

PDC Drill Bit Design and Field Application Evolution

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Summary. This paper traces the development of polycrystalline diamond compact (PDC) bits from their introduction in 1973. Such design features as body materials, crown profiles, cutter density, and cutter exposure and their effect on bit performance are discussed. In addition, the paper reviews various aspects of bit applications engineering, including bit hydraulics, drilling fluids, directional behavior, and formation types.

Introduction

The introduction of PDC cutters in 1973 facilitated the development of the first drill bit that used synthetic diamonds as cutting elements. The development process has progressed so that today a large amount of footage is drilled with PDC bits. Through this process, several design features that affect bit performance have become clear. Specifically, the effects of bit body material, cutter placement and density, bit profile, back rake, side rake, and hydraulic horsepower on application and performance have been delineated. The industry has seen the introduction of first steel-body, then tungsten-carbide-matrix-body drill bits. Cutter placement and density were initially determined by way of an equal-volume-per-cutter calculation. The state-of-the-art PDC drill bits feature computerized cutter placement and density based on an equal work rate per cutter. Also incorporated is a torque-balancing function and a vector resolution that considers back rake, side rake, and bit profile. Hydraulic layouts are now optimized with the aid of a flow-visualization chamber.

Extensive field testing, in conjunction with engineering design evaluation, has defined the current application zones and limits of PDC bits. The availability of new cutter shapes and sizes, as well as improved thermal stability and mechanical toughness of the PDC cutter, will enable further evolution of PDC bit designs. Currently, large-diameter PDC cutters providing increased exposure and shaped cutters featuring a higher point loading per cutter are some of the technological advancements being tested. This influx of improved superhard materials, coupled with hydraulically and mechanically more efficient bit designs, will expand the PDC application zone of the future.

Initial Designs

Initial PDC bits differed quite drastically from the present catalog models of manufacturers. Early prototypes used concepts very similar to those of natural diamond bits (Fig. 1).

The profiles used were basically the same as those of conventional natural diamond bits, simply replacing the natural diamonds with the PDC cutting element. Various flow arrangements were investigated, including the conventional crowsfoot, waterways, and fixed nozzles.

Additionally, there were changes in the PDC cutting element. Initial cutters were 0.323 in. [8.2 mm] in diameter vs. the standard 0.524-in. [13.3-mm] -diameter cutter, which is most commonly used today. Early PDC cutters were available in both a 180 and a 360° [3.14- and 6.28-rad] blank affixed to a stud. Early bits used steel, carbide, and hardfaced steel studs, and combinations of both the 180 and 360° [3.14- and 6.28-rad] blank.

Field Application

An early field test of a petroleum drill bit that used PDC cutters took place in Nov. 1973 in Colorado. From these tests, numerous inherent design weaknesses were apparent. The problems are

thoroughly documented by Walker *et al.*¹ Basically, the problems were that the small-diameter (0.323-in. [8.2-mm]) blanks did not provide sufficient area to allow a competent braze to the stud. Furthermore, the small blank did not provide sufficient exposure necessary for high rates of penetration (ROP's). Problems were also encountered with impact breakage of the studs, cutter loss caused by braze failures, and poor hydraulic configuration to provide adequate cleaning.

Improved Designs

After discouraging early field results, bit designers realized that to make use of this new cutting element, the trend of thinking would have to deviate completely from conventional natural-diamond-bit designs. The contrast between the grinding and plowing cutting mechanism of a natural diamond and the shearing action of rock by PDC cutters necessitated that a workable bit have a radically different design for efficient drilling. This realization led to the first PDC bit style, which resembles what is commonly found today in manufacturer catalogs (Fig. 2). This bit features a bladed-type arrangement, tungsten-carbide-matrix body, waterways, and several nozzles (actual number depending on the particular design). Performance was marginal but encouraging, with the typical problems being plugged nozzles and cutter loss.

In 1978, the PDC cutter became available with an additional piece of tungsten carbide attached. This provided a larger area to braze to the bit body, and thereby a stronger bond (Fig. 3).

Field testing proceeded, and the cutter-loss problem was not completely solved until a new brazing process was developed in 1979. The success of field tests during this time was sporadic, because the learning curve of application and operating parameters of these bits was in the very early stages. However, some runs showed sensational performance and savings.

By this time, operators and manufacturers had begun to realize the potential of PDC bits, and development work received new attention in the following time period. Advancement in design, operating parameters, and formation application proceeded at a rapid pace.

Note that the bulk of the early bits mentioned here are the tungsten-carbide-matrix-body bits with brazed cutters. Stud cutters used in steel-body bits, however, were also being investigated in parallel. By now the basics of PDC bit designs were apparent, and what remained was the determination of the specifics and the effects on bit performance.

Design Features Affecting Bit Performance

Bit-Body Material. Currently, the two aforementioned materials, tungsten-carbide matrix and steel, are being used in PDC drill bits (Figs. 4 and 5). No conclusions are drawn as to which design is more efficient, but some characteristics of each have become apparent.

Steel-body bits use a stud cutter (Fig. 6) that is interference-fitted into a receptacle on the bit body. The gauge protection is typically

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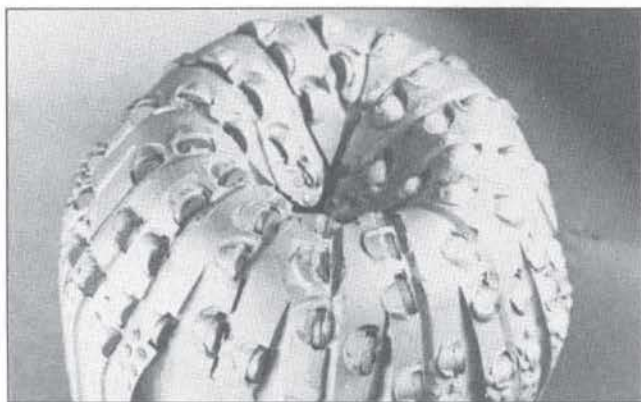


Fig. 1—Early PDC design.

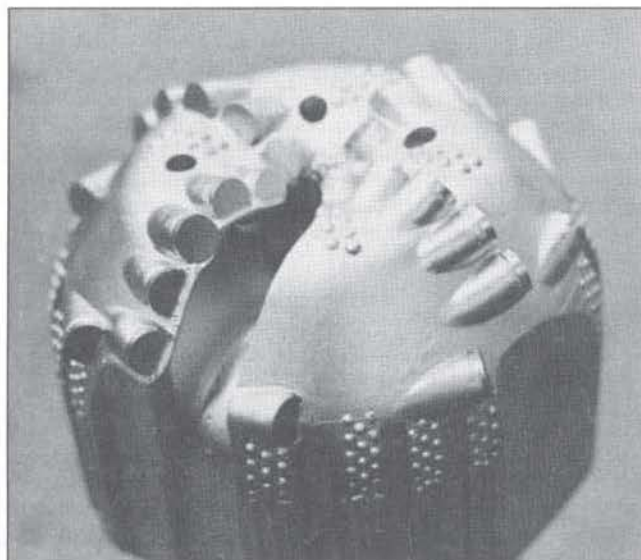


Fig. 2—Improved PDC design.

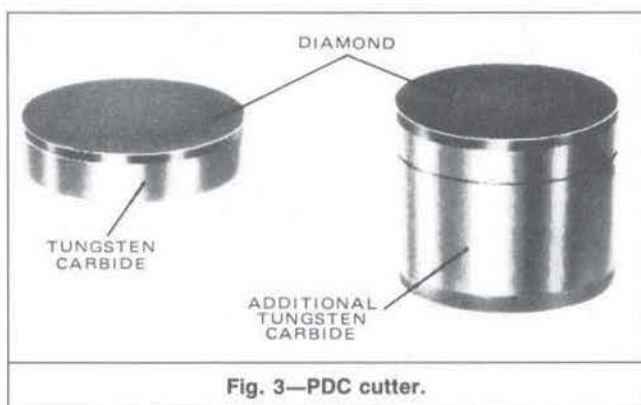


Fig. 3—PDC cutter.

a tungsten-carbide-button insert. The stud comes with a fixed back rake that limits the back-rake variation possibilities on the finished bit. An advantage of the stud is that it may be removed and replaced if bit-body erosion has not become a limiting factor. The use of the stud also eliminates the braze between the cutter and the bit body.

Field experience has shown that steel-body bits exhibit face erosion.²⁻⁵ This typically occurs in conjunction with high bit-pressure drop, extended runs, and/or high-solids-content mud situations. This becomes a limiting factor when the studs cannot be replaced or the nozzle retention system is hampered by erosion or abrasion and thus the rebuilding advantage is lost. This problem is solved somewhat by application of a hardfacing compound to the bit body, which reduces the erosion and abrasion effects.³



Fig. 4—Steel-body PDC bit.

Steel-body bits have also suffered from broken cutters as a result of limited impact resistance because there is no backing to a stud cutter.³

Steel-body bits use a tungsten-carbide insert for gauge protection, which can be of concern under such high revolutions-per-minute drilling applications as motor drilling.

Matrix-body bits use a cylindrical cutter that is brazed into a pocket after the bit body has been furnace-fitted by conventional natural-diamond-bit techniques. The advantage is that a tungsten-carbide-matrix-body bit is both erosion- and abrasion-resistant⁵ and the matrix pocket provides impact resistance. Matrix-body bits have an economic disadvantage because the raw materials are more expensive.

The features and benefits of each type of bit body are such that certain manufacturers have pursued the steel-body version, others the matrix-body version, and some offer both steel- and matrix-body bits.

Back Rake. Much work has been done in regard to field-testing of different back-rake angles to evaluate performance and single-point cutter tests.^{6,7} A number of conclusions can be drawn on the basis of this work. It is now known that as the back-rake angle is decreased, the cutting action becomes more efficient—i.e., for the same weight on bit (WOB), a greater depth of cut is achieved with a smaller back-rake angle, which generally produces a larger chip.¹ This makes the bit more aggressive and, other things being equal, a higher ROP is attained. The smaller rake angle, however, makes the cutter more vulnerable to impact breakage should a hard formation be encountered. Conversely, a larger rake angle will produce a smaller chip, but will be more durable in a hard formation, giving longer bit life.

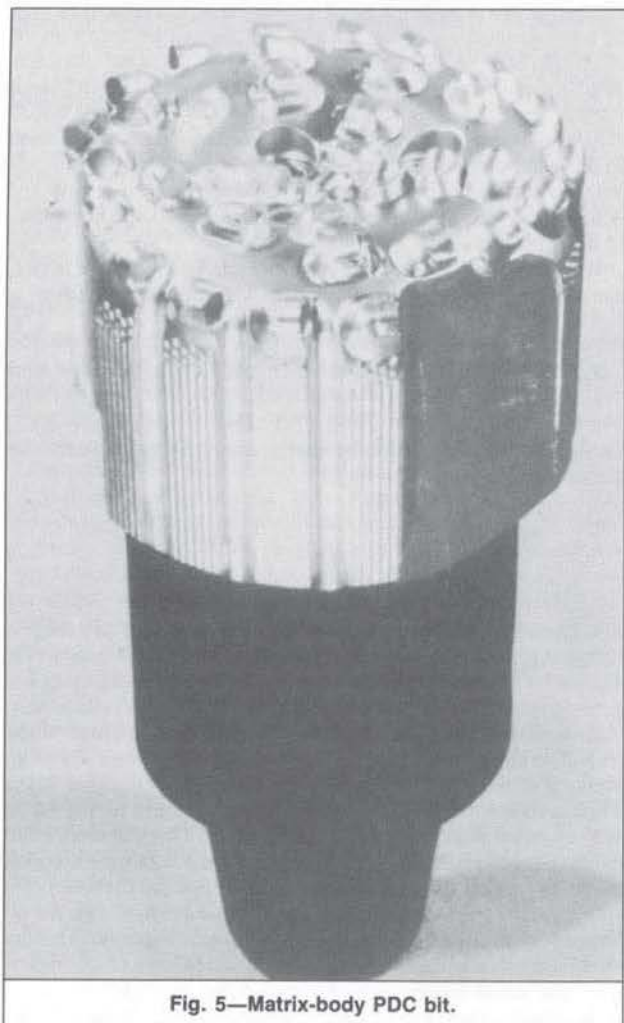


Fig. 5—Matrix-body PDC bit.

Additionally, back rake affects cleaning as it urges the cutting to curl away from the bit body for more efficient cutting removal.⁶

Side Rake. Side rake affects the cleaning of a PDC bit in that a cutter that uses side rake mechanically directs cuttings toward the annulus.⁷

Profile. There are three basic types of crown profile: flat or shallow cone, tapered or double cone, and parabolic. There are variations other than these types, but typically these variations fall

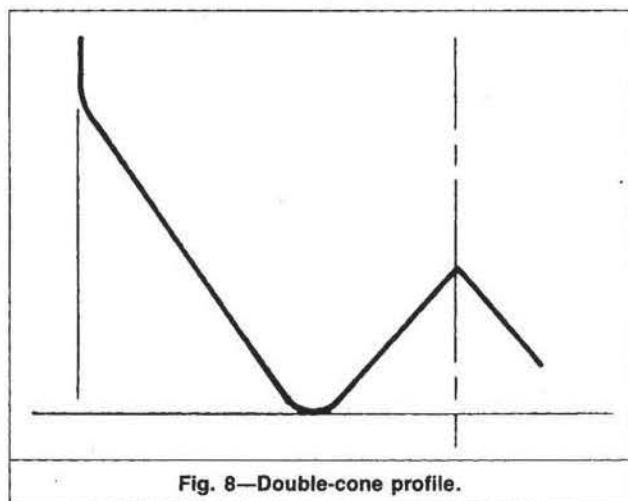


Fig. 8—Double-cone profile.

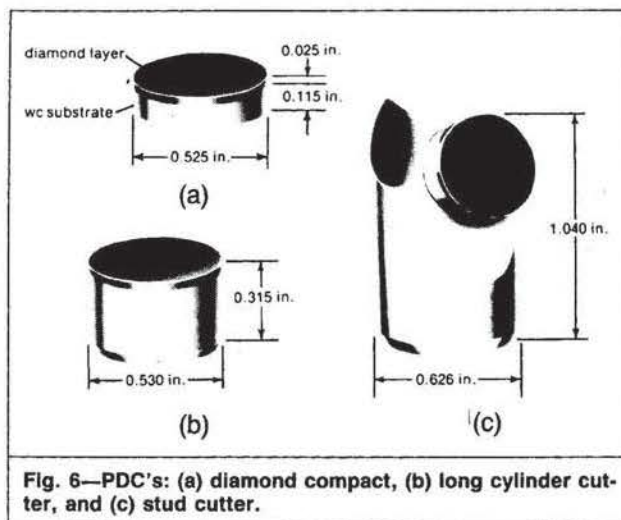


Fig. 6—PDC's: (a) diamond compact, (b) long cylinder cutter, and (c) stud cutter.

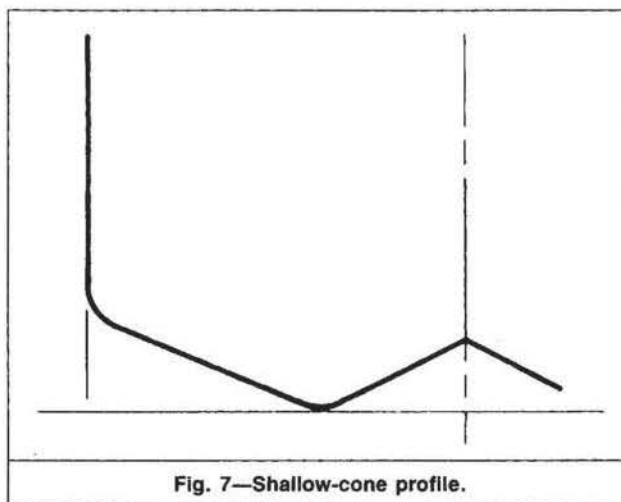


Fig. 7—Shallow-cone profile.

somewhere among the three basic types. Field application has delineated some differences in performance between profiles.

The flat- or shallow-cone crown profile evenly distributes the static WOB among each of the cutters on the bit (Fig. 7). If the analogy of a bit being able to drill only as fast as its fastest cutter is applied, then flat-profile bits have the highest ROP potential, because the cutting depth of each cutter is theoretically equal.

Two disadvantages of the flat profile are limited rotational stability and uneven wear. Because of the shallow profile, rocking can occur at high revolutions per minute. This can cause high in-

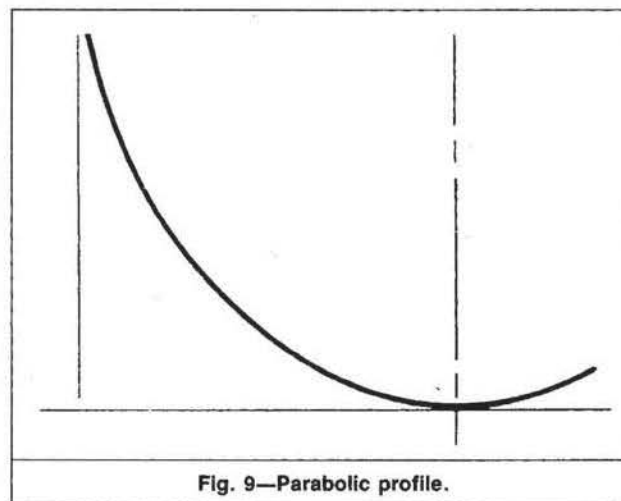


Fig. 9—Parabolic profile.

stantaneous point loading and loss of cooling to the PDC cutters, which is detrimental to bit life.

Analysis of dull bits shows a recurring wear pattern; wear increasing from the center of the bit to the OD. This means that the innermost cutters are not being used to their fullest potential.

The flat profile appears to be limited mainly to applications where hard stringers are not present. A hard stringer is differentiated from a common stringer in that it does not undergo plastic deformation before failure and thus is not sheared by the PDC cutter. The theory is that when a hard stringer is encountered, the depth of cut decreases, and because the WOB is distributed evenly over the cutters, so is the depth of cut. This is evidenced in the field by a reduction in both ROP and rotary torque when a hard-sand stringer is encountered. To achieve the necessary depth of cut and therefore ROP, the WOB would have to be increased. This may cause overloading of the cutters and catastrophic failure. Alternatively, because of the increased peripheral speed of the OD cutters, this new WOB value will create elevated work rates of the OD cutters and consequently accelerated wear.

The tapered- or double-cone and the parabolic crown profiles (Figs. 8 and 9) allow increased distribution of the cutters toward the bit OD. As a result, rotational and directional stability and more evenly distributed wear are achieved.

The resultant side forces created by the WOB on the cutters on the bit flank have a stabilizing effect on the bit that reduces bit wobble and deviation tendencies.

The evaluation of used bits has shown a typical PDC wear pattern, where wear increases toward the bit OD. However, these profiles use the cutters near the bit center more effectively.

Additionally, the consensus is that the tapered profile is more suitable for drilling in areas where hard-sand stringers are common. The sharp nose will provide elevated point loading on the nose to allow a greater depth of cut in harder formations.

The parabolic profile provides a smooth load distribution over the profile of the bit, which eliminates sharp transition zones (Fig. 9). This profile has the largest surface area, which then requires the most cutters for adequate coverage. The parabolic profile is typically the bit of choice in motor or turbine drilling.

Cutter Density

Qualitative measurements of bit performance relative to various cutter densities are possible. This is apparent from both laboratory and field studies.⁸

As cutter density—or the number of cutters of a PDC bit—increases, ROP decreases. This occurs for a number of reasons, two of which are most important. First, for equal WOB values, the depth of cut, and therefore ROP, decreases for increased cutter densities. Second, adding more cutters to the bit face reduces the efficiency of cleaning, which directly affects ROP's.⁹

Conversely, increasing the cutter density of a given PDC drill bit will reduce the effective load per cutter. The work rates and therefore wear rates of individual cutters will be decreased, which will extend bit life.

Cutter Exposure

Cutter exposure is considered for its effect on cleaning and mechanical strength. It is discussed in terms of full or partial exposure of the PDC cutter in relation to the bit face.

Cerkovnik⁸ discussed the effect of exposure on the ability of a cutting to be generated without interference from the bit body. Therefore, the cutting would be carried away quickly and bit balling or regrinding of cuttings would not occur. It can be concluded that increased exposure provides more clearance between the bit body and the formation for cutting generation. This increased clearance is at the expense of face velocity, however, because increasing the area between bit and formation reduces face velocity.

The benefit of partial exposure is that it provides additional mechanical backing to the PDC cutter for increased resistance to impact loads. This would be of concern in applications where harder formations, such as hard-sand stringers, are expected that could result in higher impact loads.

Further studies of the advantages and disadvantages of full and partial exposure were discussed by Huang and Iversen.⁷

Field Application

Hydraulic Horsepower. Extensive field testing has shown that only on a broad overview can qualitative conclusions be drawn on the effect of increased hydraulic horsepower on PDC-bit performance. The conclusion is that increased hydraulic horsepower will benefit PDC-bit performance. This is consistent with roller-cone bits.

Several examples of improved performance in terms of increased ROP, reduced bit balling, etc., have been documented.^{2,4,5,8,9} Additionally, included in the examples cited are both laboratory and field studies where the benefits of increasing hydraulic horsepower have been proved.

When hydraulic horsepower is considered, two terms are important: bit pressure drop and flow rate. This can be seen from

$$P_{hh} = \frac{pq}{1,714} \quad (1)$$

Further, the specific hydraulic energy expended per inch of hole diameter, d , is calculated by

$$P_{hsi} = \frac{P_{hh} \times 4}{\pi d^2} \quad (2)$$

It is known that a combination of flow rate and pressure drop is required to clean the bit efficiently.⁸ The flow rate available for a given bit is usually fixed between certain limits. These limits are generally specified for cuttings-carrying capacities, critical annular velocities, and other concerns. The pressure drop across the bit will be limited by standpipe pressure and the maximum discharge pressure of the pump. To maximize hydraulic horsepower at the bit, it is recommended that all the available pressure for the bit be used after the system losses are accounted for. This will ensure that the maximum available hydraulic horsepower is being expended at the bit, which is a major component in optimal drilling.

One further point worth mentioning in regard to hydraulic horsepower optimization is that the output and input horsepower of the mud pump should be recognized. Many cases have arisen where the rated output horsepower of a mud pump at a given flow rate is much higher than the available input horsepower to the mud pump. If this is not recognized, nozzle sizing will be based on a hydraulic horsepower level that the pump cannot deliver.

Operating Parameters

The operating parameters of a PDC bit differ greatly from those of a conventional roller-cone bit. To achieve optimal performance from a PDC bit, it is critical that this fact be recognized. It is consistent that PDC bits require different operating parameters, because the shearing action of a PDC bit is quite unlike the crushing, grinding action of a roller-cone bit.

The basic trend is that PDC bits drill best with light weight and high revolutions per minute, and require much higher torque than roller-cone bits.¹⁰ Cheatham and Loeb¹⁰ recommend that the highest available rotary speed be used and that its effect on ROP be evaluated in each instance. Their work showed that this remains true whether the bit is in new or used condition, in the field or in the laboratory.

Another commonly observed characteristic of PDC bits in field applications is torque and revolutions-per-minute cycling. This is attributed to the resemblance of the drillstring to a torsional spring, achieving its natural frequency with certain revolutions-per-minute, WOB, and torque combinations. Cheatham and Loeb¹⁰ attributed this to a discrepancy between mechanical horsepower supplied and demanded by the bit. In the field, this cycling can be reduced by reducing WOB or increasing rotary speed.

Directional Tendencies

The directional tendencies of PDC bits have not been clearly defined to this point. In areas where an extensive amount of PDC drilling has been done, and azimuth and drift have been monitored, conclusions have been drawn.

Balkenbush and Onisko⁴ report that PDC bits have been run in Alaska simply to overcome the characteristic right-hand walk of roller-cone bits. Earlier, Paterson and Shute¹¹ developed quantitative measurements of left-hand walk rates to be expected with various near-bit and bit stabilizer-gauge lengths during turbodrilling. Directional characteristics were also investigated by Powell *et al.*¹²

A very general conclusion is that PDC bits tend to walk left (counterclockwise). However, azimuth and drift are both influenced by formation characteristics, bit profile, bit size, formation dip, WOB, bottomhole assembly, and other factors. This means that the specific directional characteristics must be determined on a local level for a specific application.

Formations

Formation selection, like directional tendencies, can be talked about only in broad terms. Specific formation applicability must be determined on a local level, giving attention to such things as length of section, frequency of stringers, roller-cone bit performance, and rig rates.

Generally, PDC bits have proved successful in formations that range from soft to medium hardness ratings. More specifically, PDC bits are applicable in formations that lend themselves easily to the shearing/cutting action of the PDC cutter. These formations undergo plastic deformation before failure, so are typically revolutions-per-minute sensitive rather than weight sensitive. Applicable formation types would include shale, claystone, clay, limestone, anhydrites, chalk, and marl.³

Two types of formation cause the most frequent problems with PDC bits: hydratable shales and sandstone stringers.

The hydratable shale is most often encountered in the U.S. gulf coast region, where it is often referred to as "gumbo." Shale hydration is a function of the specific surface area of the clays contained in the shale. These clays, specifically illite and montmorillonite, undergo hydration during drilling with water-based muds. The result is a plastic, sticky shale that is no longer brittle and is not revolutions-per-minute sensitive to the PDC bit. A common result in drilling hydrated shales is bit balling.

Sandstone stringers are quite common in shale sections that are PDC-drillable. These stringers are not PDC-drillable and can cause bit damage or prematurely short runs and ultimately result in misapplication.³

Drilling Fluids

PDC bits have been successful in both water- and oil-based muds and variations of the two.^{2,4,5} Extensive work has been done, however, on the improved performance of PDC bits when oil-based mud systems are used. This improved performance has been most evident when the formation being drilled is a hydratable shale.^{2,5} Holster and Kipp¹³ found that a hydratable, gumbo-type shale could not be drilled effectively without the use of oil-based mud. Furthermore, they found that ROP was sensitive to hydraulic-horsepower-per-square-inch increases when a hydratable shale was drilled, but not when a relatively nonhydratable shale was drilled with an oil-based mud.

Besides the attributes of preventing clay hydration to reduce bit balling during PDC drilling, other benefits have been found with oil-based muds. Moore *et al.*⁵ reported that in the Tuscaloosa trend of southern Louisiana, PDC bit performance increased in terms of ROP and footage. Reasons for this improved performance have been attributed to such factors as increased lubricity with oil muds, lower cutter-wear-flat temperature, which is related to cutter wear rate, and preferential oil-wetting of the bit body.

The benefits of oil-based muds have been well documented and accepted. The fact remains that even though oil-based muds do provide benefits to PDC drilling, they are not prerequisite to economical PDC runs.

Consistent with conventional roller-cone bits, PDC bit performance is affected by mud properties. An increase in solids content or mud weight will decrease PDC bit performance.⁵

Design Evolution

As mentioned earlier, PDC bit designs have undergone great changes since their initiation in 1973. A wide range of different

designs are being used today. Realistically, there is no way to define which is the "best" design without being equivocal or ambiguous. Alternatively, some design criteria are discussed.

One method of determining the cutter placement and density of a PDC drill bit is to perform an equal-volume-per-cutter calculation.¹⁴ This means that each cutter on the drill bit will be responsible for removing the same volume of rock per revolution of the bit. Because the volume of rock removed increases with distance from the centerline, cutter density must be increased also to maintain the equal-volume-per-cutter relationship.

PDC cutters have two basic limits: the maximum threshold impact force that can be sustained and a thermal limit that dictates wear rate. The PDC cutter is given its resistance to impact failure by the more ductile tungsten-carbide or steel stud that backs the diamond table.

Two temperatures, 662 and 1,382°F [350 and 750°C], are important when PDC thermal loads are considered. At a cutter temperature of 662°F [350°C], Glowka and Stone¹⁵ estimated that PDC-cutter wear rates would be accelerated by a factor of 1 to 2. Above 1,382°F [750°C], stresses generated by the differential thermal expansion between the diamond and the binder (primarily cobalt) cause catastrophic failure. This failure takes the form of whole-diamond-grain extraction made possible by the breaking of the diamond/diamond bonds. Essentially, the PDC cutter loses its polycrystalline nature and becomes susceptible to cleavage fracture as in monocrystalline natural diamonds.

In light of this, it would seem paramount to consider PDC-cutter temperatures and resultant wear rates in the design stages of PDC bits. The temperature of a PDC cutter is affected by many factors in drilling. The major factors, however, are WOB and rotary speed. Further, it has been shown that WOB increases are felt quickly by the PDC cutter in terms of temperature and in nearly proportional amounts.¹⁵

If the location of the cutter is considered, as well as its back rake, side rake, torque, WOB, revolutions per minute, ROP, and some formation parameters, a work-rate calculation is then possible. Clearly, a work-rate calculation for each cutter would be a tedious task. The use of computers is a necessity and computer-aided design (CAD) is commonplace. The specific formulas and calculations for such a design program are beyond the scope of this paper. It is sufficient to say that the computer can now provide the bit designer a tool that was previously unavailable. The effective load per cutter can be determined with respect to back rake, side rake, and bit profile, as can the direction of reactive torque for the total bit, and discrepancies can be corrected so no unintentional deviation occurs.

Recent developments now allow testing of full-size drill bits in a flow-visualization chamber. This makes possible evaluation of the cleaning characteristics of a PDC bit before it is recognized as a problem from dull bits. The effect of nozzle orientation with respect to cutter location and junk slots is now discernible.

PDC Future

In certain areas, such as North America, the PDC-drillable formation types have been delineated to a certain degree.³ Undoubtedly, many more formations will be discovered in various parts of the world that are PDC-drillable. Hydraulically and mechanically improved bit designs will provide enhanced performance in these formations.

A large growth potential for PDC drill bits lies in the formations that are not currently being drilled with PDC bits. An example of this would be the gumbo shale of the U.S. gulf coast region. As the thermal limits of the PDC cutter are raised, and the size and shape varied, formations that were classified as non-PDC-applicable will become PDC-drillable.

Review

1. PDC bits evolved from designs that resembled conventional surface-set natural diamond bits to today's versions.
2. Early steel-body, stud cutter bits suffered from broken studs and erosion.
3. As the number of cutters of a PDC bit increases, ROP will decrease.

4. Increasing the hydraulic horsepower expended at the bit will improve PDC performance.

5. Optimal PDC bit performance is achieved by the use of light weight, high revolutions per minute, and high torque.

6. PDC bits are applicable in soft to medium-hard formations.

7. PDC bits show improved performance when oil-based mud systems are used, especially if the formation being drilled is a hydratable shale.

8. PDC cutters have two important thermal limits: 662 and 1,382°F [350 and 750°C]. At these temperatures, cutter wear rate is accelerated.

9. PDC bit design theories include equal volume per cutter and equal work rate per cutter. Both are well suited for CAD.

Nomenclature

d = diameter, in. [cm]

p = pressure, psi [kPa]

P_{hh} = hydraulic horsepower, hp [kW]

P_{hsi} = hydraulic horsepower per square inch, hp/in.² [kW/cm²]

q = flow rate, gal/min [m³/min]

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SI Metric Conversion Factor

$$\text{in.} \times 2.54^* \quad \text{E}+00 = \text{cm}$$

*Conversion factor is exact.

JPT

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