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3,298,451

DRAG BIT

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2 Sheets-Sheet 1

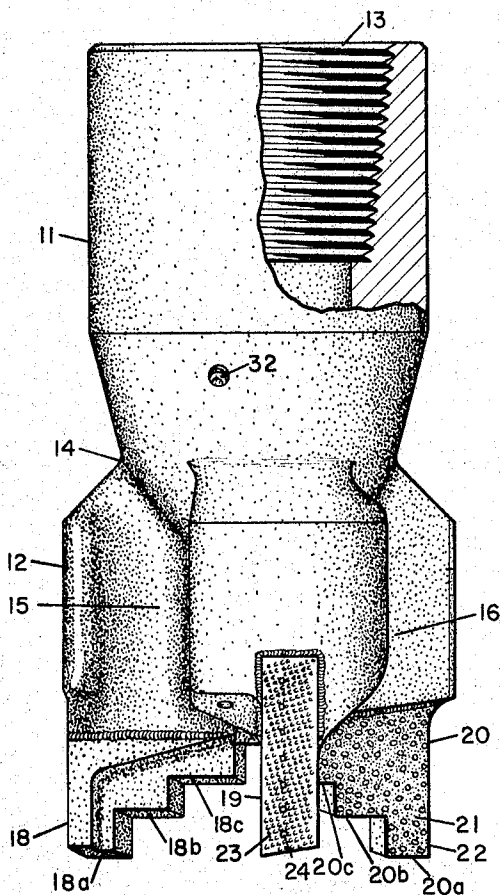


FIG. 1

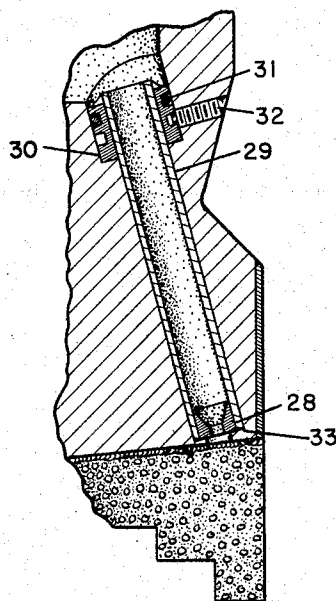


FIG. 3

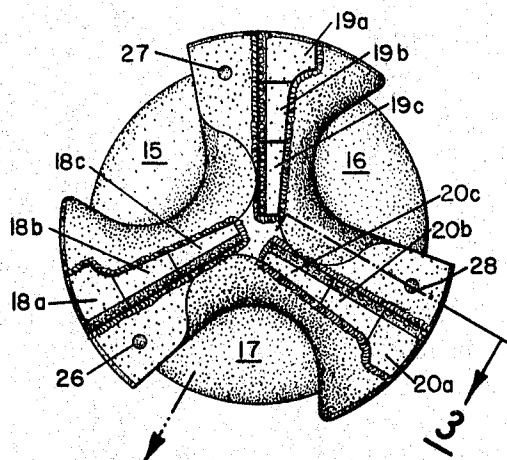


FIG. 2

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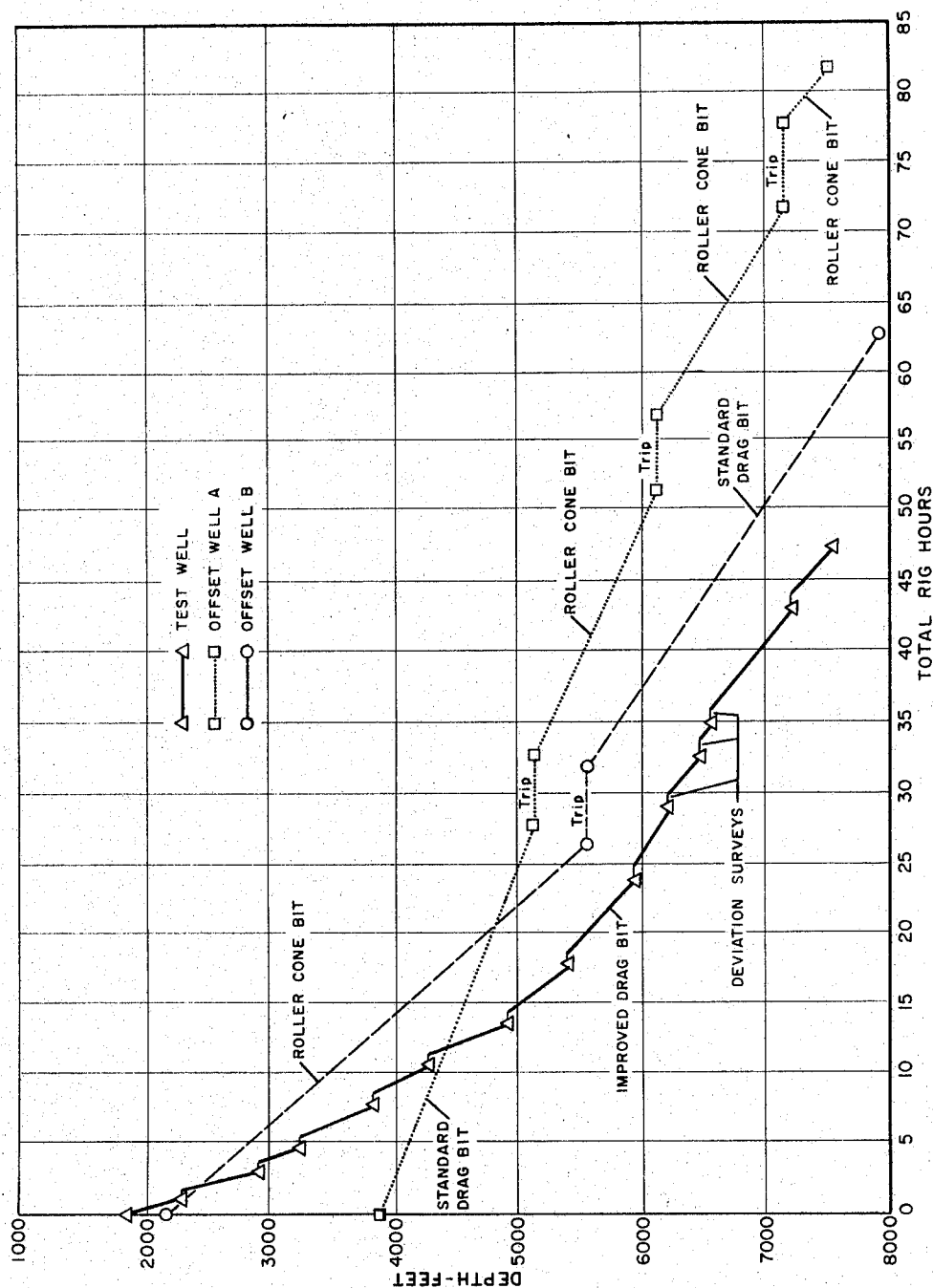


FIG. 4

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3,298,451
DRAG BIT

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The present invention relates to rotary drill bits and is particularly concerned with an improved drag bit for drilling oil wells and similar boreholes.

One of the problems encountered with drag bits used in the petroleum industry is the tendency for the blades to "hang up" on the formation at the bottom of the borehole, particularly in dipping formations. Studies have shown that this may occur repeatedly and that the blade edges may be forced into the borehole wall and then dislodged as the center of rotation shifts from one blade to another. This contact between the blades and wall leads to enlargement of the borehole and is in part responsible for the borehole deviation frequently encountered with drag bits. It also promotes severe vibration of the drill string and rapid failure of the blades and may thus shorten the life of the bit and auxiliary equipment appreciably. It has been suggested that these difficulties might be alleviated by mounting stabilizer pads on the bit above the blades but this has not proved entirely satisfactory. Tests have shown that such pads are generally only partially effective and that they may seriously interfere with the removal of cuttings through the borehole annulus surrounding the tool. The reduction in cross-sectional area of the annulus due to presence of the pads often causes the cuttings to "ball up" and accumulate at points adjacent the blades. Since this precludes proper cleaning of the bit and formation and may thus aggravate the tendency of the blades to hang up as the bit rotates, the pads may in some cases promote rather than alleviate the difficulties outlined above.

It is therefore an object of the present invention to provide an improved drag bit which can be used to drill oil wells, gas wells and similar boreholes more effectively than has generally been possible with drag bits available in the past. Another object is to provide a bit including means for alleviating difficulties encountered with conventional bits due to the tendency of drag bit blades to hang up on the formation at the bottom of the borehole. A further object is to provide a drag bit which will facilitate cleaning of the formation and the entrainment of cuttings. Still another object is to provide a drag bit having improved features which effectively reduce vibration, blade failure, deviation, borehole enlargement and related phenomena. Other objects will become apparent as the invention is described in greater detail hereafter.

The present invention provides an improved drag bit which alleviates many of the difficulties encountered with earlier bits due to the tendency of the blades to hang up on the formation at the bottom of the borehole. The bit of the invention is characterized by a body having an upper section including means for connecting the tool to the lower end of a rotary drill string and an enlarged lower section which extends outwardly adjacent the borehole wall. The lower body section contains longitudinal channels which are spaced at intervals about the bit periphery and extend inwardly below the upper section to permit the transmission of drilling fluid and cuttings into the annular space between the upper section and the surrounding formation. The blades of the tool are embedded in and extend downwardly beneath the lower section at intermediate points between the longitudinal channels so that both the leading and trailing

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edges are protected near the gage surface against impact with the borehole wall. Tests have shown that this structure simplifies borehole deviation problems; reduces vibration of the bit, drill string and surface equipment; prevents premature blade failure at the gage edges; and promotes more effective cleaning of the formation than has generally been obtained with drag bits available in the past.

The nature and objects of the invention can best be understood by referring to the following detailed description of a preferred embodiment of the improved bit and to the accompanying drawing, in which:

FIGURE 1 is a vertical elevation of the improved bit, partially in section, showing the arrangement of the body and blades;

FIGURE 2 is a bottom view of the bit depicted in FIGURE 1;

FIGURE 3 is a fragmentary section of the bit depicted in FIGURES 1 and 2 taken along the line 3-3 in FIGURE 2 to show the nozzle construction; and

FIGURE 4 is a plot showing results obtained with the bit of the invention and those obtained with rotary bits in off-set wells.

As indicated in FIGURE 1 of the drawing, the bit of the invention comprises a hollow body member of steel, cast iron or similar metal including an upper section 11 and a lower section 12. The upper section of the body is of generally cylindrical shape and includes a standard A.P.I. tool joint box 13 at the upper end to permit connection of the tool to the lower end of a rotary drill string. An A.P.I. tool joint pin or other connecting means may be used in lieu of the box shown if desired. The outer surface of the bit body tapers inwardly below the tool joint to form a throat 14 of reduced diameter between the upper and lower body sections. Below this throat, the lower section 12 extends outwardly to substantially full bit diameter. The radial dimensions of the throat and upper and lower body sections may be varied, depending upon the nominal size of the bit. In general, however, the throat diameter will normally be considerably less than the diameter of either the upper section or the lower section. In a typical 9 $\frac{1}{2}$ inch bit, for example, the diameter of the upper section may be about 7 $\frac{3}{4}$ inches, that of the throat may be about 6 $\frac{5}{8}$ inches, and the diameter of the lower section may be about 9 $\frac{27}{32}$ inches. The nominal size of the bit is based upon the blade diameter and hence the blades on this particular bit extend radially beyond the lower body section about $\frac{1}{4}$ of an inch.

As can be seen from FIGURES 1 and 2 of the drawing, the lower body section of the bit contains longitudinal channels 15, 16 and 17 through which drilling fluid and cuttings are conducted upwardly into the annular space surrounding the throat and upper body section of the tool. Each channel is open at the outer surface of the tool and extends inwardly in the lower body section below the throat. As shown in FIGURE 2, the radial distances from the inner walls of the channels to the bit axis are considerably less than the throat radius. It is preferred that the channels be generally semicircular in cross-section as indicated in FIGURE 2 and that they extend inwardly behind the adjacent outer surface of the lower body section to provide the area required for passage of the fluid and cuttings without unduly reducing the contact area of the lower body section with the borehole wall. The channels are enlarged and streamlined at their lower ends to provide for uninterrupted entry of the fluid and cuttings. Tests have shown that instantaneous drilling rates of 2000 feet per hour or more can be obtained in shales and similar soft rock formations and that this necessitates the removal of over 18 cubic feet of cuttings

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per minute. The smooth contour of the channels in the bit shown facilitates high flow rates without "balling." The cross-sectional area of the channels will preferably be approximately the same as the annular cross-sectional area between the upper section of the body and the surrounding borehole wall so that the fluid velocities adjacent the two sections will be about the same.

The blades 18, 19 and 20 on the bit shown in the drawing are mounted in generally radial slots in the lower body section between channels 15, 16 and 17 and are welded in place. The outer surfaces of the lower body section adjacent the upper end of each blade extends circumferentially in front of and behind the blade, thus supporting and protecting the blade edges against failure due to impact of the tool against the borehole wall. It is generally preferred that the gage edges of the blades protrude laterally beyond the outer surface of the lower body section about $\frac{1}{64}$ to about $\frac{1}{32}$ of an inch in order to reduce friction against the borehole wall but this is not essential. The gage surfaces may be laterally coextensive with the outer surface of the lower body section if desired. The bottom of each blade is stepped upwardly from the gage edge to the inner edge near the center line of the tool, thus providing lower cutting surfaces 18a, 19a and 20a; intermediate cutting surfaces 18b, 19b and 20b; and upper cutting surfaces 18c, 19c and 20c. As can be seen from FIGURE 2, each blade is relatively thick near the gage edge and tapers inwardly toward the center of the tool, thus giving it an L-shaped cross-section. This structure provides the additional strength needed at the gage edge and promotes uniform wear as drilling progresses.

The face of each of the blades on the bit shown is hard surfaced with a binder metal 21 containing particles 22 of tungsten carbide, a tungsten carbide alloy, or a similar abrasion resistant material, preferably one having a Rockwell A hardness in excess of about 85. A variety of metallic binders may be employed, including copper-nickel alloys, copper-nickel-tin alloys, copper-nickel-manganese alloys, iron-carbon alloys, iron-nickel-manganese alloys, S-Monel and the like. Powdered tungsten carbide granules or grains of a similar hard metal are preferably incorporated within the matrix metal to improve its strength and abrasion resistance. The hard metal particles on the face of the blades shown are irregular particles or chips of tungsten carbide or the like ranging in size between about $\frac{1}{8}$ and about $\frac{3}{16}$ of an inch. The gage edges of the blades are hard surfaced in a similar manner and contain cubes of sintered tungsten carbide embedded in a suitable binder metal to increase the abrasion resistance. Diamonds may also be embedded in the gage edges of the blade as indicated by reference numeral 24. The outer surface of the lower body section adjacent the blades and between the channels is preferably also hard surfaced with tungsten carbide or a similar abrasion resistant material.

The nozzles 26, 27 and 28 employed on the bit of the invention are mounted in the lower body section between the blades and the adjacent channels. As shown in FIGURE 3 of the drawing, each nozzle is preferably bonded in place in the lower end of a tube of tungsten carbide or similar erosion resistant material 29 which extends downwardly through a hole in the body from an internal opening below the tool joint. The tube is held in place by a collar 30 of steel or similar material which is bonded to it and seats in an enlarged upper portion of the hole in the body. A groove containing a seal ring 31 of rubber or similar resilient material is provided in the collar to prevent the leakage of fluid around the collar. Set screw 32 extends through a hole in the body into a groove in the collar to prevent vertical movement of the nozzle assembly. The lower end of the tube and nozzle rest on a shoulder 33 on the body and are held in place by differential pressure. The tubes and nozzles may be removed by loosening the set screws

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and withdrawing the tubes upwardly through the bit body. It has been found that this structure eliminates problems encountered with previous bits due to erosion through the body above the nozzles and permits higher nozzle velocities than might otherwise be employed. Other nozzle arrangements may be employed in lieu of that shown if desired.

The nozzle outlets on the bit shown are located in front of the blades near the outer periphery of the lower body section and are oriented so that the fluid discharged beneath the bit impinges against the formation near the lower gage corners of the blades. High pressure tests in a viewing chamber have shown that positioning the nozzles in this manner results in flow of the fluid across the formation at the bottom of the hole along substantially horizontal paths. This permits much more efficient entrainment of cuttings than can be obtained when the fluid impinges against the formation near the center of the blades. The fluid moving parallel to the formation is diverted upwardly into the flow channels by the rear surfaces of the blades. Streamlined, laminar-type flow with essentially no vortices to drive the cuttings back down toward the cutting edges of the blades is obtained. Viewing chamber tests of the bit of the invention and conventional drag bits showed that this use of nozzles located near the gage edges of the blades and smooth, streamlined flow channels between the blades gave much better cleaning of the formation that could be obtained with the conventional bits and greatly reduced the tendency of the cuttings to ball up and accumulate on the bit surfaces.

Conventional rotary drilling equipment may be utilized in conjunction with the bit of the invention. At the onset of a drilling operation, the bit is connected to the lower end of the drill string and lowered into the borehole in the usual manner. Drilling fluid is circulated downwardly through the string and returned through the annulus between the drill string and the borehole wall. After circulation has been established, drilling is commenced by rotating the string from the surface and applying weight to the bit. As the drilling operation progresses, the lower body section of the bit bears against the borehole wall and stabilizes the bit in the hole much more effectively than stabilizers or pads employed in the past. This in turn reduces lateral motion of the bit due to the tendency of the blades to hang up on the formation at the bottom of the borehole and assists in controlling deviation. Vibration of the bit, drill string and surface equipment are minimized because of the high polar moment of inertia of the tool, which is more than twice that of a conventional two blade drag bit, and the low center of gravity made possible by concentrating the mass near the lower end of the tool. This permits higher rotary speeds than might otherwise be permissible. The outer surface area of the lower body section in front of and behind each blade, about twice the contact area of a conventional bit, protects the blades against failure due to impact of the gage edges against the borehole wall and thus prolongs bit life. The channels in the lower body section permit smooth flow of the drilling fluid and entrained cuttings upwardly into the annular space above the bit, reducing turbulence and the balling up and accumulation of cuttings adjacent the blades. These effects all contribute to higher drilling rates and lower drilling costs than have generally been obtained with drag bits available in the past.

The superior performance of the improved drag bit is shown by comparing the results obtained in a test well with those obtained in two offset wells drilled with conventional bits. The test well was drilled with a diesel electric rig having a D.C. motor-driven rotary table and two 18 inch stroke mud pumps. The drill string contained 270 feet of 7 inch O.D. and 3 inch I.D. drill collars and five $9\frac{3}{4}$ inch blade-type stabilizers spaced at 60 ft. intervals. A conventional bentonite mud having a weight of from about 10 to about 11 lbs. per gallon was

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used. The drag bit employed in the test well was a 9 7/8 inch 3-blade bit having an enlarged lower body section containing vertical flow channels and nozzles located in front of the blades as shown in FIGURES 1, 2, and 3 of the drawing. The blades were 1 1/2 inches thick and the nozzles were located 3 1/8 inches above the gage corner as shown in FIGURE 1.

The test well had previously been drilled to a depth of 1830 ft. with conventional equipment. Surface casing had been set at 1800 feet and cemented in place. At the start of the test, the cement was encountered at a depth of 1757 feet. This was drilled out rapidly. The rubber cement plug beneath the cement was sliced by releasing all of the weight of the bit several times while indexing the drill string. The cement, plug and shoe were drilled out to a depth of 1830 feet in 45 minutes with no difficulty. The operation of the bit during this initial stage was very smooth. The formation below the cement consisted primarily of shale containing occasional hard streaks. The drag bit of the invention was used to drill through this shale from the initial depth of 1830 feet to a final depth of 7500 feet. During most of the run, the deviation ranged from about 1° to about 2 1/2°. At one point where deviation increased to 3 1/2°, the bit weight was reduced from 12,000 lbs. to 7,000 lbs. and the deviation was rapidly corrected. A record of the time required to drill each 30 foot interval was kept during the first hour of drilling. The record showed that a total of 417 feet of formation was drilled in 20 minutes of actual rotation time. The other 40 minutes during the first hour was consumed in making connections. The instantaneous drilling rate for this first hour was therefore 1250 feet per hour. This included two 30 ft. intervals drilled in 0.9 minute each for an instantaneous rate of about 2,000 ft. per hour. The actual drilling rate for the 5670 interval, ignoring time required for deviation surveys and rig repairs, averaged 144 ft. per hour. No excessive vibration or other indications of "rough running" was encountered. The drag bit was pulled at a depth of 7500 ft. in order to log the well. The bit was in excellent condition when pulled and could obviously have been used for further drilling. Each blade retained over 2 1/4 inches of gage surface. Examination of the blades indicated that cleaning had been much better than is normally obtained with conventional drag bits.

Following completion of the log, the well was completed to final depth by drilling another 1481 feet with conventional two-blade drag bits and roller cone bits. The first standard drag bit employed drilled a total of 997 feet in 30 1/2 hours for an average rate of 33 feet per hour. Rates with the latter bits were even lower. The bit of the invention was drilling at a rate of 68 feet per hour when pulled before the logging operation. The higher drilling rate and longer life obtained with the improved bit was apparently due primarily to the better cleaning and more stable operation achieved by virtue of the enlarged lower body section, flow channels, and nozzle arrangement. The drilling record for the entire well is shown in the following table.

Bit	Interval Drilled		Feet Drilled	Total Rig Time, Hours	Average Overall Rate, Ft./Hr.
	From	To			
Improved Drag Bit.....	1,830	7,500	5,670	47	121
Standard Drag Bit.....	7,500	8,497	997	30 1/2	33
Do 1.....	8,497	8,581	84	5 1/2	15
Roller Cone Bit.....	8,581	8,781	200	10	20
Do.....	8,781	8,981	200	10	20

¹ The second standard drag bit was a used bit and hence the 5 1/2 hours shown do not represent the total bit life.

Offset well A, drilled with a comparable rig and auxiliary equipment, was located a short distance from the test well and penetrated essentially the same formations. The upper part of the offset well was drilled with larger bits

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and hence only the interval between 3945 feet and 7631 feet can be compared with the test well. This interval of 3686 feet was drilled with a standard 9 7/8 inch drag bit and three 9 7/8 inch roller cone bits in a total of 82 hours. As can be seen from the curves in FIGURE 4 of the drawing, both the drag bit and the roller-type bits drilled more slowly than the improved drag bit used in the test well. In addition, several hours were consumed in making trips to replace the worn out conventional bits. It was estimated that the use of the improved drag bit to drill the entire offset well from the surface casing at 1830 feet to the total depth of 7631 feet would have approximately halved the total drilling time and would have permitted a reduction in drilling costs of about \$13,900.

Offset well B was located in the same area as the test well and offset well A and again penetrated essentially the same formations. The rig used on the second offset well included automatic deviation measuring equipment and a kelly spinner which permitted an estimated saving of about 9 hours in reaching the total depth of 7995 feet. Despite the use of these time saving devices, the total rig time in offset well B at the 7500 foot level was 10 hours greater than in the test well. It was estimated that the improved drag bit used in the test well would have permitted a saving of at least \$3,000 if it had been used in offset well B.

It can be seen from the foregoing description of the test results and from FIGURE 4 of the drawing that the performance of the improved drag bit was much better than that of the conventional drag and roller cone bits over essentially the same subsurface intervals. Drilling rates and bit life with the improved tool were both substantially better than with the conventional bits. Rapid blade failure due to impact at the gage edges, severe borehole deviation, excessive drill string vibration, pronounced balling of the cuttings and other difficulties which are normally encountered with drag bits and may have been in part responsible for the relatively poor performance of the conventional bits posed no problems during the test. As a result of this improved performance, the bit of the invention permits substantial savings in overall drilling costs.

What is claimed is:

1. A rotary drag bit comprising:

a hollow bit body including an upper body section provided with means for connecting said body to the lower end of a rotary drill string and an enlarged lower body section containing circumferentially-spaced flow channels of streamlined cross section extending longitudinally in the outer surface thereof to permit the passage of drilling fluid upwardly from beneath said lower section into the space surrounding said upper section;

a plurality of elongated blades attached to and depending from said lower body section at intermediate positions between said flow channels, the outermost surface of said lower body section adjacent each blade extending circumferentially in front of said blade to a flow channel and behind said blade to a flow channel and each of said blades including a face extending laterally in a substantially radial direction from a point near the longitudinal axis of said lower body section to a point adjacent the outer surface of said lower body section; and

nozzles located in said lower body section between the faces of said blades and the adjacent flow channels near the periphery of said lower body section, each of said nozzles communicating with the interior of said body and being oriented to direct a stream of drilling fluid downwardly toward a point near the lower gage corner of a blade.

2. A bit as defined by claim 1 wherein said flow channels extend in part behind the outermost surfaces of said lower body section at the rear of said blades and are enlarged at the lower ends thereof.

3. A bit as defined by claim 1 including erosion-

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resistant nozzle tubes extending upwardly in said lower body section, said nozzles being mounted in the lower ends of said tubes, a collar containing an annular groove on the upper end of each of said tubes, and a member extending into the groove in each collar from the outer surface of said body for holding said tubes and collar in place.

4. A rotary drag bit comprising:

a hollow bit body including an upper body section provided with means near the upper end thereof for connecting said body to the lower end of a rotary drill string and an enlarged generally cylindrical lower body section separated from said upper section by a throat of reduced diameter, said lower body section containing circumferentially-spaced flow channels of streamlined cross-section extending longitudinally in the outer surface thereof to permit the passage of drilling fluid upwardly from beneath said lower section into the space surrounding said throat and upper section and the radial dimensions of said lower section within said flow channels being less than the radial dimensions of said throat and upper body section;

a plurality of blades attached to and extending downwardly beneath said lower body section between said flow channels, the outer surfaces of said lower body section between adjacent flow channels extending circumferentially in front of and behind said blades

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and each of said blades including a gage edge which extends outwardly to the outer surface of said lower body section;

a plurality of nozzle tubes extending from the interior of said body through holes in said lower body section to openings in front of said blades near the gage edges thereof;

means for holding said tubes in place and effecting a seal between the tubes and body; and

a plurality of nozzles mounted in the lower ends of said nozzle tubes, each of said nozzles being oriented to direct a stream of drilling fluid downwardly in front of a blade toward a point near the gage edge thereof.

5. A bit as defined by claim 4 including three flow channels and three blades spaced at 120° intervals about the bit circumference.

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