameter to drill a hole that is larger than the previous section or casing (*above*). The latest versions of these bits combine Bicentrix reamer and Steeringwheel directional designs with a patent-pending reamer that allows an enlarged hole to be drilled without tripping the bit after drilling out cement. Shorter reamer blades are shaped to provide clearance between the casing and outer cutters on the longest blades.

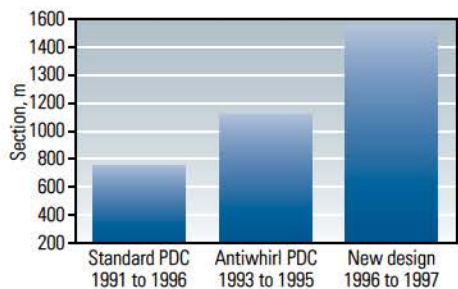
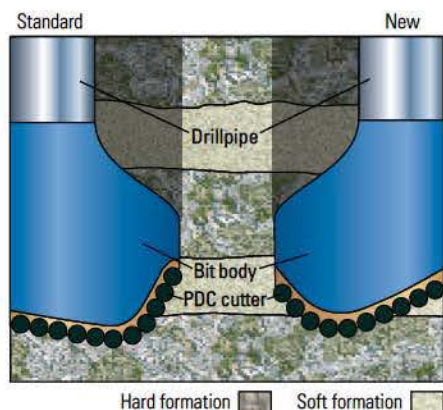
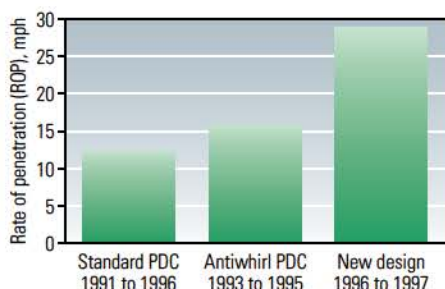


^ Impregnated bits. Diamond-impregnated bits are specialized grinding wheels. Duradiamond technology provides options to handle any type of hard formation. Special mixtures of diamonds and tungsten carbide were developed to increase penetration rates and ensure longer bit life. Matching matrix and diamond wear balances bit life and penetration rate. If the matrix is too soft, diamonds are released before they wear out, which shortens bit run time. If the matrix is too hard, diamonds are not properly exposed and penetration rates are reduced. Three profiles are available (*middle*). The most aggressive profile is a deep double cone (blue) for drilling softer interbedded formations and horizontal sections. A rounded, shallow double cone (red) is used in intermediate-strength formations. A flatter rounded profile (green) is a general-purpose design for harder, abrasive formations and angle-building sections of directional wells. Duradiamond (*top left*) and Duradiamond Transformation (*right, top and bottom*) bits use radial-flow hydraulics to provide even flow across the bit face (*bottom left*).

years, the range of applications expanded into interbedded sands, shales, carbonates and coal, as well as rock types like igneous, metamorphic and conglomerate, drilled directionally with downhole motors. Today, diamond-impregnated bits are capable of drilling many types of formations (*above*). A balance between diamond and matrix properties optimizes drilling performance and cost savings, especially in high-speed positive-displacement motor and turbine drilling applications. Three profiles—deep double cone, shallow, round double cone, and flat profile—are available to increase the range of applications for these bits.

Because impregnated bits are also used in interbedded formations, demand for more aggressive cutting structures has risen. For soft formations with thin hard stringers, impregnated bits are supplemented with TSP cube or triangular cutting elements for increased aggressiveness. Duradiamond Transformation designs use patent-pending ridged profiles with primary, secondary and tertiary blades at different heights. TSP blocks are placed in the ridges on leading edges of each blade to keep these edges sharp. These bits start drilling with five blades, then become a 10-blade bit and eventually a 15-blade bit as variable-height ribs wear down.

Because there are no low-pressure areas to draw fluid across the bit, secondary water courses connect directly to the main waterways, or crowsfoot, so high-pressure radial fluid flow goes to every waterway. This provides even flow to all parts of the bit and reduces plugging. Water courses converge at different radii to spread out areas without diamonds and reduce ring-wear failure. V-shaped waterways are easier to clean, maximize blade volume and diamond-grit for a given flow area, and provide an aggressive cutting edge.



Customized fixed-cutter bits. A combination of PDC technologies, including LFGP, optimized profile and Switchblade hydraulics, provides a bit solution that consistently drills interbedded formations without compromising overall performance. A shallow bit profile minimizes cutter damage when entering and leaving hard stringers by distributing loads evenly between inner cone and outer shoulder areas. Two bit types run in the Tunu field near Balikpapan in Indonesia (top left) from June 1991 to April 1997 were analyzed and compared with this new design (top right). The first bit was a standard PDC design with 14 runs; the second was a conventional antiwhirl design with 42 runs. The new bit had 20 runs at the time. The new design drilled 180% farther (bottom right) and 141% faster (bottom left) than standard PDC bits; and 68% farther and 70% faster than conventional antiwhirl bits.

Customizing Fixed-Cutter Performance

Drilling in Tunu field in Mahakam delta near Balikpapan, Indonesia, is complicated by interbedded formations in a 12¼-in. hole section. Lithology at the top of the section consists of soft, homogeneous sand and claystone. Lower down, formations are composed of medium-strength homogeneous sandstone and shale. Unpredictable limestone and dolomite layers are encountered throughout the interval. Limestone stringers, which are not abrasive and much softer than dolomite, are up to 2 m [7 ft] thick. Extremely hard dolomite stringers have little porosity and are about 0.5 m [1.6 ft] thick.

When field development began in 1973, the 12¼-in. section was drilled with water-base mud and 8 to 12 roller-cone bits at an average rate of about 9 m/hr [30 ft/hr]. By the 1980s, PDC bits and oil-base mud were also being used. The first PDC bits were standard designs. Three roller-cone bits and three PDC bits were needed to drill the section,

which improved average penetration to 10 m/hr [33 ft/hr]. In the late 1980s and early 1990s, roller-cone bits were replaced and three or four PDC bits were used to complete the section. Analysis of dull bits indicated that high-impact loads in hard dolomitic stringers caused catastrophic failures—broken, chipped and lost cutters. After conventional antiwhirl bits were tried, a new design was evaluated to improve performance.

More stable bits were required to reduce bit vibration, primarily lateral whirl, and complete the section with a single bit. However, interbedded formations make selecting an optimal bit problematic. Bit features required for hard stringers conflict with those needed in softer formations. Soft formations require effective hydraulic cleaning, aggressive profiles, large cutters and high usable diamond volumes to achieve high penetration rates. Antiwhirl technology, low-gauge friction for stability and optimal cutter designs for long bit life are necessary in hard stringers.

Cutter failures are caused by initial contact in hard stringers and increased vibrations when leaving hard rock. When entering hard rock, nose cutters make contact first and become overloaded relative to cutters that are still in a soft stringer. This overload is reduced by a short profile. On departure from hard stringers, shoulder and gauge cutters become overloaded. This is even more damaging because gauge cutters are at a greater radius than face cutters, which increases impact inertia. Designing cone depth and height to be the same so shoulder, gauge and cone cutters share bit weight and loads evenly as the bit leaves a hard stringer minimizes this effect (left).

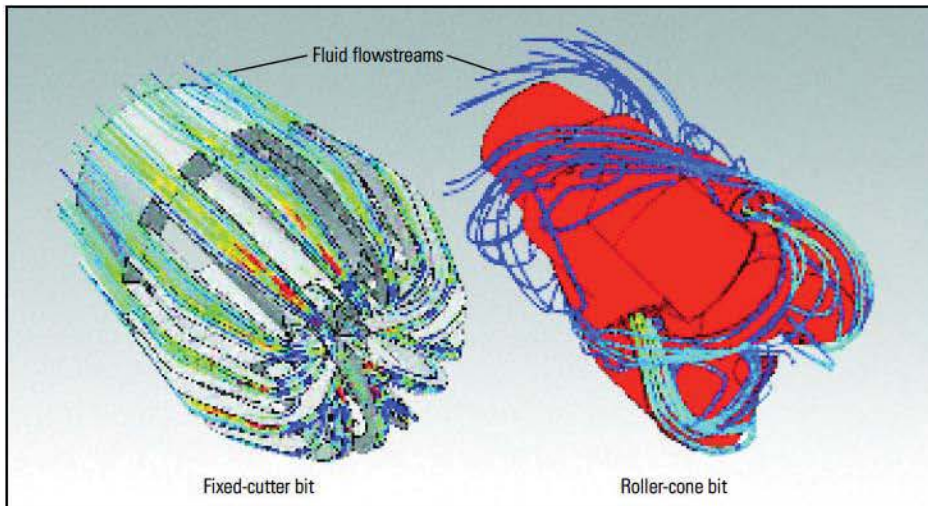
Bits were equipped with large cutters to maintain high penetration in soft formations and maximize available diamond volume to achieve required bit life and drill the entire section with one bit. A LFGP was used to reduce vibrations and prevent whirl. Bit balling in soft formations was a problem, so a Switchblade hydraulic design was used to improve flow across the bit face for better cleaning, particularly in the junk-slot area enclosed by the LFGP. Steel-body bits were selected for this application because they give elastically under impacts and reduce cutter damage.

The new bit initially drilled sandstone at 120 m/hr [394 ft/hr] and claystone at 80 m/hr [262 ft/hr]. As the formation became harder near the bottom of the section, sandstone was drilled at up to 40 m/hr [131 ft/hr] and shale at up to 30 m/hr [98 ft/hr]. Hard dolomite stringers were drilled about 0.5 to 1 m/hr [1.6 to 3.3 ft/hr]. Analysis of the new design revealed little or no impact damage, indicating sufficient bit stability. There was no heat damage or wear, which suggested that the hydraulic design was cooling cutters effectively.

The 12¼-in. bit optimization was extremely successful. In 1997, TotalFinaElf converted part of the Tunu field drilling program to slimhole wells, so 12¼-in. sections had to be drilled as 8½-in. A smaller bit based on combined PDC technologies was designed to confirm that these features could be transferred to other bit sizes. When the 8½-in. bits were tested in the field, performance matched that of the larger bits.

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Ledgerwood LW, Wells MR, Wiesner BC and Harris TM: "Advanced Hydraulics Analysis Optimizes Performance of Roller Cone Drill Bits," paper IADC/SPE 59111, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 23-25, 2000.



▲ Computational fluid dynamics (CFD). Like other finite-element analysis methods, CFD programs model fluid flow around bits inside a borehole. In addition to simulating PDC bit hydraulics, CFD is being used to optimize cuttings removal and minimize regrinding in Mudpick and Mudpick II designs. This modern design program reduces the time required to get new bits into the field.

Bit Design, Testing and Selection

Simulation and modeling drive many of the advances that are being made in bit design and optimization. Computational Fluid Dynamics (CFD) programs are used to investigate design and optimize fluid flow in diverse applications. CFD techniques complement laboratory testing or serve as an alternative to experimental data. Modeling bit hydraulics by CFD produces results quickly and economically, and is particularly useful when complex shapes and flow conditions are difficult to reproduce experimentally.

Analysis by CFD influenced fixed-cutter designs like Switchblade hydraulics and is increasingly utilized for designing roller-cone bit hydraulics (above).²⁸ Simulation results must be validated quantitatively, so CFD will not replace experimental flow testing, especially for radically different shapes and designs. However, modeling will be an important tool for accelerating the design process.

A key to PDC bit modeling is equations for cutter-rock forces and interactions. The HYDI program, an advanced design tool for predicting forces that result from interactions between PDC cutters and rock, has been under development for more than three years. During this time, algorithms have been optimized through single-cutter tests and testing in the Pressurized Drilling Laboratory. Currently, the HYDI program is used primarily to calculate unbalanced forces, but it can also indicate inherent bit stability. Bit simulations can be run in kinematic (motion) or dynamic (force) modes. Other options are also available, including bit motion, tilting of the bit and PDC density. A torsional model is in development and testing.

Advanced computer-aided design (CAD) software allows engineers to design tools and bits in three dimensions and generate mathematical models to drive computer numerically controlled (CNC) machines that replicate designs exactly in steel or tungsten carbide. These capabilities facilitate optimization and customization by further reducing lead-time, which moves bits from engineering to manufacturing in weeks instead of months.

In the past, drilling bits were evaluated primarily by testing individual components and limited small-scale tests on complete bits, followed by prototype field testing. This approach is costly in terms of time and money. Design decisions are often based on incomplete or inconsistent field performance, and final products are not always optimized. Full-scale bit testing in rock samples under pressure began at TerraTek in Salt Lake City, Utah, USA, in 1977. In 1982, Reed built the first in-house Pressurized Drilling Laboratory (PDL) to bridge the gap between component tests and field testing (below). This facility provides



▲ Pressurized Drilling Laboratory (PDL). PDL facilities, including a Flow-Visualization Chamber and Endurance Test Rig, were instrumental in development of Mudpick, Mudpick II and Switchblade hydraulic designs, texturized radial seals and the Threaded Ring bearing. The main rig is a triangular frame that supports hydraulic cylinders that provide force to the bit. A pressure vessel within this structure contains the rock samples. Two 500-hhp triplex mud pumps provide system flow and pressure. Vessel pressure to simulate downhole borehole conditions is generated by a computer-controlled choke that creates the proper backpressure. The PDL facility has a complete mud system that allows either water- or oil-base mud systems to be used.

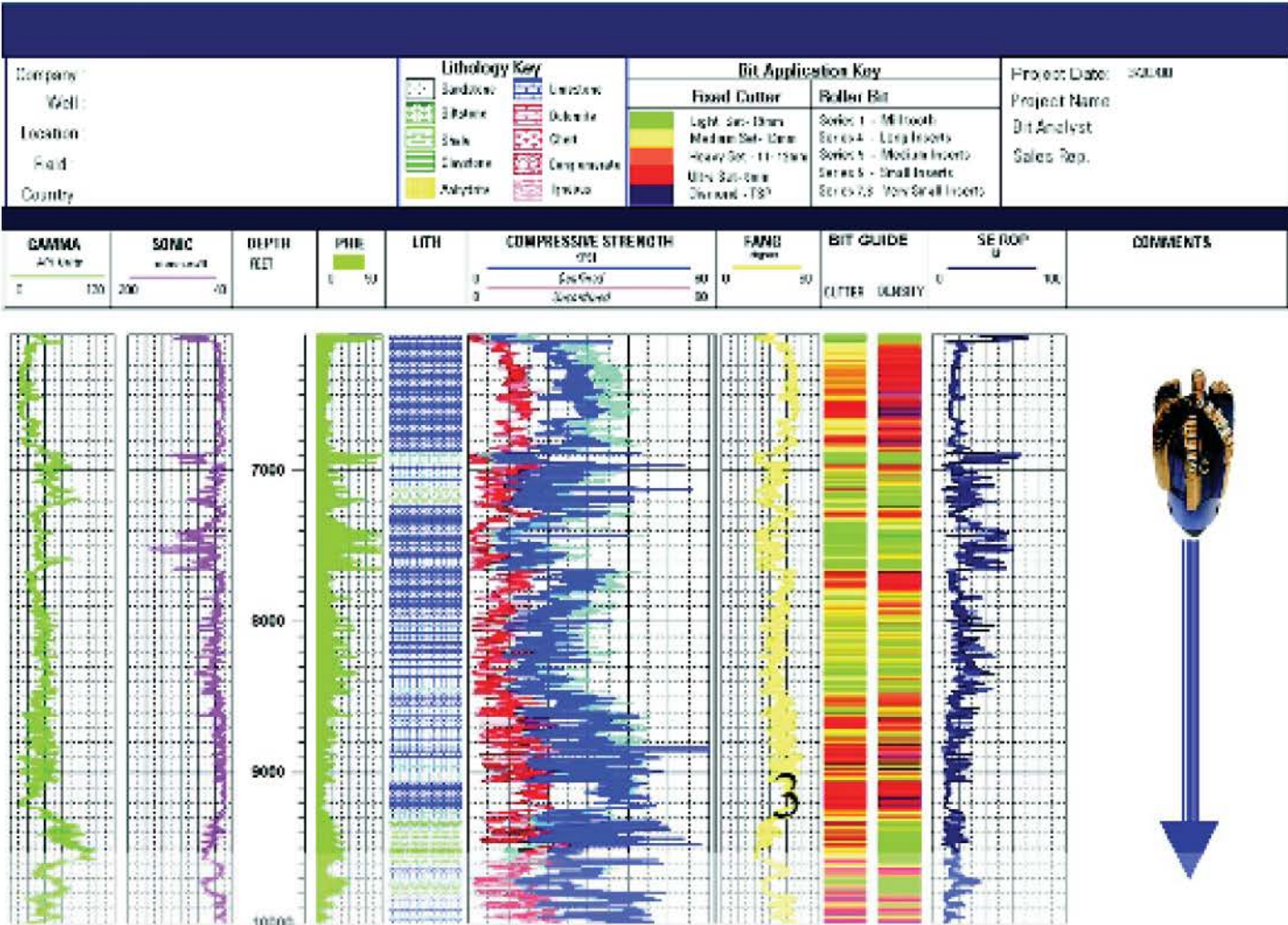
operators with cost-effective solutions and reduces the time to commercialize new bit products by allowing extended evaluation of bearings, seals and grease.

Individual components like bushings, seals and cutting structures are still tested using specialized equipment. An Endurance Test Rig is available to test instrumented full-size bits in pressurized drilling mud at elevated temperature for long periods. Bits are then disassembled to determine wear characteristics. The system is capable of applying bit weights and rotary speeds similar to field parameters. Temperatures, pressures and stresses are recorded. Because these tests generate bearing conditions that are similar to field runs, test results can distinguish design improvements. A Flow-Visualization Chamber

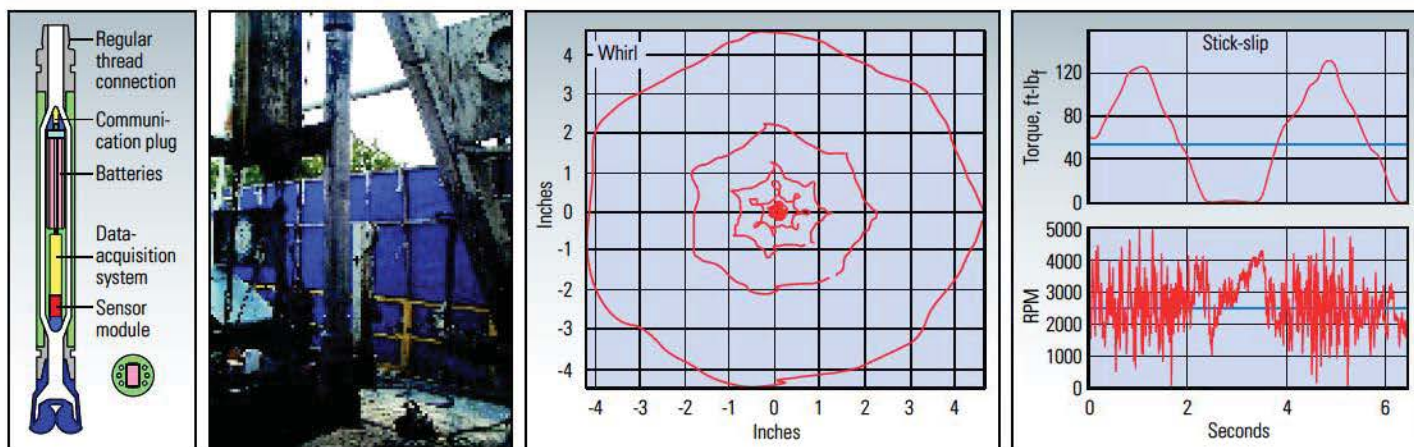
allows circulation over a bit face to be viewed through clear plastic. Areas of insufficient or excess flow can be identified and corrected before prototype bits are tested downhole.

Traditionally, bit selections were made using data and logs from offset wells, but this approach does not take into account formation strength. Because sonic velocity is related to rock hardness, sonic well logs have been used as an indication of formation strength.²⁹ Recently, programs were developed that use sonic log data to compute unconfined compressive strength—rock hardness at atmospheric pressure. This is an improvement over using sonic velocities directly, but often understates in-situ formation strength. Compressive-strength analysis is a new quantitative method to estimate rock hardness, which can be used to identify the proper application for a bit.³⁰

The Rock-Strength Analysis (RSA) program was developed in 1993 for PDC bit selection and recently adapted for roller-cone bits. The RSA system defines rock hardness in terms of confined compressive strength, which approximates in-situ hardness. The program uses sonic and gamma ray well logs plus data from mud logs. Within lithology ranges for which this program is valid, rock hardness can be determined accurately. Program output is typically graphed in a log format that displays raw data traces from well logs, computer-interpreted lithology, calculated confined compressive strength and various optional rock-mechanics outputs (below).



▲ Rock-Strength Analysis (RSA). A computer analysis program was developed to aid in PDC bit selection. The program uses sonic and gamma ray data from well logs and input from mud logs to accurately define rock hardness in terms of confined strength or in-situ hardness. Program output is typically graphed in log format that displays raw data traces from well logs, computer-interpreted lithology, calculated values of confined compressive strength and rock mechanics parameters.



▲ Recording bit data downhole. The instrumented Drilling Research Tool (DRT) system contains accelerometers to measure lateral, axial and torsional (rotational) acceleration, and also to determine the spatial position of a bit. In addition, the tool measures bit speed and angular orientation with a magnetometer, and weight on bit and torque with strain gauges. Sensors measure temperature and pressure—internal and external.

Output from the RSA program is used in new bit designs and to modify current designs. The program is most effective when formations are homogeneous, isotropic and plastic, which is typical of most rocks that contain oil and gas. It does not work well for conglomerates, unconsolidated sediments or highly brittle and nonplastic rock types like igneous and metamorphic, and compressive-strength analysis alone does not indicate abrasive formations or damaging minerals like pyrite.

Tracking and Monitoring Bit Performance

The surest way to optimize bits and improve drilling performance is to quantify experience by monitoring successes and failures. A database of bit runs and parameters is vital for bit manufacturers to evaluate drilling performance. Reed-Hycalog has long recognized the advantages of having a bit-run database to close the design loop.

A single, company-wide BitTrak database is linked throughout the organization, so that bit-performance data and available offset-well information are accessible in field locations worldwide. Engineers from all parts of the company use the BitTrak database for both roller-cone and fixed-cutter bits to analyze and solve problems.

PowerSteering strategies require that the database record the factors and variables related to directional drilling, including bottomhole assembly data, motor specifications, well profiles

and survey data. The BitTrak database is also useful for monitoring test-bit performance as well as bits in general use. Being able to track, manipulate and evaluate bit-performance data makes analysis easier and more useful.

Downhole dynamics affect bit life, but phenomena like whirl and stick-slip are difficult to detect and monitor accurately at surface because of drillstring mass, flexibility and damping effects. As a result, it has been difficult to develop a full understanding of downhole dynamics. Similarly, laboratory data do not always represent actual operating environments. To overcome these limitations, Reed developed the Drilling Research Tool (DRT) sensor package to capture high-frequency downhole data, evaluate bits in real operating environments, identify potential new developments, validate laboratory tests and enhance predictive modeling (above). Two DRT tools—a 6½ in. and a 9½ in.—are currently in use.

The 6½-in. tool has been used with both roller-cone and fixed-cutter bits. The DRT system measures bit motion—axial, lateral and rotational accelerations—speed, angular orientation, weight and torque as well as internal and external pressures and temperatures. Continuous slow-speed data are collected for the entire run. High-speed data bursts can also be collected during specific events or timed windows. This tool improves understanding of downhole dynamics, possibly the single most important area of drilling operations. Predicting and controlling bit dynamics will increase bit performance and facilitate bit optimization. In combination, DRT sensors and the BitTrak database are powerful tools for optimizing bit designs and drilling performance.

On the Horizon

What is the future of drilling bits? Product and drilling service delivery will include seismic while drilling, global positioning of bits, reservoir analysis at the bit, bit-life prediction and real-time dynamics monitoring and control. Areas of ongoing research include full-scale laboratory testing, downhole data monitoring, modeling to support bit and drilling optimization, and emerging-materials technology. Bit specialization and customization will play increasingly important roles in the delivery of optimized bit products, services and solutions. Streamlining manufacturing by locating mills and lathes together in centers, or cells, has facilitated bit customization, improved efficiency and reduced manufacturing time. This allows quick retooling to accommodate design revisions.

In the final analysis, the primary objective of any drilling bit is to apply the best cutting structure and optimal cutting action to help construct cost-effective wells. Emerging-materials technology, like diamond composites, will continue to be critical in future bit developments. The full potential of these materials for improving drilling performance depends on developing processes for manufacturing more efficient cutting shapes and robust materials. Substrate-interface modifications, residual-stress measurement and modification, and functionally graded diamond layers are also active areas of research. New high-pressure, high-temperature processes are generating diamond production efficiencies that reduce cost and extend the application of diamond-composite elements across cutting structures for both fixed-cutter and roller-cone bits. —MET

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