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## The Effect of PDC Cutter Density, Back Rake, Size, and Speed on Performance

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### Abstract

This paper evaluates the effect of cutter density, back rake angle, size, and speed on the steady state wear rate and performance of Polycrystalline Diamond Compact (PDC) cutters. The analysis is based on laboratory and controlled field testing results at Amoco's Catoosa Test Facility<sup>1</sup>.

### Introduction

PDC cutter wear can be divided into two categories depending on the basic cause of the wear. The first category, abrasive wear, is steady-state wear that is normally associated with the development of uniform wear flats on the PDC cutter and the gradual degradation in rate of penetration over the bit life. It is a function of the operating parameters applied to the bit and individual cutters, cutter temperature, cutter velocity, formation properties, and cutter properties.

The second category of wear is the result of impact loading of the cutters. This type of wear may be caused by dynamic loading of the bit during bit whirl (backwards vibration) or from drilling through nonhomogenous formations. Cutter wear from impact loading is typified by chipped, broken, and lost cutters. Dynamic loading of the cutters can be caused by abrupt changes in the surface drillstring control, forces induced by cutter/rock interaction, or from drill string dynamics. Figure 1 is a good example of the detrimental wear and damage to a PDC bit with 2 in. PDC cutters during dynamic loading. This particular bit was run in a North Sea well and was damaged while drilling a limestone stringer. Maximum reported weight-on-bit was 15,000 lbs.

Numerous studies have been performed to better understand the steady state wear of drag style bits. Early modeling was initiated in the 1960's by Appl, et. al.<sup>2</sup> in an effort to better understand the drilling stresses on the hard metal blades which were used as cutting structures. The high stresses were thought to be the cause of accelerated wear in abrasive formations. Breakthroughs in diamond cutter technology expanded the application of drag bits in oil well drilling through the use of man-made diamond cutting elements which were later called PDC cutters.



Fig. 1: Dull PDC bit after unsteady state wear from dynamic loading of cutters.



The application of PDC bits continues to expand in the softer homogeneous formations but breakage and wear of the PDC elements in the harder or nonhomogeneous formations has limited their broader application. Between 1989 and 1996, Turner<sup>3</sup> showed that the penetration rate of PDC bits had increased 60% and the footage per bit had increased 115%. The overall cost per foot dropped a corresponding 35% during this period. Warren<sup>4</sup> correlated the increase in PDC bit performance with the discovery of unsteady-state wear from bit whirl and the development of whirl reducing bit features (Fig. 2). The performance change of PDC bits was indicative of a significant technology change which was much higher than then normal evolutionary improvements observed with roller cone bits.

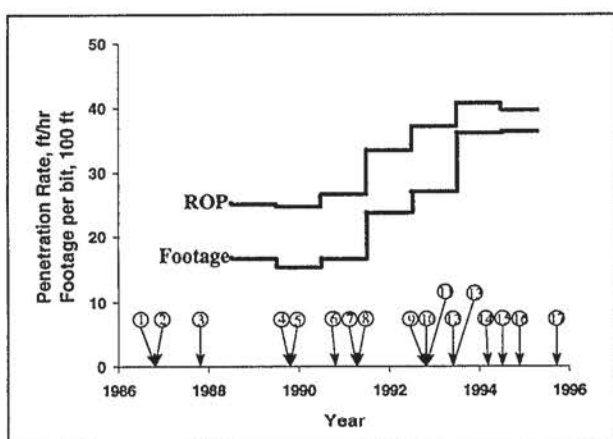


Fig. 2: Performance history of PDC bits. Arrows indicate the dates of specific technical papers.

The discovery of bit whirl caused a major shift in the research and development efforts in a number of bit companies. The engineering trend for bit designs had been toward stronger cutters and blades to help minimize catastrophic failure downhole. The focus was also on bits with higher cutter back rake which, although they drilled slower, appeared to make the bits last longer thereby reducing the overall cost per foot.

New bit designs with whirl reducing features helped eliminate or minimize unsteady state wear which was the number one cause of premature failure in the field. Once whirl was understood and methods developed to correct this problem, research shifted back toward improving the steady state wear of PDC cutters.

### Background

Field testing in a controlled environment offers the unique capability to exclude many of the unknown variables which hamper typical evaluations in an exploration or production environment. Past wear observations at Amoco's Catoosa Test Facility (CTF) covering over 100 PDC bit runs were showing results opposite to the thinking held by many industry PDC bit experts. Unfortunately, a majority of this data had never been

published in any technical journals or discussed at forums. If these observations were true, they could cause a change in the R&D focus for improving rate of penetration and bit life with PDC bits. In general, the industry consensus for PDC bit designs in firmer formations is as follows:

- Cutter density- light vs. heavy set  
- trend toward heavy set bits
- Cutter size- big vs. small PDC cutters  
- trend toward smaller (8mm) cutters
- Cutter back rake angle- low vs. high  
- trend toward higher 20 - 30° back rake
- Bit speed / WOB- low or high in hard stringers  
- trend toward higher rpm / lower WOB

### Cutter Density

A common industry practice is to use PDC bits with more cutters when drilling firmer formations, the theory being that the increased diamond content will help minimize cutter breakage and abrasive wear. Recent testing has shown this might not always be the best solution for abrasive wear.

Figure 3 shows the results of laboratory testing an 8-1/2 in. PDC bit in Carthage limestone. Separate tests were performed on the bit when it was new and as it was dulled at the CTF. The development of wear flats on the PDC cutters required the bit weight to be increased to overcome the compressive strength of the rock. Once the applied weight on the cutters overcomes the compressive strength of the rock (inefficient drilling), the rate of penetration becomes parallel with the previous tests (efficient drilling).

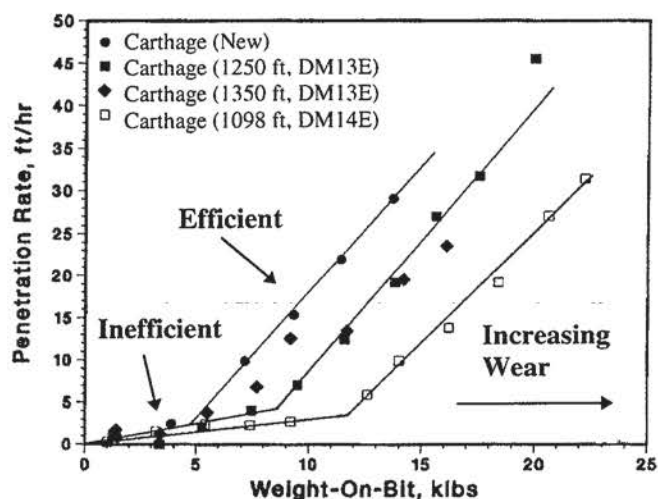


Fig. 3: Laboratory test results of a six bladed PDC bit in Carthage limestone during increasing stages of wear.

The increase in weight-on-bit requirement is directly proportional to the increase in cutter wear flat area in contact with the rock. Cutter wear must be minimized in hard



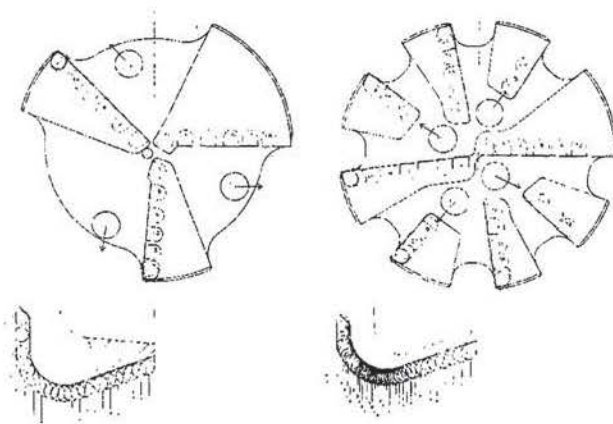
formations to obtain satisfactory rates of penetration. The testing results with cutter wear are consistent with earlier results reported by Glowka<sup>5</sup>. He showed that for hard rocks, the penetrating stresses on the order of the compressive rock strength must be imposed on the rock surface before significant penetration occurs. The penetrating force component is important in crushing the surface of hard rocks, leading to cutter penetration. With softer rocks like Berea sandstone, Glowka observed that significant penetration can be achieved with penetrating stresses much lower than the compressive rock strength. This suggests that with soft rocks, crushing of the rock surface is less important and the drag force component plays a greater role in machining of the rock surface rather than crushing of the surface.

Referring back to Fig. 3, there are two distinct slopes for rate of penetration, one labeled inefficient and the other labeled efficient. Field testing at CTF has shown that low rates of penetration in abrasive sands result in accelerated wear. At higher rates of penetration, the chip generation process is more efficient resulting in reduced wear rates.

Dull bit analysis has also shown that the inside cone of most PDC bits experience minimal wear whereas the nose and outside taper of the bit experience accelerated wear. Industry thinking would suggest that the accelerated wear is the result of higher cutter speed on the outside of the bit compared to the inside cone. What is surprising however is that as the bit diameter gets larger, the cutters inside the cone of the larger bit generally experience minimal wear, much like the cutters inside the cone of the smaller bits where wear is a minimum. This phenomenon indicates that something more than cutter velocity is causing the accelerated wear on the outside taper of the bits.

One hypothesis for the decreased wear is partially explained by drag bit computer modeling<sup>6</sup>. The model shows that although the cutters inside the cone have high cutter loads (low cutter density and overlap), these cutters are generating much bigger chips than the cutters on the taper. The efficiency of rock removal improves as the depth of cut increases. This observation was also reported by Hibbs<sup>7</sup> in 1978. These bigger chips also result in less cutter/rock contact time. The cutters on the outside taper generally have low cutter loads (high cutter density and overlap) and take much finer cuts. This results in a grinding mode vs. a chip generation mode. The decreased cutting efficiency and increased cutter/rock contact time in the grinding mode is believed to be a primary cause of increased cutter wear.

Tests were prepared at the CTF to evaluate this theory of chip generation and cutter wear. Two 9-7/8 in. PDC bits (Fig. 4) with the same cutter profile and 13mm PDC cutters were built for testing. The first bit was a three bladed design and the second bit was an eight bladed design.



**Fig. 4: Three bladed and eight bladed Anti-Whirl PDC bits used for wear analysis.**

The bits were tested at the CTF beginning at the same depth using a rotary speed of 120 rpm. The light set three bladed bit drilled to a planned depth of 1,253 ft at relatively light WOB and fast rates of penetration. The drilling torque was smooth throughout the drilling. The bit was pulled at the planned depth with the expectation that the bit would have minimal wear because of the good drilling response. Visual inspection of the bit showed very little wear on the PDC cutters but excessive damage was observed from overloading the cutters and from diamond delamination. The cutter breakage is believed to have occurred toward the end of the run through hard sand stringers. The total wear flat area including the breakage was calculated to be 1.64 in<sup>2</sup>.

The heavier set eight bladed PDC bit was run through the same intervals but was pulled at 1,204 ft because of difficulties in drilling through thin hard stringers. High WOB was required to make the bit drill the harder intervals which would result in the power swivel stalling once the interval was penetrated and the bit was back in shale. Inspection of the bit showed no signs of cutter damage or breakage. The total wear flat area of the bit was calculated to be 1.61 in<sup>2</sup>.

Figure 5 shows the percent face diamond loss for the two bits. If we assume the worst two damaged cutters on the lighter set bit (67% and 72% diamond loss) experienced nominal wear of 20-25% instead of breakage from overloading, the total wear flat area for the bit reduces to approximately 1.03 in<sup>2</sup>. In this case, the heavier set bit has approximately 60% more wear flat area than the lighter set bit. This additional contact area is why the heavier set bit experienced problems drilling in the firmer formation.

Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases. More wear requires more weight. Nothing



new here except that it keeps bringing us back to one common thought; the need to minimize the amount of cutter contact with the rock. Lighter set bits should in theory experience less wear provided the individual cutters are not overloaded while drilling. Since lighter set bits generally have less blades by design, cooling with the drilling mud should also be more efficient which could possibly aid cutter wear by helping to reduce cutter temperature. Elimination of cutter breakage from overloading is the major hurdle to overcome.

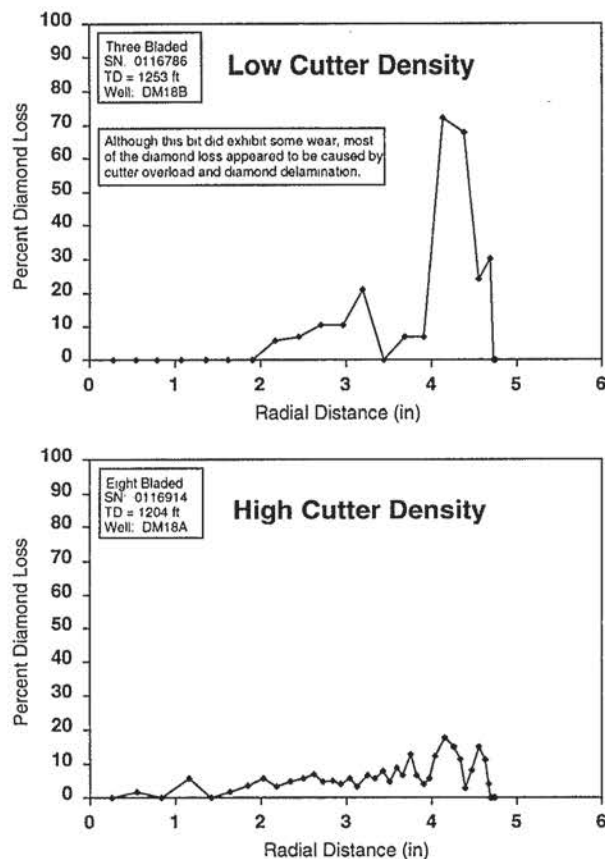


Fig. 5: Percent diamond loss vs. radial distance showing effect of cutter density.

### Cutter Back Rake Angle

The cutter back rake angle used on most commercial PDC bit designs is 20°. Cutter back rake angle is defined here as the angle the cutter face makes with respect to the rock as shown in Fig. 6. But is the use of one back rake angle the best solution for all drilling conditions? First, let's understand why the use of 20° back rake angle became standard on PDC bits.

Hibbs<sup>7</sup> reported in 1978 that the forces required to cut Jack Fork sandstone with 8.1mm cutters were minimized at rake angles between 10 and 20° regardless of speed. In 1986, Hough<sup>8</sup> followed up this work with the analysis of cutter backrake angles (7, 15, 20, and 25°) while cutting Mancos

shale under atmospheric conditions. He concluded that the mean penetration rate for bits with 15, 20, and 25° backrake were statistically the same and superior to the bit with 7° backrake. The bit with 20° backrake gave the highest mean rate of penetration although it was not statistically superior to the bits with 15° or 25°. Hibbs also reported that the bit with 7° backrake gave the lowest torque. He concluded that 20° gave the maximum rate of penetration and would be the best choice for drilling in shales if other factors were properly considered.

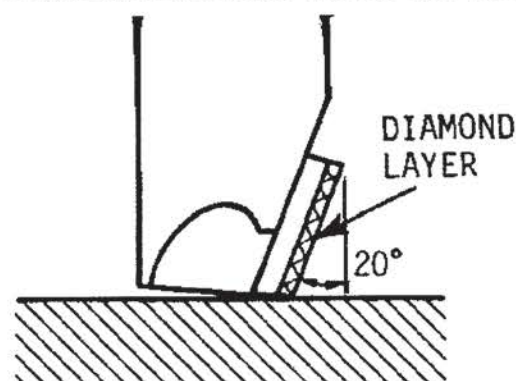


Fig. 6: PDC cutter showing back rake angle.

The significance of this early research along with other studies is that it established a baseline of 20° backrake as the standard used by most commercial PDC bit manufacturers. Attempts at building PDC bits with different cutter backrake typically led to poor results in the field and helped reaffirm the use of 20° back rake. Higher backrake generally improved bit life but reduced the average rate of penetration. Lower backrake would generally cause the bit run to end prematurely from catastrophic damage to the cutting structure but in rare cases, the rate of penetration and bit life would be significantly improved, contradicting some of the previous research.

It was not until the discovery of bit whirl<sup>9,10</sup> and the introduction of whirl reducing features<sup>11</sup> that researchers began to understand why some of the earlier field results with lower cutter backrake (aggressive cutters) were poor. These researchers found the tendency for bit whirl increased with:

- increasing rock strength
- increasing rotary speed
- increasing cutter aggressiveness (less back rake)
- decreasing weight-on-bit

Elimination of bit whirl has allowed researcher's the opportunity to reevaluate some of the earlier assumptions of cutter wear and the effect of cutter backrake on performance under steady state conditions. Recent testing of PDC cutters by Karasawa<sup>12</sup> and Li<sup>13</sup> showed that cutters with lower backrake are less likely to be chipped when drilling hard rock and more durable than cutters set at higher backrake. Their testing

included cutters with backrake angles of 10, 15, 20, 25, 30, and 40°. They found that the optimum backrake angle for drilling very hard rock such as Sori granite to be 10°, quite contradictory to the results previously shown.

This inconsistency was explained by Warren<sup>14</sup> as follows. The path of the cutters while drilling is not always the way they were designed. When a bit is exposed to axial and lateral vibrations, the cutters may impact the rock on their edge. Having high backrake (for axial vibrations) and high side rake angle (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 a benefit to the higher rake angles. The implication here is that better performance in hard rock could be obtained with lower backrake if vibrations could be eliminated. Karasawa also indicated that a lower clearance angle between the cutter substrate and rock surface improved cutter strength.

To further evaluate the cutting efficiency at different back rake angles, four 8-1/2 in. PDC bits with 13mm cutters were built for laboratory testing. The bits were identical except for the back rake angles which were 10°, 20°, 30°, and 40°, respectively. An additional bit with variable 7-10-15° using 19mm cutters was also tested for comparison. The bits were tested in Carthage limestone and Catoosa shale using a rotary speed of 120 rpm and a confining pressure of 3,000 psi. Figures 7 and 8 show the rate of penetration and torque response for Carthage limestone. Figures 9 and 10 show the results for testing in Catoosa shale.

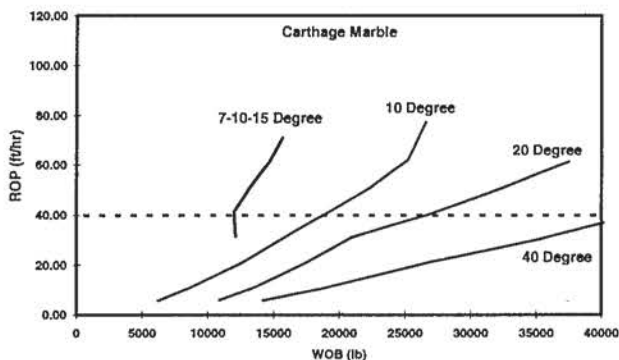


Fig. 7: ROP vs. WOB in Carthage limestone.

The laboratory results shown in Figs. 7 - 10 are quite surprising to most since the published technical papers typically only compare PDC bits with 20° back rake. The figures show substantial differences in WOB and torque requirements as a function of cutter back rake angle. Probably the most surprising feature in the plots is the fact that torque is

strongly influenced by the back rake angle of the cutter. Most of the PDC bit models currently in use today will show minimal if any difference in torque as a function of cutter back rake angle.

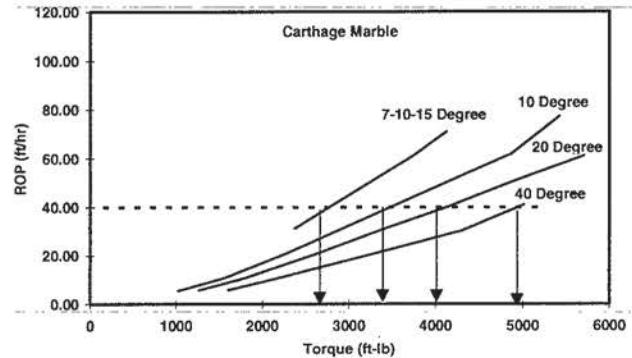


Fig. 8: ROP vs. Torque in Carthage limestone

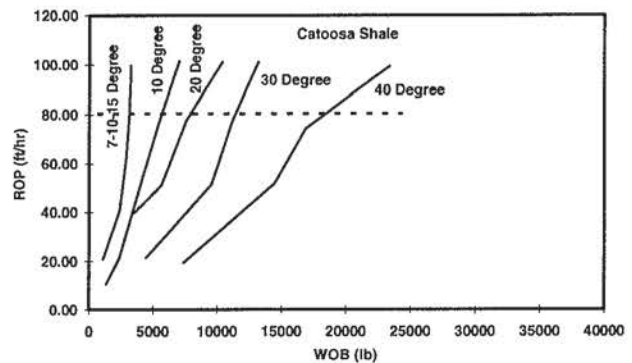


Fig. 9: ROP vs. WOB in Catoosa Shale.

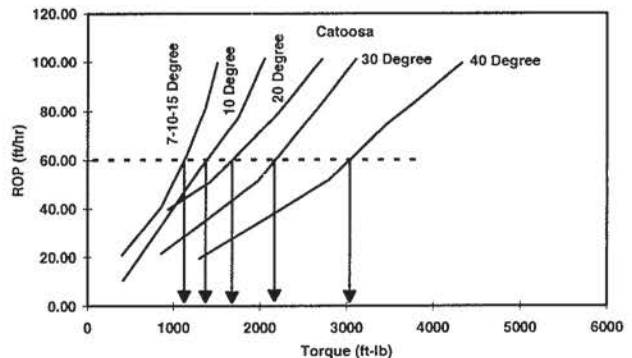


Fig. 10: ROP vs. Torque in Catoosa shale.

At a constant rate of penetration of 40 ft/hr in Carthage limestone, Fig. 7 shows the WOB requirement varies from 12,000 for the bit with 7-10-15° back rake to approximately



45,000 lbs for the bit with 40° back rake, a nearly 4 fold increase. Figure 8 shows the torque varying from 2,800 ft-lbs to nearly 5,000 ft-lbs. For Catoosa shale at 80 ft/hr, Fig. 9 shows the WOB requirement varies from 3,000 lbs for the bit with 7-10-15° back rake to approximately 18,000 lbs for the bit with 40° back rake, a nearly 6 fold increase. Similarly, the torque is shown to increase from 1,100 ft-lbs to approximately 3,000 ft-lbs at 60 ft/hr, a three fold increase.

Field experience has shown PDC cutter wear is strongly influenced by the amount of applied weight, since increased weight causes increased cutter temperature. Figures 7 and 9 show one method for minimizing the applied weight would be to use PDC bits with less cutter back rake angle. Figures 8 and 10 provide another subtle but very significant insight for steerable applications where motor torque is limited; decreasing the cutter back rake will significantly reduce the amount of motor torque required. For steerable applications, the general industry practice is to increase the cutter back rake angle across the entire face of the bit. A better alternative would be to increase the back rake (decrease the aggressiveness) of the cutters at the center of the bit while decreasing the back rake angle toward the gage. This would allow the bit to be less sensitive to changes in WOB without the penalty of increased torque requirements.

### Cutter Size

An early observation from a test at the CTF indicated that a PDC bit with smaller cutters wore faster. This observation was made while running an 8-1/2 in. eight bladed PDC bit with 8mm PDC cutters on well DM17D. The objective of the run was to determine if smaller diameter cutters would minimize cutter wear and possibly drill harder stringers since the depth of cut was smaller. This was opposite of the theory that bigger chips resulted in less wear. However the smaller depth of cut could possibly improve cutter strength, especially through nonhomogenous formations.

Figure 11 compares the CTF testing results for the 8 mm PDC bit against a 13 mm PDC bit of the same design. The 8 mm cutters are shown to be worn much higher than the 13mm. The bit with 8mm cutters had wear past the end of the carbide pockets on a number of cutters. Out toward the O.D. taper, the usable diamond was worn into the matrix of the blades. Wear and temperature reached a point that one cutter (no. 23) actually became debrazed from the cutter pocket.

More recently, three PDC bits with four blades each were designed and built for testing to further evaluate the effect of cutter size on wear rate. The bits were designed to have 7° back rake on the cutters inside the cone, 10° angle at the nose, and 15° on the taper of the bit vs. the standard 20° back rake. The only difference between the three bits was the size of the PDC cutters; 19mm, 13mm, and 8mm, respectively. Fig. 12 shows the top and side view of the three four bladed bits.

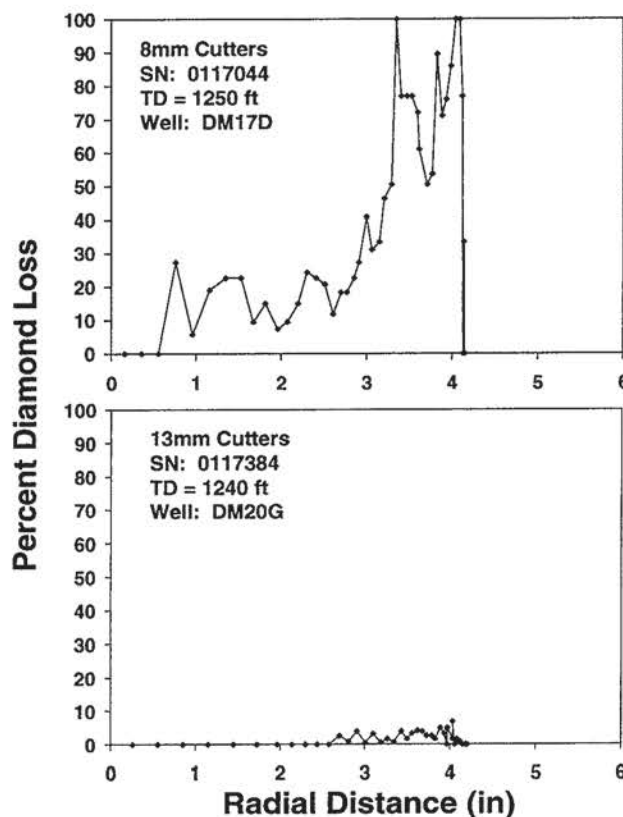


Fig. 11: Wear comparison of 8mm vs. 13mm PDC cutters

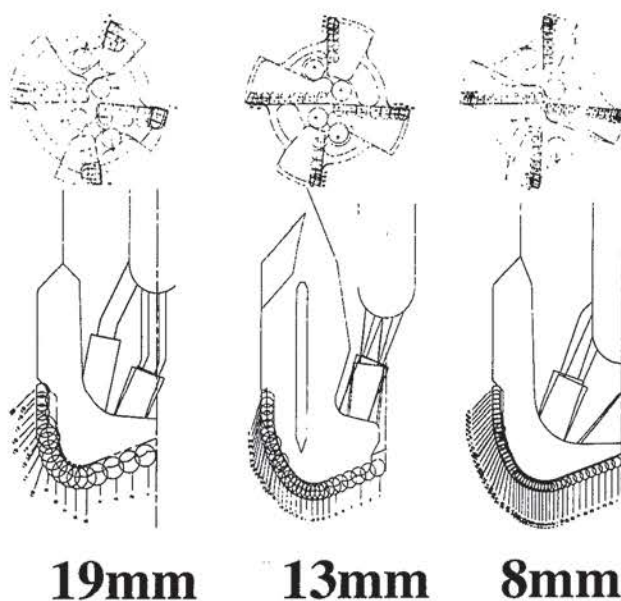


Fig. 12: Four bladed 8-1/2 in. Anti-Whirl PDC bits used in cutter size field evaluation.

Figure 13 compares the percent diamond loss for the four bladed bits tested at the CTF. During the testing, the rotary speed was held constant at 120 rpm, the flow rate was held at 450 gpm, and the rate of penetration was limited to 150 ft/hr.

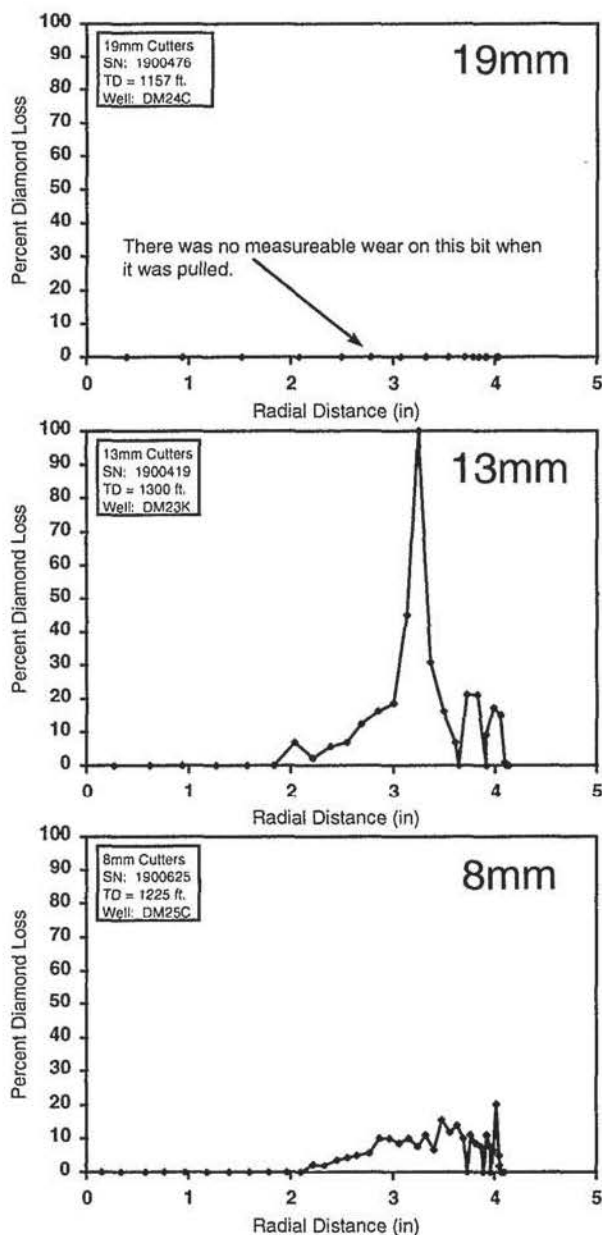


Fig. 13: Effect of cutter size on diamond loss.

Problems with old wellbore intersections resulted in the 8-1/2 in. bit with 19mm cutters being run on four wells before a suitable test was obtained. The bit was run for 1,008 ft on well DM23L, rebuilt, run on DM23M for 234 ft, run on well DM24A for 439 ft, rebuilt, and then run on well DM24C where it reached total depth of 1,157 ft before intersecting an old wellbore again. The wear testing for this bit was

terminated on the fourth run with no measurable wear. The run was 100 ft short of the planned depth for wear comparison but the run was deemed acceptable to minimize additional expenditures for testing

The 8-3/4 in. bit with 13mm cutters was run on well DM23K and was pulled at a depth of 1,300 ft inside the Mississippi limestone. Inspection of the cutters indicated that the bit had sustained catastrophic damage sometime during the run, presumably from downhole bit vibration. The bit was later rerun on well DM25E (not shown in Fig 13) and was pulled with similar wear results. A down hole vibration sub run on this well verified that the bit experienced downhole vibrations with peaks in the x,y plane (lateral) reaching 75 - 100 G's at a depth of 1,040 - 1,075 ft.

The 8-1/2 in. bit with 8mm cutters was run on well DM25C and was pulled at 1,225 ft. The wear averaged 10 to 15% on the O.D. taper with a single cutter wearing to about 20%. The wear was considerably less than observed with the heavier set eight bladed bit with 8mm cutters shown in Fig. 11.

Another eight bladed bit with 8mm cutters was run at the CTF to further validate the improved wear with the lighter set bits. The 8mm PDC cutters in this bit were an improvement over the ones shown in Fig. 11. Figure 14 shows the percent diamond loss. The diamond loss was reduced from the earlier version in Fig. 11 but the wear was nearly two fold higher than with the lighter set bit shown in Fig. 13. The results of this testing further validate the observations made regarding cutter density.

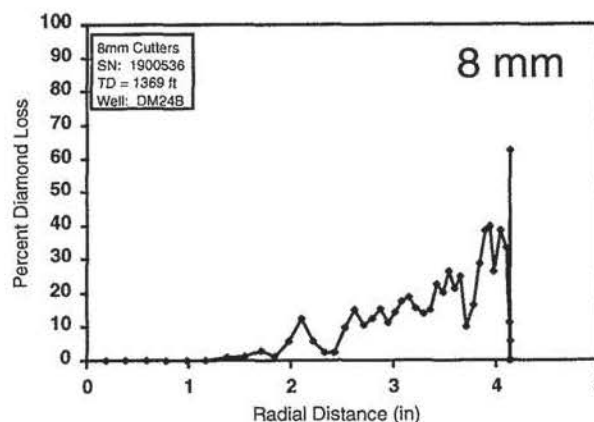


Fig. 14: Percent diamond loss with an eight bladed 8-1/2 in. PDC bit using 8mm PDC cutters

#### Cutter Speed

Early technical literature reported that accelerated PDC cutter wear in the harder formations was caused primarily by high cutter temperature. These papers indicated that the proper method for drilling harder intervals was to increase the rotary speed and decrease the applied bit weight, which should in



result in less cutter temperature and wear. We now know that this is the absolute worst practice to perform in the field since impact loading of the cutters plays a major role in hard formations. When hard stringers are encountered, the diamond table of the cutter is more susceptible to chipping and breakage from vibration. Once the diamond table is lost because of damage, the tungsten carbide wear process proceeds very quickly. We now know the bit speed should be reduced and the applied bit weight increased to help minimize the detrimental effects of bit and drill string whirl in harder formations.

Observations from the CTF help substantiate the use of lower bit speeds to reduce PDC cutter wear. During one project, an eight bladed PDC bit with 13mm cutters was run on a rotary steerable system at speeds of 60 - 80 rpm and was pulled with no measurable cutter wear. There was evidence of slight chipping or diamond delamination on a number of cutters but measurable wear was nil which was unusual for the footage drilled. Because of the minimal wear, the bit was rebuilt and rerun in a separate well at 120 rpm. The measured wear was considered normal for a smooth drilling PDC bit averaging less than 10% diamond loss out to the gage.

As a follow-up test, an identical PDC bit was later run on a third well using a 6-3/4 in. motor. The total bit speed including surface and motor rotation was 270 rpm. Figure 11 compares the percent diamond loss for each of the three PDC bit runs at different speeds. The effect of bit speed on wear rate is clearly seen in this example. The most worn cutter at 120 rpm is only worn 7% compared to approximately 20% diamond loss for the bit at 270 rpm, a three fold increase in cutter wear for the same footage drilled.

### Summary

Field testing in a controlled environment offers the unique capability to exclude many of the unknown variables which hamper typical evaluations in an exploration or production environment. The observations presented in this report have good technical merit and many of the concepts are presently finding their way into commercial designs and field applications. The summary below highlights the major findings of this work.

1. Heavy set PDC bits can be a detriment to the drilling performance in hard formations. Testing showed a three bladed PDC bit with 19mm cutters out performing an eight bladed bit under identical conditions with less wear. These results were further validated by the test results with 8mm cutters for a four bladed bit against one with eight blades. Cutter overloading is the major limitation to bits with less cutter density.
2. The rate of penetration and torque response with new PDC bits is primarily controlled by the aggressiveness of the cutter, i.e. cutter back rake angle. A four fold increase

in WOB was shown in Carthage limestone for a bit with 7-10-15° back rake compared to a bit with 40° back rake. For Catoosa shale, the difference was nearly six fold. For improved steerability, a bit design should use less aggressive cutters inside the cone and more aggressive cutters toward the gage.

3. Cutter wear was shown to increase as the cutter size decreases.
4. Bit speed was shown to increase the rate of wear, from basically no wear at 60-80 rpm to 20% wear for a bit rotating at 270 rpm through the same formations.

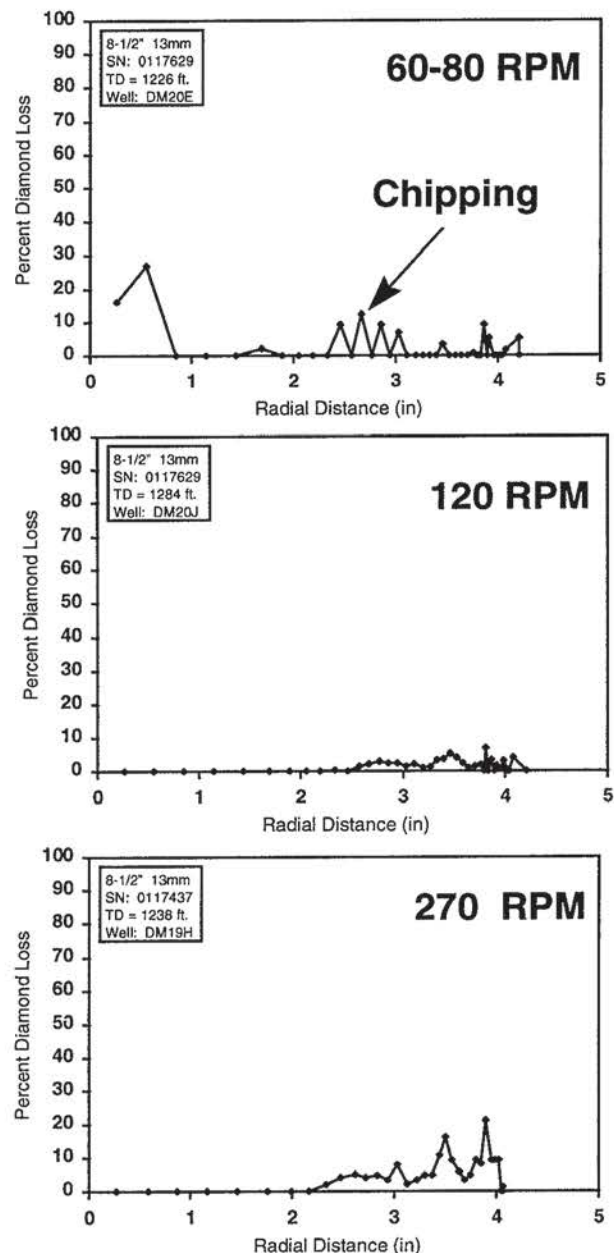


Fig. 15: Effect of bit speed on wear rate of PDC cutters.



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