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PDC Bits: What's Needed To Meet Tomorrow's Challenge

T.M. Warren and L.A. Sinor, Amoco Production Co.

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Abstract

When polycrystalline diamond compact (PDC) bits were introduced in the mid-1970s they showed tantalizingly high penetration rates in laboratory drilling tests. Single cutter tests indicated that they had the potential to drill very hard rocks. Unfortunately, 20 years later we are still striving to reach the potential that these bits seem to have. Many problems have been overcome, and PDC bits have offered capabilities not possible with roller cone bits. PDC bits provide the most economical bit choice in many areas, but their limited durability has hampered their application in many other areas.

Introduction

Polycrystalline Diamond Compact (PDC) cutters were first introduced by General Electric in 1973, and a specific commercial product for application in oil field drill bits was introduced in 1976.¹ Laboratory drilling tests at the University of Tulsa demonstrated that PDC bits could drill Carthage Marble much faster than natural diamond bits.² After struggling with an initial difficulty with the integrity of the cutter attachment process, PDC bits first demonstrated a commercial success in drilling evaporites that contained little shale and no hard or abrasive streaks.³ Later work showed that the bits could drill shale in oil based muds which minimized bit balling tendencies.⁴ By the early 1980s, successful PDC bit applications were being reported in many places beyond their initial successful applications in the North Sea. These successes were still largely limited to soft to medium hard rocks and were limited in shale formations to applications with oil based mud. The introduction of the fish-tailed bit by StrataBit provided a breakthrough that greatly reduced the bit balling problem in shale and allowed shales to be drilled consistently with water based muds for the first time.⁵ The application of PDC bits continued to expand throughout the 1980s, but they failed to penetrate the harder rock market.

Feenstra⁶ found that the two main stumbling blocks to the expansion of PDC bits into harder rock was their limited temperature stability and impact resistance. When PDC bits were run in hard rock the cutters often showed evidence of heat damage on

both the diamond layer and carbide substrate. Often cutters were also broken, and this was attributed to the cutters being overloaded from hitting ledges when the bit was tripped into the hole or from hitting chert or pyrite nodules while drilling.

In 1989 Brett et al.⁷ demonstrated that PDC bits suffered from a dynamic instability known as bit whirl and showed that this was a primary cause of PDC cutter damage. Once whirl was identified as a cause of PDC bit failure, many of the early difficulties were easier to understand. In fact, many of the early observations about PDC cutter damage, in retrospect, are known to have been caused by whirl.

Whirl caused the cutters to be damaged by impact loading, even in homogeneous rock, by allowing the cutters to move sideways and backward so that the diamond cutting edge was damaged. This damage to the cutting edge allowed the carbide substrate to contact the rock and generate heat. This in turn further damaged the diamond and gave the appearance that the cutter had been damaged by heat, when in fact the root cause of the damage was the initial chipping, as indicated in Figure 1.

Whirl Limits PDC Performance in Hard Rock

Whirl => Cutters Chip => Wear Flats => Failure

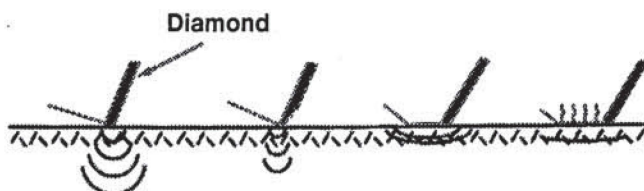


Figure 1: Mechanism of whirl damage to PDC cutter.

The identification of bit whirl as a primary cause of PDC cutter damage caused a significant shift in emphasis of research on ways to build bits for drilling hard rock. The development of a more heat tolerant cutter became less important and the development of a more impact resistant cutter and a more stable bit design became more important.

Development of More Robust PDC Bits

Any PDC bit design is, by necessity, a compromise of design principles. It must provide adequate penetration rate and durability in order to make it economical compared to alternatives, such as roller cone bits. Often the design features that beneficially affect penetration rate adversely affect durability and vice versa.

Modern PDC Bit Design

Bit manufacturers use numerical models to design the cutter lay out for PDC bits so the loads and wear for cutters over the face of the bit are balanced. These models often include proprietary cutter load and wear models, but they are generally based on the assumption that the bit rotates about its centerline. There are some dynamic and kinematics models that allow other bit motions, but these models are rarely used in the bit design process.^{8,9}

Early PDC bit manufacturers often did not have adequate quality control to assure the cutters were positioned as specified by the design. Out of tolerance cutters caused individual cutters to be overloaded and could cause the bit to be out of balance.¹⁰ Over the last few years the quality of cutter placement has been greatly improved through increased emphasis on quality control and the development of methods to measure the cutter placement on completed bits. Most major manufacturers now routinely produce bits with adequate tolerance in cutter placement.

Cutter attachment methods which were previously a large concern has become less of a concern. Cases are relatively rare where the cutter attachment fails or the cutters are thermally damaged during the manufacturing of bits.

The process of designing bits to provide adequate cleaning and cooling seems to be less sophisticated than the cutter layout process. Some bit designs have been heavily studied, but generally the hydraulic design of many bits are less than optimum. Often studies are conducted by drilling with a number of bits and trying to identify the "good" hydraulic features. Alternately, the studies are used to identify the effect of horsepower, jet velocity, flow rate, etc. on performance with the intent to generalize this to other bits. Unfortunately, this rarely works because the hydraulic performance of a bit is dependent on a more complicated interaction of fluid mechanics and geometrical bit features.

Subtle changes in hydraulic design can make an appreciable difference. The design of a particular bit needs to be optimized, but often bit designs change too fast for this optimization to occur. Sophisticated hydraulic models are available to evaluate bit designs, but they are much more difficult to use than the cutter layout models. This results in there being considerable potential to improve the hydraulic design of many PDC bits in use today.

Vibration Control

PDC bit manufacturers recognize that an essential part of bit design is vibration control. Many studies have shown that PDC bits are easily influenced by a lateral vibration known as "whirl."^{7,11,12} Although this is widely recognized, the response by different manufacturers varies quite widely.

One manufacturer has converted a significant portion of their production to incorporate a specific design concept, low friction gauge, that is aimed at minimizing the effect of whirl.¹³ This design concept provides that the cutters are arranged to provide a net resultant force directed toward a portion of the bit that develops less friction than other parts of the bit, as shown in Figure 2. This provides a stability that resists the tendency to whirl. This bit design has been a commercial success with several hundred of the bits having been run. Designs are available for almost all standard PDC bit sizes and for several formation hardnesses.

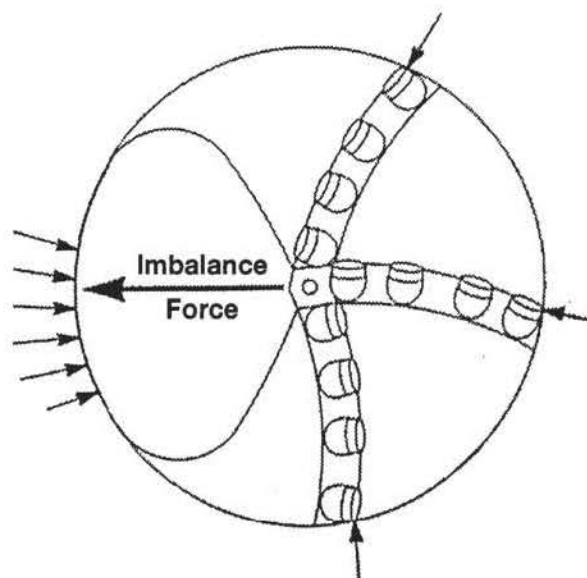


Figure 2: Schematic of anti-whirl bit.

Another manufacturer has relied heavily on an alternate technique of using tracking cutters^{14,15} to provide stability. This concept has demonstrated less stability in lab testing than the low friction concept, but has claimed a fair amount of field success. It generally drills slightly slower than other comparable PDC bits (due to the increased amount of diamond on bottom), but the design allows a higher density of cutters on the gauge than does the low friction concept.

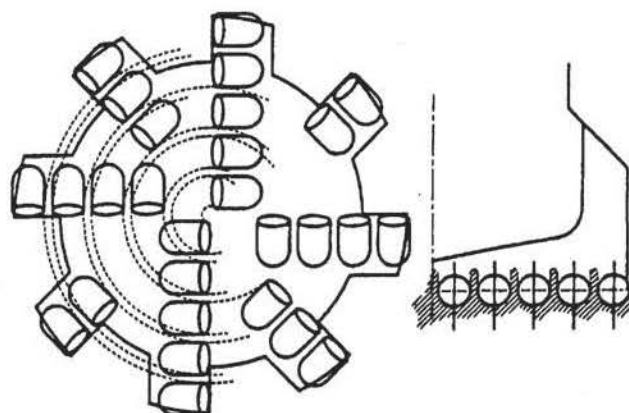


Figure 3: Schematic of stabilizing groove bit.

Still other manufacturers believe that utilizing a "balanced" design is adequate to prevent whirl. Laboratory tests have shown that a balanced design does not prevent whirl, even in homogeneous rock.¹³ Unfortunately, most of the rock that is drilled in the search for hydrocarbons is very nonhomogeneous. When a balanced bit drills these nonhomogeneous sections a large lateral force may be created that is sufficient to initiate whirl.⁸ Once the bit begins to whirl, the bit is no longer balanced and the whirl is self-sustaining.

In addition to these specific design concepts used to reduce whirl, there are many other features that have been generally incorporated in bit designs for this purpose. The gauge pads are likely to be smoother than a few years ago, gauge trimmers are oriented with higher side rake, blades are often asymmetrically laid out, impact arrestors are used, chamfered and curved cutters are used, etc. All of this has tended to reduce the problem of whirl in many formations.

The question of whether or not an anti-whirl bit is needed often arises. In soft formations there is generally less tendency for a bit to whirl; and even if it does whirl, there is less chance for the bit to be damaged. Unfortunately, many soft formations include harder zones, such as concretions in shale, that can be very damaging to a whirling bit. If PDC bits are consistently being pulled with no evidence of damage to the diamond layer near the wear flat, then an anti-whirl bit probably would not be beneficial. On the other hand, if the diamond table is being damaged, the PDC bit runs are inconsistent, or there is other evidence of whirl, then the use of an anti-whirl bit is probably warranted.

Cutter Performance

PDC cutters are available in a variety of shapes, sizes, and mechanical properties. There appears to be little inherent advantage in the way a particular cutter size or shape cuts rock,¹⁶ but an advantage may be gained by how particular cutters are applied in bit designs. Large cutters are often used on bits designed for soft drilling to facilitate greater stand off and better removal of cuttings from in front of the cutters. Smaller cutters are used for harder rocks and to provide smoother on bottom torque, but our testing indicates that they may wear faster and are not easily rebuildable.

The impact resistance of PDC cutters is limited by the relatively high internal stresses created during the manufacturing process by the differential thermal expansion of the diamond and substrate.¹⁷ Cutter manufacturers are working to extend the impact resistance by altering materials, manufacturing processes, and the geometry of the cutters and the diamond/substrate interface. The use of cutters with a chamfered edge to reduce the stress concentrations on the diamond is one proven method that helps reduce the initial chipping of new cutters. Our testing also indicates that cutters with a longer substrate behind the diamond are less likely to be broken while drilling.

PDC cutters are installed on the bit in an orientation inclined toward the designed trajectory of the cutter (effective back rake). In general, field performance indicates that higher back rake is more durable. Recent testing by Karasawa¹⁸ and Li¹⁹ found that a lower back rake is in fact less likely to be chipped when drilling hard rock. This inconsistency may be explained as follows. On an actual bit the cutters do not always move in the direction they are expected to move. When the bit is exposed to axial and lateral vibrations, the cutters may impact the rock on their edge. Having high back rake (for axial vibrations) and high side rake (for lateral vibrations) helps to assure that the impact stresses on the diamond layer are compressive. If the diamond is exposed to tensile stresses, it is much more likely to be chipped or delaminated. Thus, the field evidence may indicate that there is benefit to the higher rake angles. The two references mentioned above

indicate that if the bit could be rotated without vibrations, better performance in hard rock could be obtained with **lower back rake** and the first reference indicates that a **lower clearance angle** between the cutter substrate and rock surface is also beneficial.

Even though there is a considerable interest lately in cutter breakage, there is still room for improvement of cutter abrasion characteristics. Our research shows definite differences in the wear performance of different cutters when they are worn primarily by abrasion.

There is also a need to develop bit designs that provide a better balance between abrasive wear and cutter breakage. A high density of cutters can help retard cutter breakage; but since each cutter has a low load and takes a small depth of cut, the abrasive wear is significantly increased.⁹ The benefit of higher cutter loading can be demonstrated by examining the cutters on the shoulder of a small PDC bit compared to the cutters at the same radius (and same rotational velocity) in the cone of a larger PDC bit. The cutters on the larger bit will almost always be spaced further apart so that they take a higher load and remove more rock per cutter than on the smaller bit, but they will show less wear than cutters at the equivalent radius on the smaller bit.

Drill String Effects

The drill string provides a less than optimum method of providing rotational power to the PDC bit. The best bit performance is obtained when the bit is rotated with a constant feed rate with a stiff drive to minimize the vibrations. The drill string does not provide either of these conditions.

The drill string can vibrate axially, laterally, and torsionally, as indicated in Figure 4. The lateral and torsional vibrations are the most significant for PDC bit operation. Much work has been done to design PDC bits that limit lateral vibrations (whirl), but a vibrating drill string can overpower even the best bit design.

The bit and drill string must be considered as a system in order to get the best performance. The drill string should be adequately stabilized and the stabilizer spacing should be chosen to prevent operating any drill string section near the bit at its natural frequency in order to obtain good performance with PDC bits.²⁰ In general, whirl is less likely to cause a problem with PDC bits in directional wells where gravity acts to dampen the vibrations, particularly above 20° inclination.

Torsional oscillation of the drill string can also be a serious problem when drilling with PDC bits. This mode of vibration is generally referred to as stick/slip and may be caused by friction on the drill string components or by the bit itself as proposed by Brett.²¹ These oscillations can damage the drill string and cause the bit to be damaged, particularly if the bit is allowed to move backwards. The torsional oscillations can generally be minimized by rotating the drill string at higher rotary speeds. In some cases a "soft torque" system is used to limit the oscillations.²² In other cases the bit is run on a motor to act as a torsional shock limiter and to prevent drill string damage.²³

Both laboratory and field tests show that setting a bit on bottom with high RPM and low WOB will almost always initiate whirl. As the WOB is increased, the whirl will often die out; but this may be only after the bit is damaged. When a motor is used with a PDC bit for drilling near vertical, it is important to reduce the flow rate as much as possible to minimize the rotational speed of the motor before the bit is set on bottom. After the bit is on bottom, the flow rate can be increased to its normal value. Even with this technique, the lower speed for some motors will still be high enough to initiate whirl as the bit is seated.

Figure 6 shows laboratory measured data for a PDC bit rotating at 200 rpm near the bottom of the hole. The bit began to

PRIMARY MODES OF DRILLSTRING VIBRATION

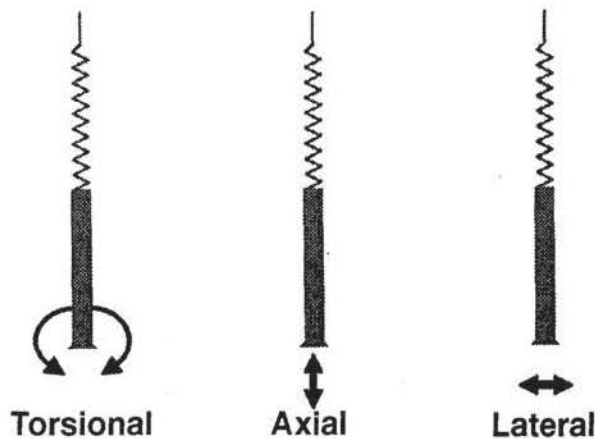


Figure 4: Primary modes of drillstring vibration.

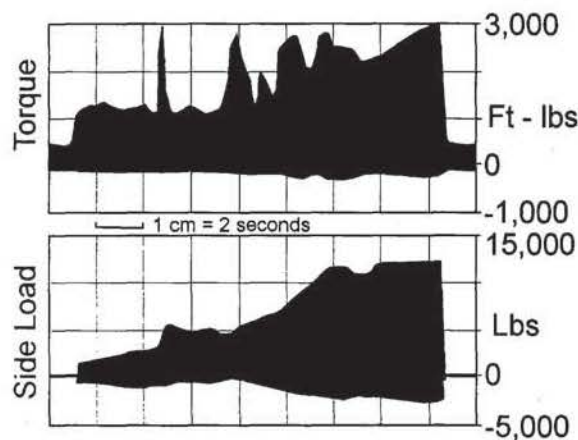


Figure 5: Example of off-bottom bit whirl.

whirl when the rotary speed was increased from 60 rpm to 200 rpm. After about 15 seconds the whirl ended when the borehole wall of the drilling sample was destroyed. The data in Figure 6 shows the peak-to-peak torque and lateral force exerted on the rock. Both the torque and lateral force had a frequency of about 40 Hz. The dynamic impact forces were measured to be greater than 12,000 lb.

One cause of torsional drill string oscillations that is usually not given adequate attention is the operation of the drawwork brake. The procedure used to advance the drill string can either make the problem worse or almost eliminate it. Most automatic drillers allow the drill line to feed off in a "load up/drill off" method rather than continuously feeding off the drill line. Even when a driller manually operates the brake, there is a tendency to operate it in the same fashion. This method of operation is much more likely to initiate and reinforce torsional oscillations than allowing the drill line to smoothly and continuously feed off.

When the drill string is being operated with significant torsional oscillations present, the WOB is often limited by the peak torque that occurs during the torque cycling. This may limit the penetration rate that is obtained and can easily result in a reduction of 30-40% below the ROP that could be obtained with con-

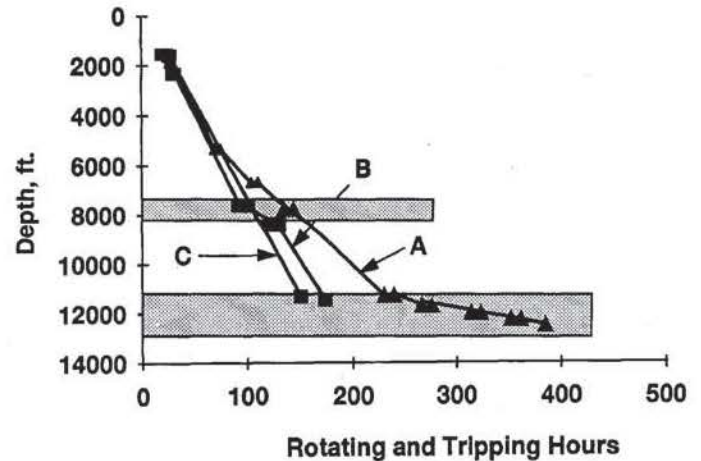


Figure 6: Example of well impacted by PDC bits.

stant feed rate. In many cases the brake can be adjusted so the driller can obtain a relatively constant feed off of drill line.

Applications

PDC bits have become a standard tool that is used in almost all drilling provinces rather than being a specialty tool used in only a few specific formations. They typically drill twice as fast as roller cone bits and can often replace two or three roller cone bits in places where they are successful. Since they have no moving parts, they are less likely to leave junk in the hole. Unfortunately, there are still many formations that are not successfully drilled with PDC bits. Two major limitations to PDC bit usage is difficulty in drilling hard, nonhomogeneous rocks and difficulty drilling over pressured shales with water based muds.

Harder Rocks

One of the greatest challenges for PDC bit manufacturers is to improve the consistency in performance and extend the PDC bit usage into more difficult drilling sections. Figure 6 shows an example of how new PDC bit designs are meeting the challenge of drilling more difficult sections, but also shows the potential benefit if they could drill even harder rocks. This example from Wyoming is typical of many areas found world wide and is shown as a generic case for the limitations of PDC bits rather than as a recommended prescription for drilling in one location.

The interval from surface casing to 7,500 ft is generally soft drilling with some hard streaks that have made drilling with PDC bits hit and miss. It is shallow enough so that trip time is minimal. The section from 7,500 ft to 8,100 ft, on the other hand, is notoriously difficult to drill with PDC bits. The lower interval between 8,100 ft and 11,200 ft is a relatively homogeneous shale section (70-75 us sonic travel time) that is routinely drilled with PDC bits. For several years the choice for drilling these wells was to use 3-4 roller cone bits in the upper interval, use a PDC bit for the shale section, and then drill the final section with several roller cone bits, as indicated by well A. Recently bit designs have improved sufficiently so that the upper section can be routinely drilled with PDC bits (well B), but the section from 7,500-8,100 ft is still not consistently drilled with standard PDC bits. Anti-whirl bits have drilled this entire section in a single run as shown by well C in Figure 6 and may become the accepted drilling program if their performance is consistent.

The last 1,000 ft of the well takes about as long to drill as the upper 11,300 ft. This section is composed of sandstone, siltstone, and shale and is drilled with a 10-10.5 ppg mud instead of

water as is the upper section. It is typically drilled with three to four roller cone bits at 5-8 ft/hr. The sonic travel time of this section is general 60-65 us with some peaks as low as 55 us. The successful application of PDC bits in this section could easily reduce the drilling time by 60%.

Limitations to the economical application of PDC bits in this interval appear to be related to both vibrational effects and rock hardness. The section is deep enough so that there may be substantial drill string effects. The slow drilling coupled with the abrupt changes in rock hardness provides an ideal situation for bit whirl to develop. Thus, it is a situation where particular attention should be paid to both drill string and bit vibration control.

Conventional wisdom would indicate that the hard streaks in this interval are strong enough to break PDC cutters, but laboratory tests with large river gravel imbedded in cement shows that a PDC bit can easily drill through the nodules without damaging the bit. Hibbs and Flom²⁴ has reported results that indicates that when a cutter passes from a soft zone to a hard zone and back into soft there is no impact loading of the cutter above what would be caused by continuously drilling the hard material at the same rate.

Behr et al.⁸ has shown that when a PDC bit encounters a hard nodule the cutter loading can increase very dramatically, particularly if the drilling rate is very fast. At high ROP the cutters take a deep depth of cut and when they encounter the hard rock almost the full WOB may be applied to a few cutters. This clearly happens and can account for cutters broken in the manner shown in Figure 7 where the diamond has been sheared back through the carbide substrate. When the penetration rate is already very low, it is more difficult to over load a cutter if the bit is rotating concentrically; but it is also more likely for the bit to whirl.

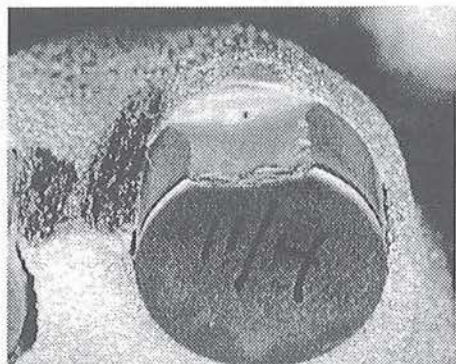


Figure 7: Cutter broken from frontal impact.

There are many cases where laboratory data indicates that PDC bits should be able to drill a particular formation, but field runs are unsuccessful. Thus, there is still room for learning more about the exact mechanisms that damages PDC cutters in hard rock and there is reason to hope that the benefits of using PDC bits can be expanded.

Over Pressured Shales

There are many cases where deep shales can not be drilled adequately with PDC bits run in water-based muds. Adequate penetration rates are obtained with oil mud; but when water muds are used, the penetration rate is less than with a roller cone bit. When the PDC bits are pulled they are found to be unworn and not balled up.

Laboratory tests have shown that cuttings can retard the penetration rate in two different ways. In one case a large portion of the bit face may be packed with rock material that prevents the

bit from drilling, as shown in Figure 8. In another case, the balling may occur only immediately in front of each cutter and act to prevent the cutter from exerting adequate stress on the rock to form chips and drill at a reasonable rate. This phenomenon can be shown to happen with Indiana limestone, but to a lesser degree than is often seen with deep shales.

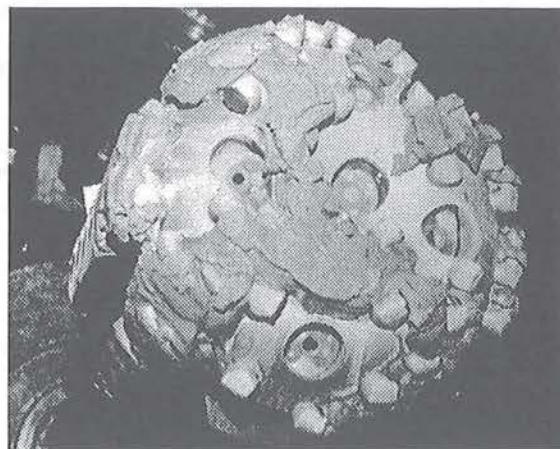


Figure 8: Balled PDC bit.

Laboratory tests with PDC bits show that as the WOB is increased the penetration rate normally increases at a slightly increasing rate as the chip formation process is slightly more efficient at higher weights. For example, in Figure 9 this is clearly seen for the Carthage limestone and Catoosa shale drilled at 1,100 psi borehole pressure and for the Indiana limestone drilled at 200 psi borehole pressure. When the borehole pressure is increased to 1,100 psi on the Indiana limestone, the penetration rate tends to flatten out rather than increasing as expected as indicated by the dashed line. This response is what would be expected if the bit were balled up; but when the bit is inspected it is not balled up, but rather sometimes a small mass of cuttings is stuck to the leading edge of the cutters, as described by Warren et al.¹⁰ as cutter balling.

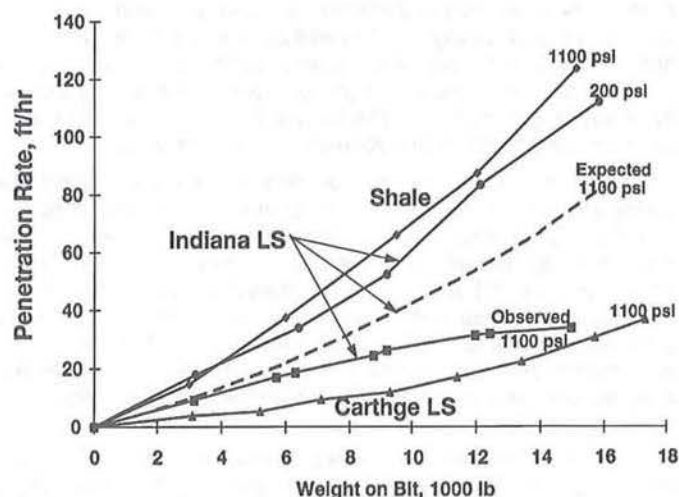


Figure 9: Penetration rate limited by cutter balling in Indiana Limestone.

When the mass of cuttings is examined, it does not appear to be cuttings at all, but rather is small granular particles. The Indiana limestone (porous and friable) is not saturated before the drilling tests but all the surfaces of the sample other than the

borehole are sealed. Thus, the borehole pressure with the water based mud applies a confining pressure at the cutting face.

The PDC cutter normally creates "chips" by shear failure of the rock in front of the cutter at an angle from the rock surface, typically 30°. The cutter is inclined toward the work face at the effective back rake angle, typically 20°. This means that the failed rock is confined between the unfailed rock surface and cutter face with an included angle of about 40°. At sufficient borehole pressure, the combination of borehole pressure and friction will create adequate stress to crush the chips in compression and trap them between the cutter face and the rock face. When this occurs, the cutter load is supported on the large area of the failed rock and the stress is reduced to a level where the drilling rate is much slower than expected.

Zijlsing²⁴ provided a similar description of what happens when drilling Mancos shale at high borehole pressure. Dilatancy in the shear zone reduces the pore pressure to the cavitation pressure (near zero). The effective contact stress is then the total borehole pressure and high frictional forces act on the cuttings. Consequently, the chips collapse and ball up at the diamond face of the cutter, particularly in the presence of water based mud.

The foregoing discussion indicates that one potential method of increasing the drilling rate in shales that tend to ball up at the cutter face is to reduce the back rake of the cutters. When this is done on a conventional PDC bit, the tendency to whirl becomes much greater. When the bit whirls, the penetration rate will again be very slow and there may be no apparent improvement from using the lower back rake.

Figure 10 shows an example of where the combination of low back rake was applied to an anti-whirl bit in the Gulf of Mexico. The dashed line shows the average penetration rates from three of the best offset wells. The first roller cone bit drilled about as expected, based on the offsets. The experimental low back rake bit was then run and drilled about twice as fast as the offsets. Since it was an experimental bit, there was not another bit like it ready to run when it was pulled. A standard 20° back rake anti-whirl bit was run next and it drilled only half as fast as the offsets and was pulled for low ROP in perfect condition after having drilled only 34 ft. Three roller cone bits were then run with a performance about as expected based on the offsets, while a second experimental bit was being prepared. The second experimental bit drilled about two and one half times as fast as the average of the offsets. The remainder of the hole was drilled by the repaired first bit at a reduced penetration rate.

Additional work needs to be done before the problems of drilling slow shales will be solved, but this example indicates that a better understanding of the problem is being gained. Even when the experimental bits were being run, there were times when it appeared that they had "lost their bite." This may indicate that the design was just marginally adequate to overcome the cutter balling problem. It is possible that a properly designed bit with zero or even positive back rake could provide a substantial improvement, but only if combined with the proper hydraulic and whirl preventing design.

The two previous examples discussed PDC bit applications that are on the leading edge of what can be achieved with PDC bits, but there are other applications that are directly benefiting from the improved understanding of PDC bit mechanics.

Slim Hole Drilling

There is an increasing interest in drilling "slim holes" in order to save on the cost of drilling wells. There have been several different concepts for the best method to drill the wells at the lowest cost. One concept is to use mining type equipment that

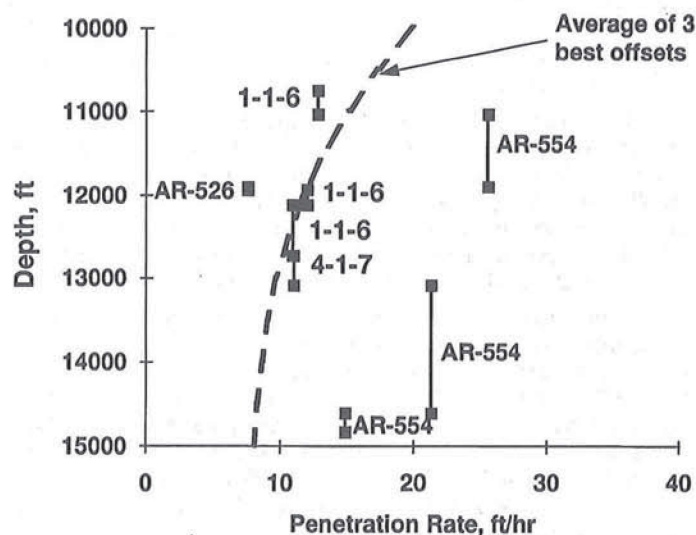


Figure 10: Low back rake anti-whirl bit performance in overpressured shale.

incorporates a narrow annulus between the drill string and borehole wall to stabilize the drill string so that it can be rotated at high speed. Another concept uses more conventional drilling equipment and simply scales down the sizes used.²⁵ In either case, roller cone bits are usually not an option because of the fragility of the small bearings and low ROP due to small teeth, thus PDC and natural diamond bits must be relied upon.

An often heard complaint with slim hole drilling is that the penetration rate suffers when the hole size is reduced. It is often found that the reduced penetration rate occurs more frequently in shales than in limestones or sandstones. The cause of the reduced penetration rate is that it is often difficult (even impossible with the mining equipment) in a slim hole to have adequate hydraulics for proper bit cleaning. Figure 11 shows two 4-3/4 in. PDC bits that are appropriate for drilling shale in a slim hole. The three-bladed bit is the same design as the five-bladed, with the two minor blades removed. Both bits are bladed with sufficient blade height and standoff for drilling shale. Figure 12 shows the result of laboratory drilling tests in shale with both bits.

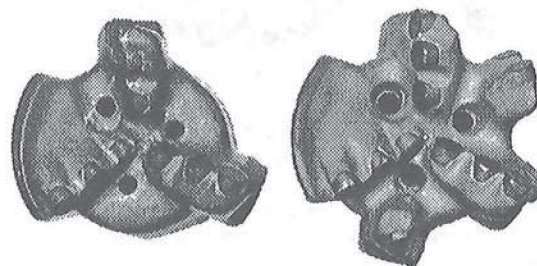


Figure 11: Photograph of 3 bladed and 5 bladed bits.

At 100 gpm, the five-bladed bit balls up readily and even at an unrealistically high WOB of 9,000 lb the ROP is only 20 ft/hr. At 180 gpm, the bit performs much better; but again if it is pushed too hard, it balls up and the penetration rate will fall. On the other hand, the three bladed bit performs much better and is less likely to ball up at reasonable operating conditions.

Another complaint often heard for slim hole drilling is that the bits are not as durable as their large counterparts. Our testing

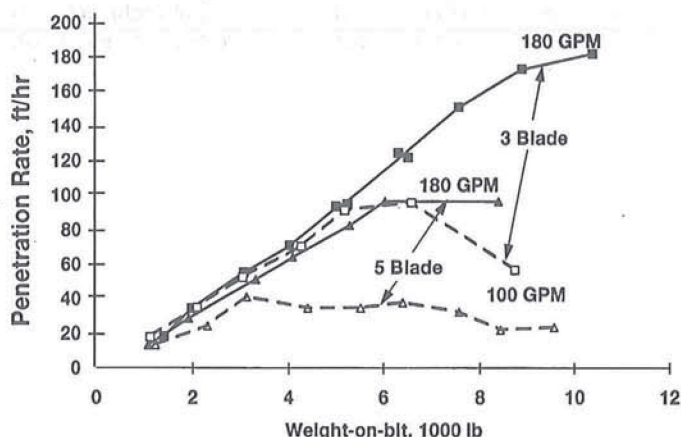


Figure 12: Effect of hydraulics and bit design on ROP in shale.

has found that under equivalent conditions, the smaller PDC bit may be **more durable** than a larger PDC bit. In many cases the reduced life seen in slim holes is a result of running the bits at higher rotary speeds and with inadequate hydraulics. A properly designed and operated small bit is capable of drilling just as fast and as many feet as a larger bit.

Coring

PDC bits have been used for core bits almost as long as they have been used for full hole bits, but recent advances in PDC bit stabilization has provided a capability to improve core recovery and quality for conventional coring operations and has renewed interest in developing wireline coring systems. Armagost et al.²⁶ described the successful application of anti-whirl core bits to core unconsolidated sands from a floating drilling vessel where both the penetration rate and core recovery were significantly improved over the performance of conventional PDC core bits.

The anti-whirl core bits, shown in Figure 14, have been applied in many different applications now and have been particularly successful in Canada. Runs in several fields in Alberta have shown that the anti-whirl core bits have improved both penetration rate and core recovery. The bits have been successful in coring some abrasive formations that were previously drilled with natural diamond core bits.

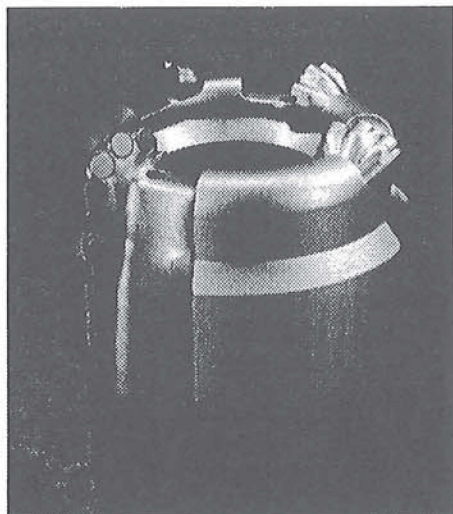


Figure 14: Anti-whirl core bit.

Sinor et al.²⁷ has shown that the anti-whirl PDC bits can routinely cut a small diameter core that can be wireline retrieved through a conventional drill string. This allows wireline coring with a conventional rig and equipment which preserves many of the contingencies that are given up when a decision is made to wireline core with mining equipment. It also allows coring rates that are much higher than with natural diamond bits and are nearly as high as with full hole PDC bits. Two coring companies now have equipment available for wireline coring through conventional drill strings.

Summary

The increased emphasis in reducing vibrations with PDC bits has resulted in more consistent runs and an extension of PDC bits into areas previously marginal for their applications. A better understanding of rock/cutter interaction and bit kinematics is opening the door to improved drilling in overpressured shales. The ROP advantage of PDC bits is helping to revive older technologies like wireline coring and offers the best hope for drilling slim holes to reduce drilling costs. There is still considerable room for improved performance for PDC bits, particularly toward using the PDC cutters effectively in harder rocks, drilling faster in over pressured shales, improving the hydraulics of PDC bits, and designing better methods of stabilizing the drillstring for PDC bit runs.

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