US 20060196699A1

(19) United States

(12) Patent Application Publication

(10) Pub. No.: US 2006/0196699 A1

(43) Pub. Date: Sep. 7, 2006

Estes et al.

(54) **MODULAR KERFING DRILL BIT**

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(21) Appl. No.: **11/073,051**

(22) Filed: **Mar. 4, 2005**

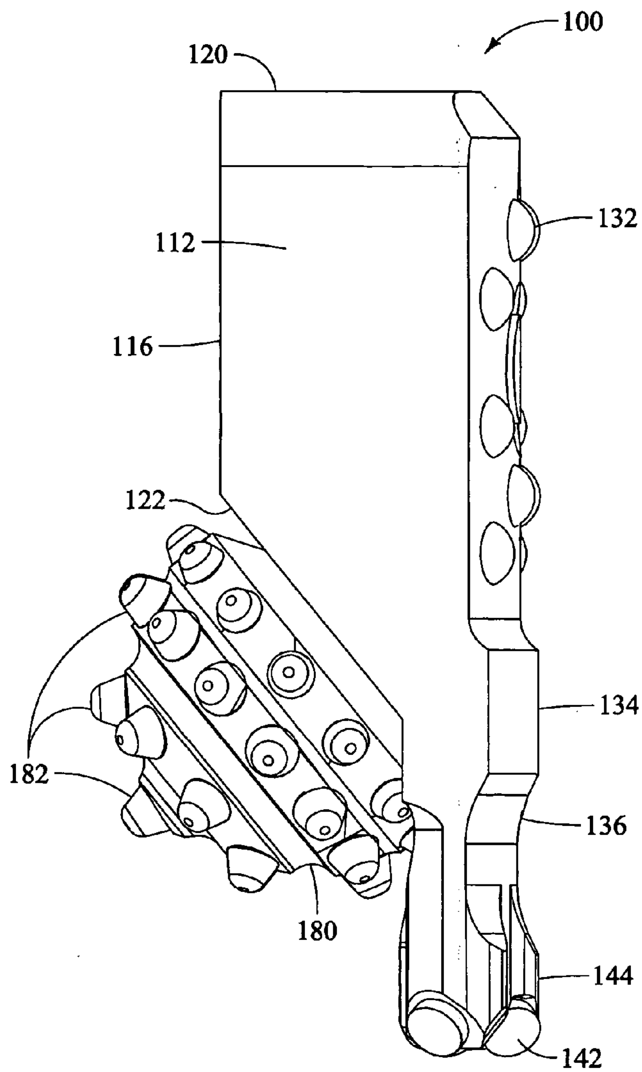
Publication Classification

(51) **Int. Cl.**
E21B 10/00 (2006.01)

(52) **U.S. Cl.** **175/374**; 175/398; 175/415

(57) **ABSTRACT**

A modular kerfing rock drilling bit (**10**) is presented. Drill bit (**10**) comprises a bit body (**12**) having a connection (**14**) for attachment to a drill string member. A base portion (**16**) below the connection (**14**) has an outer portion (**18**) and a bottom (**20**). Slots (**22**) are formed in the base portion (**16**). A cutter assembly (**100**) comprises a leg (**110**) insertable into the slot (**22**) of the bit body (**16**). A journal (**126**) extends angularly downward and inward from the leg (**110**) for bearing support of a cone (**180**) rotatably mounted on the journal (**126**). A plurality of cutters (**182**) extend outward from the surface of the cone (**180**). A kerfing segment (**140**) extends downward from the leg (**110**) beyond the cone (**180**). A plurality of kerf cutters (**142**) are attached to the bottom of the kerfing segment (**140**).



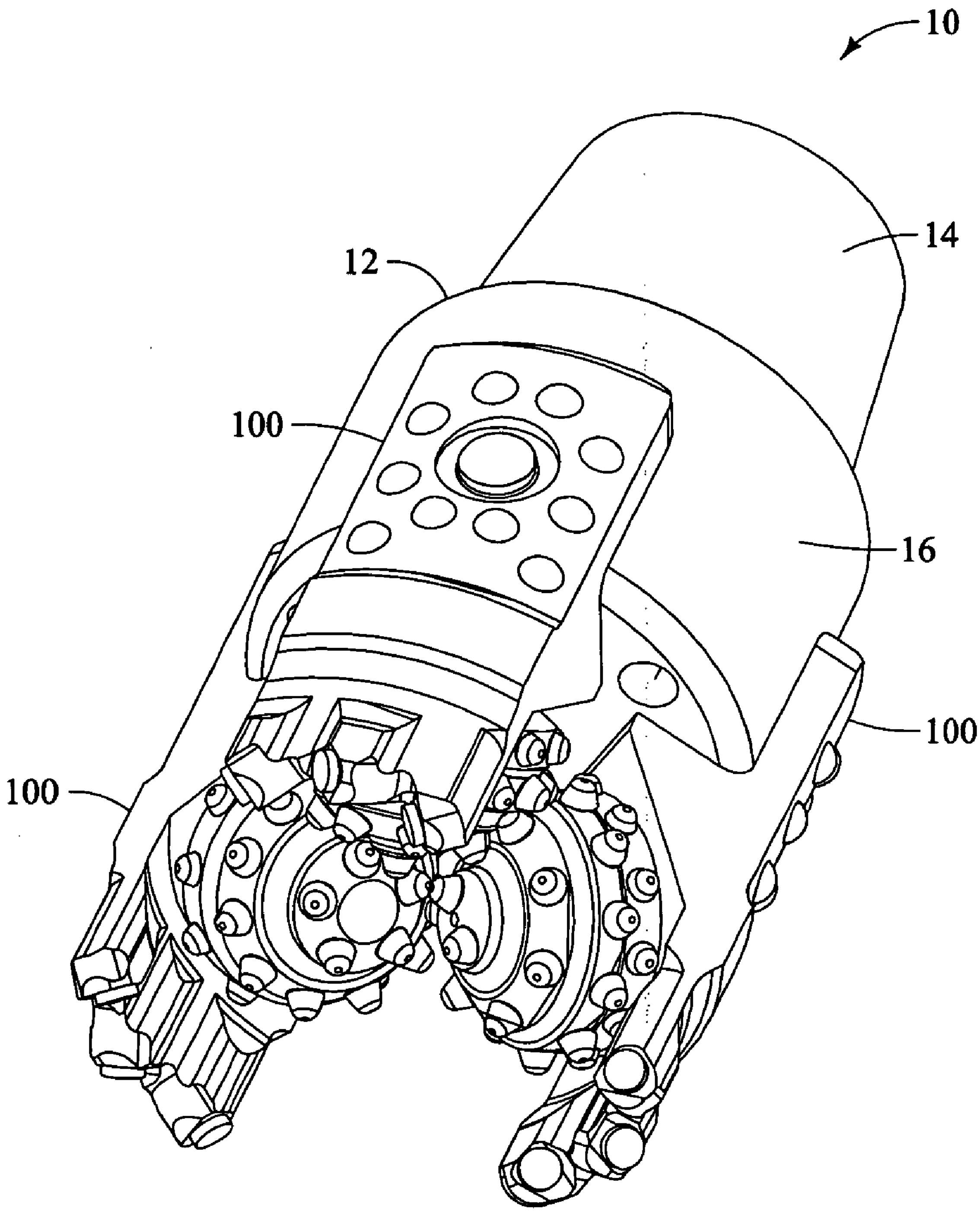


FIG. 1

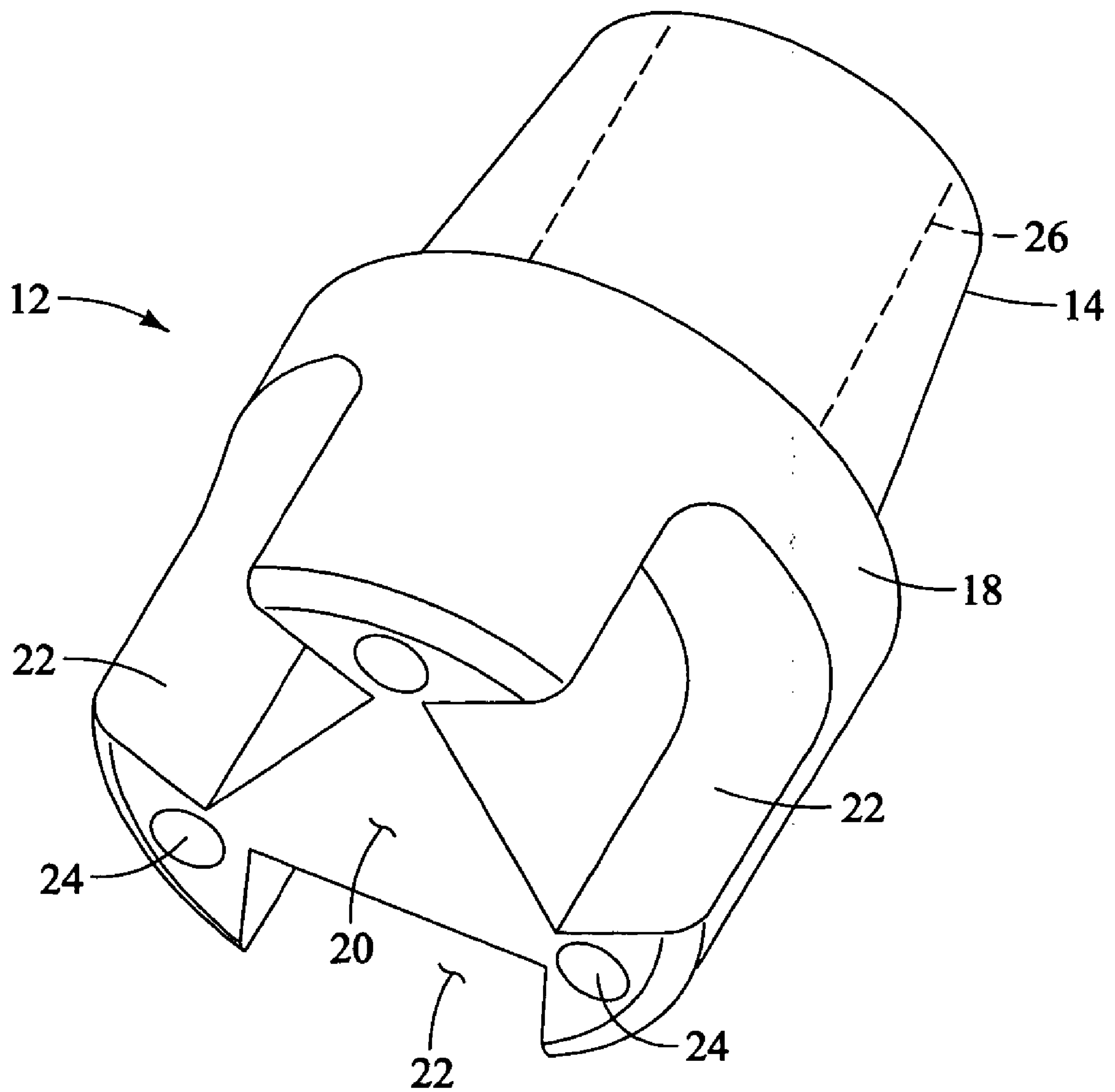


FIG. 2

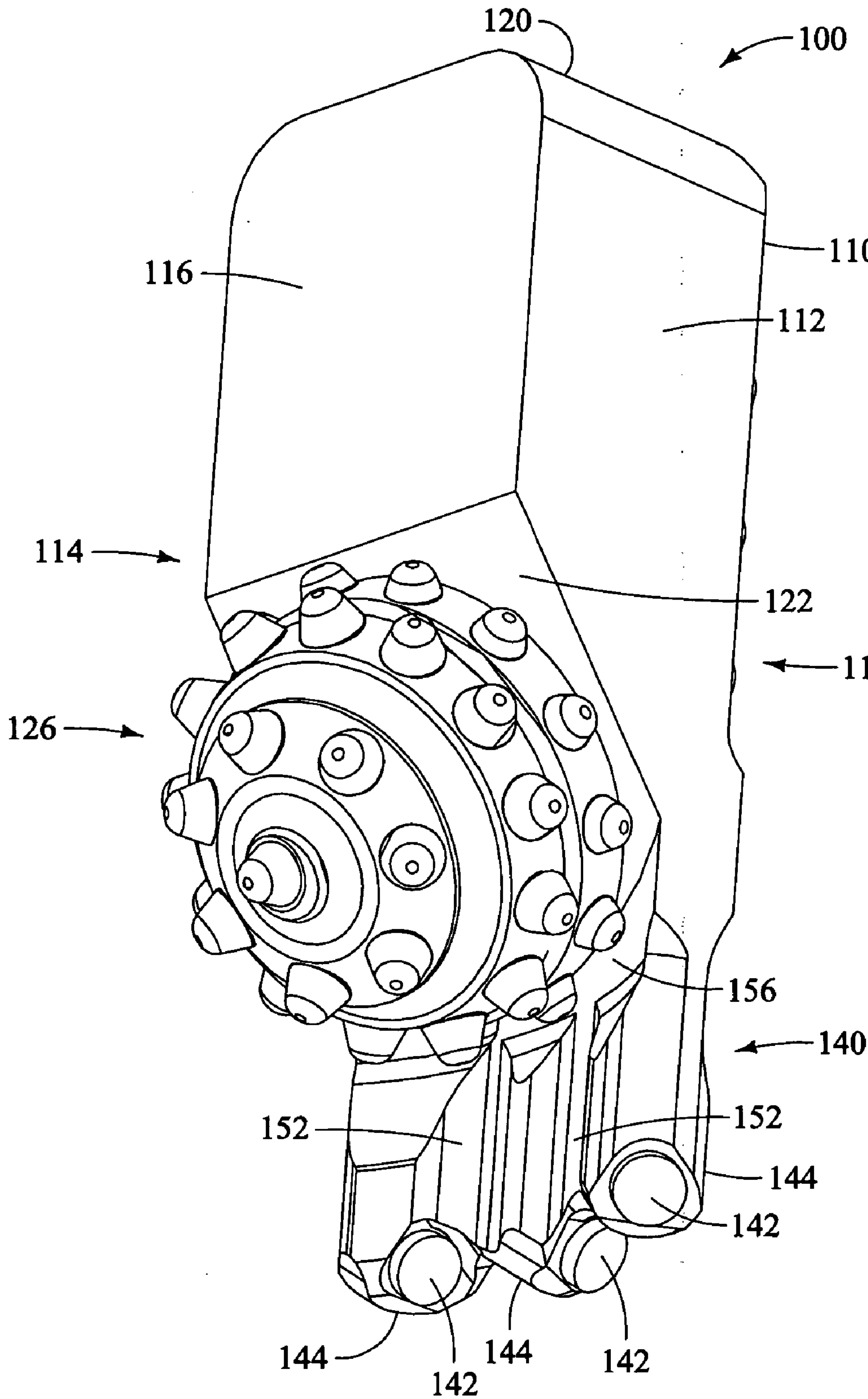

120
100
110
116
112
114
122
118
126
156
140
152
152
144
142
144
142
144
142

FIG. 3

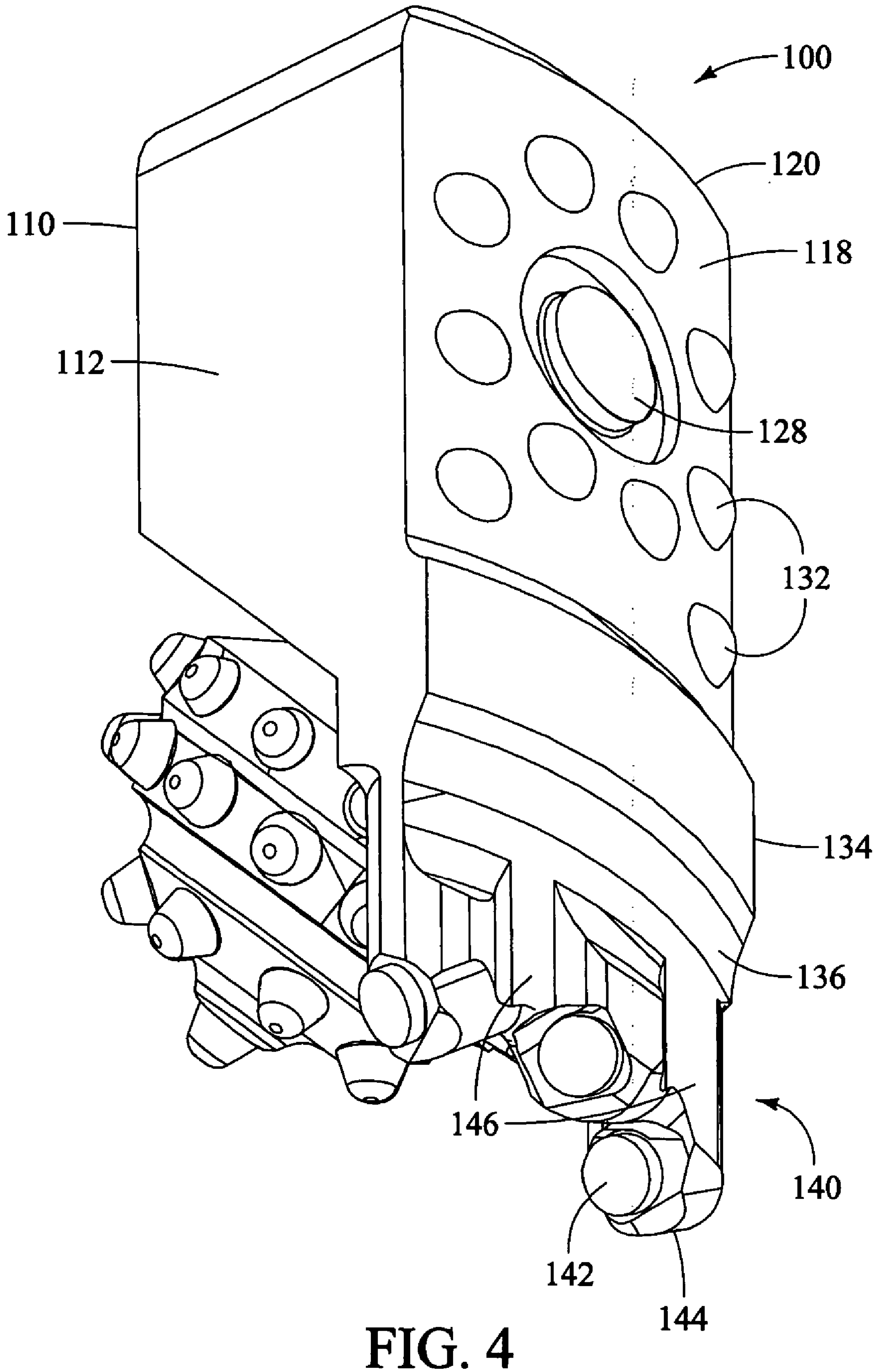


FIG. 4

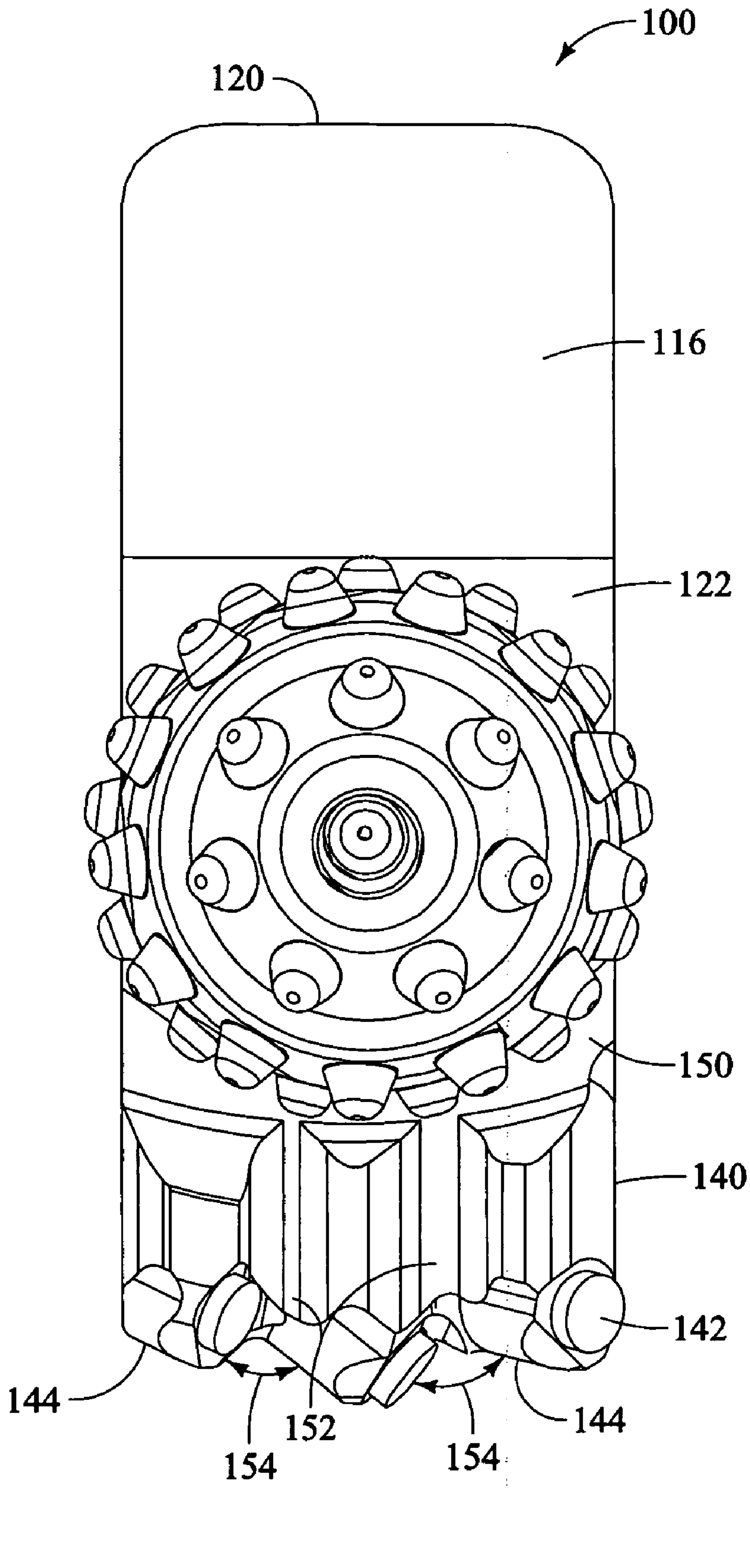


FIG. 5

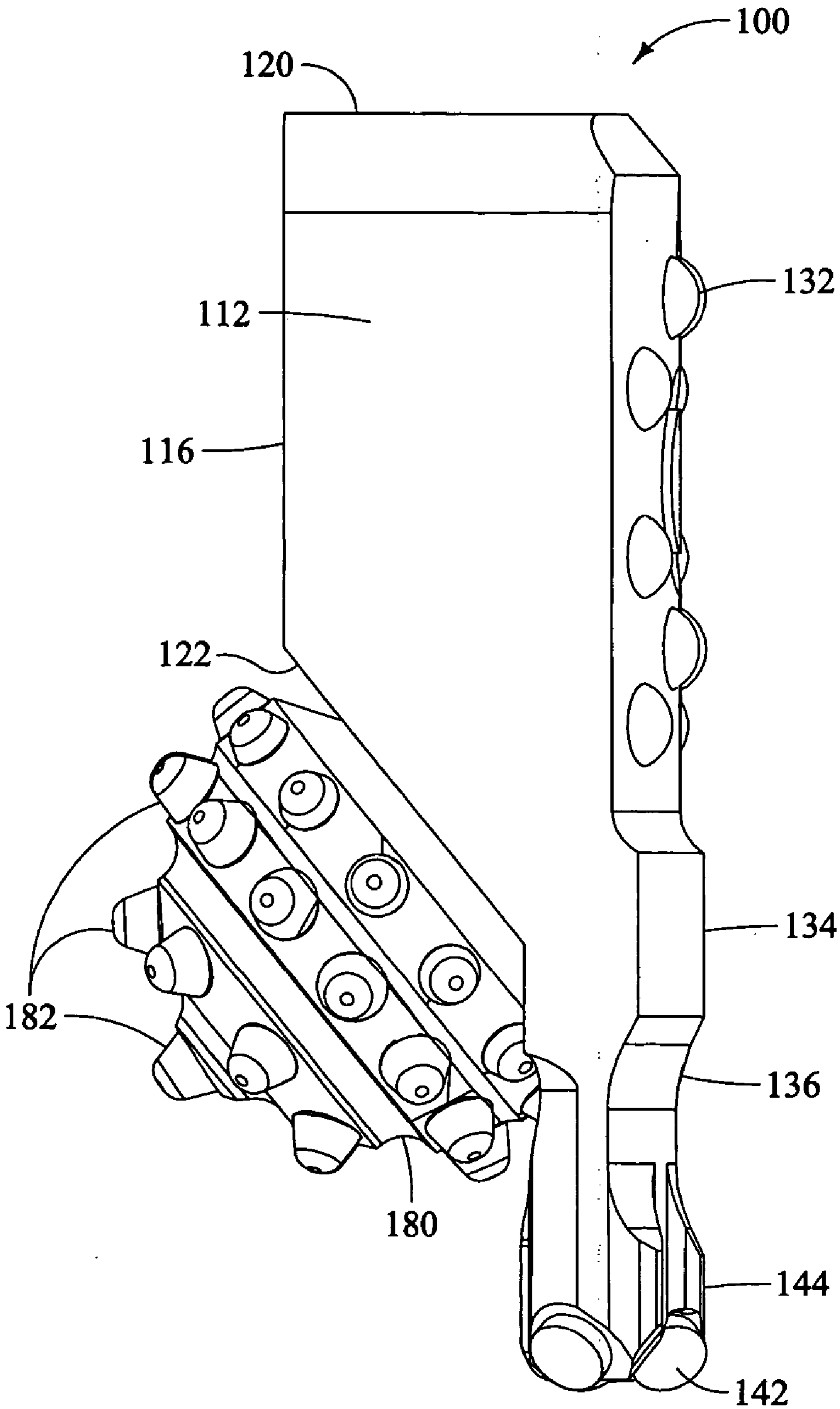


FIG. 6

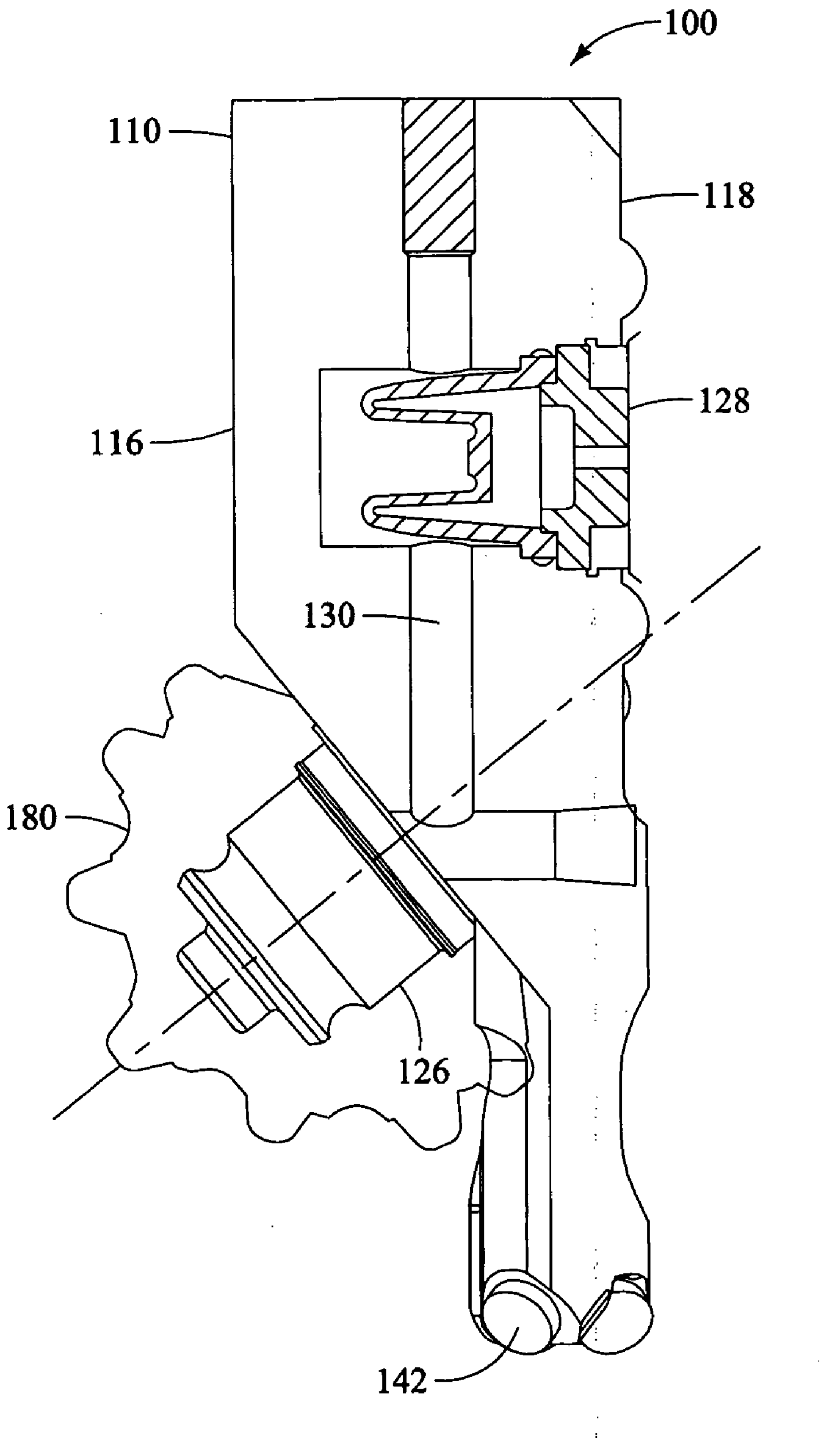


FIG. 7

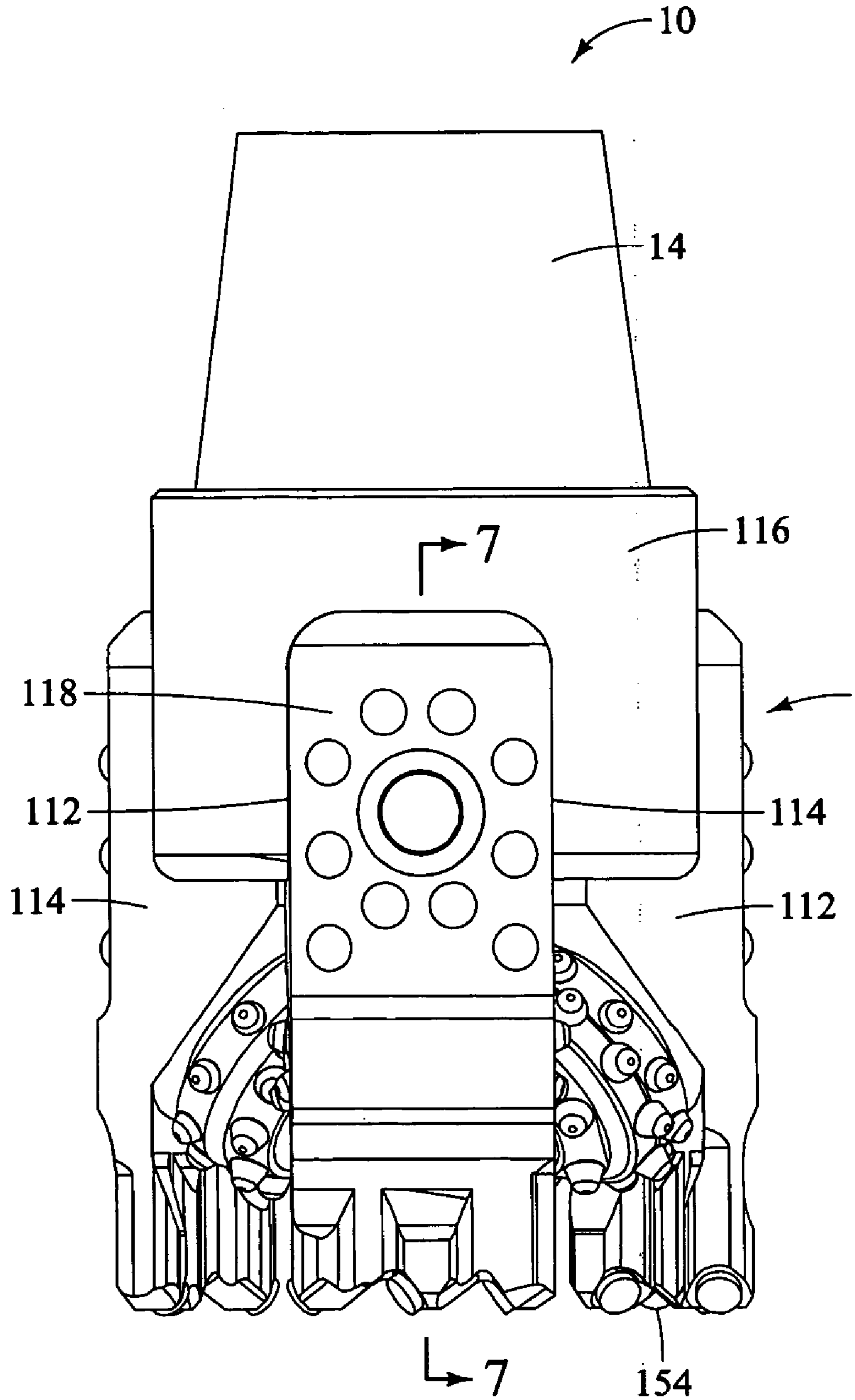


FIG. 8

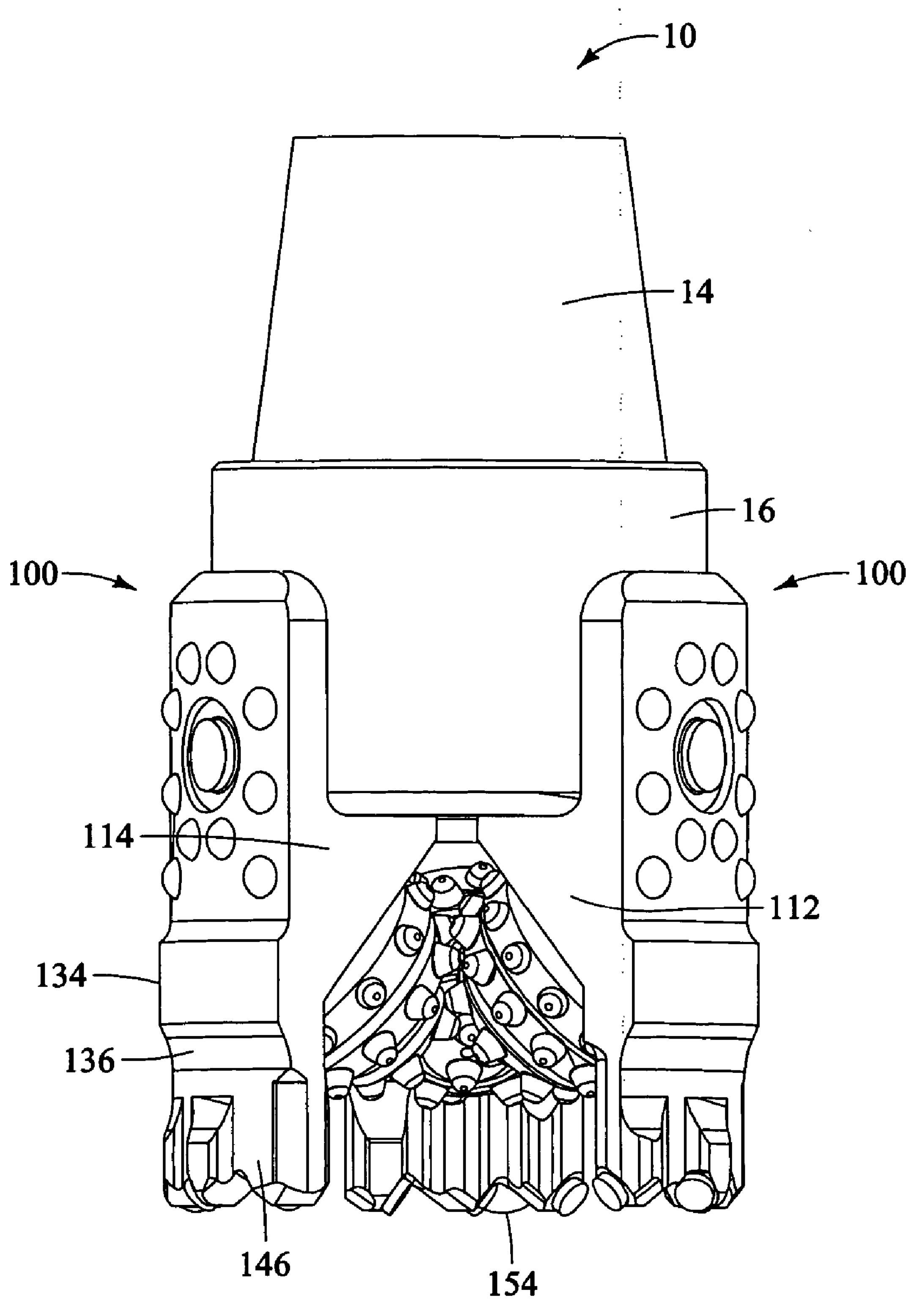


FIG. 9

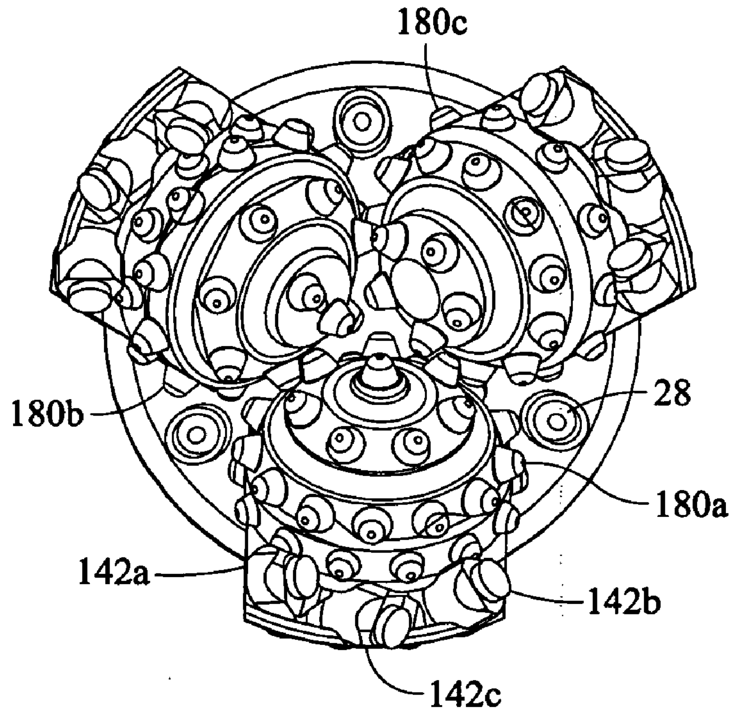


FIG. 10

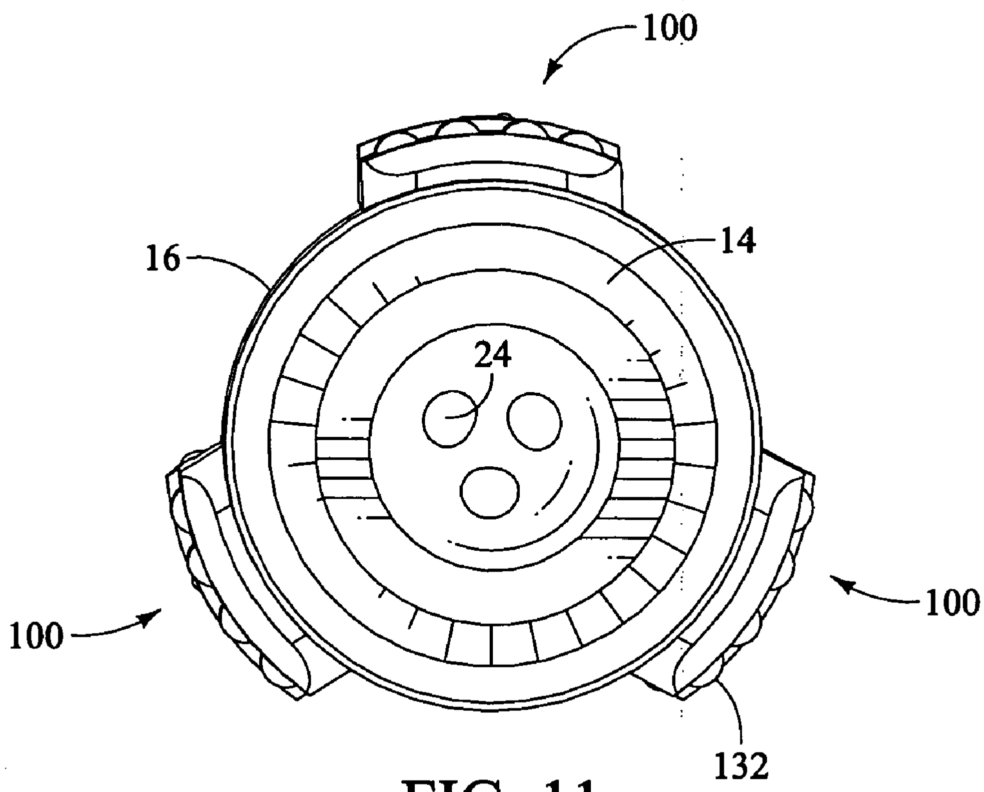


FIG. 11

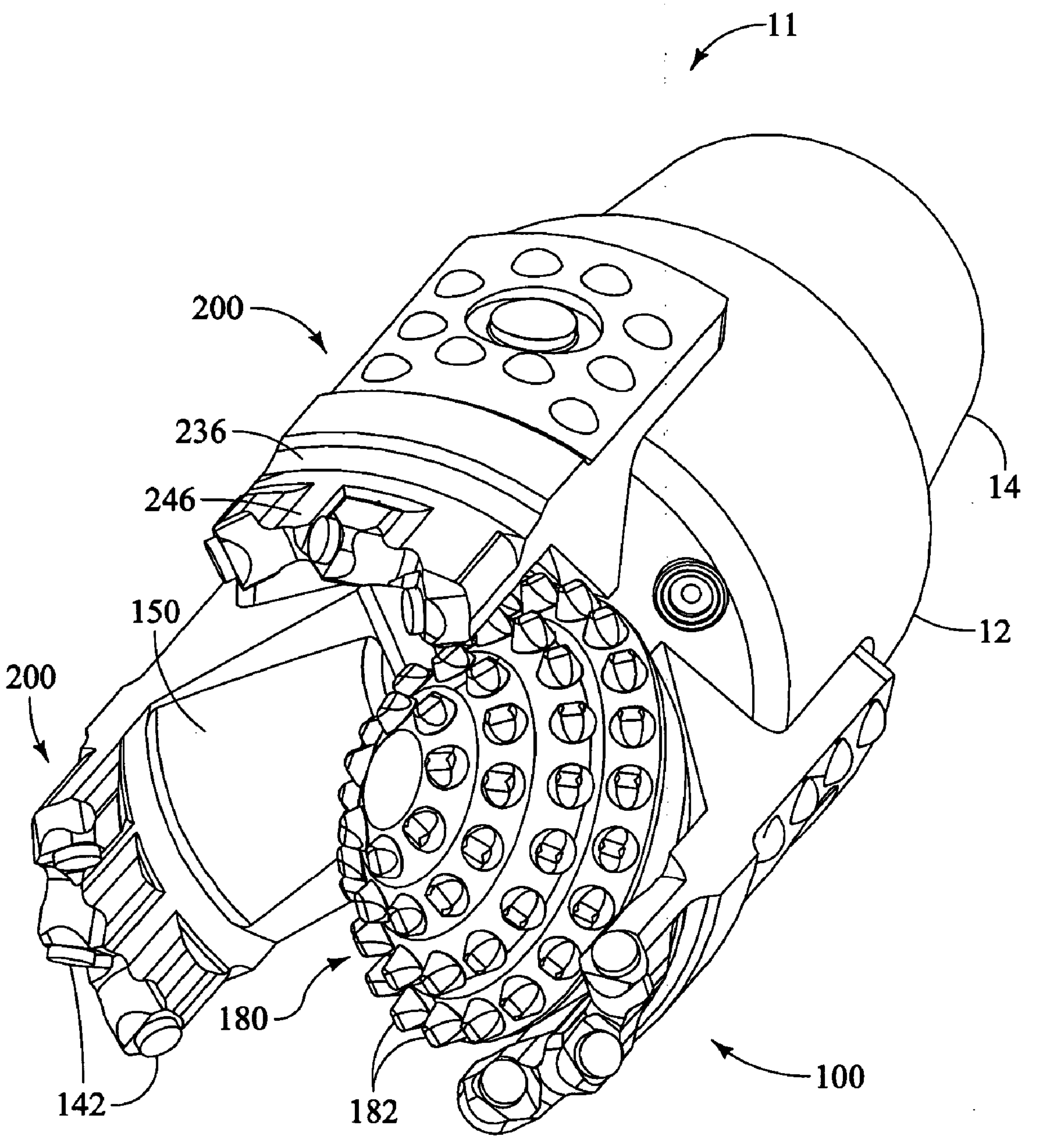


FIG. 12

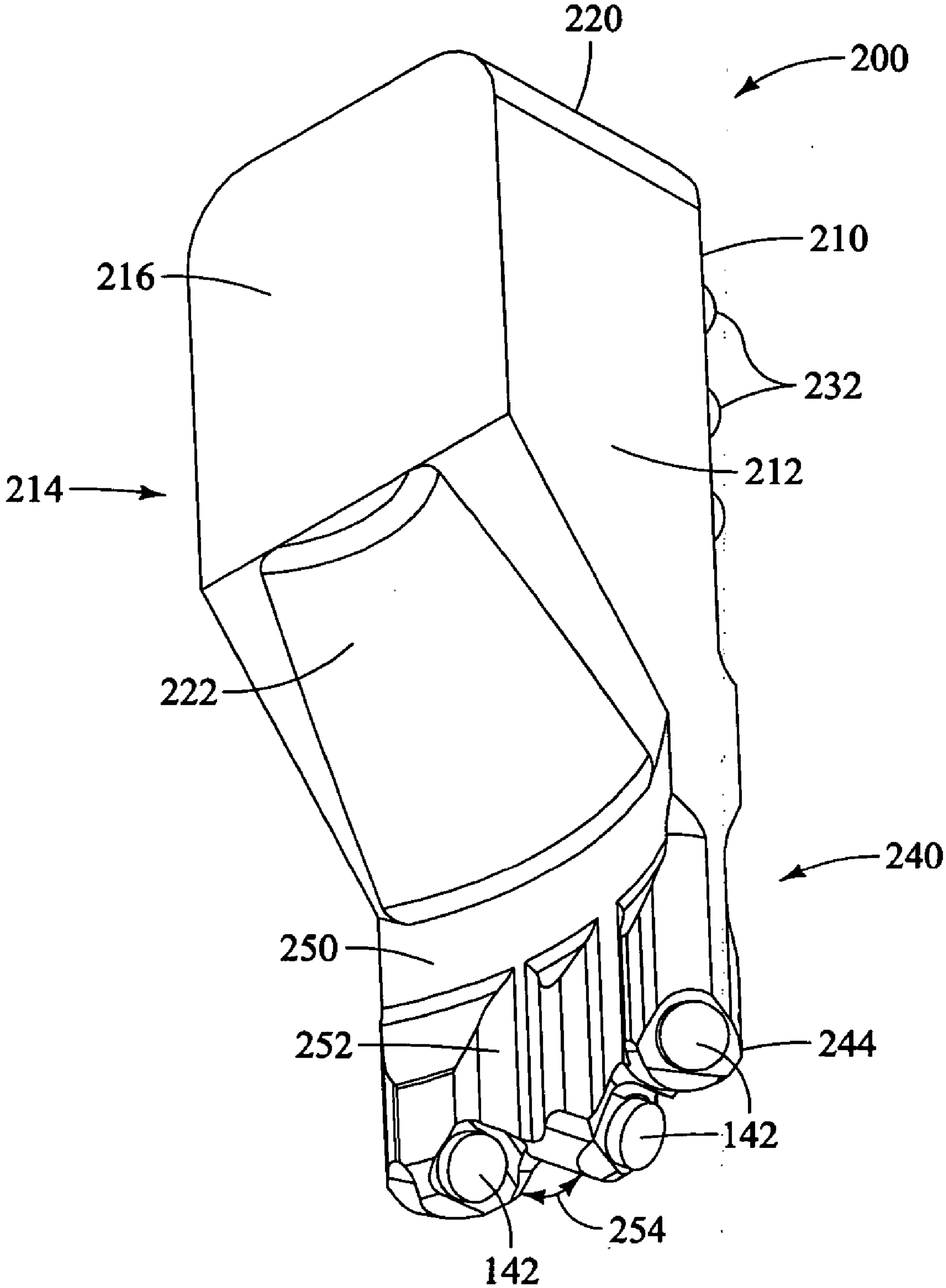


FIG. 13

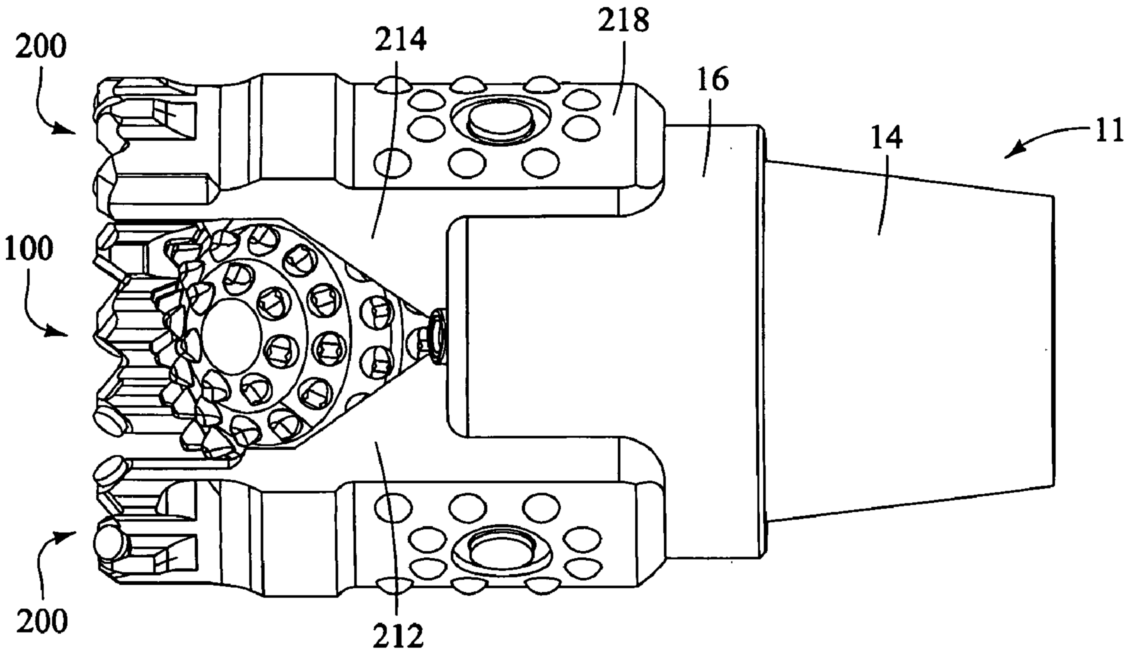

200
214
218
16
14
11
100
200
212

FIG. 14

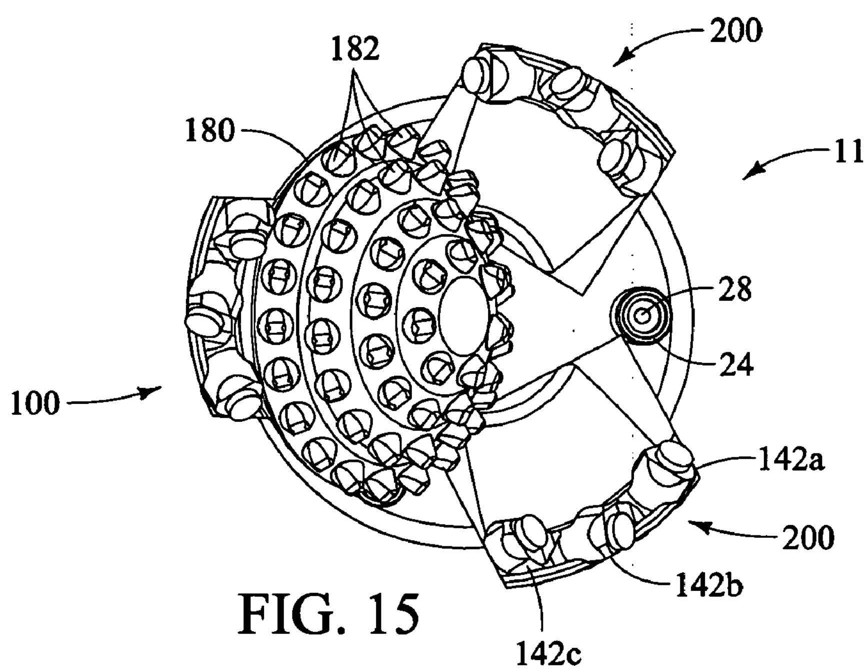

182
200
180
11
28
24
100
142a
200
142b
142c

FIG. 15

MODULAR KERFING DRILL BIT

CROSS REFERENCE TO RELATED APPLICATION

[0001] None.

BACKGROUND OF THE INVENTION

[0002] 1. Technical Field

[0003] The present invention relates generally to drilling bits used for drilling earth formations. More specifically, the present invention relates to a novel modular design for the improved construction of kerfing type rock bits, comprised of a combination of fixed cutters and roller cone cutters.

[0004] 2. Description of Related Art

[0005] In the exploration of oil, gas, and geothermal energy, drilling operations are used to create boreholes, or wells, in the earth. These operations normally employ rotary and percussion drilling techniques. In rotary drilling, the borehole is created by rotating a tubular drill string with a drill bit secured to its lower end. As the drill bit deepens the hole, tubular segments are added to the top of the drill string. While drilling, a drilling fluid is continually pumped into the drilling string from surface pumping equipment. The drilling fluid is transported through the center of the hollow drill string and into the drill bit. The drilling fluid exits the drill bit at an increased velocity through one or more nozzles in the drill bit. The drilling fluid then returns to the surface by traveling up the annular space between the borehole and the outside of the drill string. The drilling fluid carries rock cuttings out of the borehole and also serves to cool and lubricate the drill bit.

[0006] One type of rotary rock drill is a drag bit. Early designs for drag bits included hard facing applied to steel cutting edges. Modern designs for drag bits have extremely hard cutting elements, such as natural or synthetic diamonds, mounted to a bit body. As the drag bit is rotated, the hard cutting elements scrape against the bottom and sides of the borehole to cut away rock.

[0007] Another type of rotary rock drill is the roller cone bit. These drill bits have rotatable cones mounted on bearings on the body of the drill bit, which rotate as the drill bit is rotated. Cutting elements, or teeth, protrude from the cones. The angles of the cones and bearing pins on which they are mounted are aligned so that the cones essentially roll on the bottom of the hole with controlled slippage. One type of roller cone cutter is an integral body of hardened steel with teeth formed on its periphery. Another type has a steel body with a plurality of tungsten carbide or similar inserts of high hardness that protrude from the surface of the body somewhat like teeth. As the roller cone cutters roll on the bottom of the hole being drilled, the teeth or carbide inserts apply a high compressive load to the rock and fracture it. The cutting action of roller cone cutters is typically by a combination of crushing, chipping and scraping. The cuttings from a roller cone cutter are typically a mixture of moderately large chips and fine particles.

[0008] When drilling rock with a roller cone cutter, the fracture effect of loading on the teeth of the rock bed is limited due to the rock matrix surrounding the borehole. Failure of rock is prevented in a large degree by the restraint to movement offered by the surrounding rock. Thus, it appears in usual drilling operations that small cracks are created in the rock, which return to the surface of the bottom of the wellbore creating chips instead of propagating deep into the rock itself. Thus, the bit tooth of the usual rock bit presses on the rock surface tending to create small cracks which propagate downward, but by virtue of the resistance to fracture offered by the surrounding rock matrix, a crack follows the path of least resistance and emerges at the surface on the bottom of the wellbore, thus creating the small chips.

[0009] U.S. Pat. No. 3,055,443 to Edwards disclosed a combination drag bit and roller cone cutter which removes the lateral restraint on a core to be drilled. The drag bit component cuts a single annular kerf forming a core which is received within a hollow body member and drilled by multicone rolling cutters arranged within the hollow body member. Windows are provided in the bit body adjacent to the multicone cutters to provide an egress for chips formed by the destruction of the core. This bit design causes rapid failure of the drag cutters, however, since virtually all the drilling fluid escapes through the windows and results in insufficient fluid flow to cool the drag bit component.

[0010] U.S. Pat. No. 4,892,159 to Holster describes a kerf-cutting bit wherein resistance of the rock to fracture is removed or reduced by employing a drill bit which destroys the rock rapidly and efficiently. The drill bit of Holster cuts multiple annular kerfs which result in more rapid drilling rates than those achieved by cutting a singular annular kerf.

[0011] U.S. Pat. No. 5,145,017 to Holster, et al, describes a combination kerf-cutting bit and roller cone bit in which an annular kerf ring is cut in advance of rolling cutter. An inner kerf cutting structure is located internal to the annular kerf ring. Rolling cone cutter are disposed between the kerfing segments. Chipway ports are defined to improve the egress of rock cuttings as they are generated at the bottom of the wellbore.

[0012] A primary disadvantage of the prior art designs is that they are extremely difficult and expensive to manufacture. The efficiency of a drill bit is determined by a well recognized "cost per foot" equation. The equation is based on the cost of operating the drilling rig, the "trip time" need to replace the drill bit at a given depth, the rate of penetration of the drill bit, the life of the drill bit, and the cost of the drill bit. Due to the extremely high cost of manufacturing the prior art designs, they have proven to be inefficient in a cost per foot analysis.

[0013] Another disadvantage of the prior art designs is the time required for manufacturing the drill bits. In the drilling industry today, there is significant pressure to keep inventory levels very low. This is combined with the reality that drill bit selection decisions are often made while drilling, in response to the drilling rate achieved and the condition of the dull bit removed from the hole. The prior art kerf-cutting hybrid bits having combined kerf cutting segments and rolling cone cutters take far too long to manufacture, and are far too expensive to keep in inventory. The result is that they have become an impractical choice for the oilfield drilling.

[0014] Another disadvantage of the prior art designs is that they are less durable than required. The prior art designs combining inner and outer kerfing segments wherein each cover the entire circumference of the well bore. The assembly of rotating cone cutting structures within the geometrical constraints of the fully circumferential kerfing segments provides numerous challenges. For example, prior art hybrid drilling bits utilize relatively smaller bearing and seal systems which are less reliable when drilling larger diameter holes. Similarly, the smaller cones present a design constraint which require correspondingly smaller cutting elements on the cones. As with the sealed bearing system, these elements are less durable, and drill slower than the larger cutting elements conventionally used when drilling wells of the same diameter.

[0015] Another disadvantage of the prior art designs is that they lack cutting removal ability, limiting the life of cutting elements and rates of penetration at which the drill bits can operate, and subjecting the bits to balling and premature failure.

SUMMARY OF THE INVENTION

[0016] The present invention is a significant improvement over that described in the above enumerated prior art patents. The improvements of the present invention relate to both the location and relationship between cutting elements, as well as to the design, construction and manufacture of the drill bit. A principal advantage of the present invention is that it provides a drill bit capable of drilling more efficiently than prior art designs

[0017] Another advantage of the present invention is that it provides a hybrid bit design that is modular, permitting reduced inventories of component parts for assembly of multiple configurations of drill bits. Another advantage of the present invention is that it provides a hybrid bit design that can be assembled quickly, making the finished product deliverable faster than prior art designs. Another advantage of the present invention is that it provides a hybrid drill bit design that incorporates larger component cutting elements and larger bearing and seal systems which is more durable and drills faster.

[0018] Another advantage of the present invention is that it provides a hybrid drill bit design having very large flow relief area between the kerfing segments, allowing the bit to perform at very high rates of penetration without cutting build-up and balling of the bit. Other advantages of the present invention will become apparent from the following descriptions, taken in connection with the accompanying drawings, wherein, by way of illustration and example, an embodiment of the present invention is disclosed.

[0019] In carrying out principles of the present invention, in accordance with a preferred embodiment thereof, a modular kerfing drill bit is disclosed, having a bit body with a threaded connection for attachment to a drill string member at it's upper end. A base portion is provided below the connection, having an outside surface, and a bottom surface. At one or more slots are formed in the base portion. A cutter assembly is provided having a leg which is insertable into the slot of the bit body. A journal extends downward and inward from a transition portion of the leg, towards the center of the bit body. A cone is rotatably mounted on the journal. A plurality of cutters are located extending outward from the surface of the cone. A kerfing segment extends downward from the leg, beyond the journal. A plurality of cutters are positioned in the bottom of the kerfing segment.

BRIEF DESCRIPTION OF THE DRAWINGS

[0020] **FIG. 1** is an isometric view of a preferred embodiment of the present invention of a modular kerfing rock drilling bit in which three cutter assemblies are employed.

[0021] **FIG. 2** is an isometric view of a preferred embodiment of the bit body of the present invention, with the cutter assemblies unattached.

[0022] **FIG. 3** is an isometric view of the cutter assembly disclosed in **FIG. 1**, viewed in the direction of the center and lead faces of the leg.

[0023] **FIG. 4** is an isometric view of a cutter assembly of the preferred embodiment illustrated in **FIG. 3**, viewed in the direction of the back and lead faces of the leg.

[0024] **FIG. 5** is a side view of the cutter assembly illustrated in **FIGS. 3 and 4**, viewed in the direction of the center face of the leg.

[0025] **FIG. 6** is a side view of the cutter assembly illustrated **FIG. 5**, rotated 90° and viewed in the direction of the lead face of the leg.

[0026] **FIG. 7** is a side-sectional view of the cutter assembly illustrated in **FIG. 6**.

[0027] **FIG. 8** is a side view of the preferred embodiment of the present invention illustrated in **FIG. 1**, viewed in the direction of the back face of a leg.

[0028] **FIG. 9** is a side view of the preferred embodiment of the present invention illustrated in **FIG. 8**, with the drill bit rotated 60°, and viewed in the direction between cutter assemblies.

[0029] **FIG. 10** is a bottom view of the preferred embodiment illustrated in **FIGS. 1-3**.

[0030] **FIG. 11** is a top view of the preferred embodiment illustrated in **FIGS. 1-4**, showing the fluid channels internal to the bit body.

[0031] **FIG. 12** is an isometric view of an alternative embodiment of the present invention of a modular kerfing rock drilling bit, in which a single cutter assembly is employed in combination with two kerfing assemblies.

[0032] **FIG. 13** is an isometric view of a kerfing assembly of the alternative embodiment disclosed in **FIG. 12**, shown disengaged from the body.

[0033] **FIG. 14** is a side view of the alternative embodiment disclosed in **FIG. 12**, and viewed in the direction between kerfing assemblies.

[0034] **FIG. 15** is a bottom view of the alternative embodiment of the present invention disclosed in **FIG. 12**.

DETAILED DESCRIPTION OF THE INVENTION

[0035] **FIG. 1** is an isometric view of a preferred embodiment of the present invention for a Modular Kerfing Drill Bit **10**. In the embodiment shown, drill bit **10** has a body **12**. Body **12** has a connection **14** for attachment to a drill string member (not shown). Body **12** has a base **16** below connection **14** and contiguous thereto. Cutter assemblies **100** are shown attached to body **12**.

[0036] **FIG. 2** is an isometric view of a preferred embodiment of bit body **12** of the present invention, shown with cutter assemblies **100** unattached. In this view, it is seen that base **16** has a generally cylindrical outer portion **18** and a bottom **20**. Slots **22** are formed in base **16**, and intersect both outer portion **18** and bottom **20**. Slots **22** are formed for secure location of cutter assemblies **100**. Also in body **12**, ports **24** are provided, and interconnect to internal passage **26** (dashed line).

[0037] **FIG. 3** is an isometric view of a preferred embodiment of a cutter assembly **100**. Cutter assembly **100** has a leg **110**. Leg **110** has a lead face **112** and an opposite trailing face **114** (best seen in **FIG. 8**). Leg **110** has a center face **116** and an opposite back face **118** (best seen in **FIG. 4**). Leg **110** has a bottom face **120** and a transition face **122**. A journal **126** (not visible in this view) extends downward, substantially perpendicular to transition face **122**.

[0038] **FIG. 4** is another isometric view of cutter assembly **100** illustrated in **FIG. 3**, viewed in the direction of back face **118** and lead face **112** of leg **110**. In this view, it is seen that a reservoir cap **128** is located on back face **118** of leg **110**. In the preferred embodiment, reservoir cap **128** encloses an internal lubrication system **130** (best seen in **FIG. 7**). Also in the preferred embodiment illustrated, a plurality of gage buttons **132** are located on back face **118**. Also in the preferred embodiment illustrated, a stabilizer pad **134** is provided below back face **118** on leg **110**.

[0039] Still referring to **FIG. 4**, an external junk channel **136** is disposed circumferentially above stabilizer **134**. Cutter assembly **100** has a kerfing segment **140** extending downward from junk channel **136**. In a less preferred embodiment, kerfing segment **140** extends downward from stabilizer **134**.

[0040] Kerfing segment **140** supports a plurality of kerf cutters **142** mounted in cutter supports **144**. Referring to **FIG. 4**, in the preferred embodiment, annular junk slots **146** are vertically disposed between cutter supports **144**, and merge with junk channel **136**.

[0041] In a specifically preferred embodiment, kerf cutters **142** are synthetic diamond cutting elements. Specific examples of these types of cutting elements include polycrystalline diamond compacts (PDC's) and thermally stable diamond compacts (TSP's). There are numerous material and geometric variations of these products that are well known and readily available in the drilling industry. In a less preferred embodiment, kerf cutters **142** are natural diamonds.

[0042] **FIG. 5** is a side view of cutter assembly **100** illustrated also in **FIG. 3** and **4**. In **FIG. 5**, cutter assembly **100** is viewed from the center of drill bit **10**. Referring to **FIG. 5**, (see also **FIG. 3**), an internal flow channel **150** is disposed circumferentially above transition face **122**. Kerfing segment **140** extends downward from flow channel **150**. Internal flow slots **152** are vertically disposed between cutter supports **144**, and merge with flow channel **150**.

[0043] As can be seen in **FIG. 5**, cutter supports **144** support kerf cutters **142** in an angular deployment. This configuration provides a flow passage **154** between kerf cutters **142**, and connects internal flow slots **152** to external junk slots **146**.

[0044] **FIG. 6** is a side view of cutter assembly **100** illustrated **FIG. 5**, rotated 90° and viewed in the direction of lead face **112** of leg **110**. **FIG. 7** is a side-sectional view of cutter assembly **100** illustrated in **FIG. 6**. As seen in **FIG. 6** and **FIG. 7**, a cone **180** is rotatably mounted on journal **126**. Cone **180** has a plurality of teeth **182** attached to it. In the preferred embodiment, teeth **182** are interference fit within holes predrilled in cone **180**. Also in the preferred embodiment, teeth **182** are made of a material substantially harder than the formation to be drilled, such as sintered tungsten carbide.

[0045] As can also be inferred from **FIG. 7**, internal lubrication system **130** is contiguous to the external surface of journal **126** and the internal surface of cone **180**, so as to provide lubrication between journal **126** and cone **180**.

[0046] **FIG. 8** is a side view of drill bit **10**, viewed in the direction of back face **118** of leg **110**. From this view, it can be seen that a large clearance is provided between trailing face **114** of one cutter assembly **100** and lead face **112** of the adjacent cutter assembly **100**. **FIG. 9** is a side view of the preferred embodiment of drill bit **10**, as illustrated in **FIG. 8**, with drill bit **10** rotated 60°, and viewed in a direction between cutter assemblies **100**. **FIG. 10** is a bottom view of the preferred embodiment illustrated in **FIGS. 1-3**. In the preferred embodiment, interchangeable nozzles **28** are removably connectable to ports **24**.

[0047] **FIG. 11** is a top view of the preferred embodiment of drill bit **10**. In this view, it is seen that cones **180** have dissimilar cutting structures such that combined, they can rotate without interfering, and can best cover the bottom of the wellbore. This is noted by the designation of each cone **180** with a different alphanumeric suffix a through c.

[0048] Similarly, in the preferred embodiment, each kerf cutter **142** on a given cutter assembly **100** is located at a different radial distance to the center of drill bit **10**. This is noted by the designation of each kerf cutter **142** with a different alphanumeric suffix a through c, with a designating the innermost kerf cutter **142** and c designating the outermost kerf cutter **142**. In this manner, drill bit **10** can be specifically designed so that the combined physical forces acting on the combined cutters **142** and **182** on any given cutter assembly **100** are collectively, substantially equal. This provides a drill bit **10** that operates more efficiently.

[0049] **FIG. 12** is an isometric view of an alternative embodiment of the present invention for a modular kerfing rock drilling bit **11**, in which drill bit **11** incorporates a single cutter assembly **100** having a rotating cone **180** with teeth **182**. In this embodiment shown, drill bit **10** has a body **12**. Body **12** has a connection **14** for attachment to a drill string member (not shown). Body **12** has a base **16** below connection **14** and contiguous thereto. Unique to this embodiment, a single cutter assembly **100** is shown attached to body **12**. A pair of kerfing assemblies **200** are attached to bit body **12** in place of cutter assemblies **100**.

[0050] **FIG. 13** is an isometric view of kerfing assembly **200** disclosed in **FIG. 12**, shown detached from bit body **12** of drill bit **11**. Kerfing assembly **200** has a leg **210**. Leg **210** has a lead face **212** and an opposite trailing face **214** (best seen in **FIG. 14**). Leg **210** has a center face **216** and an opposite back face **218** (best seen in **FIG. 14**). Leg **210** has a bottom face **220** and a transition face **222**. Unlike cutter assemblies **100**, there is no journal **126** extending from transition face **222**, and no cone **182** having teeth **184** mounted thereon.

[**0051**] Referring back to **FIG. 2**, bit body **12** of previously disclosed can readily serve as bit body **12** of the alternative embodiment, shown with cutter assembly **100** and kerfing assemblies **200** unattached. In this view, it is seen that base **16** has a generally cylindrical outer portion **18** and a bottom **20**. Slots **22** are formed in base **16**, and intersect both outer portion **18** and bottom **20**. Slots **22** are formed for secure locations of cutter assembly **100** and kerfing assemblies **200**. Also, in body **12**, ports **24** are provided, and interconnect to internal passage **26** (dashed line).

[**0052**] **FIG. 14** is a side view of the alternative embodiment of drill bit **11** disclosed in **FIG. 12**, viewed in the direction between kerfing assemblies **200**, and having cutter assembly **100** and kerfing assemblies **200** attached in slots **22** of bit body **12**. From this view, it can be seen that a large clearance is provided between trailing face **214** of one kerfing assembly **200** and lead face **212** of the adjacent kerfing assembly **200**.

[**0053**] **FIG. 15** is a bottom view of the embodiment of drill bit **10** disclosed in **FIG. 12**. In this view, it can be seen that cone **180** has teeth **182**, and is the only rolling cutting element on drill bit **11**.

[**0054**] The foregoing detailed description is to be clearly understood as being given by way of illustration and example, the spirit and scope of the present invention being limited solely by the appended claims.

OPERATION OF THE INVENTION

[**0055**] As seen in **FIG. 1**, the preferred embodiment of Modular Kerfing Drill Bit **10** of the present invention is unique and vastly different from the prior art kerfing bit designs. Prior art designs are consistent in having fully circumference kerfing rows with cutters uniformly distributed thereon. The present design departs radically from this concept.

[**0056**] As seen in **FIG. 2**, body **12** is comprised of base **16** extending from bottom **20**. Bottom **20** is preferable a threaded connection such as an API connection as is well known in the drilling industry. Bottom **20** is thus suitable for secure connection to a drill collar, bit sub, or other drilling tool. The inside of body **12** provides internal passage **26** which is connected to ports **24** located on bottom surface **20** of body **12**.

[**0057**] Internal passage **26** and ports **24** provide a passageway for drilling fluid. Since drilling fluid is most advantageously provided at high velocity, in the preferred embodiment, ports **24** are receivable of interchangeable nozzles **28** made of a hard metal, such as tungsten carbide, or titanium carbide (see **FIG. 10** and **FIG. 15**). The hardness of the hard metal nozzles provides wear resistance to the abrasive forces associated with the high-velocity flow of the drilling fluid through the constricted diameter of the nozzles. In this embodiment, nozzles **28** can be interchangeably selected based on known operating parameters to optimize the hydraulic benefit of the drilling fluid on the performance of drill bit **10**.

[**0058**] Body **12** has at least one slot **22** formed on base **16**. Slots **22** intersect outer portion **18** and bottom **20**. Slots **22** provide a secure location for cutter assemblies **100**, and/or kerfing assemblies **200**.

[**0059**] Cutter assembly **100** is shown in **FIGS. 3-6**, unattached to body **12**. Cutter assembly **100** has a leg **110**. Leg **110** has a lead face **112** (**FIG. 3**) and an opposite trailing face **114** (best seen in **FIG. 8**). The reference to lead and trailing indicate the normal direction of rotation of the drill string and drill bit **10**. Leg **110** also has a center face **116** (**FIG. 5**) and an opposite back face **118** (**FIG. 4**). Leg **110** also has a bottom face **120** and a transition face **122**. Lead face **112**, trailing face **114**, and bottom face **120** are dimensionally and geometrically configured to fit in close tolerance within slots **22** of body **12**. This is seen in **FIG. 1**.

[**0060**] As seen in **FIG. 1**, and also in **FIGS. 8-10**, legs **10** of cutter assemblies **100** extend radially outwards from outer portion **18** of base **16**. As is clearly visible in **FIG. 10**, this provides a very large annular opening for the vertical passage of cutting laden drilling fluid between cutter assemblies **100**, body **12** and the side wall of the well bore. The size of this passage far exceeds the passage found in conventional kerfing bit designs, and thus resolves a principal disadvantage of the prior designs which rely on full circumference bit bodies and kerf cutter configurations.

[**0061**] In the paragraph above, and herein below, the terms "vertical" and "horizontal" used in reference to the direction of drilling fluid flow are made in reference to the central axis of a vertically drilled well. This reference is made by way of example only, for the purpose of understanding the operation of the invention. The reference is not intended as a limitation. The present invention is capable of directional drilling operations in any direction, including horizontally.

[**0062**] The preferred embodiment illustrated discloses drill bit **10** having three slots **22** in body **12**, for accommodation of three cutter assemblies **100**. In another preferred embodiment not shown, drill bit **10** has two slots **22** in body **12** for accommodation of two cutter assemblies **100**. In another preferred embodiment not shown, drill bit **10** has four slots **22** in body **12** for accommodation of a combination of cutter assemblies **100** and kerfing assemblies **200**. In still another preferred embodiment, drill bit **10** has one slot **22** in body **12** for accommodation of one cutter assembly **100**.

[**0063**] Each cutter assembly **100** has a cylindrical journal **126** extending from transition face **122**. In the preferred embodiment, journal **126** extends downward, substantially perpendicular to transition face **122**. A cone **180** is mounted to each journal **126**. Cone **180** may be mounted to journal **126** in the manner known for mounting cones to journal in conventional rotary drilling bits, using legs **110** in exchange for rotary drill bit sections, which normally include the base **16** and connection **14** portions as well. Cones **180** have teeth **182** located about the outer surface of cone **180**.

[**0064**] As seen in **FIG. 7**, a lubrication system **130** may be located in leg **110** to provide a lubricant between rotatable cone **180** and journal **126**. Lubrication system **130** may include a lubricant reservoir and pressure compensation means beneath a reservoir cap **128**. In the preferred embodiment, reservoir cap **128** is located on back face **118** of leg **110**. As drill bit **10** experiences increases in pressure at deeper well depths, or in response to increases in drilling fluid density, the pressure compensation means adjusts the pressure of the lubricant between rotatable cone **180** and journal **126**, to prevent drilling fluid from entering between rotatable cone **180** and journal **126**, and causing failure of the bearing relationship between them.

[**0065**] In the preferred embodiment illustrated, teeth **182** are tungsten carbide inserts, press fit into cone **180**. Teeth

182 may be made of other materials and may be otherwise attached to cones **180**. As an example, teeth **182** may be machined from the cone material. Teeth **182** may include a hard material deposited on them to increase their wear resistance. In the preferred embodiment, a plurality of gage buttons **132** are located on back face **118** to protect leg cutter assembly **100** from abrasive wear resulting from contact with side of the well bore. This location of gage buttons **132** provides particular protection to reservoir cap **128**.

[0066] Beneath gage buttons **132**, a stabilizer section **134** extends outward from back face **118** of leg **110**. Stabilizer **134** acts to stabilize and center drill bit **10** in the well bore during rotary drilling operations, increasing drilling rate and drill bit life by assisting drill bit **10** to drill a true and centered well bore. Since the present invention lacks full circumference kerfing sections, stabilizer **134** can extend the full width of leg **110**, and still provide vertical passage for cutting laden drilling fluid. This capability substantially simplifies the manufacturing process of drill bit **10**.

[0067] As seen in **FIG. 4**, external junk channel **136** is disposed circumferentially above stabilizer **134** providing horizontal passage for cutting laden drilling fluid, interlaced with the vertical passage provided between cutter assemblies **100**.

[0068] Referring to **FIG. 4**, kerfing segment **140** extends downward from junk channel **136**. Kerfing segment **140** supports a plurality of kerf cutters **142** mounted in cutter supports **144**. Annular junk slots **146** are vertically disposed between cutter supports **144**. Annular junk slots **146** provide vertical passage for cutting laden drilling fluid between individual kerf cutters **142**, and are interlaced with horizontally disposed junk channel **136**, which is in turn interlaced with the vertical passage provided between cutter assemblies **100**.

[0069] Kerf cutters **142** are primarily shear cutting elements that also impart compressive forces to fail the formation being drilled. As a result of this process, high flow rates of drilling fluid at the kerf cutter **142** and formation interface are preferable to lower flow rates. This helps removes the cuttings and lower the temperature at the interface of kerf cutter **142** and the formation. It is detrimental to performance when the cuttings generated by kerf cutters **142** and teeth **182** are limited in their ability to escape from the center of drill bit **10** (or **11**) to the annular section of the well bore surrounding drill bit **10** (or **11**).

[0070] Teeth **182** on cones **180** are primarily compressive cutting elements, that also impart shear forces to fail the formation being drilled. As a result of this process, high jet impact forces imparted to the hole face being drilled are preferable to lower impact forces. The higher impact forces help dislodge cuttings and prevents re-drilling the chips that remain on the formation face.

[0071] Notwithstanding the optimization requirements of kerf cutters **142** and teeth **182** of cones **180**, it is further noted that drilling systems are limited in the amount pressure their equipment can tolerate. Selecting smaller nozzles to increase jet impact forces beneficial to teeth **182** increases the drilling system operating pressure. Increasing pump speed to achieve flow rates beneficial to kerf cutters **142** likewise increases the drilling system operating pressure.

[0072] Thus, it is advantageous to be able to interchangeably select nozzles **28**, and to have a contiguous connections between relief's on bit **10** (or **11**) sufficient to readily permit removal of the cuttings generated by bit **10** (or **11**). The present invention accomplishes this. First, there are interchangeable nozzles **28** connectable to ports **24**. Second, there is a contiguous mesh of vertically and horizontally oriented flow channels and flow slots that being near nozzles **28** on the internal portions of legs **110** and continue to the outer portions of legs **110**. Third, the contiguous mesh is interconnected to very large annular spaces provided between cutter assemblies **100** (and kerfing assemblies **200**) in the modular, non-circumferential design of drill bit **10** (and **11**).

[0073] **FIG. 5** is a side view of cutter assembly **100** illustrated also in **FIG. 3** and **4**. In **FIG. 5**, cutter assembly **100** is viewed from the center of drill bit **10**. Referring to **FIG. 5**, (see also **FIG. 3**), an internal flow channel **150** is disposed circumferentially above transition face **122**, in the immediate proximity of where cuttings will be generated by teeth **182** on cone **180**. Kerfing segment **140** extends downward from flow channel **150**. On the inside of kerfing segment **140**, internal flow slots **152** are vertically disposed between cutter supports **144**, and merge with flow channel **150**.

[0074] As can be seen in **FIG. 5**, cutter supports **144** support kerf cutters **142** in an angular deployment. This configuration provides flow passages **154** between kerf cutters **142**, which connect internal flow slots **152** to external junk slots **146**. This is best seen in **FIG. 4**, which also illustrates external junk slots **146** merged to junk channel **136**, which is itself contiguous with both lead face **112** and trailing face **114** of leg **110**. Lead face **112** and trailing face **114** of leg **110** define the boundaries of the large annular relief between cutter assemblies **100**.

[0075] **FIG. 9** is a side view of drill bit **10**, as viewed between adjacent cutter assemblies **100**. From this view, the large annular clearance provided between trailing face **114** of one cutter assembly **100** and lead face **112** of the adjacent cutter assembly **100** is clearly visible.

[0076] Likewise, in the alternative embodiment for drill bit **11**, seen in **FIG. 13**, kerfing assemblies **200** have an internal flow channel **250** is disposed circumferentially above transition face **222**. Kerfing segment **240** extends downward from flow channel **250**. On the inside of kerfing segment **240**, internal flow slots **252** are vertically disposed between cutter supports **244**, and merge with flow channels **250**.

[0077] Flow passages **254** between kerf cutters **142**, connect internal flow slots **252** to external junk slots **246**. This is best seen in **FIG. 12**, which also illustrates external junk slots **146** merged to junk channel **236**, which is itself contiguous with both lead face **212** and trailing face **214** of leg **210**. Lead face **212** and trailing face **214** of leg **210** define the boundaries of the large annular relief between kerfing assemblies **200**, and between kerfing assemblies **200** and cutter assembly **100**.

[0078] **FIG. 7** is a side-sectional view of cutter assembly **100**. As can also be inferred from **FIG. 7**, internal lubrication system **130** is contiguous to the external surface of journal **126** and the internal surface of cone **180**, so as to provide pressure neutralized lubrication between journal **126** and cone **180**, and to prevent the intrusion of drilling fluid between journal **126** and cone **180**, in the manner that is well known in the industry.

[0079] **FIG. 14** is a side view of alternative embodiment drill bit **11**, as viewed between adjacent kerfing assemblies **200**. From this view, the large annular clearance provided between trailing face **214** of one kerfing assembly **200** and lead face **212** of the adjacent kerfing assembly **200** is clearly visible.

[0080] **FIG. 10** is a top view of the preferred embodiment of drill bit **10**. In this view, it is seen that cones **180** have dissimilar cutting structures such that combined, they can rotate without interfering, and can best cover the bottom of the wellbore. This is noted by the designation of each cone **180** with a different alphanumeric suffix a through c.

[0081] Similarly, in the preferred embodiment, each kerf cutter **142** on a given cutter assembly **100** is located at a designated radial distance to the center of drill bit **10**, known as the radial position of the kerf cutter **142**. The radial position of each kerf cutter **142** may be unique. This is noted by the designation of each kerf cutter **142** with a different alphanumeric suffix a through c, with a designating the innermost kerf cutter **142** and c designating the outermost kerf cutter **142**. In this manner, drill bit **10** can be specifically designed so that the combined physical forces acting on the combined cutters **142** and **182** on any given cutter assembly **100** are collectively, substantially equal. This provides a drill bit **10** that operates more efficiently. Due to the modular construction of drill bit **10**, modification can be made on the basis of test and/or field results with minimal disruption to the manufacturing process.

[0082] **FIG. 15** is a top view of the preferred embodiment of drill bit **11**. In this view, it is seen that cone **180** is considerably larger than cone **180** of drill bit **10**. In this embodiment, cone **180** and teeth **182** will drill substantially the entire well face internal to the placement of kerf cutter **142**. The larger structure of a single cone **180** provides substantial design flexibility related to the larger components associated with a single cone bit, since cone size is reduced relative to hole size to accommodate outer diameter kerf cutters **142**. Also, the larger structure of a single cone **180** provides substantial design as associated with the different performance characteristic of a single cone drill bit **11**.

[0083] Moreover, the modular design of the present invention, while disclosed in detail a three-cone embodiment drill bit **10** and a one-cone embodiment drill bit **11**, it can easily be configured to accommodate two cutting assemblies **100** and a single kerfing assembly **200**. Likewise, by adding or removing slots **22** on body **12**, other combinations of cutter assemblies **100** and kerfing assemblies **200** can be created.

[0084] The foregoing detailed description is to be clearly understood as being given by way of illustration and example, the spirit and scope of the present invention being limited solely by the appended claims.

I Claim:

1. A modular kerfing drill bit, comprising:

a bit body comprising;

a connection for attachment to a drill string member;

a base portion below the connection means, having an outside surface, and a bottom surface; and,

at least one slot formed in the base portion;

a cutter assembly comprising;

a leg insertable into the slot of the bit body;

a journal extending angularly downward and inward from the leg;

a cone rotatably mounted on the journal;

a plurality of cutters extending outward from the surface of the cone;

a kerfing segment extending downward from the leg; and,

a plurality of kerf cutters attached to the bottom of the kerfing segment.

2. The modular kerfing drill bit of claim 1, further comprising:

a kerfing assembly comprising;

a leg insertable into the slot of the bit body;

a kerfing segment extending downward from the leg; and,

a plurality of kerf cutters attached to the bottom of the kerfing segment.

3. The modular kerfing drill bit of claim 1, further comprising:

wherein each kerf cutter on a kerfing segment is located at a unique radial position.

4. The modular kerfing drill bit of claim 1, further comprising:

wherein a kerfing segment contains kerf cutters located at radial positions substantially equal to the radial positions of the kerf cutters on another kerfing segment of another leg.

5. The modular kerfing drill bit of claim 1, the leg further comprising:

a lead face and an opposite trailing face;

a back face and an opposite center face;

a transition face angularly disposed between the center face and the kerfing segment; and,

wherein the journal extends outward substantially perpendicular to the transition face.

6. The modular kerfing drill bit of claim 5, the leg further comprising:

a contiguous mesh of flow channels and flow slots extending from the leg center face, to between the kerf cutter, and to the leg back face.

7. The modular kerfing drill bit of claim 6, the contiguous mesh of flow channels and flow slots further comprising:

alternating vertically and horizontally oriented of flow channels and flow slots.

8. A cutter assembly comprising;

a leg insertable into the slot of the bit body;

a journal extending angularly downward and inward from the leg;

a cone rotatably mounted on the journal;

a plurality of cutters extending outward from the surface of the cone;

a kerfing segment extending downward from the leg; and, a plurality of cutters attached to the bottom of the kerfing segment.

9. A kerfing assembly comprising;

a leg insertable into the slot of the bit body;

a kerfing segment extending downward from the leg; and, a plurality of cutters attached to the bottom of the kerfing segment.

10. A modular kerfing drill bit, comprising:

a bit body comprising;

a connection for attachment to a drill string member;

a base portion below the connection means, having an outside surface, and a bottom surface; and,

a plurality of slots formed in the base portion;

a cutter assembly comprising;

a leg insertable into the slot of the bit body;

a journal extending angularly downward and inward from the leg;

a cone rotatably mounted on the journal;

a plurality of cutters extending outward from the surface of the cone;

a kerfing segment extending downward from the leg; and,

a plurality of cutters attached to the bottom of the kerfing segment; and,

a kerfing assembly comprising;

a leg insertable into the slot of the bit body;

a kerfing segment extending downward from the leg; and,

a plurality of kerf cutters attached to the bottom of the kerfing segment.

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