The Economic Impact of Polycrystalline Diamond Compact (P.D.C.) Drilling Bits

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HISTORY

Since the perfection of a process for producing artificial or manufactured diamonds in 1955, attempts have been made to adapt their use for stone cutting. The original stones were commercially applied to manufacturing processes for grinding and polishing as they did not exhibit resistance to abrasion sufficient for stone cutting. Additional improvements in manufactured diamonds have resulted in a high enough abrasion resistance to utilize them in stone and masonry cutting applications.

Drill bits utilizing natural diamonds have individual stones as the cutting element. Manufactured diamonds are of such a small size as to make the use of individual stones as cutters impractical. The introduction in the early 1970's of a polycrystalline aggregate of manufactured diamonds produced a cutting element that became practical for use in drill bits. Laboratory and field tests began on drill bits with P.D.C. cutting structures in 1973. Continual efforts have been made since that time to produce a drill bit that is economically feasible for use in petroleum drilling operations.

HISTORICAL COMMERCIAL APPLICATION

P.D.C. drill bits have been in commercial use for several years in Europe, the Middle East, and North Sea areas where formations consisting of salt, anhydrites, and carbonates are encountered. However, the vast majority of wells drilled for hydrocarbons encounters extensive sections of shale and sand with varying degrees of density, plasticity, and hardness. Experiments with P.D.C. drill bits in such formations had produced only periodic economic success. The lack of such success prevented the use of P.D.C. drill bits as anything other than a very specialized drilling tool.

FIELD TESTING FOR ECONOMIC APPLICATION OF P.D.C. DRILL BITS

In the summer of 1979, a field testing program was conceived to determine if a drill bit utilizing a P.D.C. cutting structure could be developed that would be economical as a general drilling tool. The following criteria were established for the bit:

(1) The combination of penetration rate and bit life must produce a per foot drilling cost low enough to provide an economic drill bit.
(2) The hole produced by the drill bit must exhibit no characteristics detrimental to future use of the bit.
(3) The operational characteristics of the bit must be such as to allow the average driller to be able to operate it.
(4) The application of the bit must cover a wide range of bit sizes, formations, and operating conditions.

Initial testing was begun in October of 1979 to determine if such a bit could be competitive against A.P.I. rock bit types 1-1-1 through 1-3-6 in water base mud systems on wells with low hourly operating costs ($275.00 to $325.00 per hour or from $6,000.00 to $8,000.00 per day). A second testing program was begun in January, 1980, to compare against A.P.I. rock bit types 4-3-7 through 5-3-7 in both water base and oil base mud systems on wells which had a medium hourly operating cost ($450.00 to $650.00 per hour or $10,000.00 to $16,000.00 per day). The testing program was later extended to cover other geographical locations, higher operating costs, and A.P.I. bit types up to 8-3-7. The original testing program was conceived as being on-going and is still continuing. However, as of December 31, 1980, 213 bits have been run in wells covering 19 different geological formations in 4 states and Canada at well depths ranging from 1800 feet to 18,600 feet in bit sizes from 5 7/8" to 12 1/4". A total of 262,327 feet of hole was drilled in 15,375 operating hours.

"SALABLE" HOLE

Examination of calipers logs from wells in which P.D.C. bits were used resulted in a determination that the hole size in water or oil base mud was no larger than with other bits and in many cases was smaller. Electric logs indicated in 4 wells that some erosion of sands took place in intervals where it did not occur with other bit types. As this occurred in such a small number of cases, it is felt that the erosion of sands occurred as a result of the particular formation or the mud properties. The 4 cases all occurred in the upper Frio formations where the sands are generally unconsolidated.

Deviation studies show that the bit either straightened hole, did not deviate, or deviated less than was historically true of rock bits. Preliminary tests in 3 directional wells show that there was no difficulty in maintaining hole angle. There was some indication in 2 of those wells that the bit has a tendency to "walk" to the left. The 3rd well showed a definite "walk" to the left by the P.D.C. bit when rock bits had all "walked" to the right.

Samples collected at the shaker showed a size much larger than a conventional diamond bit and somewhere in between the size produced by a mill tooth bit and a tungsten carbide inserted bit. In no cases were there samples of a lesser quality than those produced in a similar environment by other types of bits and were often superior.

Many "hole" problems that occur when using water base mud in shale formations subject to swelling from absorption were eliminated because of the smaller amount of time that the hole was "open." The faster penetration rate of the P.D.C. bit allowed a shortened interval in which the hole had to remain open prior to casing.

DRILLING CHARACTERISTICS

Rotational Speed

All bits, excepting 3, were run using the rig rotary. The relationship of rotational speed to penetration rate in brittle shales and sands appears to be a linear one. Plastic shales, limestone, and chalk do not show an increase in penetration rates for rotary speeds above 120 r.p.m.. Down hole motors were used on 3 of the bit runs. Penetration rates were approximately 60% less than when the bit was run in the same well using the rig rotary. There is insufficient data to determine why the use of a down hole motor resulted in a slower penetration rate.

All those trials were run in relatively high plastic formations and the stalling point of the motors allowed the use of only half the weight used when rotational power was from the rig rotary.

Torque

Torque requirements are somewhat higher than with conventional rock bits. Requirements in any given formation are about 20% in excess of those required for rock bits. Torque increases when a sand is entered. Numerous comparisons of the torque sections of drilling recorders and electric logs were made. Sand and sandy shale were as easy to locate on the torque recorder as on the electric log.

Incidences of washouts, connection damage, and "twist offs" were no higher with P.D.C. drill bits. Only in one case did pipe damage occur. This resulted from a new design in which the wrong effective cutter side rake was used and 28 joints of drill pipe were ruined.

Weight on Bit

Optimum penetration rates are achieved in most formations with approximately 50% of the weight used on a rock bit. Chalk and limestone formations often require up to 70% of the weight used on a rock bit. The correct bit weight is very easy to determine as an increase over that will cause the bit to stop drilling or, in the case of harder formations, no increase in penetration rate. Sandy shales with an oil base mud system are often drilled at 60 f.p.h. with only 12,000 pounds on an 8 1/2" bit.

Mud Systems

Oil base mud systems (both relaxed and non-relaxed fluid loss) exhibited the best environment for the bit. Penetration rate averages were never less than twice those of rock bits and were often four times as high. Bit life was 40% longer in oil base mud systems. There were no uneconomical runs in oil base mud systems. Various formations which could not be drilled in a water base mud proved susceptible when an oil base mud was used. Non-clay shales, chalk, limestone, and sandy shales are drillable in water base mud systems.

Formation and Junk Damage

The same care should be taken with a P.D.C. bit as with a conventional diamond bit to insure that there is no junk in the hole. The P.D.C. bit was found to be able to drill formations with pyrite, quartz, and chert with no difficulty when a conventional diamond bit would have been destroyed. No bit damage resulted from drilling layered formations of pyrite, chert, or quartz. Fractured formations containing particles of these items are drillable as long as the particle size does not exceed 1/16 of an inch in diameter. One-inch pyrite crystals destroy the bit.

Unexplained Stops

Periodically in any given well the P.D.C. bit will completely stop drilling. The penetration rate will go from 30 to 60 f.p.h. to 0. This occurs with none of the indications that the bit is damaged. Working with the bit (wash bottom, varying rotary and weight) to make from 1 to 5 foot of hole has resulted in the resumption of the previous penetration rate. An examination of samples, electric logs, and side wall cores has produced no discernible difference in these intervals than the formation just above or below. Several bits were pulled when this occurred and a new bit run. In some cases, the bit began to drill immediately, and in others it took an hour and 1 to 2 feet to begin drilling. The bits that were pulled were later re-run. This behavior occurs in both water and oil base mud systems.

Hydraulics

Various experiments to determine the optimum bit hydraulics have been carried out. No specific determination has been made as to required hydraulic horsepower per square inch or gallons per square inch of bit area. Certain general characteristics can be stated. The circulating pressure will be approximately 50% of that used on rock bits because of the greater number of jets in the P.D.C. bit and the use of larger jets. Annual velocities or funnel viscosities should be increased to carry the additional volume of cuttings present in the annulus due to the increased penetration rate of the P.D.C. bit. Jet velocity does not appear to have an effect on drill rate.

SAFETY

A primary consideration for the use of any tool on a rig should be whether it affects the safety of the personnel and well. The majority of blow-outs and injuries to personnel occur during or result from trips. The longer bit life of the P.D.C. bit serves to reduce the risk and increase the safety of both well and personnel. The lower pressures in the mud system exhibited by P.D.C. bits reduce the risk of injury to personnel resulting from equipment failures in the mud system. The lower pressures also reduce pump down time and reduce the chances for stuck pipe and other risk relating to a pump going down. The increased penetration rate of the P.D.C. bit can produce unsafe conditions if supervisory personnel are not prepared for them. Field tests were conducted on the effects of drilling in an overbalanced condition with P.D.C. bits. Overbalanced muds to the extent of a 2-pound overbalance produced no decrease in penetration rates. An overbalance of 3 pounds significantly decreased the penetration rate. The ability to drill overbalanced significantly decreases the risk in the drilling operation.

PERSONNEL

One of the criterion for the bit was that it should be operable by untrained personnel. The field test has indicated that the bit is a failure in this regard. The operational personnel to the driller level must be instructed in the operational characteristics of the bit. This is necessary to insure the fastest penetration rate and optimum bit life. Although the operation of the bit is not complicated, printed instructions have proven to be inadequate. A manufacturer's representative should be on location to instruct rig crews and supervisory personnel the first time a bit is run by them or the first time a bit is run in a new area. The increased penetration rate of the P.D.C. decreases the lead time in preparing for certain procedures. Supervisory personnel must be aware of this and plan accordingly. For example if a mud weight increase is necessary by a given depth and personnel have been accustomed to a 10 f.p.h. penetration rate and the P.D.C. rate if 60 f.p.h., supervisory personnel may have only hours to increase mud weight rather than days. The highest drill rate possible with certain automatic drillers is 60 f.p.h. If the shale penetration rate of the P.D.C. is 60 f.p.h. and a sand is encountered, no increase in penetration rate will occur unless the driller maintains a constant weight on the bit. Proper instruction of personnel will prevent these problems.

ECONOMIC RESULT OF FIELD TEST

The primary consideration of an operator or a contractor drilling on a contract on a per foot basis must be the successful completion of the well at the lowest possible total dollar figure. The cost of a drill bit is immaterial if it results in a lower per foot drilling cost and has no detrimental side effects. Obviously such a drill bit must be competively priced among its competitors. Per foot drilling cost is generally determined by the application of the following formula:

$$\text{Cost per foot} = \frac{\text{Hourly Operating Cost (Trip hrs. + Drilling hrs.) + Bit Net Cost}}{\text{Feet Drilled}}$$

The hourly cost should include all cost and not just the rig cost. Bit cost should include not only the bit price but also a service fee if there is one.

Although the cost per foot formula is widely accepted as a means of determining the most economical bit to run, it is not truly exact as to actual cost. There are many cost items that are not reflected in the formula. Trip hours are reflected in the formula to provide a cost comparison relating to bit life; however cost secondary to a trip are not reflected. Drill line ton miles result from tripping in large part and not from drilling. The cost of cutting and slipping drill line is not reflected in the formula. Mud cost in many areas is increased proportionally as trips are increased because of additional treatments required by the inability to circulate while tripping.

The risk factor cannot be reflected in the formula because there are no definite figures available. Each operator should assign a percentage risk factor to his bit cost per foot when comparing bit cost per foot. Statistically it is inevitable that a cone will be lost from a rock bit at some time, hence the risk is lower if a journal bearing bit is used and lower still if a drag bit (diamond or P.D.C. type) is used. The higher the operating cost and the lower the personnel capability the higher the risk factor becomes. Each operator should assign a percentage risk factor that reflects his knowledge of personnel, rig capabilities, operating cost, and formation pressures. Every operator does this mentally but few actually assign numerical values to the risk factor. Refer to Chart "A" as a method of risk assignment.

All cost per foot figures for the field test of the P.D.C. bit were done with no consideration of risk factor.

The 213 P.D.C. bits run resulted in 66 uneconomical runs and 147 economical runs. The uneconomical runs drilled 54,710 feet of hole for a total loss of \$309,973.85 or an average of \$5.67 per foot of hole drilled. The economical runs resulted in a savings of \$5,960,899.85 in the 207,617 feet of hole drilled for an average savings of \$28.71 per foot. A net savings of \$5,650,926.00 or \$21.54 per foot of hole resulted from all bits run. A success factor of 69% was achieved and dollars saved to dollars lost was \$19.23 to \$1.00. The average reduction in per foot drilling cost on those runs that were successful was 38%. The highest amount of savings was 79.5% and the lowest was 1%. Cost per foot savings and percentages are for the hole interval drilled and not the entire well cost.

All cost per foot figures are biased to some extent by the following factors:

(1) Incorrect bit design for formation, later changed to achieve successful runs.
(2) Rock bit cost derived from bit run prior to P.D.C. which represented

a lower per foot cost for rock bit.

(3) Controlled drilling of the P.D.C. by operator's choice.

(4) Incorrect operation of P.D.C. by rig crews.

ECONOMIC DISASTER

A new tool that has the potential to increase penetration rates by 600% also has the potential to create a disaster. Anyone who has seen a wild well never wants to see another one. The operator and drilling contractor who has had such a well know well the cost. Few operators or contractors can afford many such wells. Even if a blow-out does not occur, hours spent "on the choke" are unproductive hours. Care must be taken to plan for the potential penetration increases of P.D.C. bits. Adequate supplies of mud materials and fluids must be on location or delivery time for such materials decreased in order to be able to build both volume and weight faster than normal. This is especially true in remote land or offshore locations. Personnel and rig equipment must be able to operate in a compressed time span. Automatic drillers must be able to maintain constant bit weights in the 5,000 to 10,000 pound range at penetration rates of 200 feet per hour to detect drilling breaks. Drillers must have the proper detection equipment to recognize a drilling break within 2 minutes instead of 10 minutes.

ECONOMIC IMPACT

The field test has shown conclusively that P.D.C. drill bits can result in reductions of up to 80% in per foot drilling cost while drilling sands and shales. The average savings of 38% created a substantial savings. The low risk factor of this type of bit enhances its application. The potential problems created by increased penetration rate are easily solved by additional training of rig crews, advanced planning by the operator, and additional monitoring equipment on the rig floor. The resulting cost of these actions is easily offset by the direct savings from the bit.

The direct savings of reduced cost per foot of hole drilled is impressive but may be small in comparison to the long range economic advantages produced by the bit. Studies conducted by two major operators show that total per well time was reduced by an average of 5 days. One operator reduced the well time from 40 to 35 days and the other from 21 to 16 days. The current shortage of rigs has prevented the operators from adding rigs to drill more wells per year. The day savings allowed the operator with 4 rigs to drill 42 wells per year rather than 36 and the other operator with 6 rigs drilled 156 wells rather than 104. The cumulative effect of securing next year's production at today's drilling cost and selling such production in current value dollars has such an impact on both current and future profits that it is hard to determine.

The best measure, or certainly the most direct, of economic impact is return on investment. The higher price of P.D.C. bits resulted in an additional investment of approximately $1,065,000.00 in bit cost over the estimated bit cost for the wells drilled. The $1,065,000.00 additional investment resulted in a return of $5,650,926.00 or a 530% return on investment.

CONCLUSION

The design and utilization of P.D.C. drill bits has only just begun. New and improved designs and a better understanding of the method of operation of such bits can only increase the reduction in per foot drilling cost. The application of the bit will increase in terms of bit size range and formations. The average life of of the bits during the field test showed an increase from 45 hours to 90 hours with one bit having a life of 403 hours. Although successful bits in the test ranged from 5 7/8" to 8 3/4", other sizes are currently being tested. The P.D.C. cutters in currently designed bits do not show enough abrasion resistance for utilization in formations requiring A.I.D.C. type 7-3-7 and 8-3-7. Future improvements in the cutters and in bit design could show the bit to be most economical in this area.

CHART "A"

Risk Factor Adjustment of Per Foot Drilling Cost

Risk Factor		Cost Factor (Hourly)			
Certain	20	$100	5%	$1,500	55%
		$200	10%	$2,000	60%
Probable	15	$300	15%	$2,500	65%
		$400	20%	$3,000	70%
Possible	10	$500	25%	$3,500	75%
		$600	30%	$4,000	80%
Improbable	5	$700	35%	$4,500	85%
		$800	40%	$5,000	90%
Not Possible	0	$900	45%	$5,500	95%
		$1,000	50%	$6,000	100%

EXAMPLE CHART

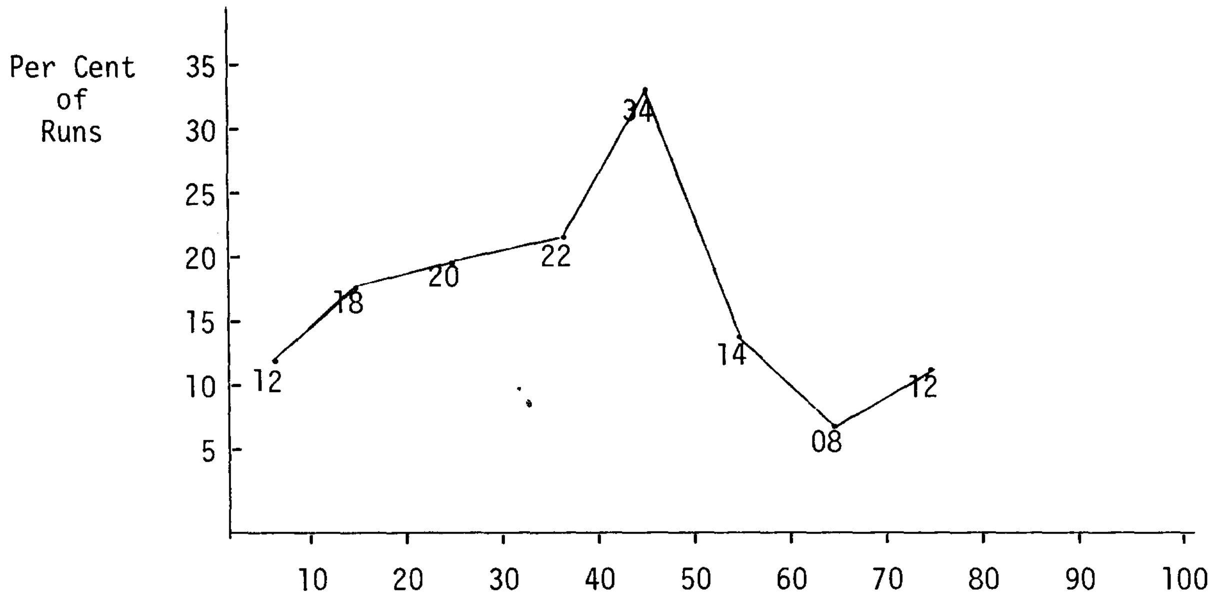
Risk	Bit Type Regular Bearing	Sealed Bearing	Journal Mill Tooth	Journal T.C.I.	Diamond	P.D.C.
Lost Bearings	20	15	0	0	0	0
Lost Cone	20	15	10	5	0	0
Lost Matrix	0	0	0	0	10	0
Trip Cost/Risk	20	15	10	5	0	5
Plugged Bit	10	10	10	10	5	15
Out of Gauge	15	15	15	10	0	5
Total	85%	70%	45%	30%	15%	25%
Cost Factor $500 per hr.	25%	25%	25%	25%	25%	25%
Net Factor	.2125	.175	.1125	.075	.0375	.0625

$$\text{Cost per foot} = \frac{\text{Hourly Operating Cost (Trip Hrs. + Drilling hrs.) + Bit Net Cost}}{\text{Feet Drilled}}$$

True Cost per foot = Cost per foot x 1 + Risk Factor

CHART "B"

Percentage Savings Distribution
of
Economical P.D.C. Bit Runs



Savings Percentage in Relation to Rock Bit Runs