

# Eggbeater PDC Drillbit Design Eliminates Balling in Water-Based Drilling Fluids

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**Summary.** This paper describes a novel polycrystalline-diamond-compact (PDC) -bit concept based on insights into PDC-bit cutting mechanism and rock behavior during drilling. The design comprises a hydraulic layout that optimizes bit cleaning and cuttings removal in soft and sticky formations. Significant improvements in performance have been achieved in Cretaceous and Triassic formations drilled with water-based muds.

## Introduction

Since the introduction of PDC bits in 1973, a new generation of bits has become available for drilling oil and gas wells.<sup>1</sup> Since then, a large variety of PDC-bit designs have been developed for specific applications, allowing a wide range of formations to be drilled economically. Optimum PDC-bit performance is usually achieved in an oil-based-mud environment.<sup>2</sup> Comparable performance with regard to rate of penetration (ROP) and bit life is largely unattainable in water-based muds. This difference in performance capability is most pronounced in soft or sticky formations and is attributed to accumulation of drilled cuttings at the bit face, resulting in bit balling and reducing drilling performance dramatically in water-based muds. Use of oil-based muds, however, is subject to rigorous statutory regulations being developed and implemented to mitigate pollution from their use. Consequently, oil-based muds are replaced with water-based muds where possible. This trend increases drilling company's concern over the inferior performance of PDC bits in water-based muds compared with that in oil-based muds.

In view of these developments, Nederlandse Aardolie Mij. B.V. (NAM) has taken a proactive approach toward minimizing environmental impact of the use of oil-based muds in their drilling operations.<sup>3</sup> Alternatives to oil-based muds are actively sought, and significant efforts have been made to provide rigs with cuttings cleaning systems that meet the current regulations (i.e., a maximum 10 wt% oil retention on cuttings) if technical reasons dictate the use of oil-based muds. In addition, improved PDC-bit designs are being investigated and field tested to optimize their drilling performance in water-based muds.

This paper examines the PDC-bit cutting process in soft or sticky formations, and describes associated balling mechanisms. On the basis of these insights, a new "eggbeater" bit design concept was developed and is presented along with field test results of the eggbeater bit in NAM's drilling operations.

## Cutting Mechanism

Bit balling is closely related to the size and the properties of the cuttings produced by the cutting elements on a bit. These cuttings characteristics can be determined from insights into the PDC-bit cutting process in low-permeability formations, such as chalk, marl, claystone, and shale.

PDC bits primarily use a shearing action in a narrow zone to the front of the cutter for cutting (Fig. 1). During rock shearing, dilatancy occurs because microcracks in the formation are opened as the rock reaches its failure strength.<sup>4,5</sup> This increases the rock PV. Because of the high shear rate during cutting and the low permeability of the formations, pore-fluid and mud-filtrate invasion into the shear zone is limited, and the pore pressure in the rock passing through the shear zone drops. In extreme cases, the pore pressure in the rock decreases to the vapor pressure of the pore fluid. This suggests that chips initially are subjected to a high differential pressure [as high as the bottomhole pressure (BHP)], which decreases

gradually because of mud-filtrate invasion. This high differential pressure provides considerable cuttings strength and lifetime so that long, continuous cuttings can be produced.

Laboratory drilling tests in soft or sticky formations revealed that the cuttings produced by PDC bits look like stacked chips.<sup>6</sup> However, such cuttings disintegrate totally into rock flour shortly after test completion. This indicates that shearing is a continuous process and that the cuttings strength is provided by differential pressure rather than by cohesion.

The disintegration rate under downhole conditions is considerably slower than that observed during laboratory testing because after test completion the release of pressures to simulate downhole conditions reduces differential pressure across the cuttings. This increases permeability drastically in the cuttings, which accelerates fluid invasion.

## Balling Mechanisms

The PDC-bit cutting mechanism in soft or sticky rock, described above, implies that the effective contact stress at the cuttings/PDC-bit surface interface initially can be as high as the BHP. As a result, a frictional force develops at this interface at the base of the cutting and this force increases as the size of the contact area increases.

When the compressive force required to overcome this friction exceeds the cuttings strength, instability occurs, and subsequently, chips are generated and stacked up (Fig. 2). This instability also occurs when cuttings removal is hampered by the bit body (e.g., small waterway size). Cuttings accumulate when the cuttings production rate exceeds the erosion rate of the balled-up cuttings caused by the drilling fluid.

This balling mechanism may occur in both water- and oil-based muds and occurs almost instantaneously after cuttings have formed. This phenomenon is "primary" bit balling.

If primary bit balling does not occur, the cuttings are surrounded by mud and transported to the annulus. However, when drilling with water-based mud, cuttings have a strong tendency to suck in filtrate from the mud and thus equilibrate the pressure differential across the cuttings. Consequently, such cuttings can easily accumulate or become stuck on the bit surface, ultimately balling up on the bit.

If the cuttings contain clay fractions that are sensitive to water, this tendency is increased significantly. The release of formation BHP and destruction of the original bonding between the rock grains caused by the cutting process activates the full swelling potential of the cuttings. This swelling potential, which is based on hydration of the clay fraction, may be substantially larger than that associated with the pressure equilibration process.<sup>7</sup> The balling mechanism associated with pressure equilibration and swelling does not occur instantaneously because it is governed by fluid invasion; thus, it is called "secondary" bit balling.

With oil-based muds, secondary bit balling (i.e., that caused by the suction effect) is much less likely to occur than with water-based muds because oil invasion does not activate the swelling potential of the clay fraction of the cuttings.

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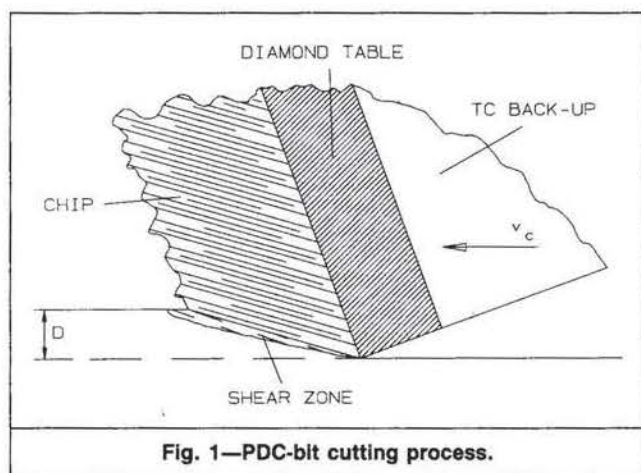


Fig. 1—PDC-bit cutting process.

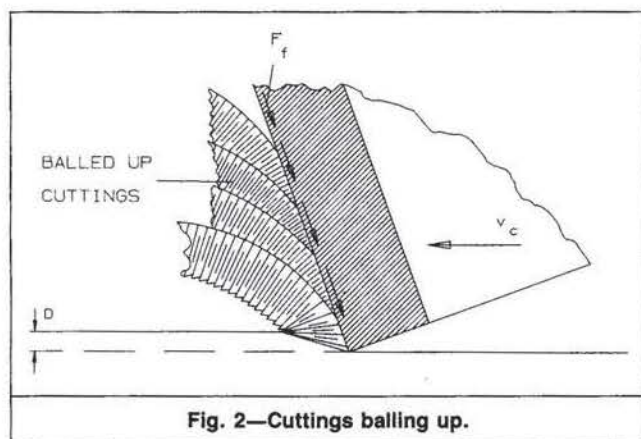


Fig. 2—Cuttings balling up.

### Bit Cleaning

The insights into the cutting process and balling mechanisms described above allow evaluation of the cleaning efficiency of a particular PDC-bit design.

The risk of primary bit balling can be minimized by creating a discontinuity at the transition between the PDC and the bit surface to limit contact between the bit face and the cuttings as they are generated. In addition, a large standoff of the PDC bits allows large cuttings to be generated and transported efficiently without significant wall contact with the bit body, thus minimizing the risk of bit balling.

Once the cuttings are fully exposed to the drilling fluid, hydrodynamic forces can break the cuttings and transport them into the annulus. The breaking efficiency of cuttings is governed largely by the section modulus relative to the direction of fluid impact and the exposed area. The efficiency of cuttings transport into the annulus is governed by the size of the waterways and the drilling-fluid velocity distribution around the bit.

Flow visualization techniques have unveiled extremely complex flow profiles around the bit that contain such anomalies as stagnation points, vortices, and reverse-flow patterns.<sup>8</sup> Areas of low mud velocity where cuttings may accumulate, clog up, and, ultimately, partially ball up the bit are associated with these anomalies. Minimization of flow anomalies has improved cleaning efficiency of blade-type bits considerably.

### PDC-Bit Drilling Characteristics

Examination of full-scale laboratory drilling test results with PDC bits in soft or sticky formations revealed a marked change in the drilling characteristics after the bit has partially balled up.<sup>6</sup> Under proper cleaning conditions, the ROP is virtually proportional to the weight on bit (WOB) and rotary speed. When the bit is partially balled up, however, ROP hardly responds to WOB and rotary speed changes; instead, flow rate becomes the main parameter governing ROP.

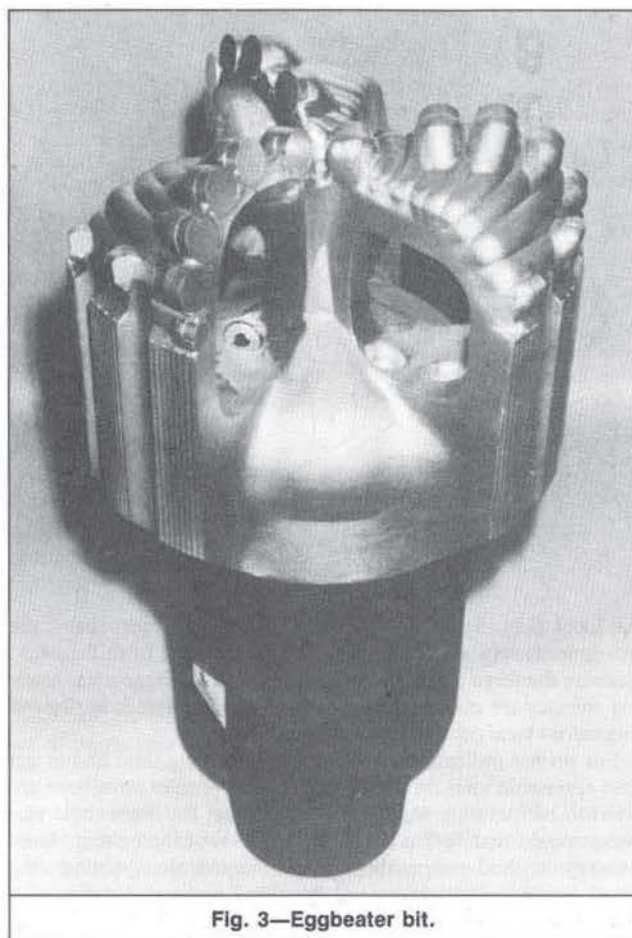


Fig. 3—Eggbeater bit.

Standpipe pressure does not necessarily increase when the bit is balled up because the fluid can erode channels through the cuttings, which are packed in the waterways and junk slots. While circulation can still be maintained at sufficient levels, a tremendous retardation in ROP normally can be seen because most of the WOB is being absorbed by rock flour.

Recognizing these PDC-bit characteristics can assist in determining whether a bit is partially balled up when, for example, the response of ROP to WOB or rotary speed variations is assessed under field conditions.

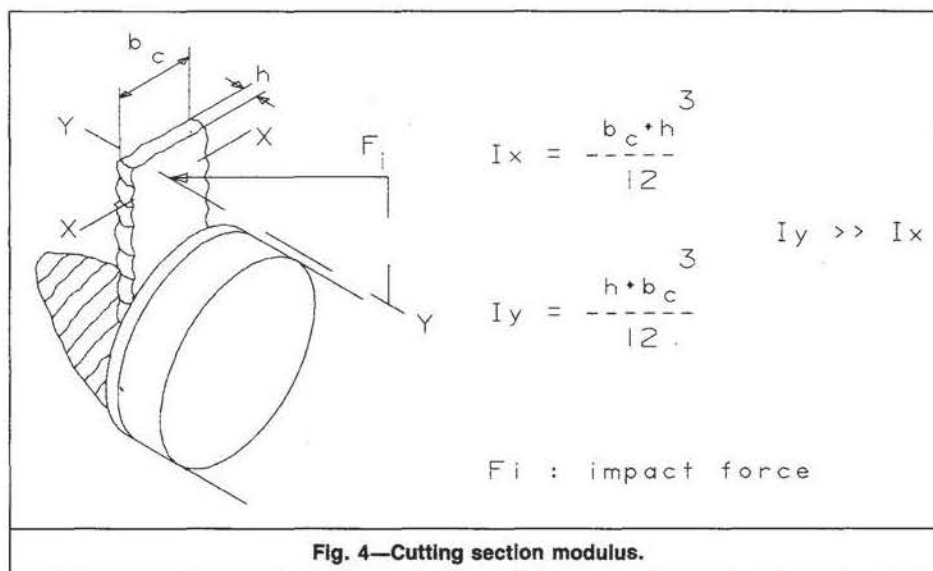
### Eggbeater-Bit Concept

Because pressure equalization around the cuttings is the ultimate goal for minimizing bit balling, direct fluid access to the back side of the cuttings has to be provided. This determination led to the design of a drag-type bit with three blades that are hollow in the center to provide the necessary interruption.<sup>9</sup>

In conjunction with the PDC-bit cutting element, the cutting lobes formed resemble those of an eggbeater (hence, the name of this bit design) (Fig. 3). Because cuttings will peel off the diamond table perpendicular to the bit profile, all generated cuttings will be forced across the diamond table and off the cutting lobe into the junk slot.

When a cutting is formed and starts to escape off the cutting blade, it begins to penetrate the open space formed by the junk slot and the hollow blade. The pressure is equalized around the cutting immediately, eliminating differential sticking. Cuttings removal then becomes the major task. Fig. 4 shows that the width of the cutting is usually greater by magnitudes than its thickness. To break and remove a cutting effectively, sufficient stress must be created inside the cutting to overcome its bending strength. The section modulus around the  $x-x$  axis of the cutting is much smaller than that around the  $y-y$  axis. Additionally, the area of the cutting around the  $x-x$  axis is largest during bending. Therefore, the nozzles on the eggbeater bit are located behind the lobes and directed through





the lobes (Fig. 5). After the cutting reaches the open space, the jets immediately start to impinge on the cuttings from the back. Because the force is maximized as a result of the large area, bending stresses are maximized inside the cutting where it is stressed around its weakest axis.

For proper utilization of the available drilling fluid and to get into applicable total-flow-area ranges, two nozzles have been applied to each cutting blade. The jets contact the bottomhole at a point approximately 7.6 cm [3 in.] in front of the cutting blade. Most of the fluid escapes directly into the junk slots, while a very small amount circulates toward the center along the trailing side of the preceding blade. After it reaches the center, the flow is directed upward, parallel to the bit axis, and is affected by the inward nozzle again; this pattern has been observed during flow visualization tests (Fig. 6). Despite this minor amount of recirculation proved in field tests, there is still sufficient turbulence to prevent cuttings from sticking to the bit body.

For maximum cuttings volume, the blade layout is designed so that the trailing side of one blade and the front side of the next blade form an approximate right angle. This feature ensures that the fluid is directed into the junk slot with minimal changes in direction. As a result, both the cuttings travel time on the bit face and the possibility of the cuttings clogging up at any point on the bit are minimized.

### Bit Integrity

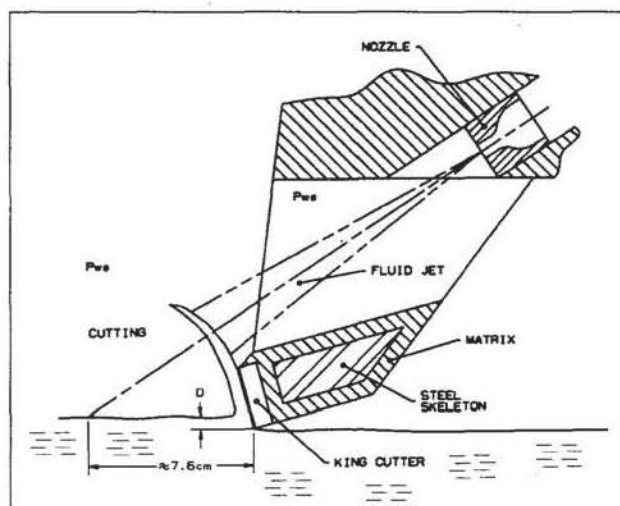
Because of the three-bladed layout, consideration had to be given to the durability of the blades. A tungsten carbide matrix surface is necessary to provide the required erosion resistance for maximum hydraulics and for positive-displacement-motor application. However, tungsten carbide matrix material is relatively brittle and cannot withstand significant impact loading on its own. Therefore, the cutting lobes of the eggbeater are designed with an internal steel skeleton that adds the required ductility for maximum impact resistance.

To minimize the stresses between the materials caused by thermal expansion, use of a special steel with a thermal expansion coefficient comparable with that of the tungsten carbide matrix was necessary.

Fig. 6 shows the geometric dimensions of the lobes (width and thickness). Because loading will be created primarily by the cutting forces, the polar moment of inertia around the  $z$ - $z$  axis is maximized by use of the maximum permissible wing width.

### Bit Profile

In today's environment, more and more wells are being drilled with steerable bottomhole assemblies that can be run in a straight-hole or a directional mode. In the directional mode, the bit usually spins



**Fig. 5—Schematic of eggbeater blade with nozzle arrangement.**

around its own axis, but significant side loads are applied to force it along a certain curvature.

In the straight-hole mode, however, the bit axis is forced onto a conical track because the string rotary speed is superimposed onto that of the motor. Because the motor has a tilted drive sub, the bit is heavily loaded on its nose. This constant change to the bit axis position with reference to the hole axis makes it necessary to apply a round profile to the bit to minimize the number of cutters losing bottomhole contact during each rotation in straight-hole mode. Because parabolic profiles also enhance an equal loading of the cutters and, to a great extent, prevent "O" rings (i.e., loss of PDC material at a specific radius), a shallow parabolic profile was selected for the eggbeater.

### Cutter Distribution

The ultimate objective of running any drill bit is to minimize drilling costs. Normally, this is a function of bit life and ROP. Any premature failure of the cutting structure obviously will reduce performance. Therefore it is preferable to provide a cutting structure that wears evenly from center to gauge.

The main factors influencing cutter wear are forces and frictional heat. The technical basis for these factors has been identified as the power output per cutting element:

$$P = FR\omega \dots \dots \dots (1)$$



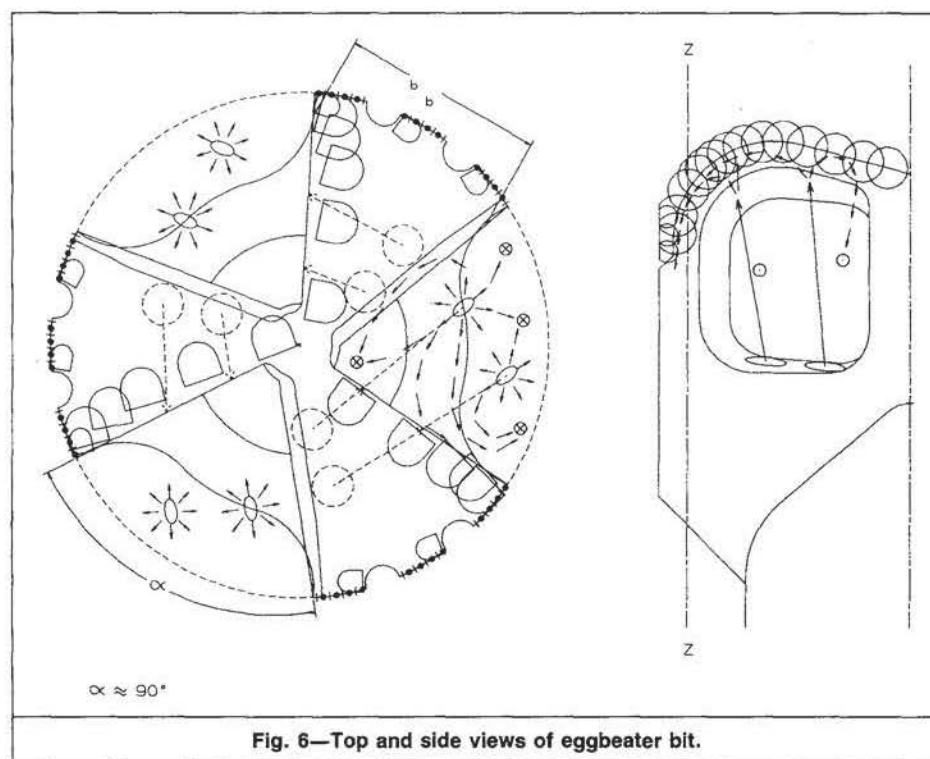


Fig. 6—Top and side views of eggbeater bit.

This power output is calculated for every cutting element. Fig. 7 shows distribution of the power output per cutting element for the 31-cm [12.25-in.] eggbeater bit. The power output for the cutters in the center of the bit is very low because the travel speed of the PDC cutting element is minimal. The power output per cutting element then gradually increases to its maximum and drops to zero at the bit gauge. Such a low power output per cutting element is maintained in the center because the entire radial distance is covered with diamond material. This produces an ultraheavy PDC-bit center section that rarely shows signs of wear.

The power output per cutting element then will climb to a maximum, which is calculated with reference to the formation strength and the engaged area of cut at expected ROP's. The power output per cutting element decreases again toward the outside, where the PDC bits provide maximum durability to ensure a correct hole dimension.

Additional 1.27-cm [0.5-in.] PDC gauge trimmers are located at each bit OD where the grind flat is aligned with the gauge. This arrangement provides optimum gauge protection by PDC bits and minimizes the cutting action of the natural diamonds positioned above the PDC gauge cutters. Consequently, the decrease in ROP observed in drilling tests after the natural diamonds start cutting the formation, which is caused by the low aggressiveness of natural diamonds, is eliminated under normal drilling conditions.

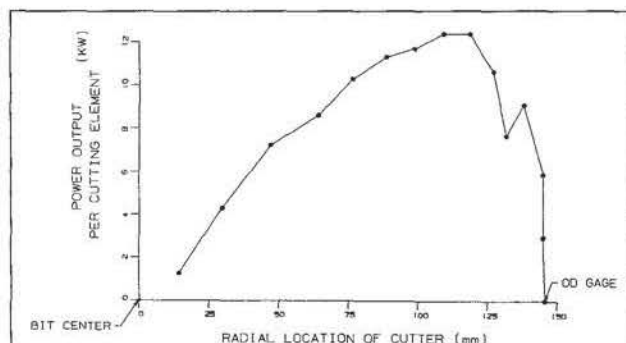


Fig. 7—Distribution of power output per cutter of 31-cm [12.25-in.] bit.

Another important factor is that the steerability of a PDC bit depends greatly on its side-cutting ability. Parabolic profiles tangent to the bit gauge provide sufficient space for gauge cutters that can be aggressively oriented perpendicular to the bit axis.

Another enhancement to PDC-bit performance is introduced by use of large (1.9-cm [0.75-in.] -diameter) cutting elements. A comparison of bits that use a cutting structure formed out of 1.27-cm [0.5-in.] standard PDC elements vs. a cutting structure of larger PDC elements reveals that the contact line from center to gauge is shorter on the large-cutter bit. More significantly, when a certain amount of wear is assumed, the increase of line contact as wear increases is less pronounced on the large-cutter bit because there are fewer multiple-coverage areas.

### Force Balancing

To minimize wear and catastrophic failure of the cutting elements, one important factor is to minimize the imbalance forces. In particular, vibrations often have led to premature cutter failure, resulting in uneconomical bit runs. A source of vibrations can be an imbalance of the cutting-force components perpendicular to the bit axis.

When drawing up a force plan for a PDC bit, the various ribs or blades on the bit face are assumed to be equipped with different numbers of cutters. Obviously, this will result in different magni-

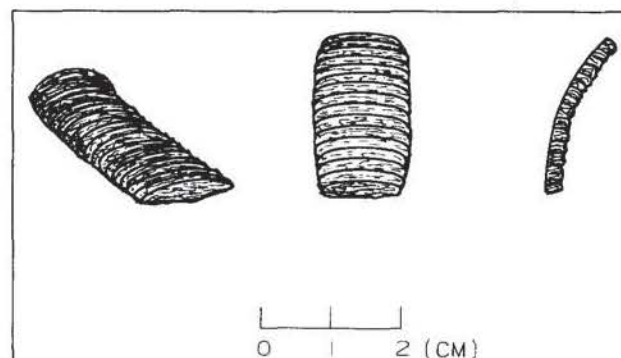
TABLE 1—PETROPHYSICAL DATA FOR FORMATIONS DRILLED

Name	Gamma Ray Intensity	Sonic ( $\mu\text{s/m}$ )
Lower North Sea	30 to 90	—
Chalk	15 to 80	246 to 295
Altena-Aalborg	65 to 85	295 to 361
Muschelkalk		
Upper	40 to 70	246 to 426
Middle	60 to 80	246 to 377
Lower	40 to 65	213 to 279
Röt		
Upper claystone	55 to 90	229 to 295
Evaporite	15 to 25	213 to 246



**TABLE 2—ROP COMPARISON IN FORMATION SEQUENCE (31-cm) BITS**

Formation	ROP (m/h)	
	Eggbeater Bit	Fishtail Bit
Muschelkalk		
Upper	12	8.5
Middle	12	4.0
Lower	10	7.5
Röt		
Upper claystone	9.2	8.5
Evaporite	6.7	7.5
Operating conditions		
WOB, kN	50	60
Flow rate, m <sup>3</sup> /s	0.043	0.041



**Fig. 8—Typical cuttings from eggbeater bit.**

tudes of combined cutting forces, which in turn leave a resultant side load that can be calculated with a magnitude and direction. Force balancing minimizes this resulting side load.

Throughout the bit design phase, modifications are made primarily to the angular positioning of single cutting elements or blades. After the layout is completed, the side load is calculated and successively reduced further by modifying the design. This iterative process is necessary because any change in cutter locations will affect not only the force balancing, but also, for example, the waterway configuration. Thus, an individual, manual check must be conducted.

The eggbeater design is balanced to within 2% of the WOB. Further reduction of the side load to zero actually will lead to an increasing bending moment around the bit apex. This eventually creates high-impact loads at the gauge cutting elements.

### Field Testing

The eggbeater-bit concept has been field tested in 31- and 40.6-cm [12.25- and 16-in.] holes in NAM's land wells in formations in the North Sea, Chalk, Altena, and Upper Germanic Trias groups. The Appendix gives brief descriptions of these formations, and Table 1 gives petrophysical data that may be used for correlation with the drillability.<sup>10,11</sup>

Blade-type and fishtail bits are used to drill these formations; however, use of these bit types involves a risk of total bit balling. So far, fishtail bits are considered to have the best potential for drilling in these formations.

In the Chalk group, PDC bits are used only in the absence of chert. If chert is present, three-cone bits (e.g., IADC 1-3 and 4-3<sup>12</sup>) are used.

All the eggbeater-bit field trials were conducted with steerable mud motors in water-based mud. Initial runs with the 31-cm [12.25-in.] eggbeater bits showed premature bit failure, which was resolved after the bit skeleton design was upgraded. Experience gained during the field trials follows.

### Drilling Characteristics

The drilling potential of eggbeater bits is expected to be similar to that of any PDC bit with a comparable cutting structure, provided the bits are cleaned adequately. The competitive advantage of eggbeater bits in terms of ROP becomes apparent in formations that ball up conventional PDC bits. This was demonstrated by drilling a 31-cm [12.25-in.] hole section where the sequence consisted

of Muschelkalk and Röt formations. The section was to be drilled with a blade-type bit. This bit balled up in the Altena-Aalburg shale overlaying the Muschelkalk formation. The bit was replaced with an eggbeater bit, which drilled the sequence without any sign of bit balling.

A similar sequence of formations was drilled in an offset well with a fishtail bit (Table 2). Comparison of both bit runs over this sequence shows that, in the lower part of the interval, the eggbeater-bit ROP is similar to that of the fishtail bit, which indicates that both bits were cleaned properly.

In the top part of the Muschelkalk formation, however, the eggbeater bit performs substantially better than does the fishtail bit. This difference is attributed to partial balling up of the fishtail bit in the center, where cutters have a small exposure that hampers efficient cuttings removal and, thus, drilling performance.

### Cutting Size

During the field trial of a 31-cm [12.25-in.] eggbeater bit in the Chalk formation, a water-based mud with a polyanionic-cellulose (PAC) polymer additive was used. Throughout this trial, large, slightly curled, rounded-off cuttings were recovered over the shale shakers. The size of the cuttings corresponded to those typical of the 1.9-cm [0.75-in.] PDC's on the bit (Fig. 8).

The curled shape is formed at the base of the cuttings. This implies that high frictional forces are unlikely to develop at the PDC/cutting interface in this formation. Because of this and the erosive action of the mud directly in front of the PDC's, which is low by design, long continuous cuttings can be produced.

Once these cuttings extend beyond the top of the PDC's, they are broken off at the base by the hydrodynamic jet forces, which leads to the generation of cuttings with a characteristic length similar to the size of the PDC's.

The PAC in the mud acts as an encapsulating agent and reduces the disintegration rate of the cuttings as they are transported to the surface.<sup>7</sup> In other field trials where PAC was not used, a much smaller percentage of large cuttings was recovered over the shale shakers. The characteristic length typically was <0.5 cm [<0.2 in.], which implies that the polymer plays an essential role in maintaining the integrity of the cuttings being transported to the surface.

The ability to control the cuttings size when the eggbeater bit is used in combination with a polymer mud can have a major effect on the workload of the solids-control equipment at the surface when drilling soft or sticky formations. As proved by the field tri-

**TABLE 3A—DRILLING PERFORMANCE COMPARISON OF 31-cm BITS IN THE CHALK AND UPPER GERMANIC TRIAS FORMATIONS**

Bit Type	TFA (cm) <sup>2</sup>	WOB (kN)	M/R*	Flow Rate (m <sup>3</sup> /s)	Average ROP	Standard Deviation Ratio
Eggbeater	5.03 to 7.61	40 to 90	M	0.037 to 0.045	—	—
PDC	2.90 to 3.87	50 to 120	M	0.037 to 0.047	1.4	0.5
Three-cone	3.36 to 4.52	200 to 250	R	0.037 to 0.045	1.9	0.6

\*Drilling rotary speed: R=rotary=90 to 120 rev/min; M=mud motor=60 to 80 rev/min.



**TABLE 3B—DRILLING PERFORMANCE COMPARISON OF 40.6-cm BITS IN THE CHALK FORMATION**

Bit Type	TFA (cm) <sup>2</sup>	WOB (kN)	M/R*	Flow Rate (m <sup>3</sup> /s)	Average ROP	Standard Deviation Ratio
Eggbeater	5.42	50 to 100	M	0.052 to 0.057	—	—
PDC	8.39 to 9.68	90 to 110	M	0.050 to 0.053	1.1	0.1
Three-cone	3.87 to 6.13	200 to 280	R	0.050 to 0.060	1.5	0.3

\* Drilling rotary speed: R = rotary = 90 to 120 rev/min; M = mud motor = 60 to 80 rev/min.

al, most cuttings can be recovered over the shale shakers, drastically reducing the workload of equipment like centrifuges and thus improving the overall economy of drilling-fluid maintenance.

Furthermore, production of large cuttings is expected to have advantages when drilling with oil-based muds as well. The large volume/surface-area ratio of such cuttings compared with those produced by conventional PDC bits will reduce oil retention on cuttings significantly. So, while the expected ROP will not exceed that of conventional PDC bits, eggbeater bits will contribute significantly to minimizing the environmental impact of using oil-based muds.

### Steerability

During the field trials, the eggbeater bits were used to drill both kickoff sections and several course corrections made at deeper depths. Throughout the runs, the bits demonstrated good steerability on steerable DTU drilling systems. Predictable and controllable directional changes in the oriented drilling mode were achieved in a similar way to those made with a dedicated, shallow-profile PDC bit with a short gauge.

### Drilling Performance

The drilling performance characteristics of eggbeater bits during the field tests have been compared with those of offset-bit runs. The various bit types were run under operating conditions recommended by the bit/motor suppliers. No significant difference in performance was apparent between rotary- and mud-motor-bit runs in the formations concerned.

The comparison revealed that eggbeater-bit ROP in the North Sea formation is similar to that of offset bits owing to controlled drilling conditions that frequently apply in this formation.

For the runs to date, Table 2 gives the average value and standard deviation of the eggbeater-/offset-bit ROP ratio. Table 3A shows that for the 31-cm [12.25-in.] bits, the average eggbeater-/three-cone-bit ROP ratio is 1.9, with a standard deviation of 0.6. This implies that the probability of an eggbeater bit drilling 1.3 to 2.5 times as fast as a three-cone bit is ≈ 67%. The difference with fishtail and blade-type bits is significantly smaller.

Table 3B shows a similar comparison made for 40.6-cm [16-in.] bits on the basis of one eggbeater-bit run. This tentative comparison shows that the improvement in ROP to be gained from the 40.6-cm [16-in.] eggbeater bit is less than that in 31-cm [12.25-in.] hole sections in similar formations. This statistical approach, however, does not represent the potential drilling advantage of eggbeater bits for eliminating bit balling properly, where they can eliminate round trips for pulling totally balled up bits, as discussed earlier.

The eggbeater-/conventional-PDC-bit life ratio is governed by the type of cutters used and the volume of diamond that can be worn off. Currently, in the 31-cm [12.25-in.] hole an average bit life of 930 m [3,051 ft] with a standard deviation of 310 m [1,017 ft] has been recorded where several bits have been rerun in different wells.

The cost-effectiveness of eggbeater bits will depend strongly on the cost regime of the specific drilling operation and can be assessed from the actual ROP of offset bits and information given above.

An additional factor in the eggbeater-bit cost-effectiveness is their potential to drill reliably between casing points. This potential is supported by the fact that a number of 40-cm [13.375-in.] shoe tracks have been drilled successfully with both rotary and steerable assemblies. Fine tuning of the bit's wear-resistance capability will allow optimum use of this feature for specific applications.

### Conclusions

1. On the basis of insights into the cutting process, a new eggbeater-bit design concept was developed that shows significant potential to reduce bit balling and associated problems.

2. During field testing, the eggbeater bits allowed substantially higher ROP's to be maintained in sticky formations than did conventional PDC and rock bits.

3. The eggbeater bit can produce cuttings with a characteristic size similar to that of PDC cutting elements.

4. When drilling soft or sticky formations with water-based polymer mud, cuttings integrity can be maintained during transport to the surface, which allows these cuttings to be recovered over the shale shakers.

5. The ability to control the cuttings size reduces the workload of the solids-control equipment. This ability should affect the level of oil retention on cuttings favorably when oil-based mud is used.

6. The average improvement of the eggbeater-bit ROP compared with that of conventional bits has been most pronounced in 31-cm [12.25-in.] hole sections.

7. Further improvements in eggbeater-bit performance are possible by fine tuning the unique design.

### Nomenclature

- $b_b$  = bit blade width, L, m [ft]
- $b_c$  = cutting width, L, m [ft]
- $D$  = cutting depth, L, m [ft]
- $F$  = cutting force, mL/t<sup>2</sup>, N [lbf]
- $F_f$  = frictional force, mL/t<sup>2</sup>, N [lbf]
- $F_i$  = hydraulic impact force, mL/t<sup>2</sup>, N [lbf]
- $h$  = cutting thickness, L, m [ft]
- $I_x$  = section modulus around x-x axis, L<sup>4</sup>, m<sup>4</sup> [ft<sup>4</sup>]
- $I_y$  = section modulus around y-y axis, L<sup>4</sup>, m<sup>4</sup> [ft<sup>4</sup>]
- $P$  = power output per cutting element, q/t, W
- $p_{ws}$  = BHP, mL/t<sup>2</sup>, bar [Pa]
- $R$  = radial position of PDC, L, m [ft]
- $v_c$  = cutting speed, L/t<sup>-1</sup>, m/s<sup>-1</sup> [ft/sec<sup>-1</sup>]
- $\alpha$  = angle between blades, degrees
- $\omega$  = bit rotary speed, t<sup>-1</sup>, seconds<sup>-1</sup>

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## Appendix—Description of Formations

**Lower North Sea.** A sequence of predominantly grey, sometimes calcareous clays, with sandstone intercalations along the edge of the North Sea basin in Limburg from the Tertiary (Paleocene to Eocene) Age.

**Chalk.** A sequence of white to light grey, fine-grained bioclastic and marly carbonates. Chert concretions, usually in layers parallel to the bedding, are common. Along the basin margin, sand tongues and coarser bioclastic limestones are present. Argillaceous material is admixed in various proportions in parts of the section, notably in the basal part. This is a Late Cretaceous/Early Paleocene Age formation.

**Altena-Aalburg Shale.** A sequence of dark grey, calcareous, locally silty shales with occasional thin limestones from the Early Jurassic Age.

**Muschelkalk.** A sequence of grey and variegated marls, argillaceous dolomites and limestones, anhydritic claystones, and an intercalated rock salt series from the Middle Triassic Age, divided as follows.

**Upper member.** A dolomite/limestone/marl sequence with a dolomitic interval at the base.

**Middle member.** A marl with a low carbonate content.

**Lower member.** A marl with an appreciable amount of intercalated argillaceous dolomites and limestones.

**RÖT.** A sequence of evaporites; red-brown, silty, anhydritic claystones; and occasional sandstones from the Lower-Middle Triassic Age, divided as follows.

**Upper claystone.** A red-brown, silty, anhydritic, sometimes slightly dolomitic claystone succession.

**Evaporite.** A halite/anhydrite sequence.

## SI Metric Conversion Factors

°API	141.5/(131.5 + °API)	= g/cm <sup>3</sup>
ft	× 3.048*	E-01 = m
ft <sup>3</sup>	× 2.831 685	E-02 = m <sup>3</sup>
in.	× 2.54*	E+00 = cm
in. <sup>3</sup>	× 1.638 706	E+01 = cm <sup>3</sup>
lbf	× 4.448 222	E+00 = N

\*Conversion factor is exact.

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