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(54) **Directional drilling system**

(57) A system is provided for directionally drilling a wellbore using a drill string having a mud motor, a drill bit, and a drive shaft for transmitting torque from the mud motor to the drill bit. The system includes a variable gauge stabilizer that is adjustable between retracted and deployed positions for influencing the drop or build angle of the drill bit. An instrument is carried within the drill string adjacent the drill bit for measuring data while drilling, and a telemetry system transmits the measured data to a driller at the surface. The telemetry system includes a transmitter disposed in the drill string beneath the mud motor for inducing a signal corresponding to the measured data into the subsurface formation surrounding the wellbore, and a receiver disposed in the drill string above the mud motor for detecting and recovering the measured data from the induced signal.

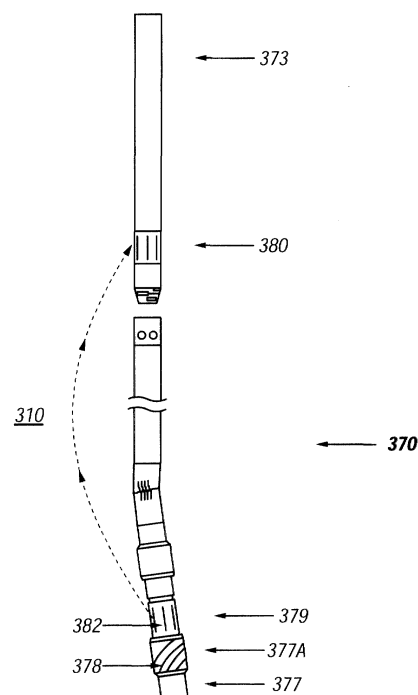


FIG. 19

Description

[0001] This application claims priority to the following U.S. patent applications: Serial No. 09/542,607 filed on April 4, 2000, Serial No. 60/200,941 filed May 1, 2000, and Serial No. 09/563,801 filed May 2, 2000.

BACKGROUND OF THE INVENTION

Field of the Invention

[0002] The present invention provides a variable gauge stabilizer for use in directional drilling of wells used to recover oil and gas, and a method for directionally drilling a well to recover oil and gas.

[0003] This invention relates generally to an apparatus and system for making downhole measurements during the drilling of a wellbore. In particular, it relates to an apparatus and system for making downhole measurements at or near the drill bit during directional drilling of a wellbore.

The Related Art

[0004] Wells are generally drilled to recover natural deposits of hydrocarbons and other desirable, naturally occurring materials trapped in geological formations in the earth's crust. A slender well is drilled into the ground and directed to the targeted geological location from a drilling rig at the surface. In conventional "rotary drilling" operations, the drilling rig rotates a drillstring comprised of tubular joints of drill pipe connected together to turn a bottom hole assembly (BHA) and a drill bit that are connected to the lower end of the drillstring. The BHA typically comprises a number of downhole tools including stabilizers, drill collars and mud motors, and is generally within 30 feet of the drill bit at the end of the drillstring. During drilling operations, a drilling fluid, commonly referred to as drilling mud, is pumped down the interior of the drillpipe, through the BHA and the drill bit, and back to the surface in the annulus around the drillpipe. Mud motors are often used to turn the drill bit without rotation of the drillstring. Pressurized mud pumped down the interior of the drillstring is used to power the mud motor that is mechanically coupled to and turns the nearby drill bit. Mud motors offer increased flexibility for directional drilling because they can be used with stabilizers or bent subs which impart an angular deviation to the BHA in order to deviate the well from its previous path and in the desired direction.

[0005] Stabilizers are generally heavy downhole tools that make up part of the BHA and are typically connected either above the mud motor and the drill bit or between the mud motor and the drill bit. Stabilizers are designed to promote smooth, continuous drilling action at the drill bit by limiting lateral movement of the BHA that could otherwise result from disruptive forces transferred from the teeth of the rapidly turning drill bit violently

breaking pieces of rock from the bottom of the wellbore. Stabilizers are also designed to accommodate the flow of drilling mud from the drillstring to the mud motor and drill bit connected downhole. Pressurized drilling mud pumped down the drillstring provides a flowing fluid to power the drill motor, suspend and remove drill cuttings from the well, and lubricate the drill bit for better drilling.

[0006] Importantly, a stabilizer that can be adjusted from the surface to a greater or lesser diameter can be used to influence the drop or build angle of the boring direction of the drill bit. The slender BHA is substantially rigid, and the angle of attack of the drill bit can be guided using the adjustable stabilizer. The outer diameter of the stabilizer substantially influences the axial alignment of the lower portion of the BHA from the stabilizer to the drill bit. Controllably affecting this alignment relative to the existing wellbore determines the angle at which the rotary drill bit engages the bottom of the wellbore.

[0007] Before adjustable stabilizers, deviating the wellbore from its existing path required removing the drillstring from the well, inserting a stabilizer with an outer diameter that provided the desired angular deviation, and running the entire drillstring back into the well. Once the newly configured BHA containing a non-adjustable stabilizer was in place at the bottom of the existing well, drilling was resumed in the desired deviated path. When the desired deviation in the path of the well had been achieved, the non-adjustable stabilizer was removed by pulling the entire drillstring from the well, replacing the stabilizer with another, and running the entire drillstring back into the well to resume drilling along the adjusted path.

[0008] Figure 1A shows an inactive adjustable diameter stabilizer connected above the mud motor and the drill bit and imparting a slight upward angular deviation to the BHA, thereby influencing the drill bit to build angle, or turn upwardly, from its existing path. Figure 1B shows an inactive adjustable diameter stabilizer connected between the mud motor and the drill bit and, again, imparting a build angle to the drill bit. Figure 2A shows how a deployed adjustable stabilizer connected above the mud motor and the drill bit has a larger effective outer diameter and imparts a slight downward angular deviation thereby influencing the drill bit to drop angle, or turn downwardly, from its existing path. Figure 2B shows a deployed adjustable stabilizer connected between the mud motor and the drill bit and imparting a drop angle to the drill bit. It is well known in the drilling industry how to obtain reliable three-dimensional location data for the bottom of the well being drilled. The driller compares this information with the target bottom hole location to determine needed adjustments in the path of the well, and the adjustments may be made using the present invention.

[0009] Anderson's U.S. Patent No. 4,848,490 provides a variable downhole stabilizer that is actuated (outer diameter increased by radially outward deployment of spacers) by reverse telescoping action; that is,

the driller actuates the tool by increasing the weight on bit to impart an axially compressing force tending to reverse telescope the stabilizer tool. When the weight on the bit reaches or exceeds a threshold force determined by the strength of an opposing spring, the mandrel engages the spacers thereby deploying the spacers radially outward to increase the diameter of the tool and affect angular deviation to the drill bit. However, Anderson's stabilizer requires the driller to slide the entire drillstring in the well in order to reverse telescope and actuate the tool. In directionally drilled wells having long horizontal or inclined portions, the frictional resistance to sliding of the drillstring in the well is a function of the co-efficient of friction and the weight of the drillstring supported by the wall of the wellbore. The frictional resistance to sliding the drillstring within the well can be extremely large and unpredictable due to the roughness of the bore wall of the well. Difficulties in obtaining controlled movement of the lower end of the drillstring can cause problems in tool actuation, especially as the length of the drillstring and the horizontal deviation of wells continues to increase. Consequently, actuating a variable stabilizer by reciprocating the drillstring is problematic.

[0010] Lee's U.S. Patent No. 5,339,914 provides a variable downhole stabilizer that is hydraulically actuated (outer diameter increased by radially outward deployment of tool elements). However, Lee's variable downhole stabilizer requires that the driller lower the entire drillstring into the well in order to lock the deployable tool elements in their deployed position. Like Anderson's stabilizer, sliding the entire drillstring against the rough wall of the wellbore is required to operate Lee's stabilizer. In order to retract the tool elements of Lee's stabilizer, the entire drillstring must be raised to unlock the stabilizer and adjust the stabilizer.

[0011] What is needed is a surface-operated variable gauge stabilizer that can be deployed or retracted solely by accurately controllable changes in hydraulic mud pressure in the drillstring without cumbersome reciprocations of the entire drillstring. What is needed is a surface-operated variable gauge stabilizer that can be adjusted without the use of wired or cabled control systems that complicate drilling operations. What is needed is a reliable variable gauge stabilizer that is easy and simple to deploy and retract. What is needed is a surface-operated variable gauge stabilizer that, once locked into its deployed position, allows the driller freedom to change the position of the drillstring and the rate of the mud pumps, within a pre-defined pressure range, without affecting the deployed condition of the tool. What is needed is a surface-operated variable gauge stabilizer that provides the driller with reliable detection of the deployed or retracted status of the tool.

[0012] In drilling a directional well, it is common to use a bottom hole drilling assembly (BHA) that is attached to a drill collar as part of the drill string. This BHA typically includes (from top down), a drilling motor assembly,

a drive shaft system including a bit box, and a drill bit. In addition to the motor, the drilling motor assembly includes a bent housing assembly which has a small bend angle in the lower portion of the BHA. This angle causes the borehole being drilled to curve and gradually establish a new borehole inclination and/or azimuth. During the drilling of a borehole, if the drill string is not rotated, but merely slides downward as the drill bit is being driven by only the motor, the inclination and/or the azimuth of the borehole will gradually change due to the bend angle. Depending upon the "tool face" angle, that is, the angle at which the bit is pointing relative to the high side of the borehole, the borehole can be made to curve at a given azimuth or inclination. If however, the rotation of the drill string is superimposed over that of the output shaft of the motor, the bend point will simply travel around the axis of the borehole so that the bit normally will drill straight ahead at whatever inclination and azimuth have been previously established. The type of drilling motor that is provided with a bent housing is normally referred to as a "steerable system". Thus, various combinations of sliding and rotating drilling procedures can be used to control the borehole trajectory in a manner such that eventually the drilling of a borehole will proceed to a targeted formation. Stabilizers, a bent sub, and a "kick-pad" also can be used to control the angle build rate in sliding drilling, or to ensure the stability of the hole trajectory in the rotating mode.

[0013] Referring initially to the configuration of Fig. 9, a drill string 210 generally includes lengths of drill pipe 211 and drill collars 212 as shown suspended in a borehole 213 that is drilled through an earth formation 209. A drill bit 214 at the lower end of the drill string is rotated by the drive shaft 215 connected to the drilling motor assembly 216. This motor is powered by drilling mud circulated down through the bore of the drill string 210 and back up to the surface via the borehole annulus 213a. The motor assembly 216 includes a power section (rotor/stator or turbine) that drives the drill bit and a bent housing 217 that establishes a small bend angle at its bend point which causes the borehole 213 to curve in the plane of the bend angle and gradually establish a new borehole inclination. As noted above, if rotation of the drill string 210 is superimposed over the rotation of the drive shaft 215, the borehole 213 will be drilled straight ahead as the bend point merely orbits about the axis of the borehole. The bent housing can be a fixed angle device, or it can be a surface adjustable assembly. The bent housing also can be a downhole adjustable assembly as disclosed in U.S. Patent 5,117,927 which is incorporated herein by reference. Alternately, the motor assembly 216 can include a straight housing and can be used in association with a bent sub well known in the art and located in the drill string above the motor assembly 216 to provide the bend angle.

[0014] Above the motor in this drill string is a conventional measurement while drilling (MWD) tool 218 which has sensors that measure various downhole parameters.

ters. Drilling, drill bit and earth formation parameters are the types of parameters measured by the MWD system. Drilling parameters include the direction and inclination (D&I) of the BHA. Drill bit parameters include measurements such as weight on bit (WOB), torque on bit and drive shaft speed. Formation parameters include measurements such as natural gamma ray emission, resistivity of the formations and other parameters that characterize the formation. Measurement signals, representative of these downhole parameters and characteristics, taken by the MWD system are telemetered to the surface by transmitters in real time or recorded in memory for use when the BHA is brought back to the surface.

[0015] As shown in Fig. 9, when an MWD tool 218, such as the one disclosed in commonly-assigned U.S. Patent 5,375,098, is used in combination with a drilling motor 216, the MWD tool 218 is located above the motor and a substantial distance from the drill bit. Including the length of a non-magnetic spacer collar and other components that typically are connected between the MWD tool and the motor, the MWD tool may be positioned as much as 20 to 40 feet above the drill bit. These substantial distances between the MWD sensors in the MWD tool and the drill bit mean that the MWD tool's measurements of the downhole conditions, related to drilling and the drill bit at a particular drill bit location, are made a substantial time after the drill bit has passed that location. Therefore, if there is a need to adjust the borehole trajectory based on information from the MWD sensors, the drill bit will have already traveled some additional distance before the need to adjust is apparent. Adjustment of the borehole trajectory under these circumstances can be a difficult and costly task. Although such large distances between the drill bit and the measurement sensors can be tolerated for some drilling applications, there is a growing desire, especially when drilling directional wells, to make the measurements as close to the drill bit as possible.

[0016] Two main drilling parameters, the drill bit direction and inclination are typically calculated by extrapolation of the direction and inclination measurements from the MWD tool to the bit position, assuming a rigid BHA and drill pipe system. This extrapolation method results in substantial error in the borehole inclination at the bit especially when drilling smaller diameter holes (less than 6 inches) and when drilling short radius and re-entry wells.

[0017] Another area of directional drilling that requires very accurate control over the borehole trajectory is "extended reach" drilling applications. These applications require careful monitoring and control in order to ensure that a borehole enters a target formation at the planned location. In addition to entering a formation at a predetermined location, it is often necessary to maintain the borehole drilling horizontally in the formation. It is also desirable for a borehole to be extended along a path that optimizes the production of oil, rather than water which is found in lower portions of a formation, or gas

found in the upper portion of a formation.

[0018] In addition to making downhole measurements which enable accurate control over borehole trajectory, such as the inclination of the borehole near the bit, it is also highly desirable to make measurements of certain properties of the earth formations through which the borehole passes. These measurements are particularly desirable where such properties can be used in connection with borehole trajectory control. For example, identifying a specific layer of the formation such as a layer of shale having properties that are known from logs of previously drilled wells, and which is known to lie a certain distance above the target formation, can be used in selecting where to begin curving the borehole to insure that a certain radius of curvature will indeed place the borehole within the targeted formation. A shale formation marker, for example, can generally be detected by its relatively high level of natural radioactivity, while a marker sandstone formation having a high salt water saturation can be detected by its relatively low electrical resistivity. Once the borehole has been curved so that it extends generally horizontally within the target formation, these same measurements can be used to determine whether the borehole is being drilled too high or too low in the formation. This determination can be based on the fact that a high gamma ray measurement can be interpreted to mean that the hole is approaching the top of the formation where a shale lies, and a low resistivity reading can be interpreted to mean that the borehole is near the bottom of the formation where the pore spaces typically are saturated with water. However, as with D&I measurements, sensors that measure formation characteristics are located at large distances from the drill bit.

[0019] One approach, by which the problems associated with the distance of the D&I measurements, borehole trajectory measurements and other tool measurements from the drill bit can be alleviated, is to bring the measuring sensors closer to the drill bit by locating sensors in the drill string section below the drilling motor. However, since the lower section of the drill string is typically crowded with a large number of components such as a drilling motor power section, bent housing, bearing assemblies and one or more stabilizers, the inclusion of measuring instruments near the bit requires the addressing of several major problems that would be created by positioning measuring instruments near the drill bit. For example, there is the major problem associated with telemetering signals that are representative of such downhole measurements uphole, through or around the motor assembly, in a practical and reliable way.

[0020] A concept for moving the sensors closer to the drill bit was implemented in Orban et. al, U.S. Patent 5,448,227. This patent is directed to a sensor sub or assembly that is located in the drill string at the bottom of the motor assembly, and which includes various transducers and other means for measuring parameters such as inclination of the borehole, the natural gamma ray

emission and electrical resistivity of the formations, and variables related to the performance of the drilling motor. Signals representative of such measurements are telemetered uphole, through the wall of the drill string or through the formation, a relatively short distance to a receiver system that supplies corresponding signals to the MWD tool located above the drilling motor. The receiver system can either be connected to the MWD tool or be a part of the MWD tool. The MWD tool then relays the information to the surface where it is detected and decoded substantially in real time. Although the techniques of this patent make substantial progress in moving sensors closer to the drill bit and overcoming some of the major telemetry concerns, the sensors are still approximately 6 to 10 feet from the drill bit. In addition, the sensors are still located in the motor assembly and the integration of these sensors into the motor assembly can be a complicated process.

[0021] A technique that attempts to address the problem of telemetering the measured signals uphole around the motor assembly to the MWD tool uses an electromagnetic transmission scheme to transmit measurements from behind the drill bit. In this system, a fixed frequency current signal is induced through the drill collar by a toroidal coil transmitter. As a result, the current flows through the drill string to the receiver with a return path through the formation. The propagation mode is known as a Transverse Magnetic (TM) mode. In this propagation mode, transmission is unreliable in extremely resistive formations, in formations with very resistive layers alternating with conductive layers, and in oil-based mud with poor bit contact with the formation.

[0022] Therefore, there still remains a need for a system that can improve the accuracy of bit measurements by placing sensors at the drill bit and reliably transmitting these signals uphole to MWD equipment for transmission to the earth's surface.

[0023] As earlier stated there can be a substantial distance between the drilling motor and the drill bit. This distance is caused by several pieces of equipment that are necessary for the drilling operation. One piece of equipment is the shaft used to connect the motor rotor to the drill bit. The motor rotates the shaft which rotates the drill bit during drilling. The drill bit is connected to the shaft via a bit box. The bit box is a metal holding device that fits into the bowl of a rotary table and is used to screw the bit to (make up) or unscrew (break out) the bit from the drill string by rotating the drill string. The bit box is sized according to the size of the drill bit. In addition, the bit box has the internal capacity to contain equipment.

[0024] Fig. 10 illustrates a conventional drilling motor system. A bit box 219 at the bottom portion of the drive shaft 215 connects a drill bit 214 to the drive shaft 215. The drive shaft 215 is also connected to the drilling motor power section 216 via the transmission assembly 216a and the bearing section 220. The shaft channel 215a is the means through which fluid flows to the drill

bit during the drilling process. The fluid also carries formation cuttings from the drill bit to the surface. In the drilling system of Fig. 10, no instrumentation is located in or near the bit box 219 or drill bit 214. The closest that the instruments would be to the drill bit would be in the lower portion of the motor power section 216 as described in U.S. Patent 5,448,227 or in the MWD tool 218. As previously stated, the sensor location is still approximately 6 to 10 feet from the drill bit. The positioning of measurement instrumentation in the bit box would substantially reduce the distance from the drill bit to the measurement instrumentation. This reduced distance would provide an earlier reading of the drilling conditions at a particular drilling location. The earlier reading will result in an earlier response by the driller to the received measurement information when a response is necessary or desired.

SUMMARY OF THE INVENTION

[0025] The present invention provides a system for directionally drilling a wellbore using a drill string having a mud motor, a drill bit, and a drive shaft for transmitting torque from the mud motor to the drill bit, the system including: a tool carried in the drill string that is adjustable for varying the direction of the drill bit and the wellbore; an instrument for measuring data while drilling, the instrument being carried within a drill bit connecting means for connecting the drill bit to the drill string; and a telemetry system for transmitting the measured data to a driller at the surface, the telemetry system including: a transmitter disposed in the drill string beneath the mud motor for transmitting a signal corresponding to the measured data; and a receiver disposed in the drill string above the mud motor for receiving the signal and recovering the measured data from the signal.

BRIEF DESCRIPTION OF DRAWINGS

[0026] So that the features and advantages of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to the embodiments thereof that are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

Figure 1A is an elevation view of an inactive variable gauge stabilizer using the mud motor as a fulcrum to impart an upward angle to the drill bit to build angle, or turn the well upwardly, from its existing path. Figure 1B is an elevation view of a deployed variable gauge stabilizer using the mud motor as a fulcrum to impart a downward angle to the drill bit to drop angle, or turn the well downwardly, from its ex-

isting path.

Figure 2A is an elevation view of an inactive variable gauge stabilizer imparting an downward angle to the drill bit to drop angle, or turn the well downwardly, from its existing path.

Figure 2B is an elevation view of a deployed variable gauge stabilizer imparting an upward angle to the drill bit to build angle, or turn the well upwardly, from its existing path.

Figure 3 is a cross-sectional side view of a variable gauge stabilizer in the inactive position.

Figure 4 is a side view, partially in section, of a four-stroke rotating position control collar.

Figures 5A through 5D are a sequential series of side views, partially in section, showing a cycle of a control collar and its interaction with a guide finger.

Figure 6 is a cross-sectional side view of the variable gauge stabilizer in its intermediate position.

Figure 7 is a cross-sectional side view of the variable gauge stabilizer in an active, deployed position.

Figure 8A through 8C are magnified side views of the beveled portion of the deployment mandrel of the variable gauge stabilizer deploying a stabilizer element through a stabilizer port in the housing.

Figure 9 is a schematic view that shows a deviated extended reach borehole with a string of measurement and drilling tools therein according to the prior art;

Figure 10 is a cross-section of the lower portion of another prior art drilling assembly;

Figure 11 is a schematic view of an extended bit box embodiment for near-bit communication of MWD data according to the present invention;

Figure 12 is a schematic view of an extended sub embodiment for near-bit communication of MWD data according to the present invention;

Figure 13 is a cross-section view of the lower portion of a drilling assembly incorporating the extended bit box embodiment;

Figure 14 is a detailed, cross-section view of the extended bit box embodiment;

Figure 15 is a perspective view of the extended bit box embodiment;

Figure 16 is a cross-section view of the batteries and the sensing instrumentation mounted inside the channel of the drive shaft of the extended bit box embodiment;

Figure 17 is a cross-section view of the transmitter and control circuitry of the extended bit box embodiment;

Figure 18 is a schematic view of the lower portion of a drilling string with an instrumented drill bit embodiment for near-bit communication of MWD data; Figures 19 and 20 are schematic illustrations of a drill strings utilizing wireless telemetry means and near-bit data communication according to present invention;

Figure 21 is a diagram of an unaltered continuous

carrier signal;

Figure 22 illustrates a modulated carrier signal containing drilling and logging information;

Figure 23 is a flow diagram of the operation of determining borehole inclination in accordance with the present invention;

Figure 24 is an illustration of a 27 bit word for data transmission uphole;

Figure 25 is an illustration of a pulse position modulated data frame transmitted to a receiver;

Figure 26 is a diagram of the pulse positions in a data region of the data frame of Figure 25;

Figures 27a, 27b, and 27c illustrate various pulse positions within a data region based on various bit sequences;

Figure 28 is a schematic of the circuit used to extract the carrier signal portion of the transmitted signal during demodulation and to detect peak amplitude; Figures 29a and 29b illustrate respectively modulated signals as transmitted and as received in the present invention;

Figure 30 is a cross-sectional view of the transmitter of the present invention;

Figure 31 is a plot of the signal amplitude resistivity transform for a two-coil deep resistivity measurement system of the present invention;

Figures 32a, 32b, 32c, and 32d are plots of the real and imaginary signal resistivity transform at various signal levels and transmitter to receiver spacings;

Figure 33 is a schematic illustration of a tool according to the present invention approaching a resistivity contrast boundary at an apparent dip angle of 90 degrees;

Figure 34a is a graph of the formation resistivity signal response as the tool of Figure 33 travels from a low resistivity formation to a high resistivity formation;

Figure 34b is a graph of the formation resistivity signal response as the tool of Figure 33 travels from a high resistivity formation to a low resistivity formation;

Figure 35 is a schematic illustration of a tool according to the present invention approaching a resistivity contrast boundary at an apparent dip angle of 0 degrees;

Figure 36a is a graph of the formation resistivity signal response as the tool of Figure 18 travels from a low resistivity formation to a high resistivity formation; and

Figure 36b is a graph of the formation resistivity signal response as the tool of Figure 18 travels from a high resistivity formation to a low resistivity formation.

DETAILED DESCRIPTION OF THE INVENTION

[0027] Figure 3 shows the general configuration of a preferred embodiment of the present invention, a varia-

ble gauge stabilizer 10. The stabilizer 10 has a housing 12 with a threaded proximal connection 22 disposed at one end of the stabilizer 10 for connection to a drillstring 30 (not shown), a threaded distal connection 24 disposed at the other end of the stabilizer 10 for connection to drill collars 32 (not shown), and an axis 26 generally defined by the centers of the threaded connections 22 and 24. The housing 12 also has a plurality of stabilizer ports 14 disposed radially about the axis 26 that receive the stabilizer elements 16 so that the elements radially reciprocate within and through the stabilizer ports 14. The stabilizer elements 16 can be radially outwardly deployed against opposing stabilizer springs 18 by actuation of the deployment mandrel 140 to its deployed position (shown in Figure 7), and radially inwardly retracted by springs when the deployment mandrel 140 returns to its inactive position (shown in Figure 3). The stabilizer elements 16 may be any support members such as pistons, stems or rods. Figure 3 shows the positioning mandrel 40, the deployment mandrel 140 and the stabilizer elements 16 all in their inactive and retracted positions. Figure 6 shows the positioning mandrel 40 distally displaced against the force of the positioning mandrel spring 36 to its intermediate position, the deployment mandrel 140 remaining in its inactive position as urged by the deployment mandrel spring 136, and the stabilizer elements 16 still in their retracted position as urged by the stabilizer element springs 18. Figure 7 shows the positioning mandrel 40, the deployment mandrel 140 and the stabilizer elements 16 all in their active and deployed positions. Figures 8A through 8C show a magnified view of the beveled portion 46 of the deployment mandrel 140 engaging and disposing the stabilizer element 16 radially outwardly through the stabilizer port 14 in the housing 12 to overcome the opposing force of the stabilizer element spring 18.

[0028] Figures 3, 6 and 7 show the positioning mandrel 40 with the rotating position control collar 42 rotatably received thereon, with both the positioning mandrel 40 and the rotatably attached control collar 42 disposed within a chamber in the housing 12. The positioning mandrel 40 has an axis 44 and an annular drillstring pressure sensing surface 48. The positioning mandrel 40 and the control collar 42 axially reciprocate together within the chamber of the housing 12 along their axis 44 that is generally aligned with the axis 26 of the housing 12.

[0029] The positioning mandrel 40 controllably and cyclically moves between three positions as determined by the angular orientation of the control collar relative to the housing 12. The positions of the positioning mandrel are the inactive position (first position - Figure 3), the intermediate position (second position - Figure 6), back to the inactive position (Figure 3), and the deployed position (third position - Figure 7), in that order. In its deployed position shown in Figure 7, the positioning mandrel 40 axially engages and displaces the deployment mandrel 140 towards the distal connection 24 of the

housing 12. The positioning mandrel 40 and the deployment mandrel 140 both reciprocate within the chamber generally along the axis 44 of the housing 12, but the positioning mandrel 40 reciprocates within a greater axial range of motion than does the deployment mandrel 140. The deployment mandrel 140 reciprocates only when displaced from its inactive position by force applied through the positioning mandrel 40. The movement of the positioning mandrel 40 is determined by the summation of axial forces acting thereon. The forces acting on the positioning mandrel 40 include the force of the positioning mandrel spring 36 and the forces applied by drilling mud pressure on various exposed surfaces. The responsiveness of the positioning mandrel 40 can be enhanced through strategic placement of circumferential seals and equalization ports to provide a net differential force on the positioning mandrel.

[0030] Figures 3, 6 and 7 show a proximal positioning mandrel seal 38 and a distal positioning mandrel seal 39 disposed on the positioning mandrel 40 for sliding contact with the housing 12, and a proximal deployment mandrel seal 138 and a distal deployment mandrel seal 139 disposed on the deployment mandrel 140 for sliding contact with the housing 12. The portion of the chamber of the housing 12 proximal to the proximal positioning mandrel seal 38 is in fluid communication with the drilling mud pressure in the drillstring 30 and in the tubular interior of the positioning mandrel 140. The portion of the chamber of the housing 12 between the proximal positioning mandrel seal 38 and the distal positioning mandrel seal 39 is isolated from the interior of drillstring 30, but is in fluid communication with the annular mud pressure outside the housing 12 through equalization port 173. The portion of the chamber of the housing 12 between the distal positioning mandrel seal 39 and the proximal deployment mandrel seal 138 is in fluid communication with the tubular interior of the positioning mandrel 40. The portion of the chamber of the housing 12 between the proximal deployment mandrel seal 138 and the distal deployment mandrel seal 139 is isolated from the interior of drillstring 30, but is in fluid communication with the annular pressure outside the housing 12 through equalization port 273.

[0031] The pressure in the drillstring 30 results from drilling mud being forcefully pumped down the drillstring 30 from the discharge of the mud pumps at the surface and out the bit nozzles. The pressure in the drillstring 30, the pressure in the annulus 34, the force of the positioning mandrel spring 36 and force of the deployment mandrel spring 136 all combine, along with friction of the seals, to determine the net axial forces acting separately on the positioning mandrel 40 and the deployment mandrel 140. For example, the pressure in the drillstring 30 bears on the exposed surfaces of the positioning mandrel 40 to provide a net force acting on the annular pressure sensing surface 48 of the positioning mandrel 40 and urging the positioning mandrel 40 from its inactive position towards either its intermediate or its deployed

positions, depending on the orientation of the control collar 42 relative to the housing 12.

[0032] The positioning mandrel spring 36 is disposed in contact with the housing 12 at a first circumferential spring shoulder 13 and with the positioning mandrel 40 at a first circumferential ridge 15. The positioning mandrel spring 36 is placed under compression to urge the positioning mandrel 40 towards its inactive position shown in Figure 3. The deployment mandrel spring 36 is designed to elastically compress when the pressure in the drillstring 30 is sufficient to provide a force on the positioning mandrel 40 greater than a first threshold actuation force. This design secures the positioning mandrel 40 in the desired intermediate or deployed position during normal drilling operations as long as the drillstring pressure is above the first threshold pressure necessary to overcome and compress the positioning mandrel spring 36. For example, the first threshold actuation pressure may be any pressure that is great enough to compress the positioning mandrel spring 36. It should be recognized that the first threshold actuation pressure is primarily determined by the amount of resistance in the positioning mandrel spring 36 and the net surface area of the annular pressure sensing surface 48, but is also influenced by the shape of the positioning mandrel 40 and the annular pressure outside the housing 12 adjacent to the equalization ports 173 and 273.

[0033] As shown in Figure 4, the control collar 42 has a proximal end 41 disposed toward the proximal end of the housing 12 and a distal end 43 disposed toward the deployment mandrel 140 and the distal connection 24 of the housing 12. The control collar 42 is the device that enables the driller to controllably deploy and retract the stabilizer elements 16 by varying the pressure in the drillstring 30 to reciprocate the positioning mandrel 40. A series of interconnected grooves are machined into the radially outer surface of the control collar 42. In a simple four-stroke design, these grooves comprise two return grooves 50 and 52 and two rotation grooves 51 and 53. The control collar 42 is axially fixed to the positioning mandrel 40 and reciprocates within the housing 12 with the positioning mandrel 40, but it is free to rotate about the axis 44 of the positioning mandrel 40 as guided by a protruding guide finger 55 in a fixed relationship to the housing 12. Throughout the inactive-to-intermediate-to-inactive-to-deployed position cycle of the positioning mandrel 40, the guide finger 55 is maintained in rolling or sliding contact with the grooves in the control collar 42. As the control collar 42 and the positioning mandrel 40 reciprocate within the housing 12, the guide finger 55 traverses the grooves in a path as dictated by the intersections of the grooves.

[0034] The position of the positioning mandrel 40 is controlled by manipulation of pressure in the drillstring 30. As shown in Figure 6, when the pressure of the drilling mud in the drillstring 30 is sufficient to overcome the opposing axial forces urging the positioning mandrel 40 towards the inactive position, the positioning mandrel 40

is axially displaced towards its intermediate position. Following an intervening low mud pressure that allows the positioning mandrel 40 to return to its inactive position as shown in Figure 3, when the pressure of the drilling mud in the drillstring 30 is again sufficient to overcome the opposing forces urging the positioning mandrel 40 towards its inactive position, the positioning mandrel 40 is axially displaced towards the deployed position shown in Figure 7. Although it is preferred that the pressure sensing surface 48 be disposed at the proximal end of the positioning mandrel 40 adjacent to the proximal connection 22 of the housing 12 to the drillstring 30, the pressure sensing surface 48 can be located at the distal end of the positioning mandrel 40 or, using a proper arrangement of seals, at any point therebetween. It should also be recognized that by strategic placement of seals, fluid communication passages and the pressure sensing surface, the positioning mandrel 40 may actuate in either the proximal or the distal (up-hole or downhole) directions.

[0035] The positioning mandrel 40 rotationally cycles through a multiple position cycle as it axially reciprocates within the housing 12. The description that follows assumes that the control collar 42 is a four-stroke collar. The invention may be used with a six-stroke, eight-stroke or higher number of cycles, and the explanation of the four-stroke cycle does not limit the applicability or adaptability of the invention.

[0036] When the stabilizer is in its inactive position shown in Figure 3, the guide finger 55 is in rolling or sliding contact in the first actuation groove 50 near the distal end 43 of the control collar 42 shown in Figure 5A. The positioning mandrel 40 begins its cycle from its inactive position shown in Figure 3. From the inactive position, the positioning mandrel 40 is proximally actuated against the positioning mandrel spring 36, by exposure of the pressure sensing surface 48 to a first threshold pressure, to its intermediate position shown in Figure 6. As the first actuation stroke of the positioning mandrel 40 begins, the guide finger 55 rolls or slides (actually, guide finger 55 is substantially stationary relative to housing 12, but since collar 42 moves relative to housing 12, guide finger 55 "rolls or slides" relative to collar 42) toward the proximal end 41 of the control collar 42 within the second leg 253 of the second actuation groove 53 to the intersection of the second actuation groove 53 and the first leg 150 of the first actuation groove 50. When the guide finger 55 reaches that intersection, it slides or rolls into the first leg 150 of the first actuation groove 50 toward the intersection of the first actuation groove 50 and the first leg 151 of the first return groove 51. The first leg 150 of the first actuation groove 50 is not aligned with the axis 44 of the control collar 42, and the sliding or rolling contact between the guide finger 55 and the first leg 150 imparts a moment causing the control collar 42 to rotate about its axis 44. The second leg 250 is non-linear to the first leg 150 and is generally aligned with the axis 44. When the guide finger 55

leaves the first leg 150 and enters the second leg 250, the guide finger 55 slides or rolls within the second leg 250 to a point near the proximal end 41 of the control collar 42 to the intermediate position shown in Figure 5B. Since the second leg 250 is generally aligned with the axis 44 of the control collar 42, there is little or no rotation of the control collar 42 as the guide finger 55 slides within the second leg 250.

[0037] At the intermediate position shown in Figure 5B, the protruding collar spacers 74 distally extending from the distal end 43 of the control collar 42 engage the second circumferential shoulder 75 on the inside wall of the housing 12. The spacers 74 thereby limit the movement of the control collar 42 and the rotatably attached positioning mandrel 40 from actuating beyond the intermediate position to displace the deployment mandrel 140.

[0038] When the pressure in the drillstring 30 is reduced to below the first threshold pressure, the positioning mandrel 40 reverses direction and moves in the direction of the force applied by the positioning mandrel spring 36. This reversal begins the first return stroke of the control collar 42. As the positioning mandrel spring 36 returns the positioning mandrel 40 to or near its inactive position, the guide finger 55 slides or rolls within the second leg 250 toward the intersection of the first actuation groove 50 and the first leg 151 of the first return groove 51. The first leg 151 of the first return groove 51 is not aligned with the axis 44 of the positioning mandrel 40, and sliding or rolling contact between the fixed guide finger 55 in the first leg 151 causes the control collar 42 to further rotate about the axis 44. The rotation of the control collar 42 during the first return stroke is in the same angular direction as the rotation caused by the guide finger 55 sliding or rolling within the first leg 150 during the first actuation stroke. The intersection of the first actuation groove 50 and the first leg 151 of the first return groove 51 directs the guide finger 55 from the second leg 250 of the first actuation groove into the first leg 151 of the first return groove 51. As the positioning mandrel 40 is displaced by the force of the positioning mandrel spring 36 toward its inactive position, the guide finger 55 slides or rolls within the first leg 151 of the first return groove 51 towards the intersection of the first return groove 51 and the first leg 152 of the second actuation groove 52. The second leg 251 of the first return groove 51 is generally aligned with the axis 44 of the positioning mandrel, and as the guide finger 55 moves from the first leg 151 to the second leg 251, there is little or no rotation of the control collar 42. As the positioning mandrel 40 returns to its inactive position under the force of the return spring 36, the guide finger 55 slides or rolls within the second leg 251 of the first return groove 51 to a point near the distal end 43 of the control collar 42. As the positioning mandrel 40 returns to or near its inactive position, the rotational moment imparted to the control collar 42 by interaction with the tracking guide finger 55 causes the control collar 42 to rotate into

the position shown in Figure 5C. This inactive position occurs between the intermediate position and the deployed position, and the rotation of the control collar 42 has rotatably aligned the spacers 74 to be received within the recesses 75 when the tool is next actuated.

[0039] When the pressure in the drillstring 30 is again raised above the first threshold pressure necessary to overcome the positioning mandrel return spring 36, the positioning mandrel 40 is distally displaced to begin the second actuation stroke to deploy the stabilizer 10. The second actuation stroke begins as the axial movement of the control collar 42 reverses and the guide finger 55 slides or rolls within the second leg 251 of the first return groove 51 toward the proximal end 41 of the control collar 42. The second leg 251 intersects the first leg 152 of the second actuation groove 52. The first leg 152 is not aligned with the axis 44 of the control collar 42, and as the guide finger 55 passes into the first leg 152 of the second actuation groove 52, it contacts and slides along the edge of the first leg 152 that is disposed towards the proximal end 41 of the control collar 42. The first leg 152 is not aligned with the axis of the positioning mandrel 40, and as the guide finger 55 slides or rolls within the first leg 152, the control collar 42 rotates about its axis 44. The rotation of the control collar 42 during the second actuation stroke in the same angular direction as its previous rotation during the first actuation stroke and the first return stroke. The rotation of the control collar 42 as the guide finger 55 slides or rolls within the first leg 152 causes the spacers 74 to become rotatively aligned with, and received into, the recesses 77 in the second circumferential shoulder 75 on the inside wall of the housing 12. The guide finger 55 enters the intersection of the first leg 152 and the second leg 252 of the second actuation groove 52 and the first leg 153 of the second return groove 53. The motion of the positioning mandrel 40 towards the distal end of the housing 12 causes the guide finger 55 to enter into the second leg 252 of the second actuation groove 52 of the control collar 42. The second leg 252 of the second actuation groove 52 is generally aligned with the axis 44 of the positioning mandrel 40, and there is little or no rotation of the control collar 42 as the guide finger 55 slides within the second leg 252 to the point near the proximal end 41 of the control collar 42 shown in Figure 5D.

[0040] At the end of this second actuation stroke the spacers 74 extending from the distal end 43 of the control collar 42 are received within the recesses 77 in the second circumferential shoulder 75 of the housing 12. The alignment of the spacers 74 and the recesses 77 allow the control collar 42 and the positioning mandrel 40 to actuate beyond the intermediate position shown in Figure 5B to the deployed position shown in Figure 5D. The position of the control collar 42 and the positioning mandrel 40 shown in Figure 5D correspond to the deployed position of the stabilizer shown in Figure 7. As the spacers 74 are received into the recesses 77, the positioning mandrel 40 engages and displaces the

deployment mandrel 140 toward the distal connection 24 to overcome the force of the deployment mandrel spring 136. As the positioning mandrel 40 displaces the deployment mandrel 140 of the housing 12, the beveled portion 46 of the deployment mandrel 140 slidingly engages the contact surface 17 of each stabilizer element 16 to displace it radially outward to overcome the force of the stabilizer springs 18.

[0041] The positioning mandrel 40, the deployment mandrel 140 and the stabilizer elements 16 all remain in their deployed positions shown in Figure 7 as drilling in the deviated direction progresses. The flow of pressurized drilling mud passes through the tubular interior of the positioning mandrel 40 and the deployment mandrel 140, and perhaps through other longitudinal passages within the housing 12, to the mud motor 90 and the drill bit 80.

[0042] When the pressure in the drillstring 30 is reduced below the second threshold pressure, this begins the second return stroke, the final stroke of the cycle. At the onset of the second return stroke, the positioning mandrel 40 again reverses direction and returns to its original inactive position shown in Figure 5A. The return of the positioning mandrel 40 is initially under the force of both the deployment mandrel spring 136 and the positioning mandrel spring 36. After the deployment mandrel 140 reaches its inactive position, the force of just the positioning mandrel spring 36 further returns the positioning mandrel 40 to its original inactive position shown in Figure 5A.

[0043] On the second return stroke, the guide finger 55 slides or rolls within the second leg 252 of the second actuation groove 52 toward the distal end 43 of the control collar 42 toward the intersection of the second actuation groove 52 and the first leg 153 of the second return groove 53. The guide finger 55 passes from the second leg 252 of the second actuation groove 52 into the first leg 153 of the second return groove 53. The first leg 153 is not aligned with the axis 44 of the positioning mandrel 40, and as the control collar 42 and positioning mandrel 40 are axially displaced relative to the guide finger 55, the guide finger 55 slides or rolls along the edge of the first leg 153 disposed towards the distal end 43 of the control collar 42. As the guide finger 55 slides or rolls within the first leg 153, the control collar 42 angularly rotates in the same angular direction as its previous rotations during the first actuation stroke, the first return stroke and the second actuation stroke. As the guide finger 55 passes through the intersection of the second return groove 53 and the first leg 150 of the first return groove 50, the guide finger 55 enters the second leg 253 of the second return stroke 53. The second leg 253 is generally aligned with the axis 44 of the positioning mandrel 40, and little or no rotation of the control collar 42 as the guide finger 55 slides or rolls within the second leg 253 to a point near the distal end 43 of the control collar 42 shown in Figure 5A. This completes the four cycles of the control collar 42 selected for this em-

bodiment.

[0044] The position of the deployment mandrel 140 controls the deployment of the stabilizer 10. The stabilizer 10 has a position indicator that provides a flow restriction when the deployment mandrel 140 is in its deployed position. The position of the deployment mandrel 140 determines the position of the stinger 63 attached to the distal end of the deployment mandrel 140. The stinger 63 is connected to the distal end of the deployment mandrel 140 using a slotted disk 62. The slotted disk 62 allows drilling mud flow from the interior of the deployment mandrel 140 while providing structural support for the stinger 63, which is axially aligned with the axis 26 of the housing 12. When the deployment mandrel 140 is distally actuated by the positioning mandrel 40, the stinger 63 approaches a flow-restricting orifice 64. The obstacle to flow presented by the stinger 63 as it approaches the orifice 64 causes increased backpressure in the drillstring 30. The increased backpressure resulting from deployment of the stabilizer is detected at the surface and provides a reliable means of tracking the cycling of the stabilizer. When the positioning mandrel 40 is in its inactive position, the deployment mandrel 140 remains biased towards the positioning mandrel 40 by the deployment mandrel spring 136. The deployment mandrel spring 136 contacts the deployment mandrel 140 at a third circumferential shoulder 23. The beveled portions 46 of the deployment mandrel 140 are located adjacent to the contact surface 17 on the radially inward side of the stabilizer elements 16.

[0045] While in the intermediate position shown in Figure 6, drilling mud flows through the annular pressure sensing surface 48, through the tubular interior of the positioning mandrel 40, through the interior of the deployment mandrel 140, through the slotted support disk 62, out the proximal end of the housing 12 through the distal connection 24 to the mud motor 90 and drill bit 80 below. When the positioning mandrel 40 is moved from the position shown in Figure 5A to the intermediate position shown in Figure 5B, and then returned to the inactive position shown in Figure 5C, the four stroke control collar 42 angularly rotates about one-half of a revolution. As further angular rotation of the control collar 42 occurs, the spacers 74 extending from the distal end 43 of the control collar 42 are rotatively aligned with recesses 77 in the second circumferential shoulder 75 on the inside wall of the housing 12. The alignment of these recesses 77 allow the positioning mandrel 40, displaced by the drilling mud pressure bearing on the pressure sensing surface 48, to move beyond its intermediate position to its deployed position. As shown in Figure 7, upon second actuation of the positioning mandrel 40 from its inactive position, the positioning mandrel 40 engages and displaces the deployment mandrel 140 toward its deployed position. The beveled portions 46 of the deployment mandrel 140 slidably engage the contact surface 17 of the stabilizer elements 16. As the deployment mandrel 140 approaches its farthest displacement to-

ward the distal end of the housing 12, the beveled portions 46 displace the stabilizer elements 16 radially outward to their deployed position.

[0046] Figures 8A through 8C show an enlarged view of the beveled portions 46 of the deployment mandrel 140. Figure 8A shows the beveled portion 46 adjacent to, but not engaging or deploying, the stabilizer element 16. Figure 8B shows the beveled portion 46 engaging and partially deploying the stabilizer element 16 radially outward through the stabilizer port 14 and against stabilizer element spring 18 that biases the stabilizer element 16 radially inwardly to its retracted, inactive position. Figure 8C shows the stabilizer element 16 in its fully deployed position.

[0047] The deployment of the stabilizer elements 16 increases the effective diameter or gauge of the housing 12 to produce the desired angular deviation of the lower portion of the BHA and the drill bit 80 at the extreme end of the well.

[0048] As discussed above, Figure 4 shows a plan view of the four-stroke rotating collar having two actuation grooves, a first actuation groove 50 and a second actuation groove 52, and two return grooves, a first return groove 51 and a second return groove 53. This configuration is referred to as a four-stroke control collar 42 because of the total number of interconnected grooves being four. By its nature as a cylindrical shape, the outside surface of the control collar 42 into which the grooves are machined provides 360 degrees of angular rotation. Equal spacing of the four distinct strokes provides about 90 degrees per stroke. For a four stroke configuration described above, it is preferable to angularly space the first actuation groove and the first return groove within about 180 degrees of the outside angular surface of the collar and the second actuation groove and the second return groove within the remaining 180 degrees. In a four stroke configuration, the control collar 42 "toggles" the positioning mandrel 40 between the two actuated positioning mandrel positions, the intermediate position shown in Figure 6 and the deployed position shown in Figure 7.

[0049] The stabilizer 10 may be modified to include a greater number of deployed positions in the cycle. For example, the control collar 42 could be modified to operate in six cycles by including a third actuation groove immediately followed by a third rotation groove angularly inserted between the second return groove 53 and the first actuation groove 50. In this six cycle configuration, each actuation groove and return groove pair will preferably comprise approximately 120 degrees of the outside angular surface of the control collar 42 so that the control collar 42 accommodates three actuated positioning mandrel positions instead of only two. The six-cycle collar would require a second set of spacers, corresponding to a partially deployed stabilizer position, extending from the distal end 43 of the control collar 42 and angularly spaced from the first set of spacers 74 corresponding to the first deployed position. The second

set of spacers may be longer or shorter than the first set of spacers 74 to make the effective diameter of the housing 12 corresponding to the partially deployed position different from the effective diameter of the housing 12 corresponding to the fully deployed position. Conversely, a second set of recesses of different depth than the first set of recesses 77 in the second circumferential shoulder 75 may receive a second set of spacers in order to make the corresponding partially deployed position impart a different diameter to the housing 12 than that of the fully deployed position. Additional deployment positions and stabilizer diameters can be created by inclusion of additional spacers, actuation grooves and return grooves in correspondingly smaller angular portions of the collar.

[0050] By further "compressing" the pairs of actuation grooves and return grooves into angularly smaller portions of the collar, the control collar can be modified to provide more than one cycle of the stabilizer per revolution of the collar. For example, an eight stroke control collar wherein each pair of actuation grooves and return grooves are disposed within 45 degrees of the angular rotation of the collar may provide strokes 5 through 8 as a mirror image of strokes 1 through 4. That is, the control collar 42 may be designed such that the first actuation stroke and the third actuation stroke displace the positioning mandrel to identical intermediate positions, and the second actuation stroke and the fourth actuation stroke displace the positioning mandrel 40 to identical deployed positions. The design of the control collar 42, in other words, the number of deployed positions and the number of cycles per revolution, should take into consideration several factors affecting the operation of the rotating position control collar 42. These factors include, but are not limited to, the diameter of the control collar 42, the thickness of the grooves, the friction between the guide finger 55 and non-aligned portions of the grooves and the overall displacement of the reciprocation of the positioning mandrel 40 within the housing 12.

[0051] The stabilizer 10 may also be integrated with other tools to provide additional benefits for improved drilling performance. For example, it is desirable to dispose instruments for monitoring and communicating weight-on-bit, azimuth, depth, inclination and location as close as possible to the drill bit 80. As the distance between the drill bit 80 and data-gathering instrumentation increases, the ability to monitor and correct the path of the well to achieve the targeted bottom-hole location is diminished.

[0052] Data gathered by downhole instrumentation are typically communicated to the surface using mud pulse telemetry systems. A mud pulse telemetry communication system for communicating data from downhole instruments to the surface has been developed and has gained widespread acceptance in the industry. Mud pulse telemetry systems have no cables or wires for carrying data to the surface, but instead use a series of

pressure pulses that are transmitted to the surface through flowing, pressurized drilling fluid. One such system is described in U.S. Patent 4,120,097. Ideally, these instruments are disposed at or immediately adjacent to the drill bit 80. However, because mud telemetry systems require a continuous, uninterrupted column of drilling mud for communicating collected data to the surface, instruments are typically disposed above the mud motor 90, thereby undesirably spacing the instruments away from the drill bit 80. This problem can be solved by disposing data-gathering instrumentation (not shown) and a data transmitter (not shown) at or immediately adjacent to the drill bit 80 in a bit box (not shown) connected to the drill bit 80 and communicating collected data via the adjacent earth formation to a receiver (not shown) located above the mud motor 90. The receiver may then feed collected data to the mud telemetry system for communication to the surface. The receiver or the transmitter may be integrated with the variable gauge stabilizer 10 of the present invention to provide a tool that not only enables control and adjustment of the path of the well, but also provides more accurate data related to the bottom-hole location of the well, thereby enabling more accurate adjustment and improved acquisition of bottom-hole target locations.

[0053] The meaning of "groove", as that term is used herein, includes, but is not limited to, a groove, slot, ridge, key and other mechanical means of maintaining two parts moving relative one another in a fixed rotational, axial or aligned relationship. Further, the meaning of "mandrel", as that term is used herein, includes, but is not limited to, mandrels, pistons, posts, push rods, tubular shafts, discs and other mechanical devices designed for reciprocating movement within a defined space. The term "gauge" means diameter, thickness, girth, breadth and extension. The term "collar" means collars, rims, sleeves, caps and other mechanical devices rotating about an axis and axially fixed relative to the positioning mandrel. "Slender" means little width relative to length. An "appendage" is a part that is joined or attached to a principal object. The term "port" means a passageway, slot, hole, channel, tunnel or opening. The term "finger" means a protruding or recessed guide member that allows rolling or sliding engagement between the housing 12 and the control collar 43 that maintains the housing 12 and the control collar 42 within a desired orientation one to the other, and includes a key and groove and rolling ball and socket.

[0054] As mentioned above, near-bit data gathering instrumentation may be used to verify a desired setting of stabilizer 10, as well as other directional determining tools, and to feed back D&I information for selecting a proper drilling heading. An extended bit box of the near-bit data communication aspect of the present invention is shown in Fig. 11. This extended bit box 221 connects the drill bit to drilling motor 216 via drive shaft 215 which passes through bearing section 220. The bit box contains instrumentation 225 to take measurements during

drilling of a borehole. The instrumentation can be any arrangement of instruments including accelerometers, magnetometers and formation evaluation instruments. The bit box also contains telemetry means 222 for transmitting the collected data via the earth formation to a receiver 223 in the MWD tool 218. Both transmitter 222 and receiver 223 are protected by shields 226. Data is transmitted around the drilling motor 216 to the receiver.

[0055] An extended sub embodiment of the invention is shown in Fig. 12. The extended sub 224 connects to a standard bit box 219. The use of an extended sub does not require modifications to the currently used bit box 219 described in Fig. 10. The extended sub contains the measurement instrumentation 225 and a telemetry means 222. (For the purpose of this description, the measurement instrumentation 225 shall be referred to as an accelerometer 225a.) These components and others are arranged and operate in a similar manner to the extended bit box embodiment.

[0056] Fig. 13 is a cross-section view of the present invention modified from Fig. 10. The bit box 219 of Fig. 10 has been extended as shown to form extended bit box 221. Transmitter 222 is now located in the bit box. The bit box now has the capability of containing measurement equipment not located in the bit box in prior tools.

[0057] The extended bit box embodiment of the present invention is shown in more detail in the cross-section view of Fig. 14. An accelerometer 225a for measuring inclination is located within a housing 227 which is made of a light weight and durable metal. The housing is attached to the inner wall of the drive shaft 215 by a bolt 228 and a through hole bolt 229. A wire running through the bolt 229 establishes electrical communication between the accelerometer 225a and control circuitry in the electronic boards 236. The housing containing the accelerometer is positioned in the drive shaft channel 215a. Since drilling mud flows through the drive shaft channel, the housing 227 will be exposed to the mud. This exposure could lead to the eventual erosion of the housing and the possible exposure of the accelerometer to the mud. Therefore, a flow diverter 230 is bolted to the upper end of the accelerometer housing 227 and diverts the flow of mud around the accelerometer housing. A conical cap 231 is attached to the housing, via threads in the housing, at the drill bit end of the housing. This cap seals that end of the housing to make the accelerometer fully enclosed and protected from the borehole elements. Contained in the accelerometer housing 227 is a filtering circuit 232 that serves to filter detected data. This filtering process is desirable to improve the quality of a signal to be telemetered to a receiver in the MWD tool. Annular batteries 233 are used to provide power to the accelerometer 225a, the filtering circuit 232 and the electronic boards 236. A standard API joint 234 is used to attach different drill bits 214 to the extended bit box. A pressure shield 235 encloses the various components of the invention to shield them

from borehole pressures. This shield may also serve as a stabilizer. Electronic boards 236, located between the drive shaft 215 and the transmitter 222, control the acquisition and transmission of sensor measurements. These boards contain a microprocessor, an acquisition system for accelerometer data, a transmission powering system and a shock sensor. This electronic circuitry is common in downhole drilling and data acquisition equipment. In this embodiment of the present invention, the electronics are placed on three boards and recessed into the outer wall of the drive shaft 215 so as to maintain the strength and integrity of the shaft wall. Wires connect the boards to enable communication between boards.

[0058] A shock sensor 237, which can be an accelerometer, located adjacent to one of the electronic boards 236 provides information about the shock level during the drilling process. The shock measurement helps determine if drilling is occurring. Radial bearings 238 provide for the rotation of the shaft 215 when powered by the drilling motor. A read-out port 239 is provided to allow tool operators to access the electronic boards 236.

[0059] As discussed previously, a transmitter 222 has an antenna that transmits signals from the bit box 221 through the formation to a receiver located in or near the MWD tool in the drill string. This transmitter 222 has a protective shield 226 covering it to protect it from the borehole conditions. The antenna and shield will be discussed below.

[0060] Fig. 15 gives a perspective view of the present invention and provides a better view of some of the components. As shown, a make-up tool 240 covers a portion of the bit box. The ports 240a in the drive shaft 215 serve to anchor the make-up tool 240 on the drive shaft. This make-up tool is used when connecting the drill bit 214 to the bit box. Also shown is the protective shield 226 around the transmitter 222. The shield has slots 241 that are used to enable electro-magnetic transmission of the signal.

[0061] Fig. 16 provides a cross-section view of the batteries and the sensing instrumentation mounted inside the drive shaft of the present invention. As shown, the measuring instruments are located in the channel 215a of the drive shaft 215. The annular batteries 233 surround the drive shaft and supply power to the accelerometer 225a. The housing 227 surrounds the accelerometer. The housing is secured to the drive shaft by a bolt 229. A connector 242 attaches the accelerometer 225a to the housing 227. A fixture 243 holds the bolt 229. The pressure shield 235 surrounds the annular batteries 233.

[0062] Fig. 17 shows a cross-section view of the transmitter 222 in an extended bit box implementation. A protective shield 226 encloses the antenna 222a. This shield has slots 241 that provide for the electro-magnetic transmission of the signals. In this embodiment, the antenna 222a is comprised of a pressure tight spindle 244. Ferrite bars 245 are longitudinally embedded in this spindle 244. Around the ferrite bars is wiring in the form

of a coil 247. The coil is wrapped by the VITON rubber ring 246 for protection against borehole fluids. An epoxy ring 248 is adjacent the coil and ferrite bars. A slight void 249 exists between the shield 226 and the VITON rubber ring 246 to allow for expansion of the ring 246 during operations. Inside the spindle 244 is the drive shaft 215. The electronic boards 236 are located between the spindle 244 and the drive shaft 215. Also shown is the channel 215a through which the drilling mud flows to the drill bit.

[0063] In another embodiment of the invention, the instrumentation for measuring drilling and drilling tool parameters and formation characteristics is placed directly in the drill bit. This instrumented drill bit system is shown schematically in Fig. 18. The drill bit 214 contains an extension 251 that connects the drill bit to the bit box and drill string. As shown, the extension 251 comprises the upper portion of the drill bit. The accelerometer 225a and the transmitter 222 are positioned in the extension in a manner similar to the extended bit box and extended sub embodiments. This instrumented drill bit would fit into a tool such as the one described in Fig. 9. The instrumented drill bit 214 is connected to the bit box 219. As with the other embodiments, the bit box 219 is attached to a drive shaft 215 that is connected to the drilling motor 216 via the bearing section 220. Drilling fluid flows through the drive shaft channel 215a to the drill bit. A receiver 223 is located above the drilling motor and usually in an MWD tool 218. It should be mentioned that the drilling motor is not essential to the operation of this embodiment.

[0064] As previously mentioned, the earth formation properties measured by the instrumentation in the present invention preferably include natural radioactivity (particularly gamma rays) and electrical resistivity (conductivity) of the formations surrounding the borehole. As with other formation evaluation tools, the measurement instruments must be positioned in the bit box in a manner to allow for proper operation of the instruments and to provide reliable measurement data.

[0065] The preferred embodiment of the wireless telemetry aspect of the present invention is illustrated in Figs. 19 and 20. A bottom-hole assembly (BHA) 370 for drilling a straight or directional borehole 309 in an earth formation 310 is suspended by means of a drill string 371 which is supported at the earth's surface by a drilling rig (not shown). The drilling rig provides power to rotate the drill string 371 and includes a mud pump to force pressurized drilling fluid downward through the bore of the drillstring 371. The drilling fluid exits the BHA 370 through ports in the drill bit 372 and returns to the earth's surface for reinjection by the mud pump. The BHA 370 typically comprises a measurement while drilling (MWD) tool 373 and a positive displacement drilling motor 374 which drives a bit shaft 375. The bit shaft 375 is supported by bearings 376 and includes at its downhole end an extended bit box 377 into which drill bit 372 is threaded. Additionally, the drilling motor 374 may incorporate

a bent housing, or a variable gauge stabilizer, as described above, to facilitate the directional drilling of wells. It will be understood that the BHA 370 may comprise other components in addition to those enumerated above, such as, for example stabilizers and logging while drilling (LWD) tools.

[0066] Mounted within the extended bit box 377, which partially extends, at least in one embodiment (see Fig. 19), within a rotating near bit stabilizer sleeve 377a and a transmitter/antenna sleeve 379, is an instrumentation and electronics package 378 which is battery powered. The instrumentation and electronics package 378 contains instruments for making measurements during drilling and may include magnetometers for monitoring the direction of the borehole, accelerometers for monitoring the inclination of the borehole, and/or formation evaluation instruments. Mounted on the extended bit box 377 (or sleeve 377a) is a transmitter coil 379 for transmitting telemetry signals carrying encoded data from the various measuring instruments through the earth formation 310 to a receiver coil 380 mounted in the MWD tool 373. It will be understood by those skilled in the art that the transmitter coil 379 may be mounted in a separate sub and that MWD tool 373 may be placed at various locations within the BHA 370, such placement determining the depth to which the transmitted telemetry signals penetrate the earth formation 10 before being received. The transmitter coil 379 and receiver coil 380 are protected from damage by shields 381, and are each loaded with a ferrite core 382 to increase the transmission range of the system. The instrumentation and electronics package 378 also carries the electronics necessary to encode the data from the measuring instruments and actuate the transmitter coil 379.

[0067] The invention uses the amplitude of the induction telemetry signal that transmits logging and drilling data obtained during the drilling of a borehole to verify the setting of variable gauge stabilizer 10, among other things such as determining earth formation resistivity as described in U.S. Application Serial No. 09/148,013, the entire contents of which are incorporated herein by reference. The transmitter coil 379 induces a signal in earth formation 310 that corresponds to the measured logging and drilling data, including inclination data from a single-axis accelerometer mounted to the drive shaft of the mud motor within extended bit box 377 in a preferred embodiment. The receiver coil 380 detects this signal and electronics associated with the receiver coil 380 recover the measured data for transmission to the earth's surface by means of a mud pulse telemetry system in the MWD tool 373 or in a separate sub. Such a mud pulse telemetry system is described in U.S. Patent 5,375,098, which is incorporated herein by reference. Before proceeding with the description of the invention, and to assist in understanding the invention, some basic concepts related to signal transmission are reviewed.

[0068] As shown in Fig. 21, signal transmission begins with the use of a continuous oscillating signal of

arbitrary amplitude and frequency that carries no intelligence. This continuous signal is called a "carrier signal" or simply a "carrier". The carrier may be interrupted or the signal amplitude altered so it becomes similar to a series of pulses that correspond to some known code as shown in Fig. 22. At this point the oscillating interrupted signal can carry some intelligence. In the present case, the intelligence is the measurement data. There are many ways to alter the carrier signal. Modulation is the process of altering a carrier signal in order to transmit meaningful information. The type of modulation that is utilized in the present invention is Pulse Position Modulation (PPM). PPM uses a pulse time arrival position in a data train to represent quantitized values of data. The characteristics of pulses within a pulse train may also be modified to convey the information.

[0069] Focusing again on the present invention, Fig. 23 shows the sequence of operations used to determine borehole inclination. Data is gathered from accelerometer measurements taken during a drilling operation. The first step 311 is to generate a signal representative of the measured parameters. This signal is in digital form and is a conversion of an analog measurement. To transmit this signal to the uphole receiver it is necessary to encode the signal (box 312). The encoding process produces a 27 bit word for transmission.

[0070] Fig. 24 illustrates a 27 bit word 322 that is ready for transmission to an uphole receiver. As shown, this word may comprise several fields containing various types of data. In this example, a 2 bit field 324 serves as a frame counter of the number of frames transmitted uphole. This field identifies each transmitted frame to permit better tracking of the transmitted data. Field 323 is a 2 bit field that serves as the frame type field and identifies the type of measurement data in the word. This data could be one of several measured characteristics such as temperature or bit inclination. Field 325 is an eleven bit field that contains the actual measurement data. For example, an inclination measurement of 238 milli-g, which equals 76.2 degrees, would be 0001101110 in field 325. Field 326 has two bits and indicates, for example, the shock level at bit. In addition to the transmission of measurement data, the bit stream may contain error detection bits. These additional bits of the bit stream help detect if an error occurred during the transmission of the data stream and verifies that the data sent was the data received. Error detection schemes are commonly used in digital transmissions. The particular error detection scheme may vary from using only one bit to several bits depending upon the desired level of detection. The last field 327 in this word is a ten bit error checking field that assists in verifying accurate transmission of the data.

[0071] Referring again to Fig. 23, the next step 313 is to transmit the signal uphole. This transmission involves modulating the signal using PPM techniques. As will be discussed in detail below, the 27 bit word is transmitted uphole in a data frame. Encoded pulses contain the in-

formation of the 27 bit word. Each pulse contains a 10 kHz signal. The position of each pulse in the data frame represents a portion of the data in the 27 bit word.

[0072] Fig. 25 illustrates the format of the transmitted and detected data in a PPM scheme. The transmitter sends one data frame approximately every two minutes. The data frame 328 consists of eleven 10 kHz pulses. The data is encoded by using pulse position. The first pulse 329 and last pulse 330 are synchronization pulses that indicate the beginning and end of the data frame 328. The remaining pulses occur in data regions 331a-331i. The data regions are separated by intervals 332 of two seconds in length as shown. Referring to Fig. 26, each data region comprises multiple positions within the region in which a pulse 334 may occur. Each data pulse position corresponds to one of eight symbols whose value corresponds to the pulse delay position. There are seven possible delay positions of 30 milliseconds or eight possible pulse positions I, II, III, IV, V, VI, VII, and VIII. In an example of the transmission of the 27 bit word of Fig. 24, each of the nine information pulses represents three bits of the 27 bit word. The data frame 328 contains these nine pulses plus the two synchronization pulses 329 and 330. As shown in Fig. 27a, if the first three digits of the 27 bit word are "101" the first data region would have a pulse 334 in the sixth position. A three digit sequence of "011" in Fig. 27b would result in a pulse 334 in the fourth data region. A sequence of "000" in Fig. 27c would result in a pulse 334 in the first position of the data region.

[0073] Referring once again to Fig. 23, the modulated signal is received (box 314) and demodulated (box 315) to obtain the data contained in the signal. As part of this demodulation function, the carrier is extracted from the modulated signal. Fig. 28 shows a schematic of the demodulation and carrier extraction process. The signal sampled from the analog-to-digital (A/D) converter of the receiver electronics is first continuously multiplied by a reference 10 kHz cosine function and its quadrature sine function. Both results are then summed over 10 milliseconds, squared, and the results are added. The resulting square root corresponds to a phase insensitive cross correlation of the incoming signal with a 10 millisecond, 10 kHz reference pulse. As shown in Fig. 23, after demodulation the next step 316 is to detect a data peak. A peak threshold applied to the cross correlated signal defines a peak or pulse whose time of occurrence and amplitude correspond to a maximum correlation amplitude.

[0074] Referring to Fig. 25, the transmitter sends data frame 328 to the receiver. As previously mentioned, each data frame includes a first pulse 329 and a last pulse 330 (synchronization pulses) that indicate the beginning and the end of the data frame. In step 316, the receiver is constantly in a search mode attempting to detect amplitude peaks. When the receiver detects a peak amplitude, the receiver begins a search for a valid data frame 328. The search for a valid data frame is nec-

essary to determine if the detected peak amplitude was data or random noise. To search for a valid frame the receiver checks for the presence of synchronization pulses. Since a data frame has a duration of approximately 21 seconds, the receiver checks the previous 21 seconds for synchronization pulses and valid time of arrival for all intermediate data bearing pulses.

[0075] After the detection of a valid data frame, the next step 317 is to reconstruct the 27 bit word at the receiver. This step is a decoding of the pulses positioned in the data frame. Conventional burst mode (27, 17) error detection techniques are now used (box 318) to determine the validity of the transmitted word. Once it has been determined that the transmission is valid, the data is extracted (box 319) from the 27 bit word. In the interpretation of the demodulated signal, the measurement data transmitted in the signal is determined from the positions of the pulses. After step 319, the focus of the procedure turns to the process of determining the formation resistivity. Step 320 measures the amplitude of the carrier signal used during the transmission of the data. Formation resistivity is determined (box 321) by comparison of the amplitude of the received signal with that of the transmitted signal.

[0076] Fig. 29a illustrates the signal 338 as transmitted. Fig. 29b illustrates the signal 339 as received. As shown, the received signal 339 resembles the transmitted signal 338. However, because the surrounding earth formation attenuates the carrier signal, the received signal 339 has a much smaller amplitude than the transmitted signal. The formation resistivity, for example, may be calculated from a resistivity transform that is dependent upon transmitter to receiver spacing in a homogeneous formation as shown in Fig. 31. Where the well trajectory is at a relatively low apparent dip angle within geometrically complicated formation layers, the signal amplitude and a forward modeling of the formation layers must be used to estimate a resistivity representation of the layers.

[0077] As previously stated, in order to increase the transmission range of the signal and therefore the depth of investigation of the resistivity measurement, both the transmitter and receiver are loaded with a ferrite core. Ferrite, or any material with high longitudinal magnetic permeability, has a focusing effect on the longitudinal magnetic field used by the induction transmission of the present invention. Fig. 30 shows a cross-sectional view of the transmitter 340 of the present invention. A protective electromagnetic transparent shield 341 encloses the antenna 342. This shield has slots 343 that provide for the electro-magnetic transmission of the signals. In this embodiment, the antenna 342 is comprised of a pressure tight spindle 344. Ferrite bars 345 are longitudinally embedded in the spindle 344. Around the ferrite bars is wiring in the form of a coil 346. An epoxy ring 348 is adjacent the coil and ferrite bars. The coil is sealed by a VITON rubber ring 347 for protection against borehole fluids. A slight void 349 exists between the

shield 341 and the VITON rubber ring 347 to allow for expansion of the ring 347 during operation.

[0078] The resistivity response or resistivity transform of the system of the present invention is shown in Fig. 31 for a signal amplitude measurement. Fig. 31 shows the signal amplitude versus formation resistivity for 25 foot (7.62 meter) and 40 foot (12.19 meter) 350 and 351, respectively, transmitter to receiver spacings. As shown, the 40 foot (12.19 meter) measurement 351 can discriminate resistivity over a larger signal amplitude range. In both measurements, the ability to measure resistivity based on signal amplitude is minimal above approximately 20 ohm-meters.

[0079] One method for extending the range of measurable formation resistivities above 20 ohm-meters is to use the complex composition of the signal as in the standard induction technique. The resistivity measurement includes the real component 354 (V_R) and the imaginary component 353 (V_I) of the signal as shown in Figs. 32a and 32b. As indicated in Figs. 32b and 32d, the real component 354 has a greater sensitivity to formation resistivity than the imaginary component 353 and can discriminate resistivity as a function of signal amplitude over a greater range. Since the present measurement is an amplitude measurement 352 (V_A) represented by the equation

$$V_A = \sqrt{V_R^2 + V_I^2}$$

and does not involve synchronizing of transmitted and received signals, a determination of the real part of the signals is not possible. However, in this asynchronous system the range of formation resistivity discrimination may be extended beyond 20 ohm-meters by using a higher frequency signal, such as 100 kHz, which moves the resistivity transforms 350 and 351 of Fig. 31 to the right towards higher resistivity (approximately 100 ohm-meters). Additionally, the resistivity of the formation at different depths of investigation may be determined from a single transmitted signal by transmitting the signal pulses at different frequencies, each frequency yielding a measurement at a different depth. In the present invention three frequencies, approximately 2, 10, and 100 kHz are preferred. However, frequencies in the range from about 1 kHz to 300 kHz may be used.

[0080] Because of its large transmitter to receiver spacing, the present invention provides a deep depth of investigation of formation resistivity. This feature is particularly useful in detecting formation boundaries. Fig. 33 schematically illustrates a tool according to the present invention operating at 10 kHz approaching a resistivity contrast boundary 356 at an apparent dip angle of 90 degrees. Figs. 34a and 34b show the resistivity signal response as the tool approaches and crosses resistivity boundary 356 at an apparent dip angle of 90 degrees. As shown in Fig. 34a, at 200 ohm-meters 357, there is no change in resistivity across the boundary

356, and therefore no change in the signal. At a contrast of 20 ohm-meters to 200 ohm-meters 358, there is virtually no change in the signal, mainly because of the limited ability to distinguish resistivities above 20 ohm-meters when operating at 10 kHz. At a contrast of 2.0 ohm-meters to 200 ohm-meters 359, there is a slight movement in the signal approximately ten feet (3 meters) before the tool reaches the boundary 356 and more movement after it crosses the boundary. At 0.2 ohm-meters to 200 ohm-meters 360, the signal begins to change rapidly approximately five feet (1.5 meters) before the tool crosses the boundary 356. Fig. 34b shows that the responses are the opposite when moving from a high resistivity formation to a low resistivity formation. There is a 10 to 15 foot (3 - 4.5 meter) look ahead 361 when approaching the boundary 356 from a resistive to a conductive formation.

[0081] Fig. 35 schematically illustrates a tool according to the present invention operating at 10 kHz approaching a resistivity contrast boundary 356 at an apparent dip angle of 0 degrees. Fig. 36a illustrates the resistivity signal response as the tool moves from a low resistivity formation to a high resistivity formation at an apparent dip angle of 0 degrees. There is of course no change in the 200 ohm-meter response 362 across the boundary. Again, the 20 ohm-meter response 363 shows virtually no change across the boundary 356. The 2.0 ohm-meter response 364 begins to respond at approximately 40 feet (12.2 meters) from the boundary. The 0.2 ohm-meter response 365 begins to show a drastic change at about 25 feet (7.6 meters) from the boundary. The well known horizontal or high angle horning effect when crossing a formation boundary causes the 0.2 ohm-meter response to exceed the 200 ohm-meter level and then return to the 200 ohm-meter level. As shown in Fig. 36b, the tool response when moving from a high resistivity formation to a low resistivity formation is essentially the opposite of that shown in Fig. 36a.

[0082] The present invention therefore provides a formation resistivity measurement with the following characteristics: 1) deep resistivity radial depth of investigation proportional to the distance between the transmitter and receiver; 2) vertical resolution also proportional to the distance between the transmitter and receiver; 3) formation resistivity sensitivity of up to approximately 20 ohm-meters when using the pulse amplitude resistivity transform at 10 kHz operating frequency, or sensitivity up to approximately 100 ohm-meters at 100 kHz operating frequency; 4) the capability to detect formation boundaries based on changes in formation resistivity; 5) look-ahead capability when the bit is crossing from a low resistivity formation to a high resistivity formation; and 6) look-around capability in wells drilled approximately parallel to formation boundaries of any significant resistivity contrast. This application is significant for landing wells and staying within a predefined formation layer during directional drilling.

[0083] It now will be recognized that new and improved methods and apparatus have been disclosed which meet all the objectives and have all the features and advantages of the present invention. Since certain changes or modifications may be made in the disclosed embodiments without departing from the inventive concepts involved, it is the aim of the appended claims to cover all such changes and modifications falling within the true scope of the present invention.

Claims

1. A system for directionally drilling a wellbore (309) using a drill string (30/211/371) having a mud motor (90/216/374), a drill bit (80/214/372), and a drive shaft (215/375) for transmitting torque from the mud motor to the drill bit, comprising:
 - a tool (10) carried in the drill string that is adjustable for varying the direction of the drill bit and the wellbore;
 - an instrument (225/378) for measuring data while drilling, the instrument being carried within a drill bit connecting means (221/377) for connecting the drill bit to the drill string; and
 - a telemetry system for transmitting the measured data to a driller at the surface, the telemetry system including:
 - a transmitter (222/379) disposed in the drill string beneath the mud motor for transmitting a signal corresponding to the measured data;
 - a receiver (223/380) disposed in the drill string above the mud motor for receiving the signal and recovering the measured data from the signal.
2. The system of claim 1 wherein the drill bit connecting means comprises a bit box (221/377).
3. The system of claim 1, wherein the drill bit connecting means comprises a sub (224) connecting the drill bit to a bit box within the drill string.
4. The system of claim 1, wherein the drill bit connecting means comprises the drill bit (80/214/372) itself.
5. The system of claim 1, wherein the instrument includes an accelerometer (225a) for measuring wellbore inclination.
6. The system of claim 1 or 5, wherein the instrument includes a magnetometer for measuring wellbore direction.
7. The system of claim 1 wherein the direction-varying

tool is a variable gauge stabilizer (10).

8. The system of claim 1, wherein the direction-varying tool is a bent housing (12).
9. The system of claim 7, wherein the variable gauge stabilizer comprises:

a housing (12) having two ends adapted for connecting to a drill string (30/211/371), one or more radially inwardly biased stabilizer elements (16) extendible through the housing, a finger element (55) extending radially inwardly from the housing, a positioning mandrel biasing member (36) engaging the housing for biasing a positioning mandrel (40) in a first axial direction, a deployment mandrel biasing member (136) engaging the housing for biasing a deployment mandrel (140) in the first axial direction (26), and one or more shoulders (75) formed on an inside surface of the housing; wherein the positioning mandrel is disposed within the housing and engaged with the positioning mandrel biasing member, wherein the positioning mandrel is adapted for fluid pressure actuation in a second axial direction (44) opposing the positioning mandrel biasing member and the deployment mandrel biasing member, and wherein the deployment mandrel has at least one actuating member (18) in axial alignment with the one or more stabilizer elements (16) for deploying the stabilizer elements radially outward; and

a J-slot collar (42) axially engaging the positioning mandrel, the J-slot collar having an outwardly facing slot (50-54) slidably receiving the finger element therein, and a cylindrical body having one or more collar shoulders (75) extending in the second axial direction for selective engagement with the one or more housing shoulders (75), wherein the outwardly facing slot is adapted to cause rotation of the collar upon reciprocating the collar in both the first and second axial directions, wherein the slot defines a repeating cycle that provides alignment of the one or more collar shoulders with the one or more housing shoulders upon a first fluid pressure actuation to prevent deploying the stabilizer elements and disalignment of the one or more collar shoulders with the one or more housing shoulders upon a second fluid pressure actuation to deploy the stabilizer elements.

10. The system of claim 1, wherein the telemetry system includes a mud pulse telemetry system for communicating data collected by said receiver to the surface.

11. The system of claim 1, wherein the transmitter is located in the bit box.
12. A method of directionally drilling a wellbore comprising: 5
- drilling a wellbore with a drill string (30/211/371) having a mud motor (90/216/374), a drill bit (80/214/372), and a drive shaft (215/375) for transmitting torque from the mud motor to the drill bit; 10
- varying the direction of the drill bit using a tool (10) on the drill string;
- determining the direction of the drill bit using an instrument (225/378) for measuring data while drilling, the instrument being carried within a drill bit connecting means (221/377) for connecting the drill bit to the drill string; 15
- transmitting the measured data to the surface using a telemetry system carried in the drill string; and 20
- adjusting the direction of the drill bit as needed using the measured data.
13. The method of claim 12, wherein the telemetry system includes: 25
- a transmitter (222/379) disposed in the drill string beneath the mud motor for transmitting a signal corresponding to the measured data; 30
- and
- a receiver (223/380) disposed in the drill string above the mud motor for receiving the signal and recovering the measured data from the signal. 35
14. The method of claim 12, wherein the drill bit connecting means comprises a bit box (221/377).
15. The method of claim 12, wherein the drill bit connecting means comprises a sub (224) connecting the drill bit to a bit box within the drill string. 40
16. The method of claim 12, wherein the drill bit connecting means comprises the drill bit (80/214/372) itself. 45
17. The method of claim 12, wherein the instrument includes an accelerometer (225a) for measuring wellbore inclination. 50
18. The method of claim 18, wherein the instrument includes a magnetometer for measuring wellbore direction. 55
19. The method of claim 12, wherein the direction-varying tool is a variable gauge stabilizer (10).
20. The method of claim 12, wherein the direction-varying tool is a bent housing.

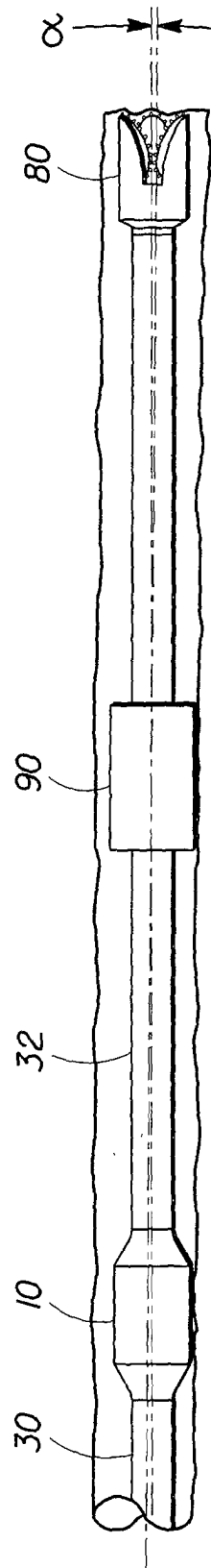


FIG. 1A

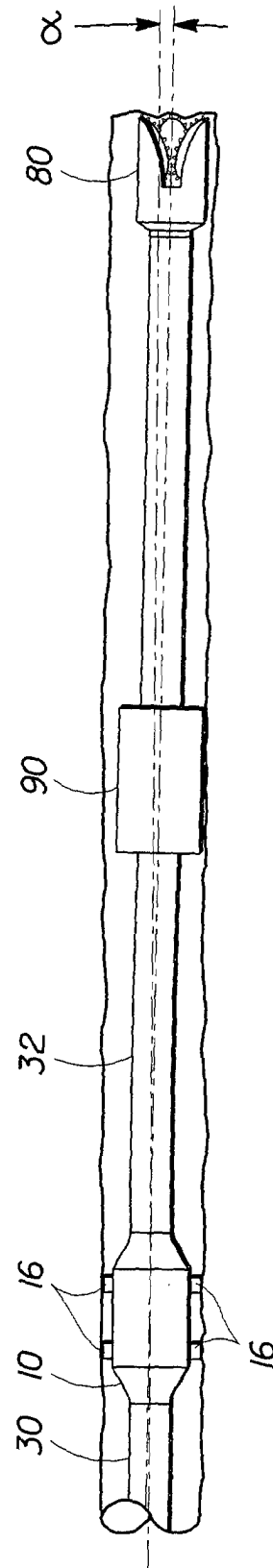


FIG. 1B

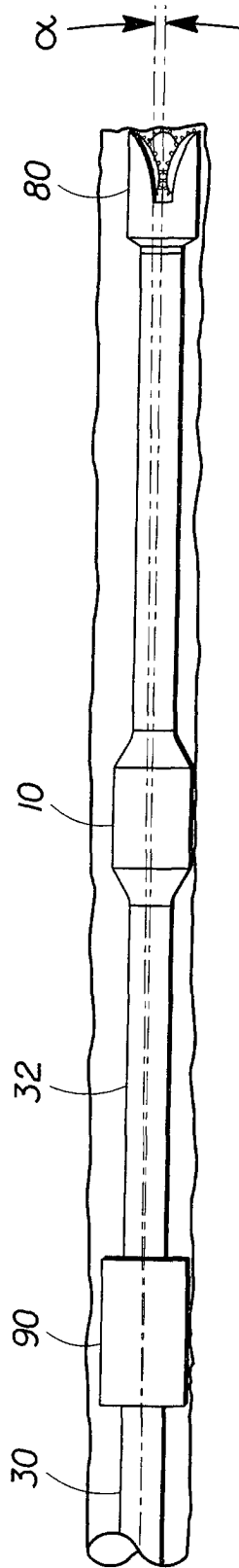


FIG. 2A

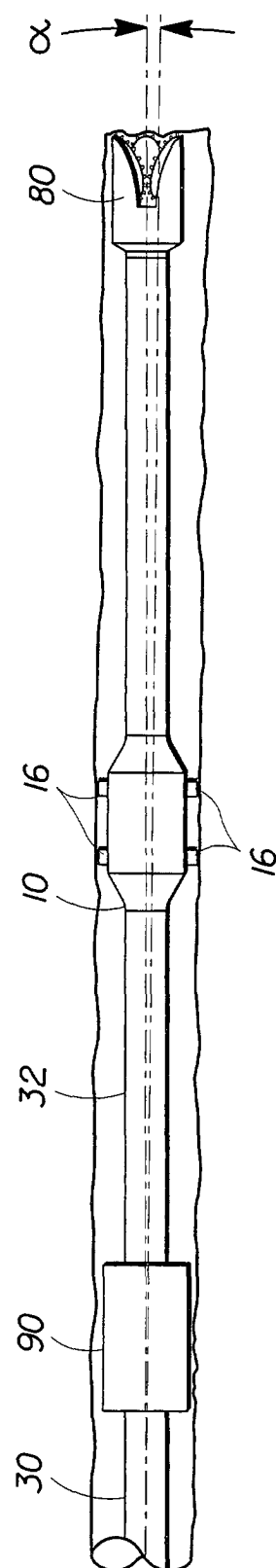


FIG. 2B

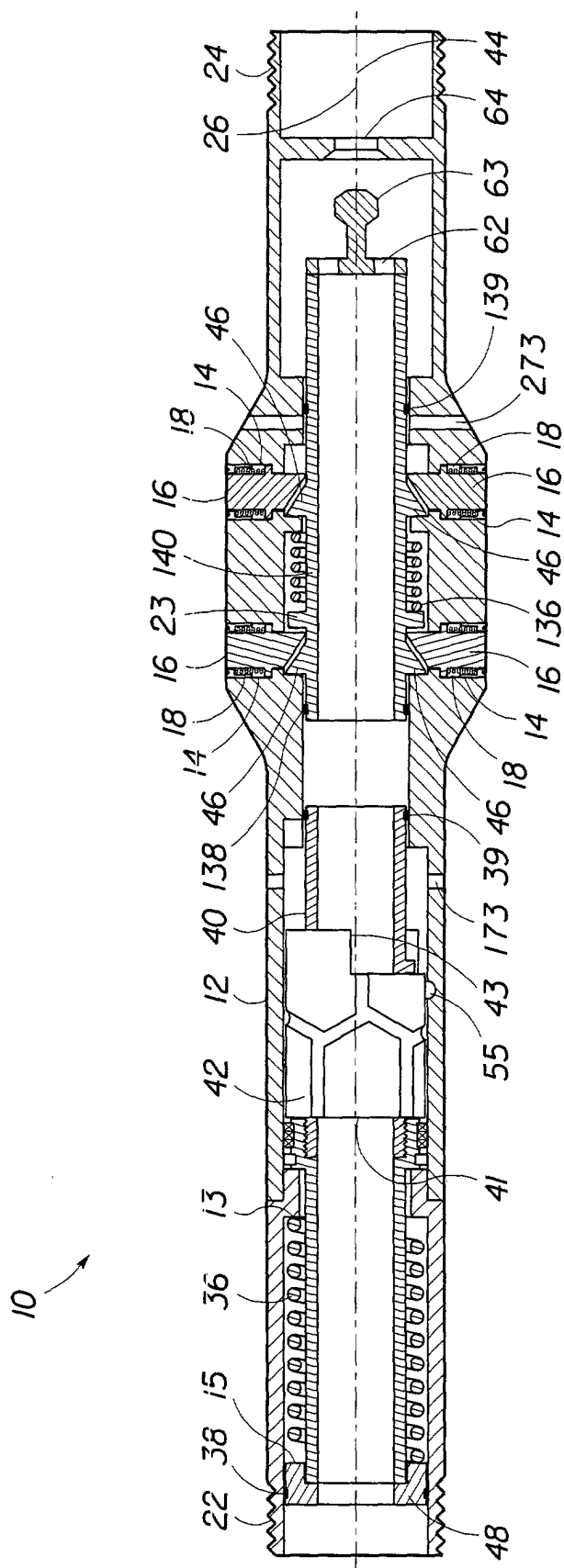


FIG. 3

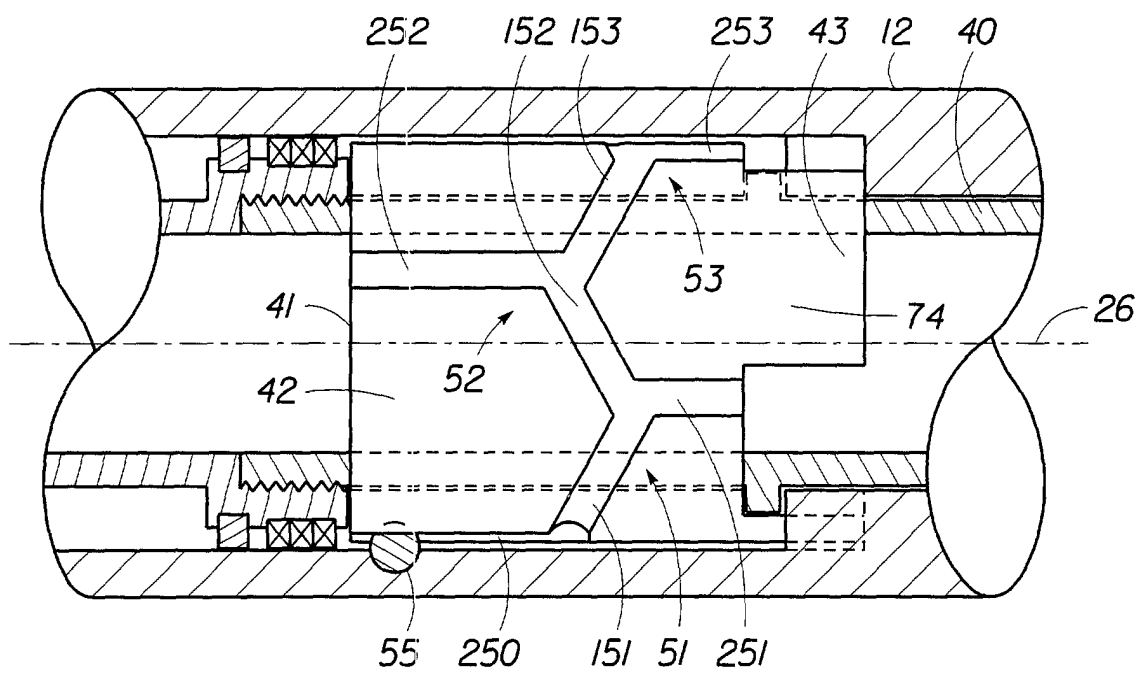


FIG. 4

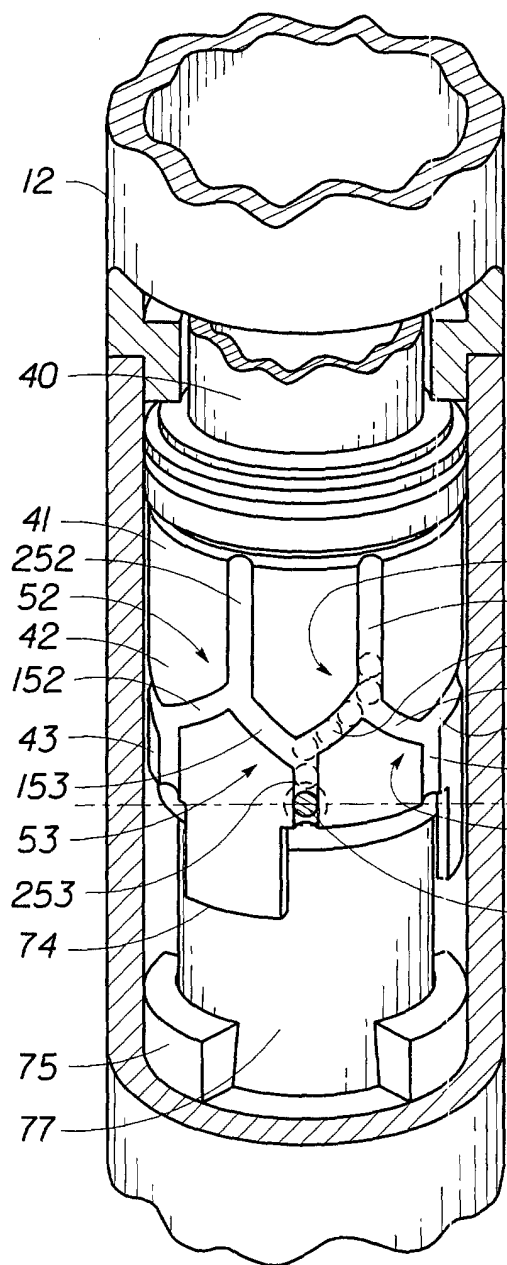


FIG. 5A

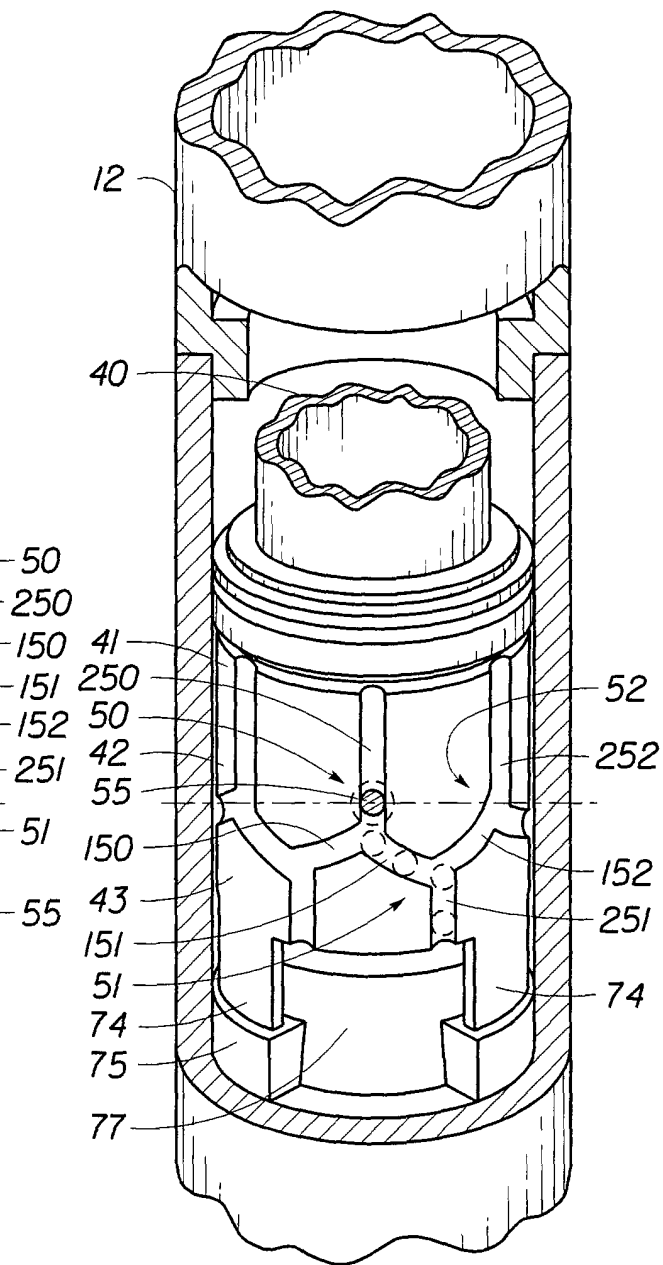


FIG. 5B

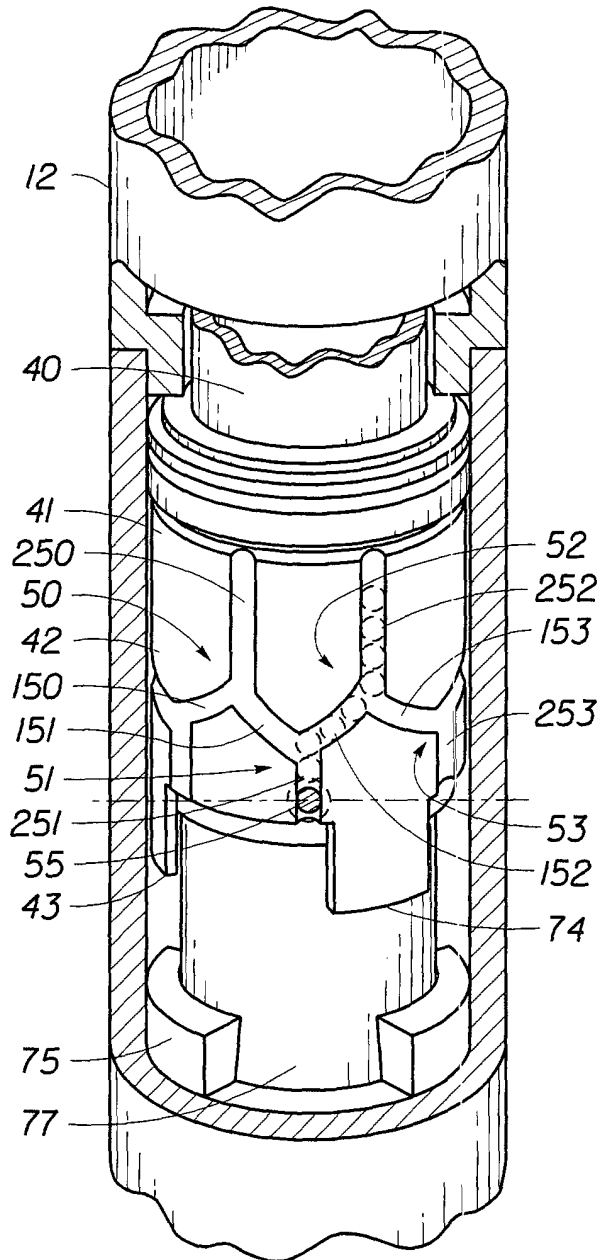


FIG. 5C

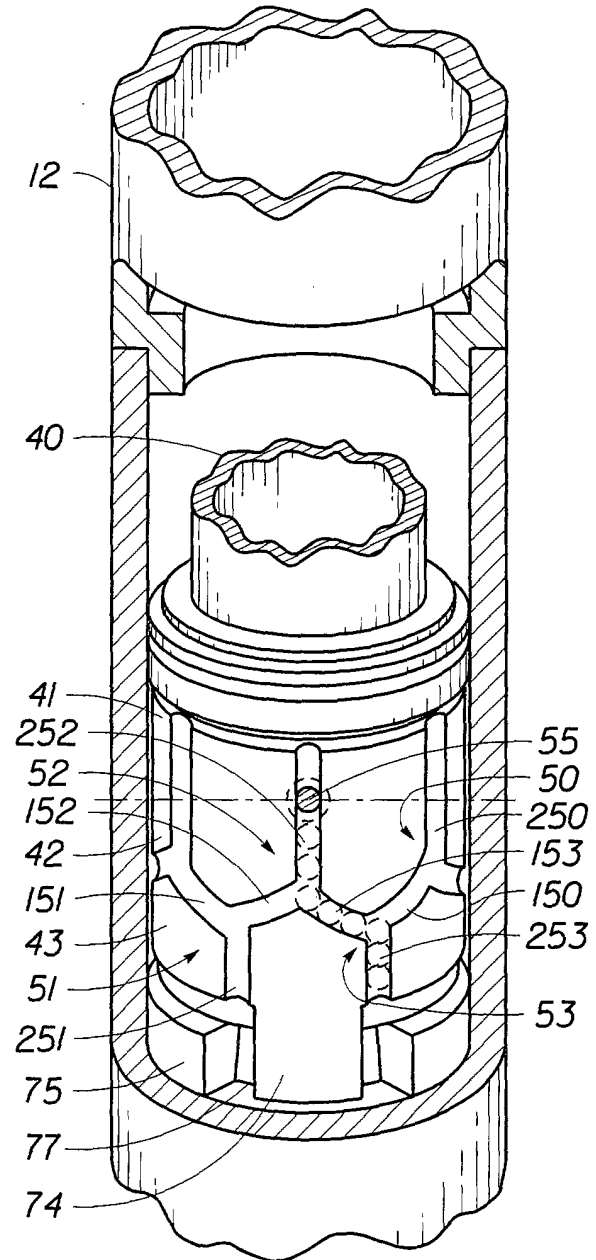


FIG. 5D

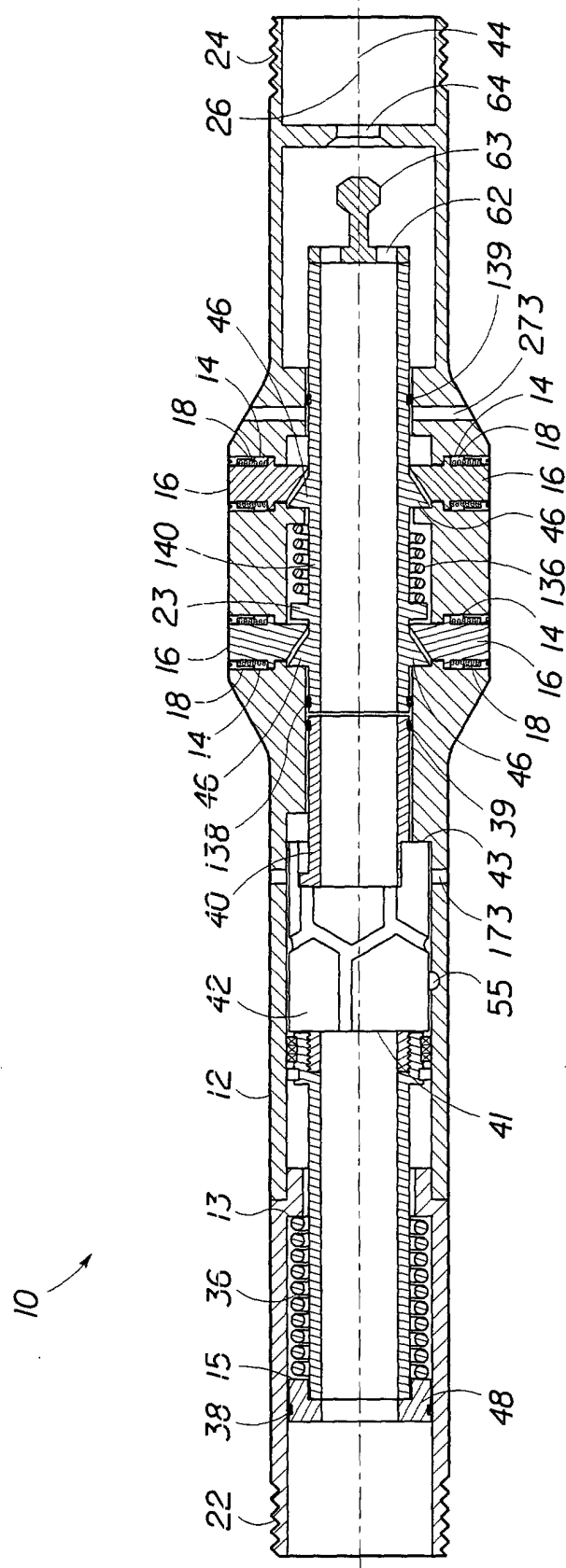


FIG. 6

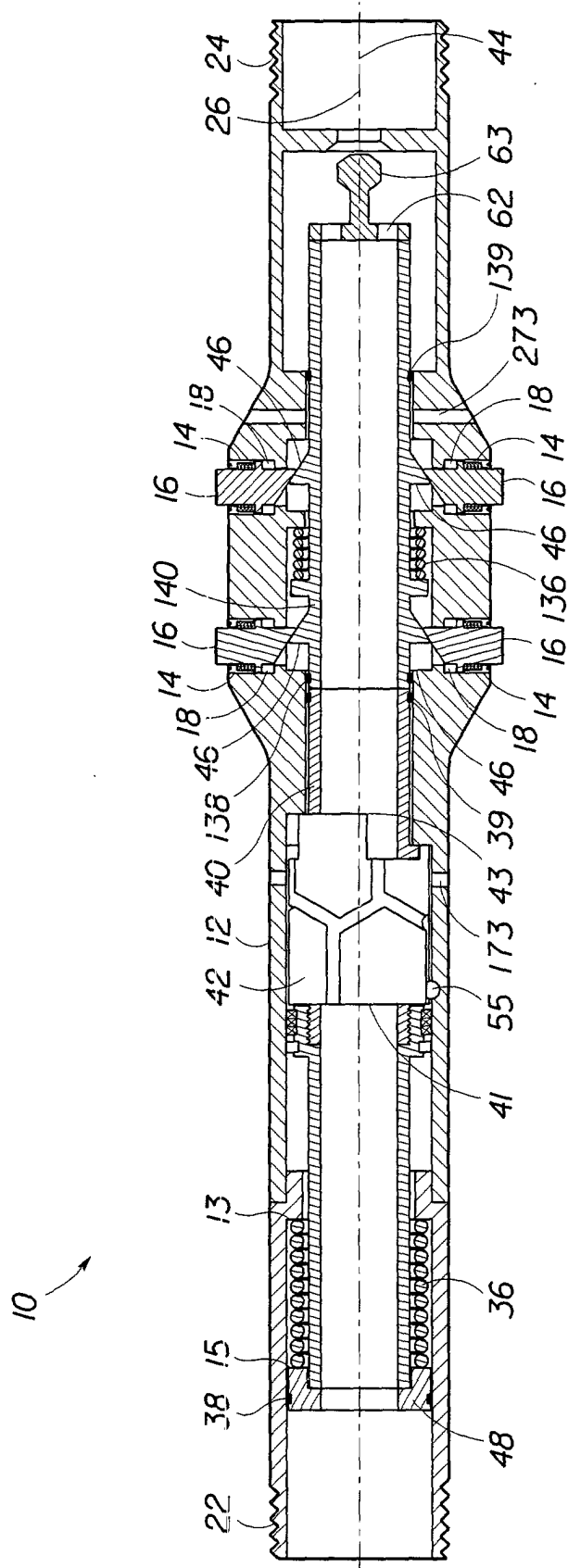


FIG. 7

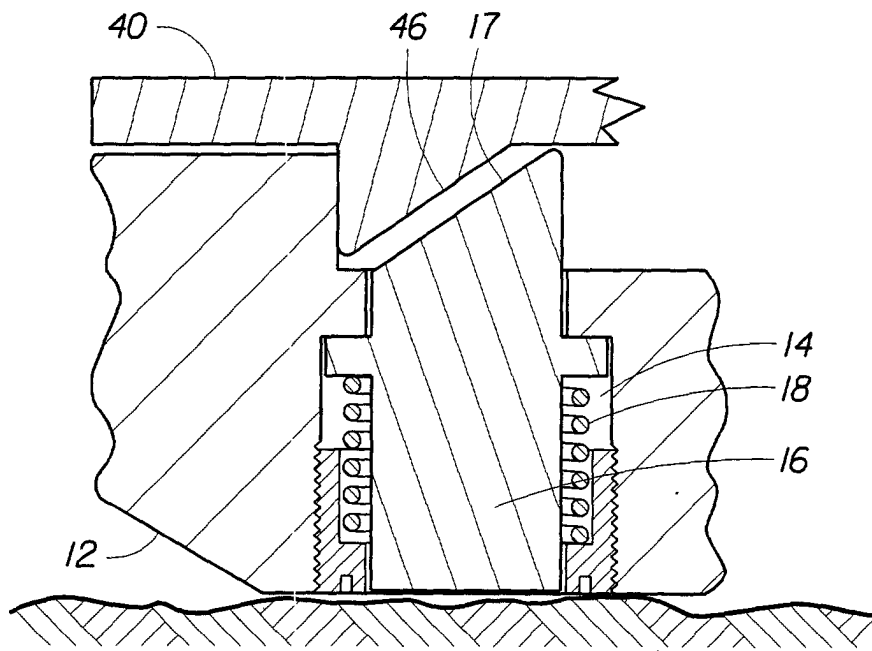


FIG. 8A

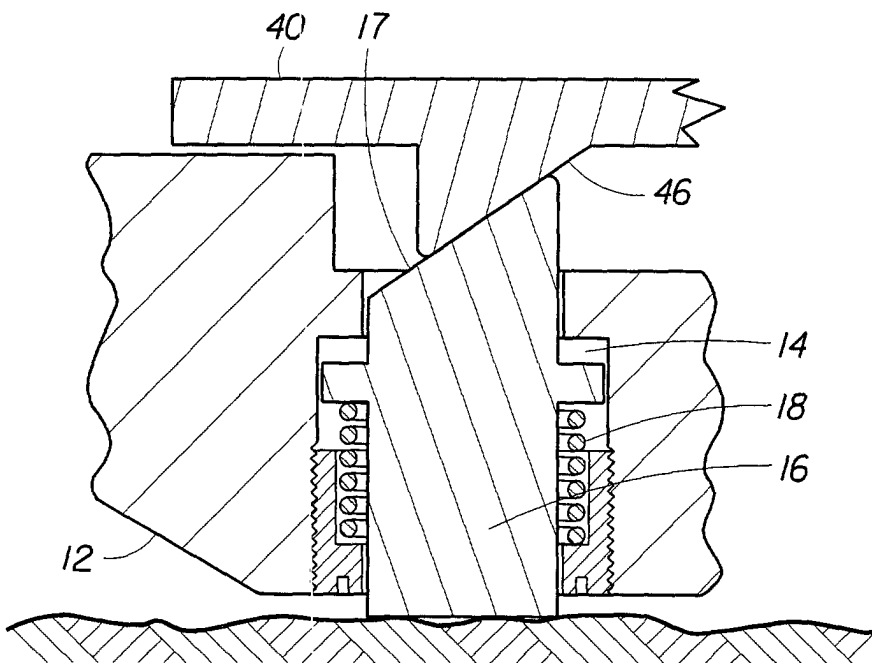


FIG. 8B

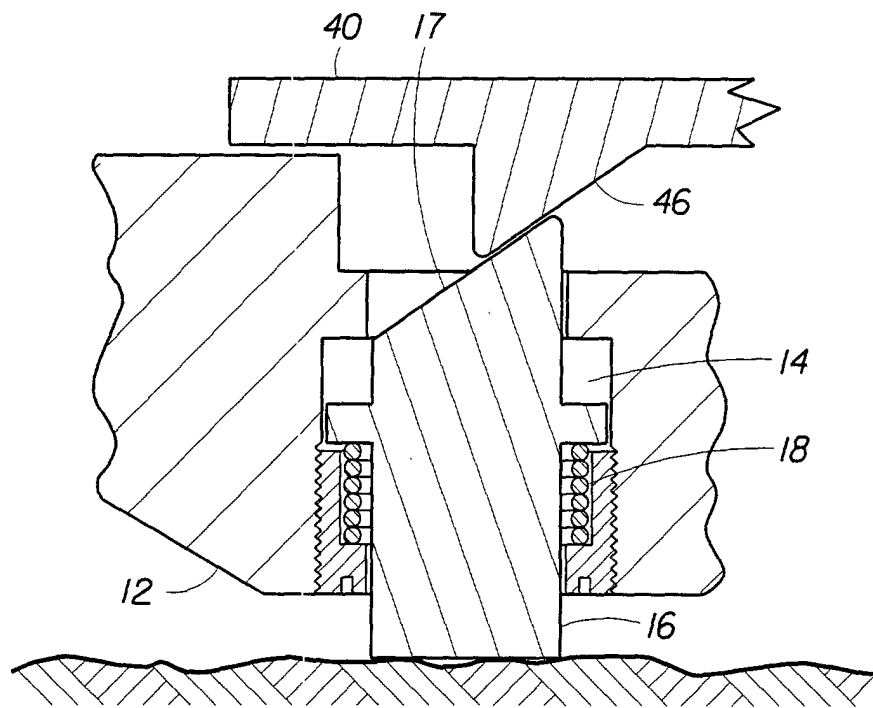


FIG. 8C

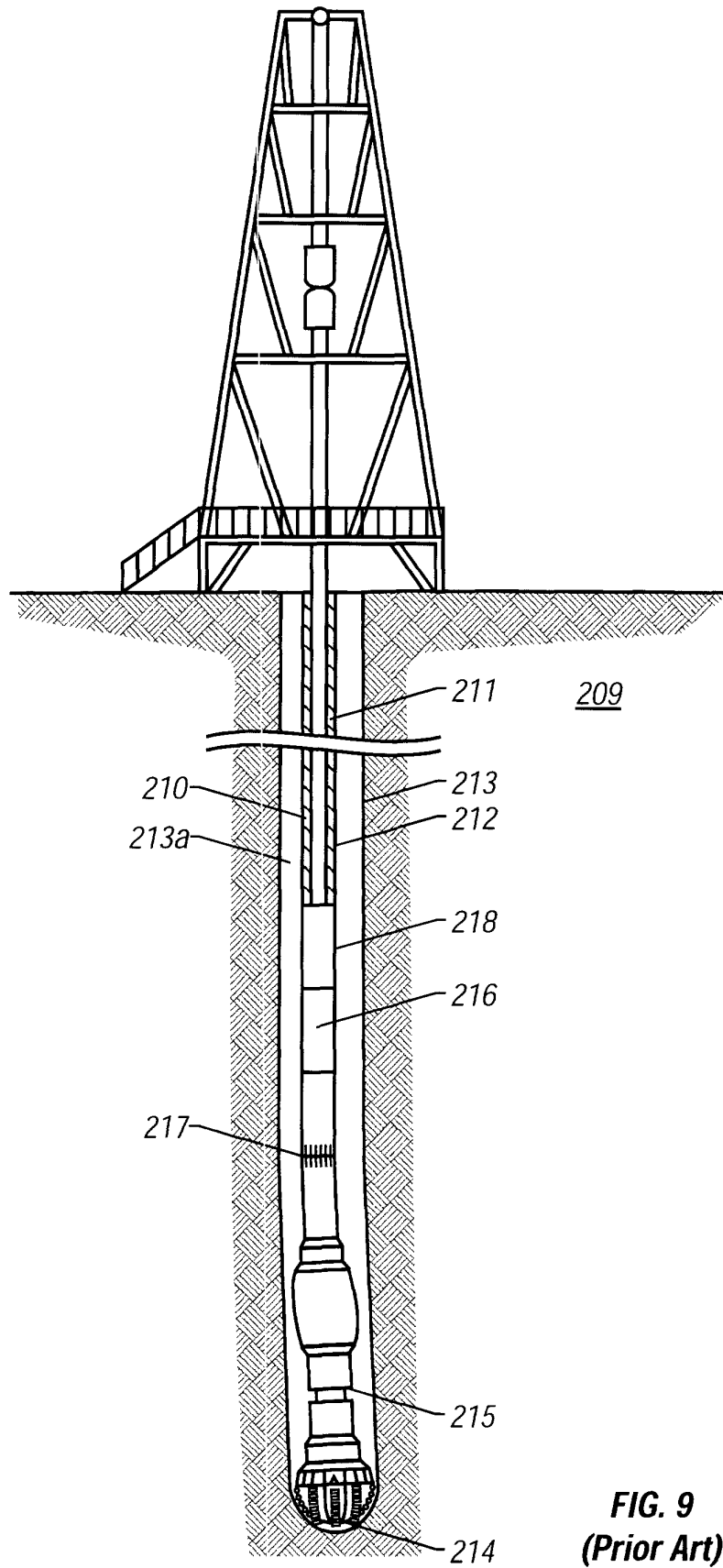


FIG. 9
(Prior Art)

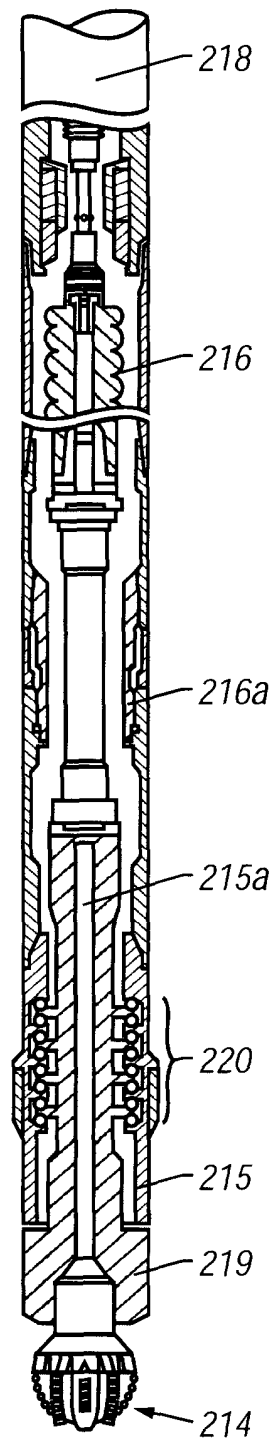


FIG. 10
(Prior Art)

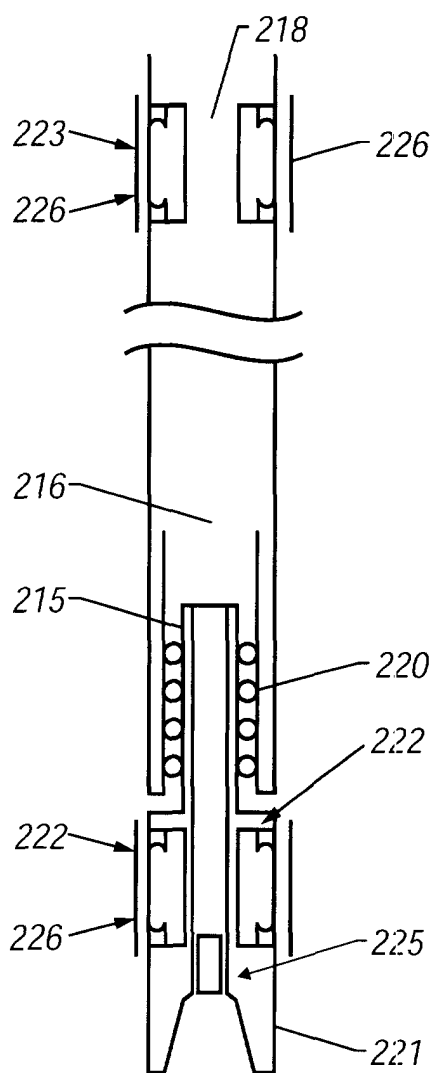


FIG. 11

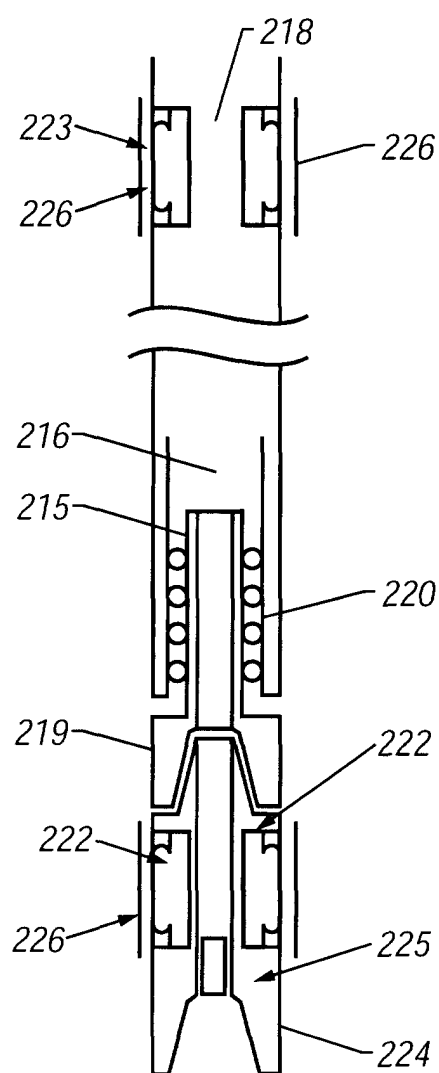


FIG. 12

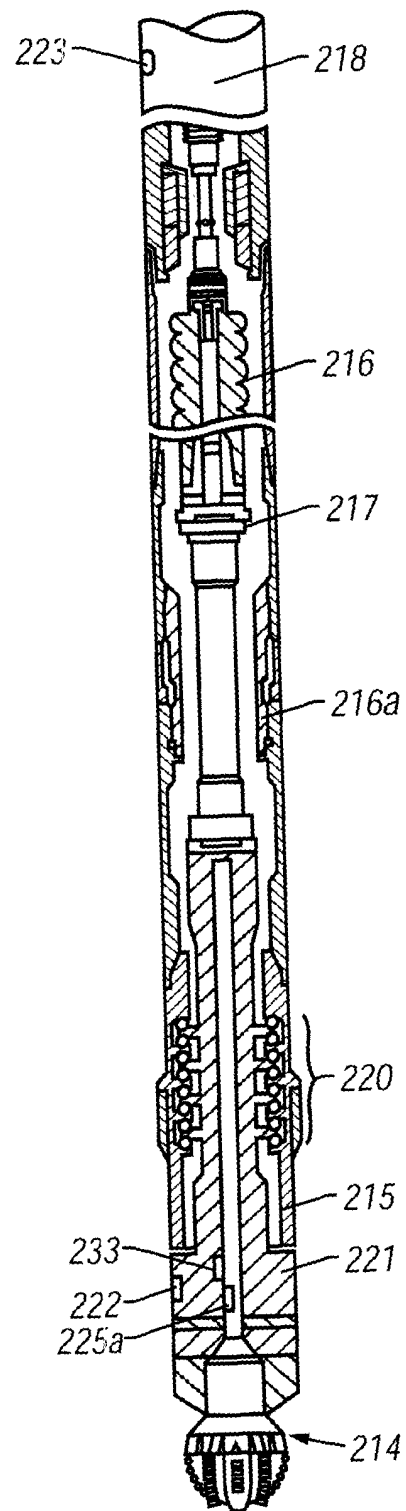


FIG. 13

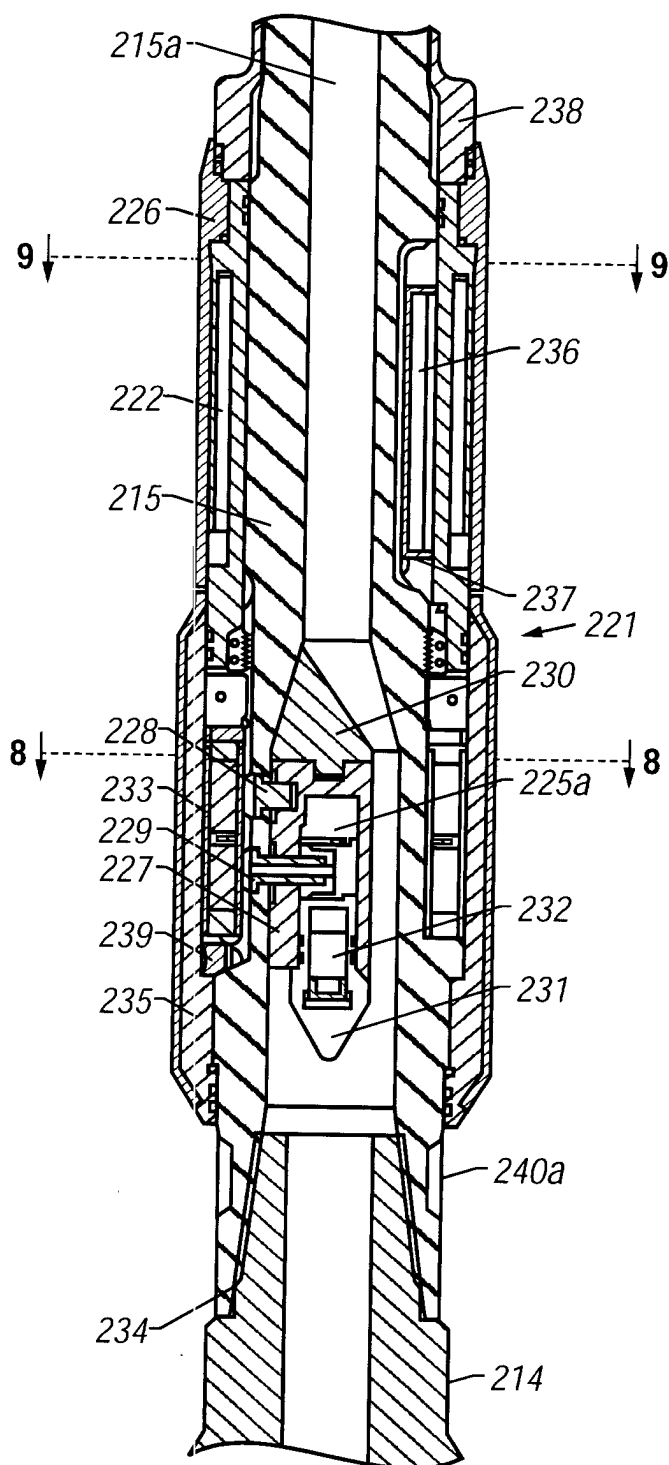


FIG. 14

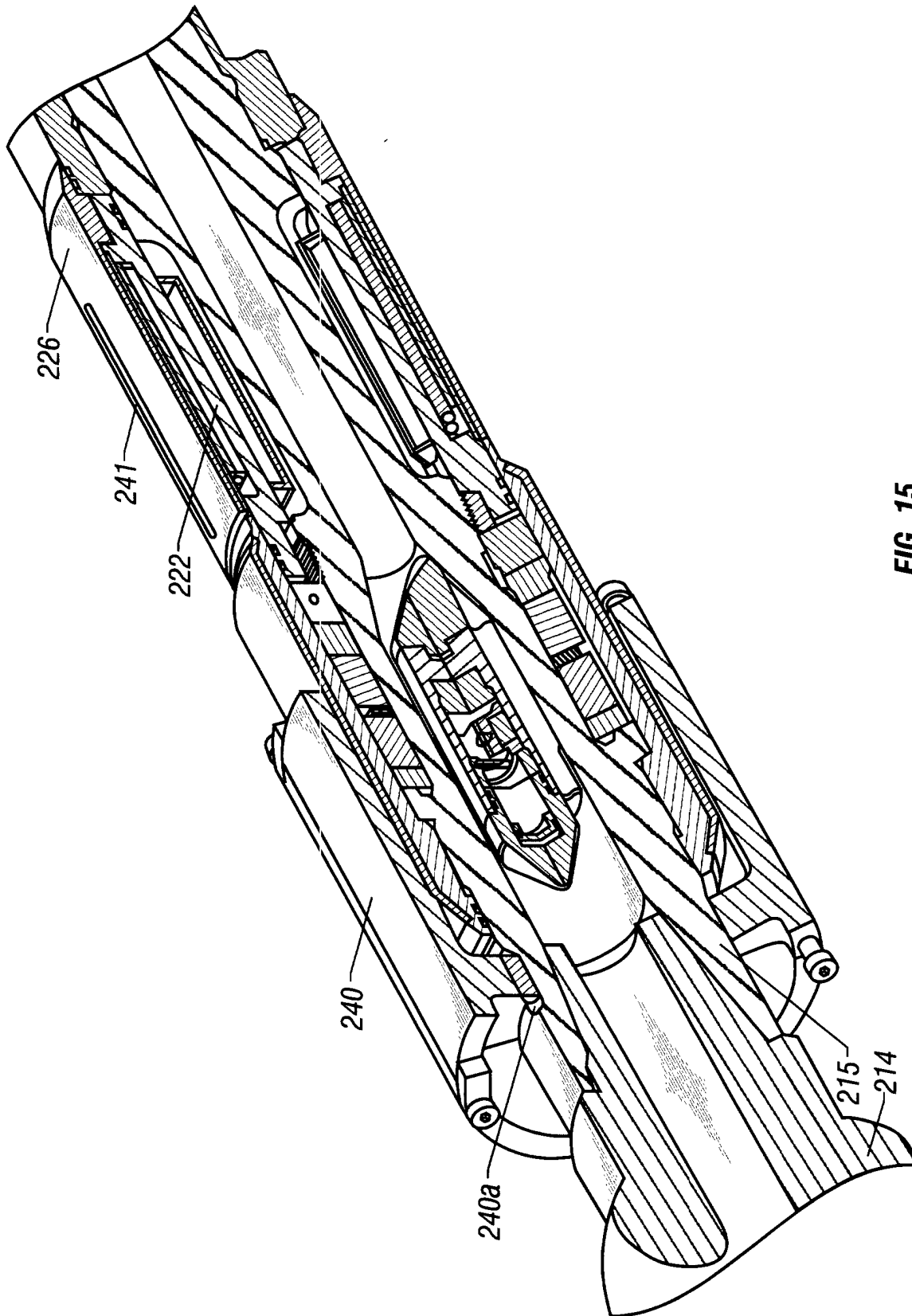


FIG. 15

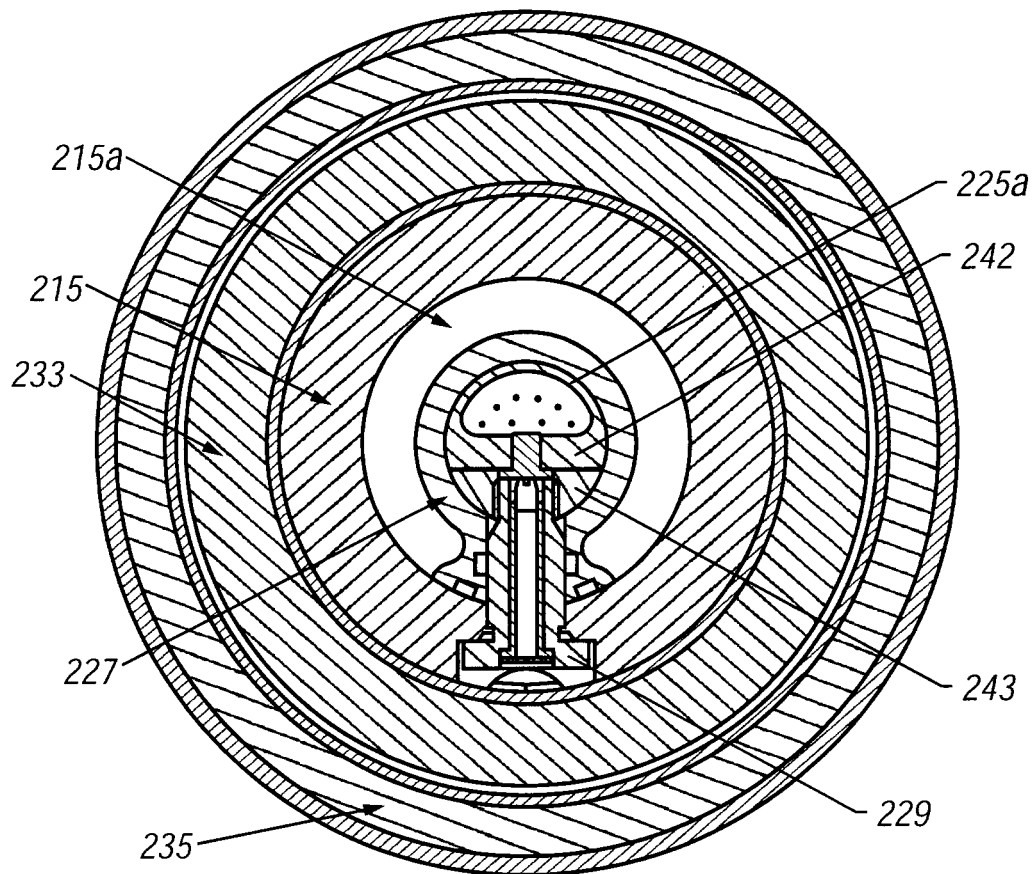


FIG. 16

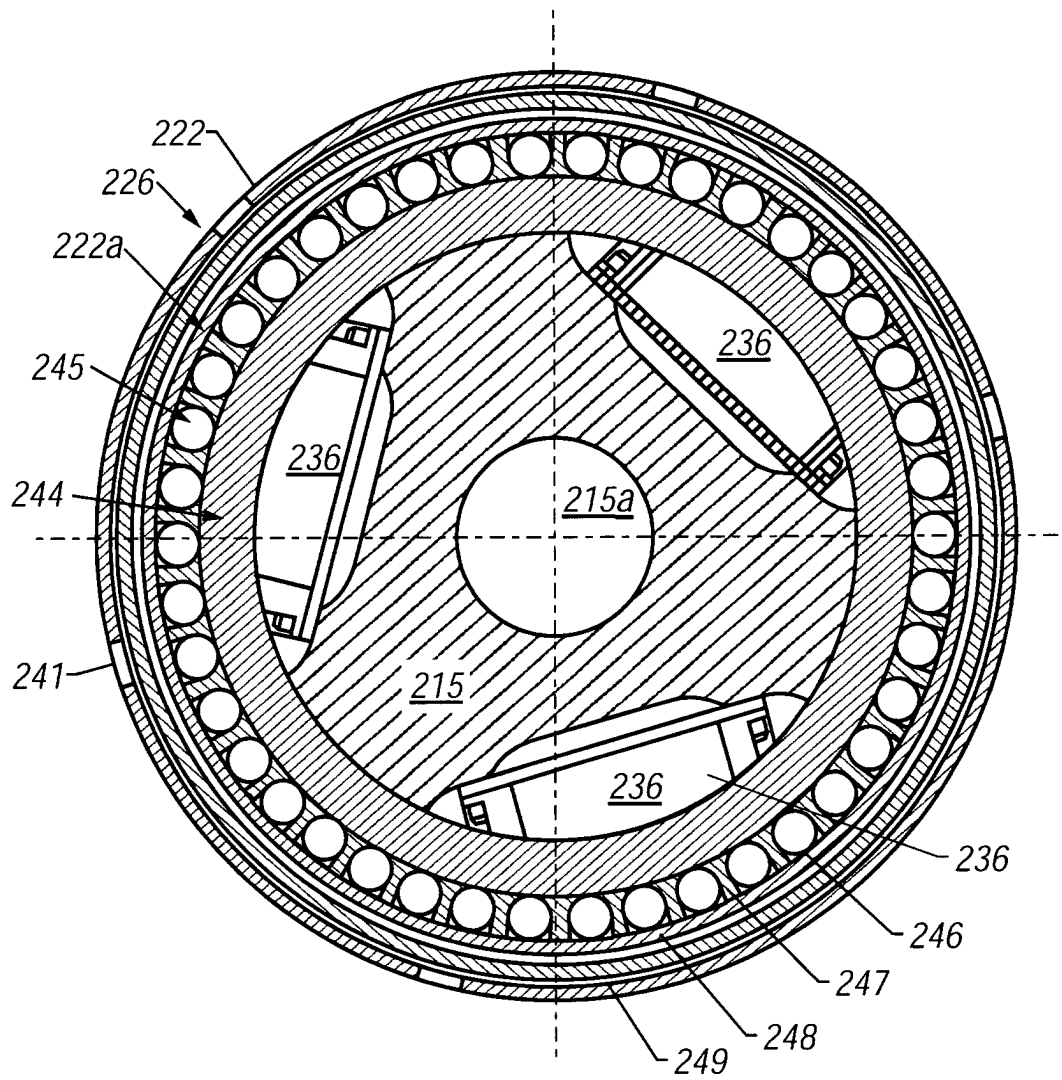


FIG. 17

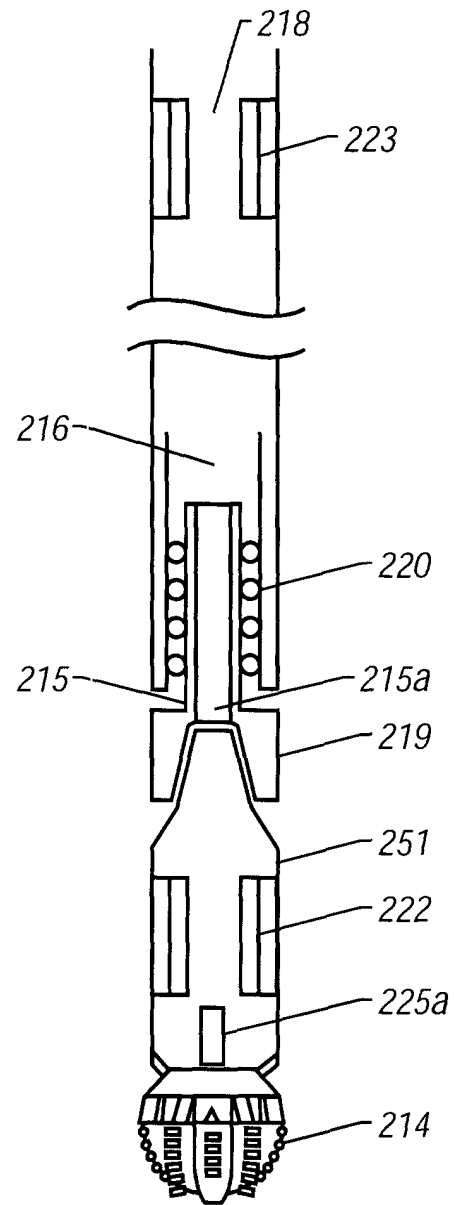


FIG. 18

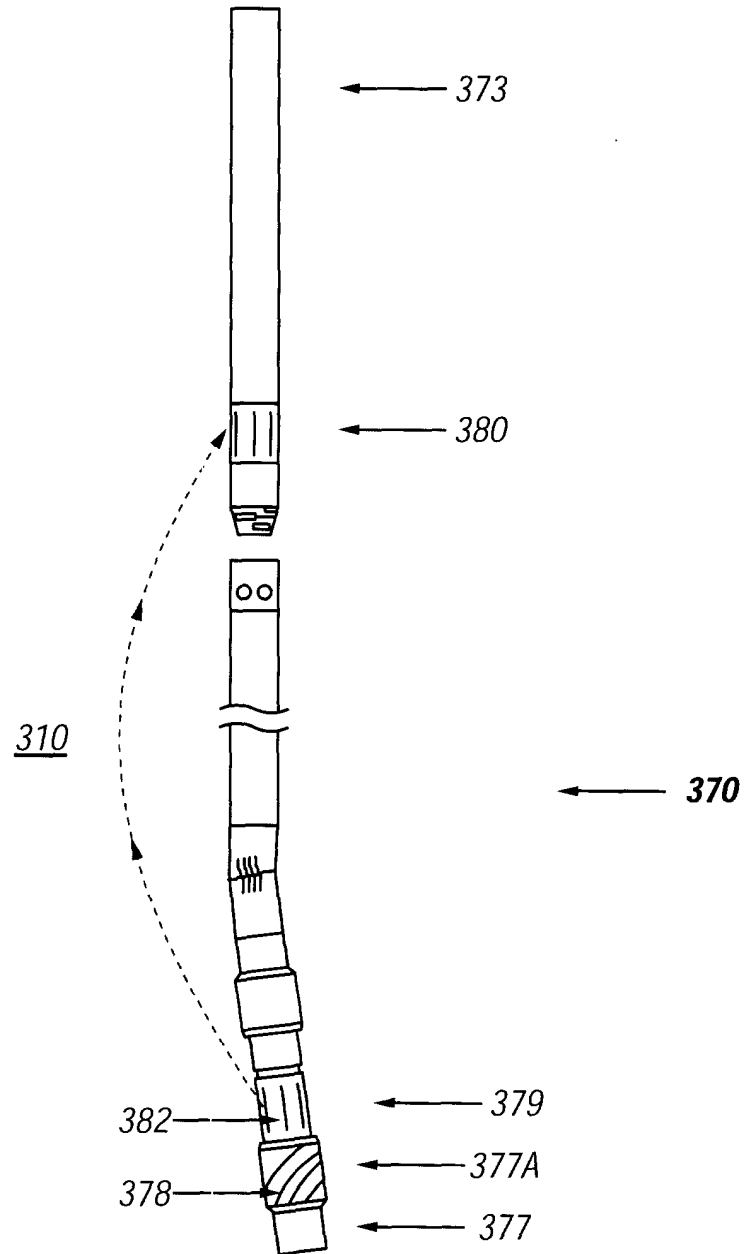


FIG. 19

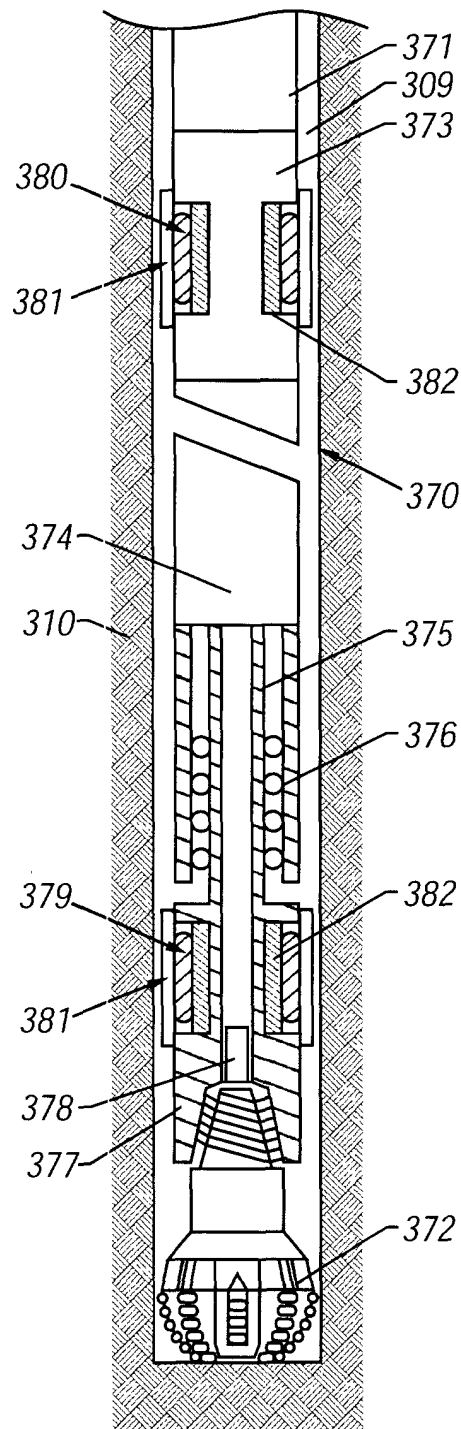


FIG. 20

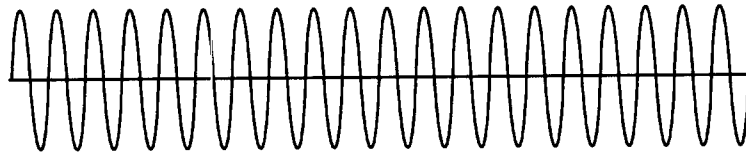


FIG. 21

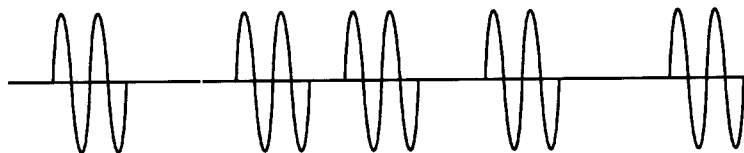


FIG. 22

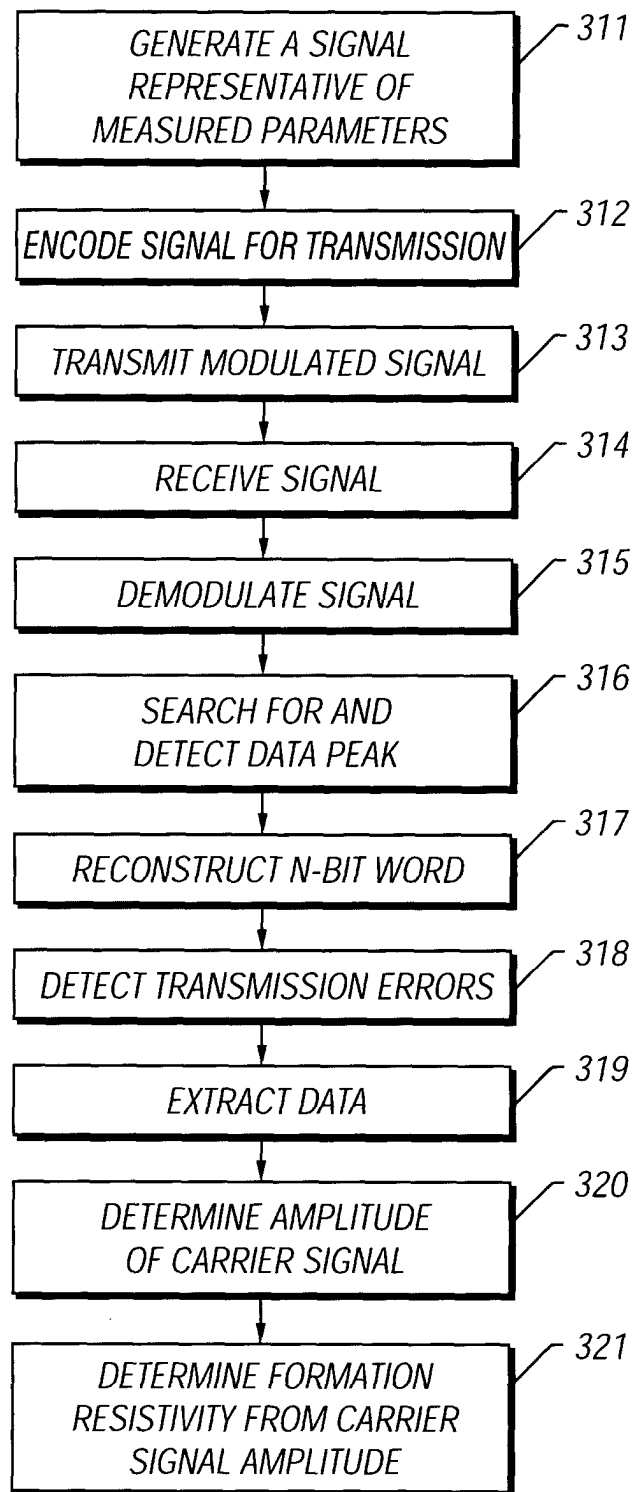


FIG. 23

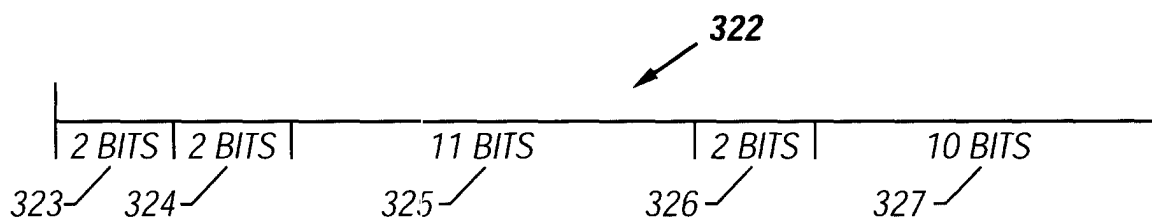


FIG. 24

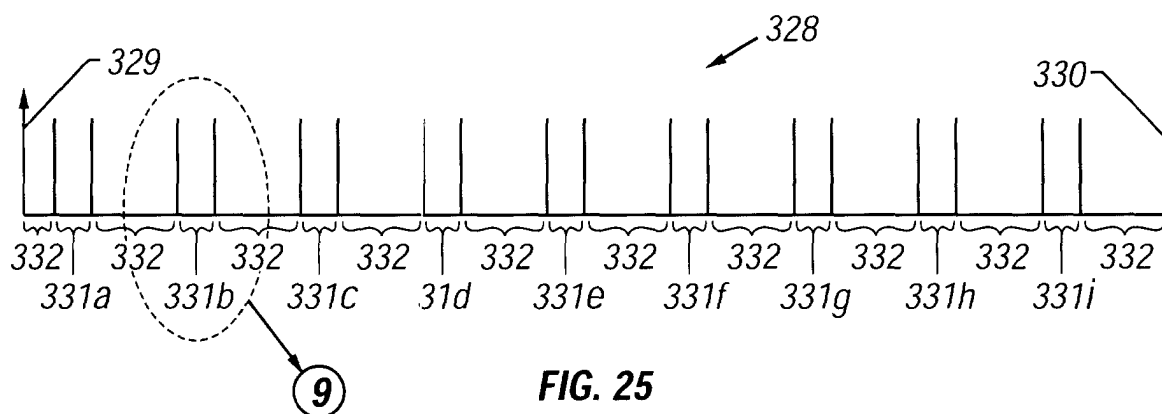


FIG. 25

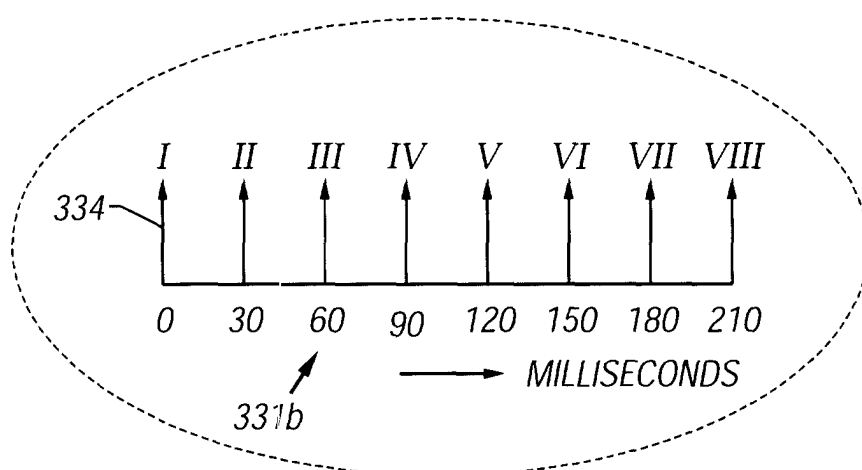


FIG. 26

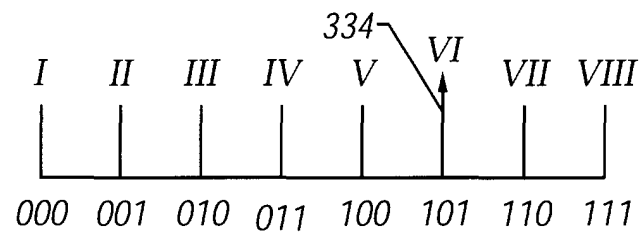


FIG. 27A

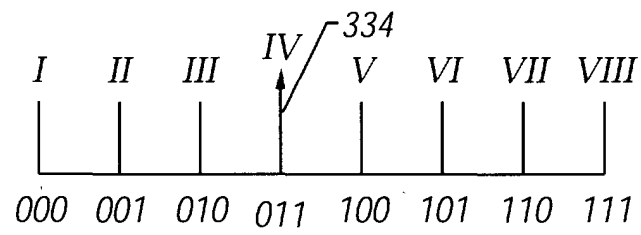


FIG. 27B

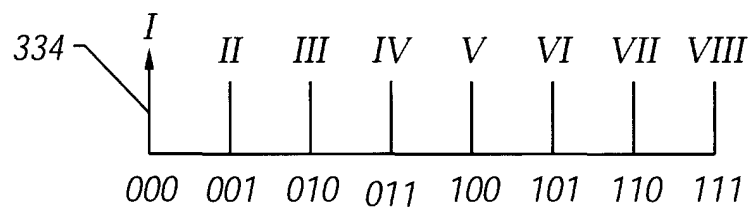


FIG. 27C

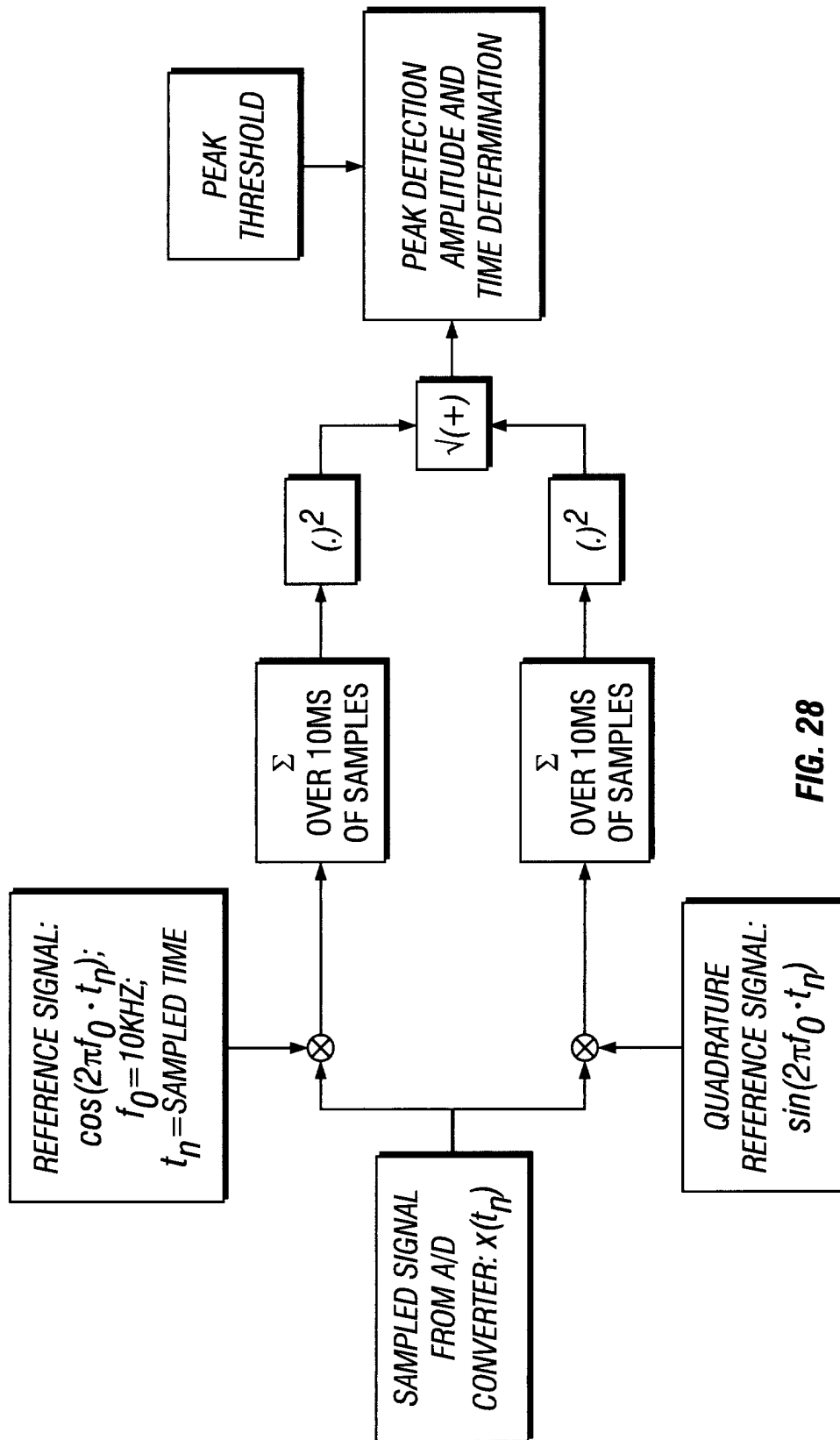


FIG. 28

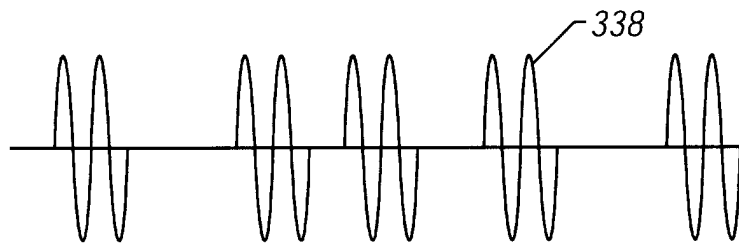


FIG. 29A

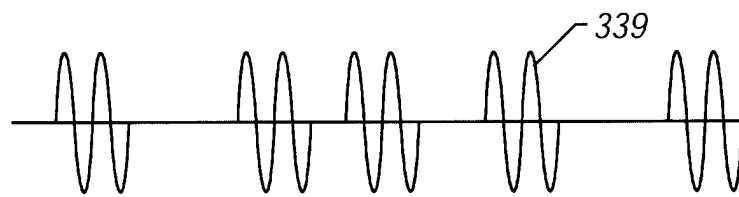


FIG. 29B

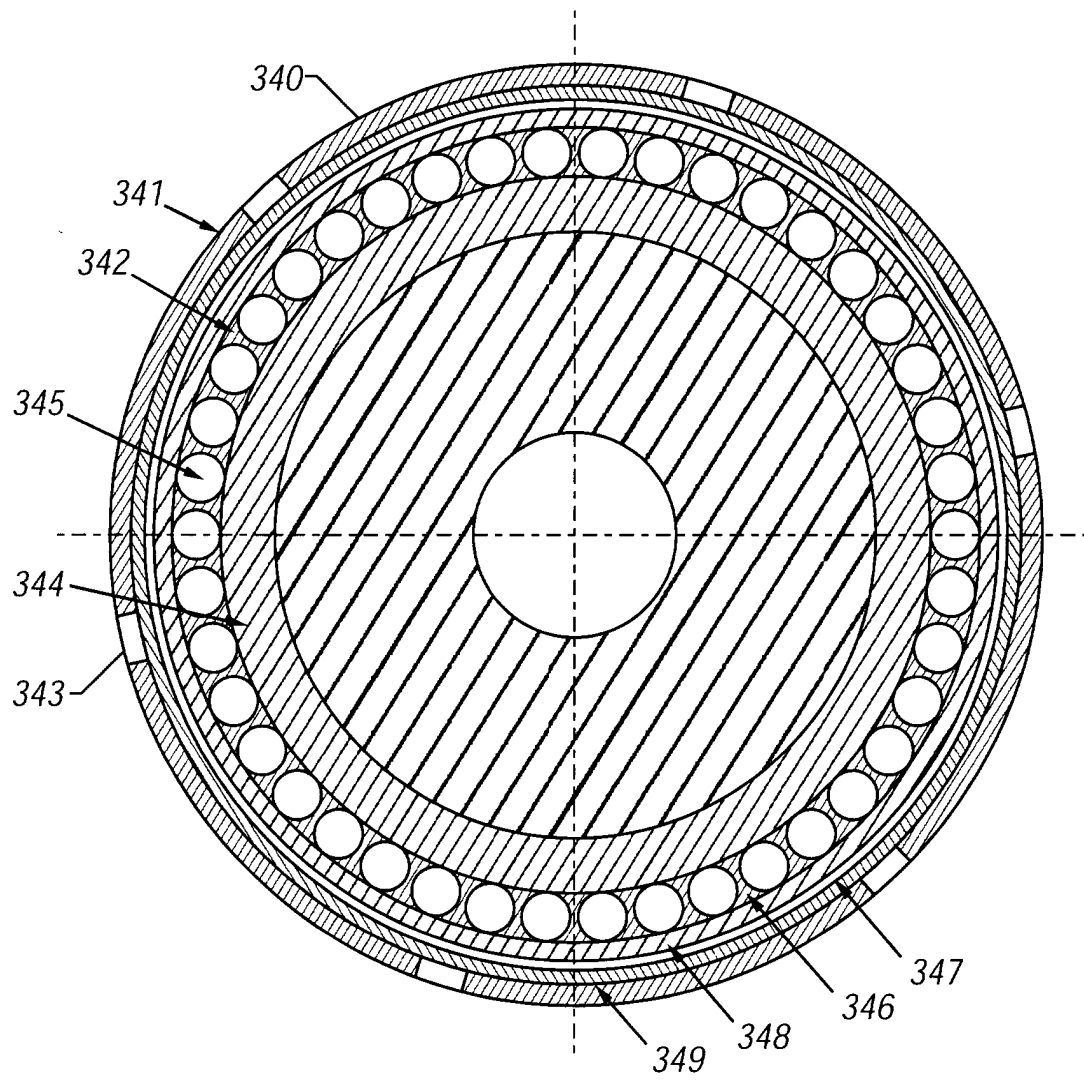


FIG. 30

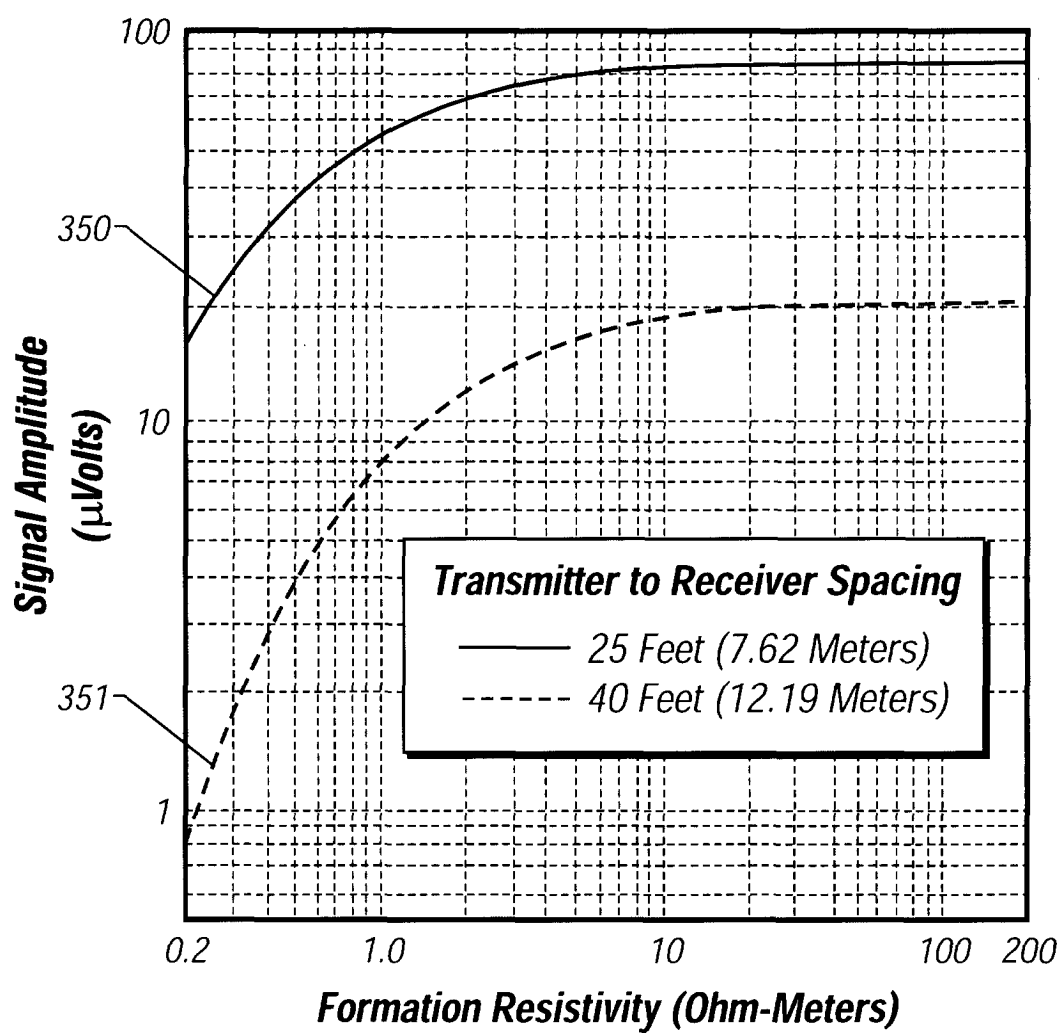


FIG. 31

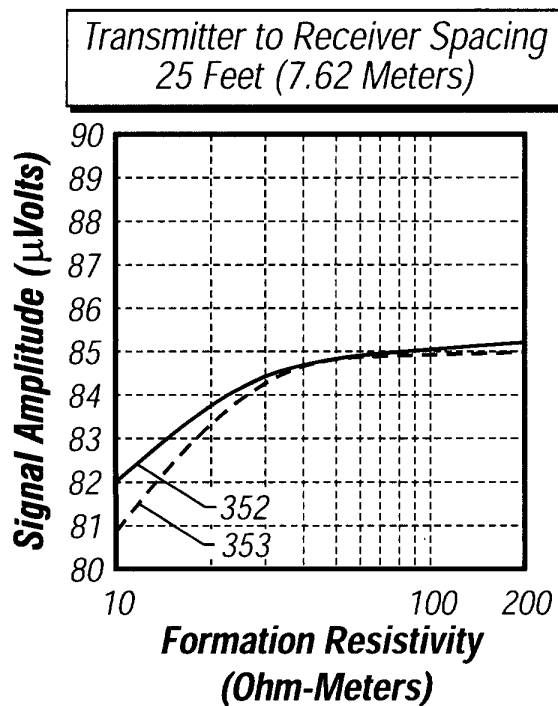


FIG. 32A

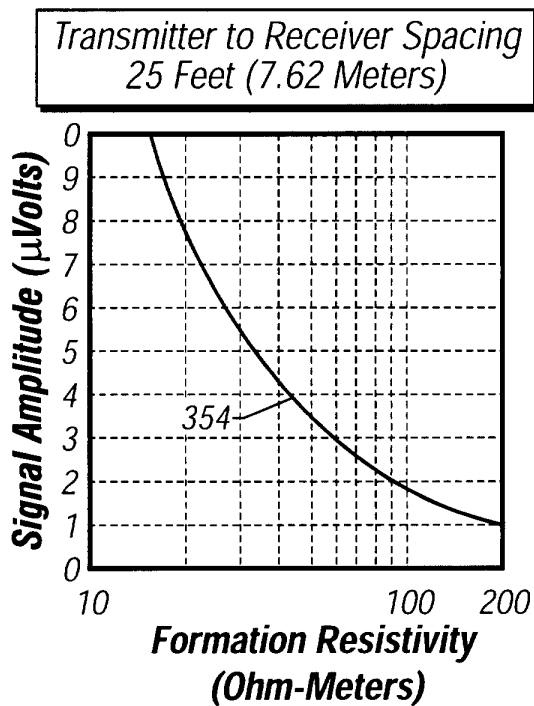


FIG. 32B

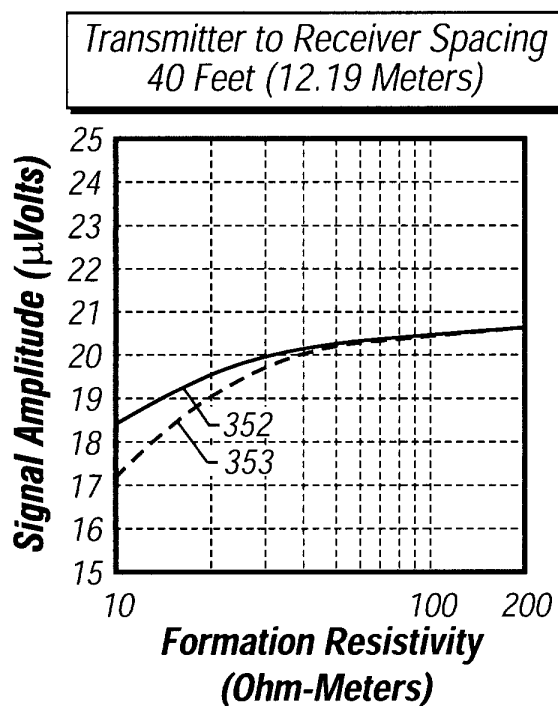


FIG. 32C

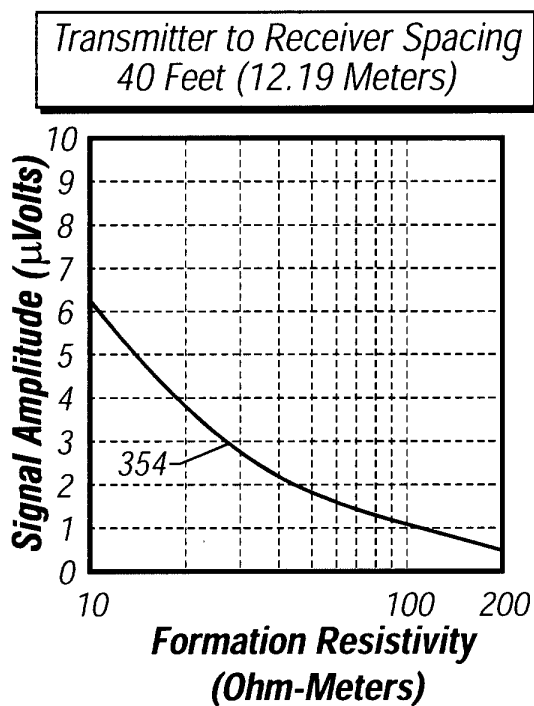


FIG. 32D

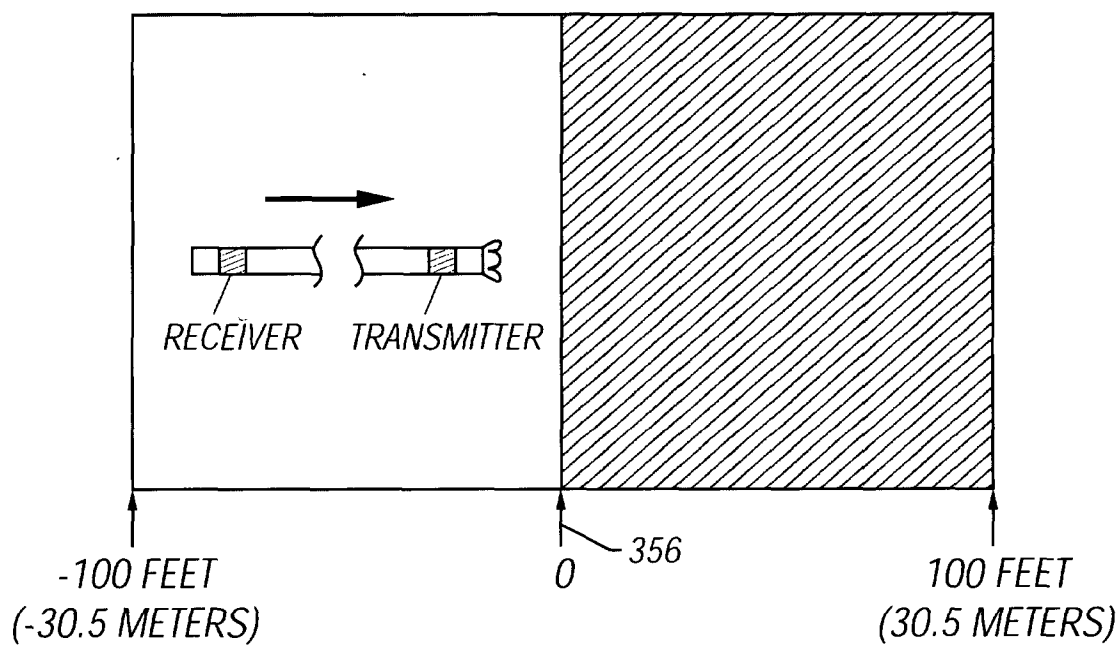


FIG. 33

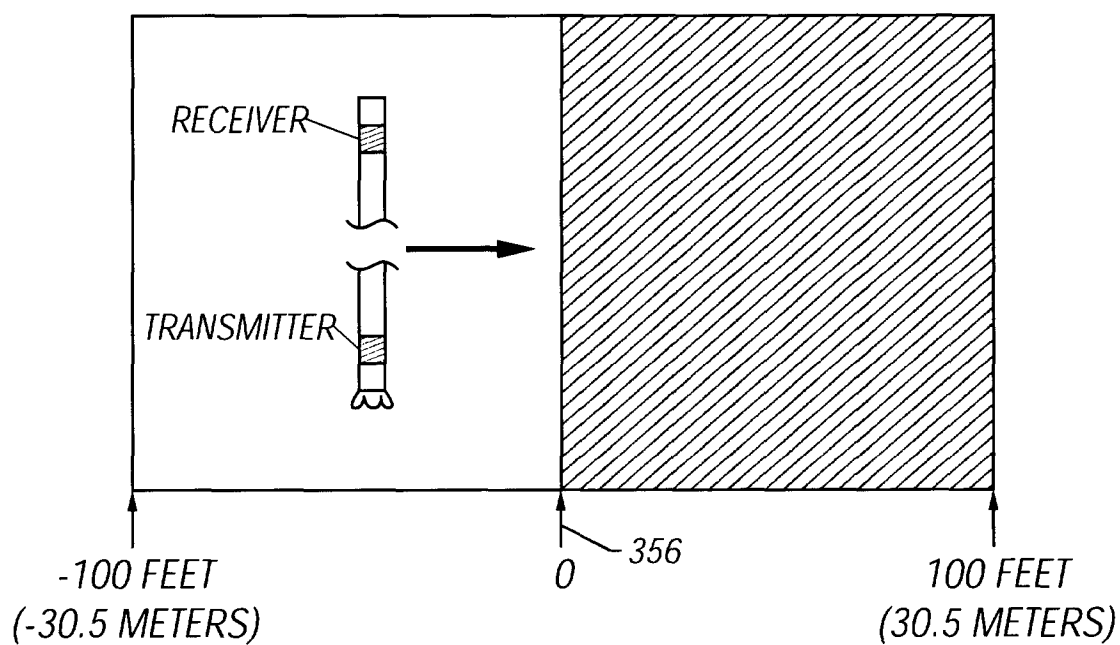


FIG. 35

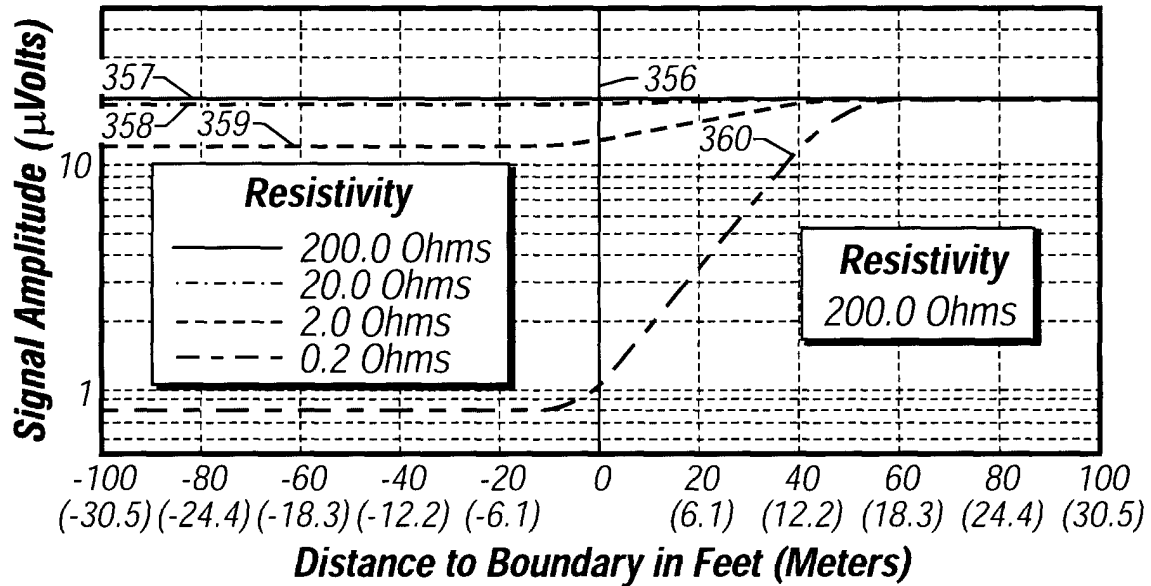


FIG. 34A

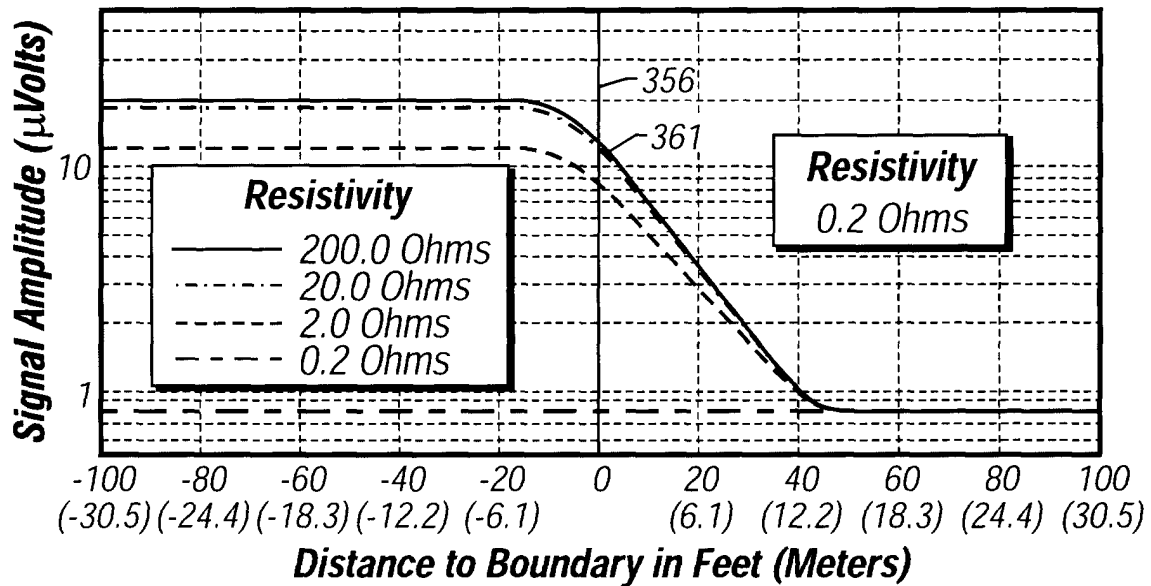


FIG. 34B

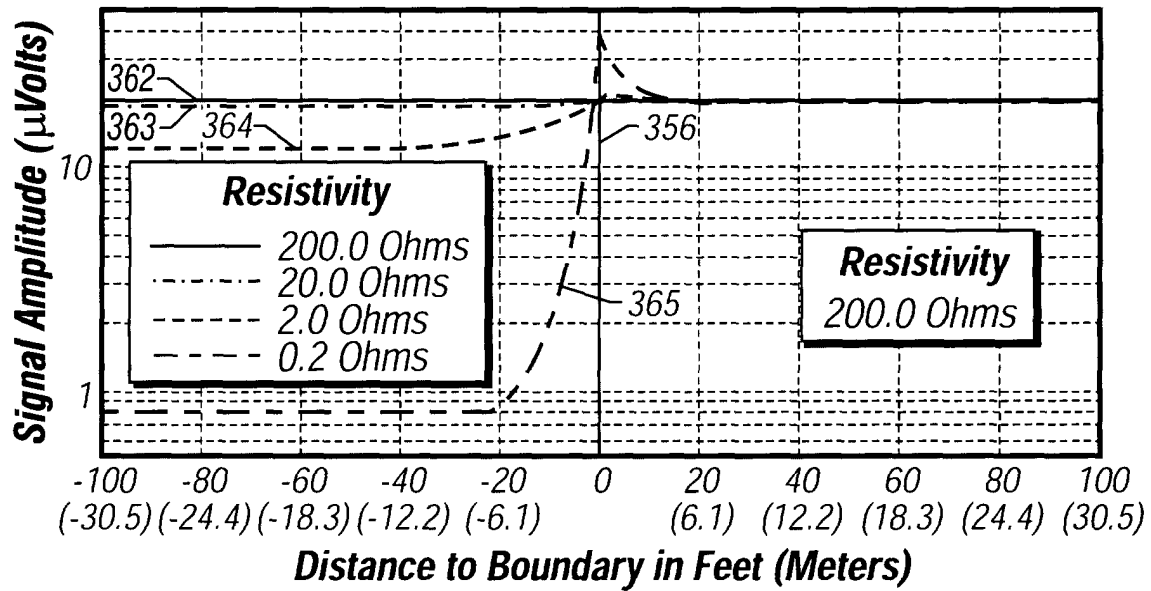


FIG. 36A

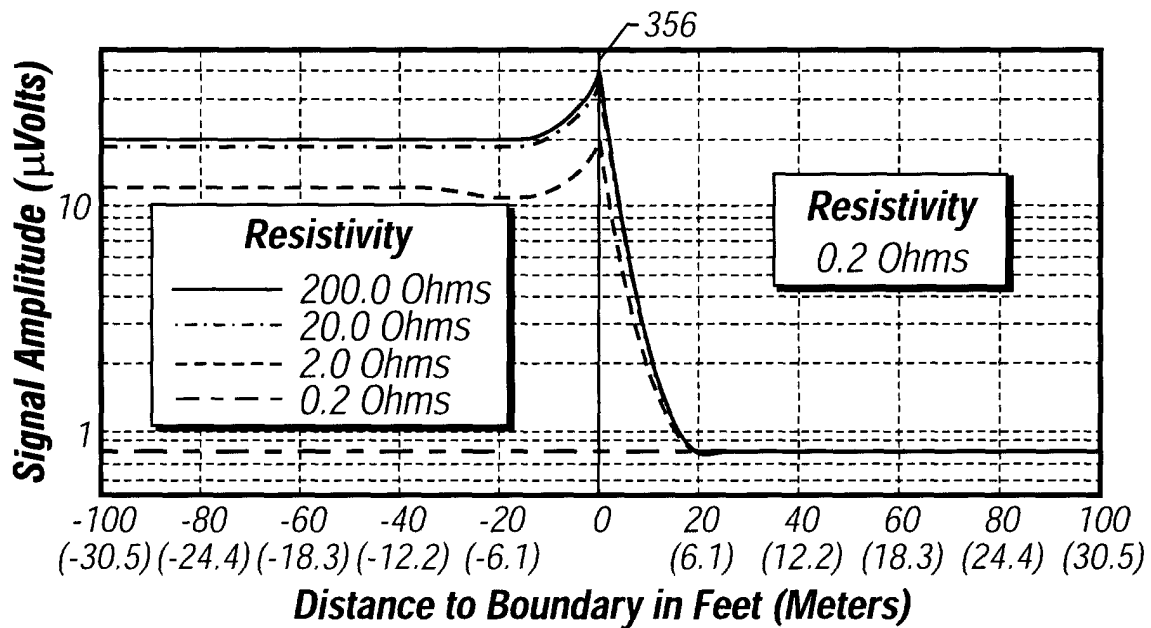


FIG. 36B



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