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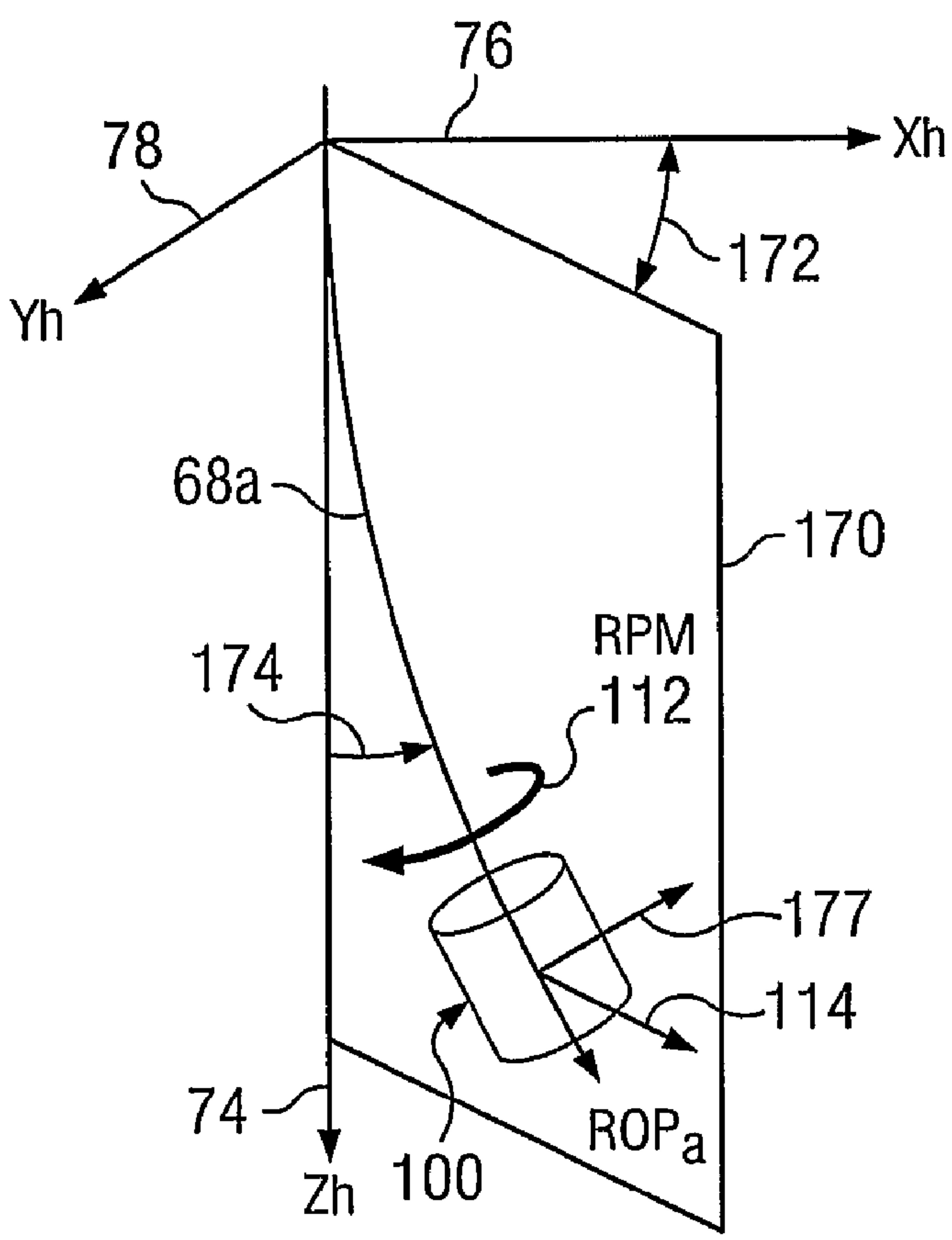
(54) Titre : PROCEDES ET SYSTEMES DE DESIGNATION ET/OU SELECTION D'UN EQUIPEMENT DE FORAGE AU MOYEN DE PREDICTIONS D'UNE AVANCEE DE TREPAN ROTATIF

(54) Title: METHODS AND SYSTEMS FOR DESIGNING AND/OR SELECTING DRILLING EQUIPMENT USING PREDICTIONS OF ROTARY DRILL BIT WALK



(57) Abrégé/Abstract:
Methods and systems may be provided simulating forming a wide variety of directional wellbores including wellbores with variable tilt rates and/or relatively constant tilt rates. The methods and systems may also be used to simulate forming a wellbore in

(57) Abrégé(suite)/Abstract(continued):
subterranean formations having a combination of soft, medium and hard formation materials, multiple layers of formation materials and relatively hard stringers disposed throughout one or more layers of formation material. Values of bit walk rate from such simulations may be used to design and/or select drilling equipment for use in forming a directional wellbore.

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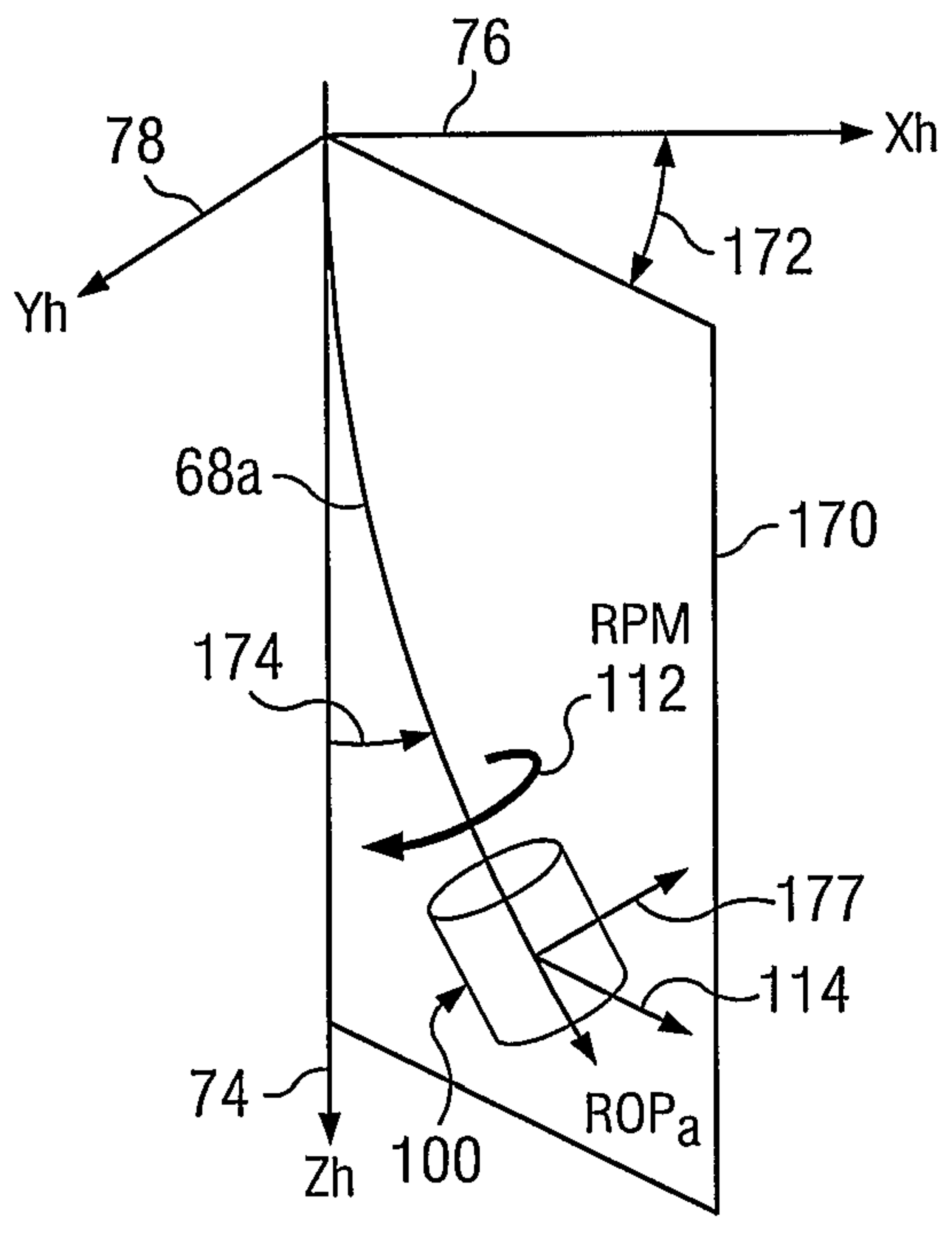
(54) **Title:** METHODS AND SYSTEMS FOR DESIGNING AND/OR SELECTING DRILLING EQUIPMENT USING PREDICTIONS OF ROTARY DRILL BIT WALK



(57) **Abstract:** Methods and systems may be provided simulating forming a wide variety of directional wellbores including wellbores with variable tilt rates and/or relatively constant tilt rates. The methods and systems may also be used to simulate forming a wellbore in subterranean formations having a combination of soft, medium and hard formation materials, multiple layers of formation materials and relatively hard stringers disposed throughout one or more layers of formation material. Values of bit walk rate from such simulations may be used to design and/or select drilling equipment for use in forming a directional wellbore.

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METHODS AND SYSTEMS FOR DESIGNING AND/OR SELECTING DRILLING EQUIPMENT USING PREDICTIONS OF ROTARY DRILL BIT WALK

RELATED APPLICATIONS

This application claims the benefit of provisional patent application entitled "Methods and Systems of Rotary Drill Bit Steerability Prediction, Rotary Drill Bit Design and Operation," Application Serial Number 60/706,321 filed August 8, 2005.

This application claims the benefit of provisional patent application entitled "Methods and Systems of Rotary Drill Bit Walk Prediction, Rotary Drill Bit Design and Operation," Application Serial Number 60/738,431 filed November 21, 2005.

This application claims the benefit of provisional patent application entitled "Methods and Systems of Rotary Drill Bit Walk Prediction, Rotary Drill Bit Design and Operation," Application Serial Number 60/706,323 filed August 8, 2005.

This application claims the benefit of provisional patent application entitled "Methods and Systems of Rotary Drill Bit Steerability Prediction, Rotary Drill Bit Design and Operation," Application Serial Number 60/738,453 filed November 21, 2005.

TECHNICAL FIELD

The present disclosure is related to wellbore drilling equipment and more particularly to designing rotary drill bits and/or bottom hole assemblies with desired bit walk characteristics or selecting a rotary drill bit and/or components for an associated bottom hole assembly with desired bit walk characteristics from existing designs.

BACKGROUND

Various types of rotary drill bits have been used to form wellbores or boreholes in downhole formations. Such wellbores are often formed using a rotary drill bit attached to the end of a generally hollow, tubular drill string extending from an associated well surface. Rotation of a rotary drill bit progressively cuts away adjacent portions of a downhole formation by contact between cutting elements and cutting structures disposed on exterior portions of the rotary drill bit. Examples of rotary drill bits include fixed cutter drill bits or drag drill bits and impregnated diamond bits. Various types of drilling fluids are often used in conjunction with rotary drill bits to form wellbores or boreholes extending from a well surface through one or more downhole formations.

Various types of computer based systems, software applications and/or computer programs have previously been used to simulate forming wellbores including, but not limited to, directional wellbores and to simulate the performance of a wide variety of drilling equipment including, but not limited to, rotary drill bits which may be used to form such wellbores. Some examples of such computer based systems, software applications and/or computer programs are discussed in various patents and other references listed on Information Disclosure Statements filed during prosecution of this patent application.

SUMMARY

In accordance with teachings of the present disclosure, rotary drill bits including fixed cutter drill bits may be designed with bit walk characteristics and/or controllability optimized for a desired wellbore profile and/or anticipated downhole drilling conditions. Alternatively, a rotary drill bit including a fixed cutter drill bit with desired bit walk and/or controllability may be selected from existing drill bit designs.

Rotary drill bits designed or selected to form a straight hole or vertical wellbore may require approximately zero or neutral bit walk. Rotary drill bits designed or selected for use with a directional drilling system may have an optimum bit walk rate for a desired wellbore profile and/or anticipated downhole drilling conditions.

One aspect of the present disclosure may include procedures to evaluate walk tendency of a rotary drill bit under a combination of bit motions including, but not limited to, rotation, axial penetration, side penetration, tilt rate and/or transition drilling. For example, methods and systems incorporating teachings of the present disclosure may be used to simulate drilling through inclined formation interfaces and complex formations with hard stringers disposed in softer formation materials and/or alternating layers of hard and soft formation materials.

Drilling a wellbore profile, trajectory, or path using a wide variety of rotary drill bits and bottom hole assemblies may be simulated in three dimensions (3D)

using methods and systems incorporating teachings of the present disclosure. Such simulations may be used to design rotary drill bits and/or bottom hole assemblies with optimum bit walk characteristics for drilling a wellbore profile. Such simulation may also be used to select a rotary drill bit and/or components for an associated bottom hole assembly from existing designs with optimum bit walk characteristics for drilling a wellbore profile.

Systems and methods incorporating teachings of the present disclosure may be used to simulate drilling various types of wellbores and segments of wellbores using both push-the-bit directional drilling systems and point-the-bit directional drilling systems.

BRIEF DESCRIPTION OF THE DRAWINGS

A more complete and thorough understanding of the present disclosure and advantages thereof may be acquired by referring to the following description taken in conjunction with the accompanying drawings, in which like reference numbers indicate like features, and wherein:

FIGURE 1A is a schematic drawing in section and in elevation with portions broken away showing one example of a directional wellbore which may be formed by a drill bit designed in accordance with teachings of the present disclosure or selected from existing drill bit designs in accordance with teachings of the present disclosure;

FIGURE 1B is a schematic drawing showing a graphical representation of a directional wellbore having a constant bend radius between a generally vertical section and a generally horizontal section which may be formed by a drill bit designed in accordance with teachings of the present disclosure or selected from existing drill bit designs in accordance with teachings of the present disclosure;

FIGURE 1C is a schematic drawing showing one example of a system and associate apparatus operable to simulate drilling a complex, directional wellbore in accordance with teachings of the present disclosure;

FIGURE 2A is a schematic drawing showing an isometric view with portions broken away of a rotary drill bit with six (6) degrees of freedom which may be used to describe motion of the rotary drill bit in three dimensions in a bit coordinate system;

FIGURE 2B is a schematic drawing showing forces applied to a rotary drill bit while forming a substantially vertical wellbore;

FIGURE 3A is a schematic representation showing a side force applied to a rotary drill bit at an instant in time in a two dimensional Cartesian bit coordinate system.

FIGURE 3B is a schematic representation showing a trajectory of a directional wellbore and a rotary drill bit disposed in a tilt plane at an instant of time in a three dimensional Cartesian hole coordinate system;

FIGURE 3C is a schematic representation showing the rotary drill bit in FIGURE 3B at the same instant of time in a two dimensional Cartesian hole coordinate system;

FIGURE 4A is a schematic drawing in section and in elevation with portions broken away showing one example of a push-the-bit directional drilling system adjacent to the end of a wellbore;

FIGURE 4B is a graphical representation showing portions of a push-the-bit directional drilling system forming a directional wellbore;

FIGURE 4C is a schematic drawing showing an isometric view of a rotary drill bit having various design features which may be optimized for use with a push-the-bit directional drilling system in accordance with teachings of the present disclosure;

FIGURE 5A is a schematic drawing in section and in elevation with portions broken away showing one example of a point-the-bit directional drilling system adjacent to the end of a wellbore;

FIGURE 5B is a graphical representation showing portions of a point-the-bit directional drilling system forming a directional wellbore;

FIGURE 5C is a schematic drawing showing an isometric view of a rotary drill bit having various design features which may be optimized for use with a point-the-bit directional drilling system in accordance with teachings of the present disclosure;

FIGURE 5D is a schematic drawing showing an isometric view of a rotary drill bit having various design features which may be optimized for use with a point-the-bit directional drilling system in accordance with teachings of the present disclosure;

FIGURE 6A is a schematic drawing in section with portions broken away showing one simulation of forming a directional wellbore using a simulation model incorporating teachings of the present disclosure;

FIGURE 6B is a schematic drawing in section with portions broken away showing one example of parameters used to simulate drilling a direction wellbore in accordance with teachings of the present disclosure;

FIGURE 6C is a schematic drawing in section with portions broken away showing one simulation of forming a direction wellbore using a prior simulation model;

FIGURE 6D is a schematic drawing in section with portions broken away showing one example of forces used to simulate drilling a directional wellbore with a rotary drill bit in accordance with the prior simulation model;

FIGURE 7A is a schematic drawing in section with portions broken away showing another example of a rotary drill bit disposed within a wellbore;

FIGURE 7B is a schematic drawing showing various features of an active gage and a passive gage disposed on exterior portions of the rotary drill bit of FIGURE 7A;

FIGURE 8A is a schematic drawing in elevation with portions broken away showing one example of interaction between an active gage element and adjacent portions of a wellbore;

FIGURE 8B is a schematic drawing taken along lines 8B-8B of FIGURE 8A;

FIGURE 8C is a schematic drawing in elevation with portions broken away showing one example of interaction between a passive gage element and adjacent portions of a wellbore;

FIGURE 8D is a schematic drawing taken along lines 8D-8D of FIGURE 8C;

FIGURE 9 is a graphical representation of forces used to calculate a walk angle of a rotary drill bit at a downhole location within a wellbore;

FIGURE 10 is a graphical representation of forces used to calculate a walk angle of a rotary drill bit at a respective downhole location in a wellbore;

FIGURE 11 is a schematic drawing in section with portions broken away of a rotary drill bit showing changes in dogleg severity with respect to side forces applied to a rotary drill bit during drilling of a directional wellbore;

FIGURE 12 is a schematic drawing in section with portions broken away of a rotary drill bit showing changes in torque on bit (TOB) with respect to revolutions of a rotary drill bit during drilling of a directional wellbore;

FIGURE 13A is a graphical representation of various dimensions associated with a push-the-bit directional drilling system;

FIGURE 13B is a graphical representation of various dimensions associated with a point-the-bit directional drilling system;

FIGURE 14A is a schematic drawing in section with portions broken away showing interaction between a rotary drill bit and two inclined formations during generally vertical drilling relative to the formation;

FIGURE 14B is a schematic drawing in section with portions broken away showing a graphical representation of a rotary drill bit interacting with two inclined formations during directional drilling relative to the formations;

FIGURE 14C is a schematic drawing in section with portions broken away showing a graphical representation of a rotary drill bit interacting with two inclined formations during directional drilling of the formations;

FIGURE 14D shows one example of a three dimensional graphical simulation incorporating teachings of the present disclosure of a rotary drill bit penetrating a first rock layer and a second rock layer;

FIGURE 15A is a schematic drawing showing a graphical representation of a spherical coordinate system which may be used to describe motion of a rotary drill bit and also describe the bottom of a wellbore in accordance with teachings of the present disclosure;

FIGURE 15B is a schematic drawing showing forces operating on a rotary drill bit against the bottom and/or the sidewall of a bore hole in a spherical coordinate system;

FIGURE 15C is a schematic drawing showing forces acting on a cutter of a rotary drill bit in a cutter local coordinate system;

FIGURES 16 is a graphical representation of one example of calculations used to estimate cutting depth of a cutter disposed on a rotary drill bit in accordance with teachings of the present disclosure;

FIGURES 17A-17G is a block diagram showing one example of a method for simulating or modeling drilling of a directional wellbore using a rotary drill bit in accordance with teachings of the present disclosure; and

FIGURE 18 is a graphical representation showing examples of the results of multiple simulations incorporating teachings of the present disclosure of using a rotary drill bit and associated downhole equipment to form a wellbore.

DETAILED DESCRIPTION OF THE DISCLOSURE

Preferred embodiments of the present disclosure and their advantages may be understood by referring to FIGURES 1A-17G of the drawings, like numerals may be used for like and corresponding parts of the various drawings.

The term "bottom hole assembly" or "BHA" may be used in this application to describe various components and assemblies disposed proximate to a rotary drill bit at the downhole end of a drill string. Examples of components and assemblies (not expressly shown) which may be included in a bottom hole assembly or BHA include, but are not limited to, a bent sub, a downhole drilling motor, a near bit reamer, stabilizers and down hole instruments. A bottom hole assembly may also include various types of well logging tools (not expressly shown) and other downhole instruments associated with directional drilling of a wellbore. Examples of such logging tools and/or directional drilling equipment may include, but are not limited to, acoustic, neutron, gamma ray, density, photoelectric, nuclear magnetic resonance and/or any other commercially available logging instruments.

The term "cutter" may be used in this application to include various types of compacts, inserts, milled teeth, welded compacts and gage cutters satisfactory for use with a wide variety of rotary drill bits. Impact arrestors, which may be included as part of the cutting structure on some types of rotary drill bits, sometimes function as cutters to remove formation materials from adjacent portions of a wellbore. Impact arrestors or any other portion of the cutting structure of a rotary drill bit may be analyzed and evaluated using various techniques and procedures as discussed herein with respect to cutters. Polycrystalline diamond compacts (PDC) and tungsten carbide inserts are often used to form cutters for rotary drill bits. A wide variety of other types of hard, abrasive materials may also be satisfactorily used to form such cutters.

The terms "cutting element" and "cutlet" may be used to describe a small portion or segment of an associated cutter which interacts with adjacent portions of a wellbore and may be used to simulate interaction between the cutter and adjacent portions of a wellbore. As discussed later in more detail, cutters and other portions of a rotary drill bit may also be meshed into small segments or portions sometimes referred to as "mesh units" for purposes of analyzing interaction between each small portion or segment and adjacent portions of a wellbore.

The term "cutting structure" may be used in this application to include various combinations and arrangements of cutters, face cutters, impact arrestors and/or gage cutters formed on exterior portions of a rotary drill bit. Some fixed cutter drill bits may include one or more blades extending from an associated bit body with cutters disposed of the blades. Various configurations of blades and cutters may be used to form cutting structures for a fixed cutter drill bit.

The term "rotary drill bit" may be used in this application to include various types of fixed cutter drill bits, drag bits and matrix drill bits operable to form a wellbore extending through one or more downhole formations. Rotary drill bits and associated components formed in accordance with teachings of the present disclosure may have many different designs and configurations.

Simulating drilling a wellbore in accordance with teachings of the present disclosure may be used to optimize the design of various features of a rotary drill bit including, but not limited to, the number of blades or cutter blades, dimensions and configurations of each cutter blade, configuration and dimensions of junk slots disposed between adjacent cutter blades, the number, location, orientation and type of cutters and gages (active or passive) and length of associated gages. The location of nozzles and associated nozzle outlets may also be optimized.

Various teachings of the present disclosure may also be used with other types of rotary drill bits having active or passive gages similar to active or passive gages associated with fixed cutter drill bits. For example, a stabilizer (not expressly shown) located relatively close to a roller cone drill bit (not expressly shown) may function similar to a passive gage portion of a fixed cutter drill bit. A near bit reamer (not expressly shown) located relatively close to a roller cone drill bit may function similar to an active gage portion of a fixed cutter drill bit.

For fixed cutter drill bits one of the differences between a "passive gage" and an "active gage" is that a passive gage will generally not remove formation materials from the sidewall of a wellbore or borehole while an active gage may at least partially cut into the sidewall of a wellbore or borehole during directional drilling. A passive gage may deform a sidewall plastically or elastically during directional drilling. Mathematically, if we define aggressiveness of a typical face cutter as one (1.0), then aggressiveness of a passive gage is nearly zero (0) and aggressiveness of an active gage may be between 0 and 1.0, depending on the configuration of respective active gage elements.

Aggressiveness of various types of active gage elements may be determined by testing and may be inputted into a simulation program such as represented by FIGURES 17A-17G. Similar comments apply with respect to near bit stabilizers and near bit reamers contacting adjacent portions of a wellbore. Various characteristics of active and passive gages will be discussed in more detail with respect to FIGURES 7A-8D.

The term "straight hole" may be used in this application to describe a wellbore or portions of a wellbore that extends at generally a constant angle relative to vertical. Vertical wellbores and horizontal wellbores are examples of straight holes.

The terms "slant hole" and "slant hole segment" may be used in this application to describe a straight hole formed at a substantially constant angle relative to vertical. The constant angle of a slant hole is typically less than ninety (90) degrees and greater than zero (0) degrees.

Most straight holes such as vertical wellbores and horizontal wellbores with any significant length will have some variation from vertical or horizontal based in part on characteristics of associated drilling equipment used to form such wellbores. A slant hole may have similar variations depending upon the length and associated drilling equipment used to form the slant hole.

The term "directional wellbore" may be used in this application to describe a wellbore or portions of a wellbore that extend at a desired angle or angles relative to vertical. Such angles are greater than normal variations associated with straight holes. A directional wellbore sometimes may be described as a wellbore deviated from vertical.

Sections, segments and/or portions of a directional wellbore may include, but are not limited to, a vertical section, a kick off section, a building section, a holding section and/or a dropping section. A vertical section may have substantially no change in degrees from vertical. Holding sections such as slant hole segments and horizontal segments may extend at respective fixed angles relative to vertical and may have substantially zero rate of change in degrees from vertical. Transition sections formed between straight hole portions of a wellbore may include, but are not limited to, kick off segments, building segments and dropping segments. Such transition sections generally have a rate of change in degrees greater than zero. Building segments generally have a positive rate of change in degrees. Dropping segments generally have a negative rate of change in degrees. The rate of change in degrees may vary along the length of all or portions of a transition section or may be substantially constant along the length of all or portions of the transition section.

The term "kick off segment" may be used to describe a portion or section of a wellbore forming a transition between the end point of a straight hole segment and the first point where a desired DLS or tilt rate is achieved. A kick off segment may be formed as a transition from a vertical wellbore to an equilibrium wellbore with a constant curvature or tilt rate. A kick off segment of a wellbore may have a variable curvature and a variable rate of change in degrees from vertical (variable tilt rate).

A building segment having a relatively constant radius and a relatively constant change in degrees from vertical (constant tilt rate) may be used to form a transition from vertical segments to a slant hole segment or horizontal segment of a wellbore. A dropping segment may have a relatively constant radius and a relatively constant change in degrees from vertical (constant tilt rate) may be used to form a transition from a slant hole segment or a horizontal segment to a vertical segment of a wellbore. See FIGURE 1A. For some applications a transition between a vertical segment and a horizontal segment may only be a building segment having a relatively constant radius and a relatively constant change in degrees from vertical. See FIGURE 1B. Building segments and dropping segments may also be described as "equilibrium" segments.

The terms "dogleg severity" or "DLS" may be used to describe the rate of change in degrees of a wellbore from vertical during drilling of the wellbore. DLS is often measured in degrees per one hundred feet (°/100 ft). A straight hole, vertical hole, slant hole or horizontal hole will generally have a value of DLS of approximately zero. DLS may be positive, negative or zero.

Tilt angle (TA) may be defined as the angle in degrees from vertical of a segment or portion of a wellbore. A vertical wellbore has a generally constant tilt angle (TA) approximately equal to zero. A horizontal wellbore has a generally constant tilt angle (TA) approximately equal to ninety degrees (90°).

Tilt rate (TR) may be defined as the rate of change of a wellbore in degrees (TA) from vertical per hour of drilling. Tilt rate may also be referred to as "steer rate."

$$TR = \frac{d(TA)}{dt}$$

Where t = drilling time in hours

Tilt rate (TR) of a rotary drill bit may also be defined as DLS times rate of penetration (ROP).

TR = DLS x ROP/100 = (degrees/hour)

Bit tilting motion is often a critical parameter for accurately simulating drilling directional wellbores and evaluating characteristics of rotary drill bits and other downhole tools used with directional drilling systems. Prior two dimensional (2D) and prior three dimensional (3D) bit models and hole models are often unable to consider bit tilting motion due to limitations of Cartesian coordinate systems or cylindrical coordinate systems used to describe bit motion relative to a wellbore. The use of spherical coordinate system to simulate drilling of directional wellbore in accordance with teachings of the present disclosure allows the use of bit tilting motion and associated parameters to enhance the accuracy and reliability of such simulations.

Various aspects of the present disclosure may be described with respect to modeling or simulating drilling a wellbore or portions of a wellbore. Dogleg severity (DLS) of respective segments, portions or sections of a wellbore and corresponding tilt rate (TR) may be used to conduct such simulations. Appendix A lists some examples of data including parameters such as simulation run time and simulation mesh size which may be used to conduct such simulations.

Various features of the present disclosure may also be described with respect to modeling or simulating drilling of a wellbore based on at least one of three possible drilling modes. See for example, FIGURE 17A. A first drilling mode (straight hole drilling) may be used to simulate forming segments of a wellbore having a value of DLS approximately equal to zero. A second drilling mode (kick off drilling) may be used to simulate forming segments of a wellbore having a value of DLS greater than zero and a value of DLS which varies along portions of an associated section or segment of the wellbore. A third drilling mode (building or dropping) may be used to simulate drilling segments of a wellbore having a relatively constant value of DLS (positive or negative) other than zero.

The terms "downhole data" and "downhole drilling conditions" may include, but are not limited to, wellbore data and formation data such as listed on Appendix A. The terms "downhole data" and "downhole drilling conditions" may also include, but are not limited to, drilling equipment operating data such as listed on Appendix A.

The terms "design parameters," "operating parameters," "wellbore parameters" and "formation parameters" may sometimes be used to refer to respective types of data such as listed on Appendix A. The terms "parameter" and "parameters" may be used to describe a range of data or multiple ranges of data. The terms "operating" and "operational" may sometimes be used interchangeably.

Directional drilling equipment may be used to form wellbores having a wide variety of profiles or trajectories. Directional drilling system 20 and wellbore 60 as shown in FIGURE 1A may be used to describe various features of the present disclosure with respect to simulating drilling all or portions of a wellbore and designing or selecting drilling equipment such as a rotary drill bit based at least in part on such simulations.

Directional drilling system 20 may include land drilling rig 22. However, teachings of the present disclosure may be satisfactorily used to simulate drilling wellbores using drilling systems associated with offshore platforms, semi-submersible, drill ships and any other drilling system satisfactory for forming a wellbore extending through one or more downhole formations. The present disclosure is not limited to directional drilling systems or land drilling rigs.

Drilling rig 22 and associated directional drilling equipment 50 may be located proximate well head 24. Drilling rig 22 also includes rotary table 38, rotary drive motor 40 and other equipment associated with rotation of drill string 32 within wellbore 60. Annulus

66 may be formed between the exterior of drill string 32 and the inside diameter of wellbore 60.

For some applications drilling rig 22 may also include top drive motor or top drive unit 42. Blow out preventors (not expressly shown) and other equipment associated with drilling a wellbore may also be provided at well head 24. One or more pumps 26 may be used to pump drilling fluid 28 from fluid reservoir or pit 30 to one end of drill string 32 extending from well head 24. Conduit 34 may be used to supply drilling mud from pump 26 to the one end of drilling string 32 extending from well head 24. Conduit 36 may be used to return drilling fluid, formation cuttings and/or downhole debris from the bottom or end 62 of wellbore 60 to fluid reservoir or pit 30. Various types of pipes, tube and/or conduits may be used to form conduits 34 and 36.

Drill string 32 may extend from well head 24 and may be coupled with a supply of drilling fluid such as pit or reservoir 30. Opposite end of drill string 32 may include bottom hole assembly 90 and rotary drill bit 100 disposed adjacent to end 62 of wellbore 60. As discussed later in more detail, rotary drill bit 100 may include one or more fluid flow passageways with respective nozzles disposed therein. Various types of drilling fluids may be pumped from reservoir 30 through pump 26 and conduit 34 to the end of drill string 32 extending from well head 24. The drilling fluid may flow through a longitudinal bore (not expressly shown) of drill string 32 and exit from nozzles formed in rotary drill bit 100.

At end 62 of wellbore 60 drilling fluid may mix with formation cuttings and other downhole debris proximate drill bit 100. The drilling fluid will then flow upwardly through annulus 66 to return formation cuttings and other downhole debris to well head 24. Conduit 36 may return the drilling fluid to reservoir 30. Various types of screens, filters and/or centrifuges (not expressly shown) may be provided to remove formation cuttings and other downhole debris prior to returning drilling fluid to pit 30.

Bottom hole assembly 90 may include various components associated with a measurement while drilling (MWD) system that provides logging data and other information from the bottom of wellbore 60 to directional drilling equipment 50. Logging data and other information may be communicated from end 62 of wellbore 60 through drill string 32 using MWD techniques and converted to electrical signals at well surface 24. Electrical conduit or wires 52 may communicate the electrical signals to input device 54. The logging data provided from input device 54 may then be directed to a data processing system 56. Various displays 58 may be provided as part of directional drilling equipment 50.

For some applications printer 59 and associated printouts 59a may also be used to monitor the performance of drilling string 32, bottom hole assembly 90 and associated rotary drill bit 100. Outputs 57 may be communicated to various components associated with operating drilling rig 22 and may also be communicated to various remote locations to monitor the performance of directional drilling system 20.

Wellbore 60 may be generally described as a directional wellbore or a deviated wellbore having multiple segments or sections. Section 60a of wellbore 60 may be defined by casing 64 extending from well head

24 to a selected downhole location. Remaining portions of wellbore 60 as shown in FIGURE 1A may be generally described as "open hole" or "uncased."

Teachings of the present disclosure may be used to simulate drilling a wide variety of vertical, directional, deviated, slanted and/or horizontal wellbores. Teachings of the present disclosure are not limited to simulating drilling wellbore 60, designing drill bits for use in drilling wellbore 60 or selecting drill bits from existing designs for use in drilling wellbore 60.

Wellbore 60 as shown in FIGURE 1A may be generally described as having multiple sections, segments or portions with respective values of DLS. The tilt rate for rotary drill bit 100 during formation of wellbore 60 will be a function of DLS for each segment, section or portion of wellbore 60 times the rate of penetration for rotary drill bit 100 during formation of the respective segment, section or portion thereof. The tilt rate of rotary drill bit 100 during formation of straight hole sections or vertical section 80a and horizontal section 80c will be approximately equal to zero.

Section 60a extending from well head 24 may be generally described as a vertical, straight hole section with a value of DLS approximately equal to zero. When the value of DLS is zero, rotary drill bit 100 will have a tile rate of approximately zero during formation of the corresponding section of wellbore 60.

A first transition from vertical section 60a may be described as kick off section 60b. For some applications the value of DLS for kick off section 60b may be greater than zero and may vary from the end of vertical section

60a to the beginning of a second transition segment or building section 60c. Building section 60c may be formed with relatively constant radius 70c and a substantially constant value of DLS. Building section 60c may also be referred to as third section 60c of wellbore 60.

Fourth section 60d may extend from build section 60c opposite from second section 60b. Fourth section 60d may be described as a slant hole portion of wellbore 60. Section 60d may have a DLS of approximately zero. Fourth section 60d may also be referred to as a "holding" section.

Fifth section 60e may start at the end of holding section 60d. Fifth section 60e may be described as a "drop" section having a generally downward looking profile. Drop section 60e may have relatively constant radius 70e.

Sixth section 60f may also be described as a holding section or slant hole section with a DLS of approximately zero. Section 60f as shown in FIGURE 1A is being formed by rotary drill bit 100, drill string 32 and associated components of drilling system 20.

FIGURE 1B is a graphical representation of a specific type of directional wellbore represented by wellbore 80. For this example wellbore 80 may include three segments or three sections - vertical section 80a, building section 80b and horizontal section 80c. Vertical section 80a and horizontal section 80c may be straight holes with a value of DLS approximately equal to zero. Building section 80b may have a constant radius corresponding with a constant rate of change in degrees from vertical and a constant value of DLS. Tilt rate during formation building section 80b may be constant if

ROP of a drill bit forming build section 80b remains constant.

Movement or motion of a rotary drill bit and associated drilling equipment in three dimensions (3D) during formation of a segment, section or portion of a wellbore may be defined by a Cartesian coordinate system (X, Y, and Z axes) and/or a spherical coordinate system (two angles φ and θ and a single radius ρ) in accordance with teachings of the present disclosure. Examples of Cartesian coordinate systems are shown in FIGURES 2A and 3A-3C. Examples of spherical coordinate systems are shown in FIGURES 15A and 16. Various aspects of the present disclosure may include translating the location of downhole drilling equipment and adjacent portions of a wellbore between a Cartesian coordinate system and a spherical coordinate system. FIGURE 15A shows one example of translating the location of a single point between a Cartesian coordinate system and a spherical coordinate system.

Figure 1C shows one example of a system operable to simulate drilling a complex, directional wellbore in accordance with teachings of this present disclosure. System 300 may include one or more processing resources 310 operable to run software and computer programs incorporating teaching of the present disclosure. A general purpose computer may be used as a processing resource. All or portions of software and computer programs used by processing resource 310 may be stored one or more memory resources 320. One or more input devices 330 may be operate to supply data and other information to processing resources 310 and/or memory resources 320. A keyboard, keypad, touch screen and other digital input mechanisms may be used as an input device. Examples of such data are shown on Appendix A.

Processing resources 310 may be operable to simulate drilling a directional wellbore in accordance with teachings of the present disclosure. Processing resources 310 may be operate to use various algorithms to make calculations or estimates based on such simulations.

Display resources 340 may be operable to display both data input into processing resources 310 and the results of simulations and/or calculations performed in accordance with teachings of the present disclosure. A copy of input data and results of such simulations and calculations may also be provided at printer 350.

For some applications, processing resource 310 may be operably connected with communication network 360 to accept inputs from remote locations and to provide the results of simulation and associated calculations to remote locations and/or facilities such as directional drilling equipment 50 shown in FIGURE 1A.

A Cartesian coordinate system generally includes a Z axis and an X axis and a Y axis which extend normal to each other and normal to the Z axis. See for example FIGURE 2A. A Cartesian bit coordinate system may be defined by a Z axis extending along a rotational axis or bit rotational axis of the rotary drill bit. See FIGURE 2A. A Cartesian hole coordinate system (sometimes referred to as a "downhole coordinate system" or a "wellbore coordinate system") may be defined by a Z axis extending along a rotational axis of the wellbore. See FIGURE 3B. In FIGURE 2A the X, Y and Z axes include subscript $_{(b)}$ to indicate a "bit coordinate system". In

FIGURES 3A, 3B and 3C the X, Y and Z axes include subscript $_{(h)}$ to indicate a "hole coordinate system".

FIGURE 2A is a schematic drawing showing rotary drill bit 100. Rotary drill bit 100 may include bit body 120 having a plurality of blades 128 with respective junk slots or fluid flow paths 140 formed therebetween. A plurality of cutting elements 130 may be disposed on the exterior portions of each blade 128. Various parameters associated with rotary drill bit 100 including, but not limited to, the location and configuration of blades 128, junk slots 140 and cutting elements 130. Such parameters may be designed in accordance with teachings of the present disclosure for optimum performance of rotary drill bit 100 in forming portions of a wellbore.

Each blade 128 may include respective gage surface or gage portion 154. Gage surface 154 may be an active gage and/or a passive gage. Respective gage cutter 130g may be disposed on each blade 128. A plurality of impact arrestors 142 may also be disposed on each blade 128. Additional information concerning impact arrestors may be found in U.S. Patents 6,003,623, 5,595,252 and 4,889,017.

Rotary drill bit 100 may translate linearly relative to the X, Y and Z axes as shown in FIGURE 2A (three (3) degrees of freedom). Rotary drill bit 100 may also rotate relative to the X, Y and Z axes (three (3) additional degrees of freedom). As a result movement of rotary drill bit 100 relative to the X, Y and Z axes as shown in FIGURES 2A and 2B, rotary drill bit 100 may be described as having six (6) degrees of freedom.

Movement or motion of a rotary drill bit during formation of a wellbore may be fully determined or defined by six (6) parameters corresponding with the previously noted six degrees of freedom. The six parameters as shown in FIGURE 2A include rate of linear motion or translation of rotary drill bit 100 relative to respective X, Y and Z axes and rotational motion relative to the same X, Y and Z axes. These six parameters are independent of each other.

For straight hole drilling these six parameters may be reduced to revolutions per minute (RPM) and rate of penetration (ROP). For kick off segment drilling these six parameters may be reduced to RPM, ROP, dogleg severity (DLS), bend length (B_L) and azimuth angle of an associated tilt plane. See tilt plane 170 in FIGURE 3B. For equilibrium drilling these six parameters may be reduced to RPM, ROP and DLS based on the assumption that the rotational axis of the associated rotary drill bit will move in the same vertical plane or tilt plane.

For calculations related to steerability only forces acting in an associated tilt plane are considered. Therefore an arbitrary azimuth angle may be selected usually equal to zero. For calculations related to bit walk forces in the associated tilt plane and forces in a plane perpendicular to the tilt plane are considered.

In a bit coordinate system, rotational axis or bit rotational axis 104a of rotary drill bit 100 corresponds generally with Z axis 104 of the associated bit coordinate system. When sufficient force from rotary drill string 32 has been applied to rotary drill bit 100, cutting elements 130 will engage and remove adjacent portions of a downhole formation at bottom hole or end 62 of wellbore 60. Removing such formation materials will allow downhole drilling equipment including rotary drill bit 100 and associated drill string 32 to tilt or move linearly relative to adjacent portions of wellbore 60.

Various kinematic parameters associated with forming a wellbore using a rotary drill bit may be based upon revolutions per minute (RPM) and rate of penetration (ROP) of the rotary drill bit into adjacent portions of a downhole formation. Arrow 110 may be used to represent forces which move rotary drill bit 100 linearly relative to rotational axis 104a. Such linear forces typically result from weight applied to rotary drill bit 100 by drill string 32 and may be referred to as "weight on bit" or WOB.

Rotational force 112 may be applied to rotary drill bit 100 by rotation of drill string 32. Revolutions per minute (RPM) of rotary drill bit 100 may be a function of rotational force 112. Rotation speed (RPM) of drill bit 100 is generally defined relative to the rotational axis of rotary drill bit 100 which corresponds with Z axis 104.

Arrow 116 indicates rotational forces which may be applied to rotary drill bit 100 relative to X axis 106. Arrow 118 indicates rotational forces which may be applied to rotary drill bit 100 relative to Y axis 108. Rotational forces 116 and 118 may result from interaction between cutting elements 130 disposed on exterior portions of rotary drill bit 100 and adjacent portions of bottom hole 62 during the forming of wellbore 60. Rotational forces applied to rotary drill bit 100 along X axis 106 and Y axis 108 may result in tilting of rotary drill bit 100 relative to adjacent portions of drill string 32 and wellbore 60.

FIGURE 2B is a schematic drawing showing rotary drill bit 100 disposed within vertical section or straight hole section 60a of wellbore 60. During the drilling of a vertical section or any other straight hole section of a wellbore, the bit rotational axis of rotary drill bit 100 will generally be aligned with a corresponding rotational axis of the straight hole section. The incremental change or the incremental movement of rotary drill bit 100 in a linear direction during a single revolution may be represented by ΔZ in FIGURE 2B.

Rate of penetration (ROP) of a rotary drill bit is typically a function of both weight on bit (WOB) and revolutions per minute (RPM). For some applications a downhole motor (not expressly shown) may be provided as part of bottom hole assembly 90 to also rotate rotary drill bit 100. The rate of penetration of a rotary drill bit is generally stated in feet per hour.

The axial penetration of rotary drill bit 100 may be defined relative to bit rotational axis 104a in an associated bit coordinate system. A side penetration rate or lateral penetration rate of rotary drill bit 100 may be defined relative to an associated hole coordinate system. Examples of a hole coordinate system are shown in FIGURES 3A, 3B and 3C. FIGURE 3A is a schematic representation of a model showing side force 114 applied to rotary drill bit 100 relative to X axis 106 and Y axis 108. Angle 72 formed between force vector 114 and X axis 106 may correspond approximately with angle 172 associated with tilt plane 170 as shown in FIGURE 3B. A tilt plane may be defined as a plane extending from an associated Z axis or vertical axis in which dogleg severity (DLS) or tilting of the rotary drill bit occurs.

Various forces may be applied to rotary drill bit 100 to cause movement relative to X axis 106 and Y axis 108. Such forces may be applied to rotary drill bit 100 by one or more components of a directional drilling system included within bottom hole assembly 90. See FIGURES 4A, 4B, 5A and 5B. Various forces may also be applied to rotary drill bit 100 relative to X axis 106 and Y axis 108 in response to engagement between cutting elements 130 and adjacent portions of a wellbore.

During drilling of straight hole segments of wellbore 60, side forces applied to rotary drill bit 100 may be substantially minimized (approximately zero side forces) or may be balanced such that the resultant value of any side forces will be approximately zero. Straight hole segments of wellbore 60 as shown in FIGURE 1A include, but are not limited to, vertical section 60a, holding section or slant hole section 60d, and holding section or slant hole section 60f.

One of the benefits of the present disclosure may include the ability to design a rotary drill bit having either substantially zero side forces or balanced sided forces while drilling a straight hole segment of a wellbore. As a result, any side forces applied to a rotary drill bit by associated cutting elements may be substantially balanced and/or reduced to a small value such that rotary drill bit 100 will have either substantially zero tendency to walk or a neutral tendency to walk relative to a vertical axis.

During formation of straight hole segments of wellbore 60, the primary direction of movement or translation of rotary drill bit 100 will be generally linear relative to an associated longitudinal axis of the respective wellbore segment and relative to associated bit rotational axis 104a. See FIGURE 2B. During the drilling of portions of wellbore 60 having a DLS with a value greater than zero or less than zero, a side force (F_s) or equivalent side force may be applied to rotary drill bit to cause formation of corresponding wellbore segments 60b, 60c and 60e.

For some applications such as when a push-the-bit directional drilling system is used with a rotary drill bit, an applied side force may result in a combination of bit tilting and side cutting or lateral penetration of adjacent portions of a wellbore. For other applications such as when a point-the-bit directional drilling system is used with an associated rotary drill bit, side cutting or lateral penetration may generally be very small or may not even occur. When a point-the-bit directional drilling system is used with a rotary drill bit, directional portions of a wellbore may be formed primarily as a result of bit penetration along an associated bit rotational axis and tilting of the rotary drill bit relative to a vertical axis.

FIGURES 3A, 3B and 3C are graphical representations of various kinematic parameters which may be satisfactorily used to model or simulate drilling segments or portions of a wellbore having a value of DLS greater than zero. FIGURE 3A shows a schematic cross section of rotary drill bit 100 in two dimensions relative to a Cartesian bit coordinate system. The bit coordinate system is defined in part by X axis 106 and Y axis 108 extending from bit rotational axis 104a.

FIGURES 3B and 3C show graphical representations of rotary drill bit 100 during drilling of a transition segment such as kick off segment 60b of wellbore 60 in a Cartesian hole coordinate system defined in part by Z axis 74, X axis 76 and Y axis 78.

A side force is generally applied to a rotary drill bit by an associated directional drilling system to form a wellbore having a desired profile or trajectory using the rotary drill bit. For a given set of drilling equipment design parameters and a given set of downhole drilling conditions, a respective side force must be applied to an associated rotary drill bit to achieve a desired DLS or tilt rate. Therefore, forming a directional wellbore using a point-the-bit directional drilling system, a push-the-bit directional drilling system or any other directional drilling system may be simulated using substantially the same model incorporating teachings of the present disclosure by determining a required bit side force to achieve an expected DLS or tilt rate for each segment of a directional wellbore.

FIGURE 3A shows side force 114 extending at angle 72 relative to X axis 106. Side force 114 may be applied to rotary drill bit 100 by directional drilling system 20. Angle 72 (sometimes referred to as an "azimuth" angle) extends from rotational axis 104a of rotary drill bit 100 and represents the angle at which side force 114 will be applied to rotary drill bit 100. For some applications side force 114 may be applied to rotary drill bit 100 at a relatively constant azimuth angle.

Side force 114 will typically result in movement of rotary drill bit 100 laterally relative to adjacent portions of wellbore 60. Directional drilling systems such as rotary drill bit steering units shown in FIGURES 4A and 5A may be used to either vary the amount of side force 114 or to maintain a relatively constant amount of side force 114 applied to rotary drill bit 100. Directional drilling systems may also vary the azimuth angle at which a side force is applied to correspond with a desired wellbore trajectory.

Side force 114 may be adjusted or varied to cause associated cutting elements 130 to interact with adjacent portions of a downhole formation so that rotary drill bit 100 will follow profile or trajectory 68b, as shown in FIGURE 3B, or any other desired profile. Profile 68b may correspond approximately with a longitudinal axis extending through kick off segment 60b. Rotary drill bit 100 will generally move only in tilt plane 170 during formation of kickoff segment 60b if rotary drill bit 100 has zero walk tendency or neutral walk tendency. Tilt plane 170 may also be referred to as an "azimuth plane".

Respective tilting angles (not expressly shown) of rotary drill bit 100 will vary along the length of trajectory 68b. Each tilting angle of rotary drill bit 100 as defined in a hole coordinate system (Z_h, X_h, Y_h) will generally lie in tilt plane 170. As previously noted, during the formation of a kickoff segment of a wellbore, tilting rate in degrees per hour as indicated by arrow 174 will also increase along trajectory 68b. For use in simulating forming kickoff segment 60b, side penetration rate, side penetration azimuth angle, tilting rate and tilt plane azimuth angle may be defined in a hole coordinate system which includes Z axis 74, X axis 76 and Y axis 78.

Arrow 174 corresponds with the variable tilt rate of rotary drill bit 100 relative to vertical at any one location along trajectory 68b. During movement of rotary drill bit 100 along profile or trajectory 68a, the respective tilt angle at each location on trajectory 68a will generally increase relative to Z axis 74 of the hole coordinate system shown in FIGURE 3B. For embodiments such as shown in FIGURE 3B, the tilt angle at each point on trajectory 68b will be approximately equal to an angle formed by a respective tangent extending from the point in question and intersecting Z axis 74. Therefore, the tilt rate will also vary along the length of trajectory 168.

During the formation of kick off segment 60b and any other portions of a wellbore in which the value of DLS is either greater than or less than zero and is not constant, rotary drill bit 100 may experience side cutting motion, bit tilting motion and axial penetration in a direction associated with cutting or removing of formation materials from the end or bottom of a wellbore.

For embodiments such as shown in FIGURES 3A, 3B and 3C directional drilling system 20 may cause rotary drill bit 100 to move in the same azimuth plane 170 during formation of kick off segment 60b. FIGURES 3B and 3C show relatively constant azimuth plane angle 172 relative to the X axis 76 and Y axis 78. Arrow 114 as shown in FIGURE 3B represents a side force applied to rotary drill bit 100 by directional drilling system 20. Arrow 114 will generally extend normal to rotational axis 104a of rotary drill bit 100. Arrow 114 will also be disposed in tilt plane 170. A side force applied to a rotary drill bit in a tilt plane by an associate rotary drill bit steering unit or directional drilling system may also be referred to as a "steer force."

During the formation of a directional wellbore such as shown in FIGURE 3B, without consideration of bit walk, rotational axis 104a of rotary drill bit 100 and a longitudinal axis of bottom hole assembly 90 may generally lie in tilt plane 170. Rotary drill bit 100 will experience tilting motion in tilt plane 170 while rotating relative to rotational axis 104a. The tilting motion may result from a side force or steer force applied to rotary drill bit 100 by a directional steering unit such as shown in FIGURES 4A AND 4B or 5A and 5B of an associated directional drilling system. The tilting motion results from a combination of side forces and/or axial forces applied to rotary drill bit 100 by directional drilling system 20.

If rotary drill bit 100 walks, either left or right, bit 100 will generally not move in the same azimuth plane or tilt plane 170 during formation of kickoff segment 60b. As discussed later in more detail with respect to FIGURES 9 and 10 rotary drill bit 100 may also experience a walk force (F_W) as indicated by arrow 177. Arrow 177 as shown in FIGURES 3B and 3C represents a walk force which will cause rotary drill bit 100 to "walk" left relative to tilt plane 170. Simulations of forming a wellbore in accordance with teachings of the present disclosure may be used to modify cutting elements, bit face profiles, gages and other characteristics of a rotary drill bit to substantially reduce or minimize the walk force represented by arrow 177 or to provide a desired right walk rate or left walk rate.

Various features of the present disclosure will be discussed with respect to directional drilling equipment including rotary drills such as shown in FIGURES 4A, 4B, 51 and 5B. These features may be described with respect to vertical axis 74 or Z axis 74 of a Cartesian hole coordinate system such as shown in FIGURE 3B. During drilling of a vertical segment or other types of straight hole segments, vertical axis 74 will generally be aligned with and correspond to an associate longitudinal axis of the vertical segment or straight hole segment. Vertical axis 74 will also generally be aligned with and correspond to an associate bit rotational axis during such straight hole drilling.

FIGURE 4A shows portions of bottom hole assembly 90a disposed in a generally vertical portion 60a of wellbore 60 as rotary drill bit 100a begins to form kick off segment 60b. Bottom hole assembly 90a may include rotary drill bit steering unit 92a operable to apply side force 114 to rotary drill bit 100a. Steering unit 92a may be one portion of a push-the-bit directional drilling system.

Push-the-bit directional drilling systems generally require simultaneous axial penetration and side penetration in order to drill directionally. Bit motion associated with push-the-bit directional drilling systems is often a combination of axial bit penetration, bit rotation, bit side cutting and bit tilting. Simulation of forming a wellbore using a push-the-bit directional drilling system based on a 3D model operable to consider bit tilting motion may result in a more accurate simulation. Some of the benefits of using a 3D model operable to consider bit tilting motion in accordance with teachings of the present disclosure will be discussed with respect to FIGURES 6A-6D.

Steering unit 92a may extend arm 94a to apply force 114a to adjacent portions of wellbore 60 and maintain desired contact between steering unit 92a and adjacent portions of wellbore 60. Side forces 114 and 114a may be approximately equal to each other. If there is no weight on rotary drill bit 100a, no axial penetration will occur at end or bottom hole 62 of wellbore 60. Side cutting will generally occur as portions of rotary drill bit 100a engage and remove adjacent portions of wellbore 60a.

Figure 4B shows various parameters associated with a push-the-bit directional drilling system. Steering unit 92a will generally include bent subassembly 96a. A wide variety of bent subassemblies (sometimes referred to as "bent subs") may be satisfactorily used to allow drill string 32 to rotate drill bit 100a while steering unit 92a pushes or applies required force to move rotary drill bit 100a at a desired tilt rate relative to vertical axis 74. Arrow 200 represents the rate of penetration relative to the rotational axis of rotary drill bit 100a (ROP_a). Arrow 202 represents the rate of side penetration of rotary drill bit 200 (ROP_s) as steering unit 92a pushes or directs rotary drill bit 100a along a desired trajectory or path.

Tilt rate 174 and associated tilt angle may remain relatively constant for some portions of a directional wellbore such as a slant hole segment or a horizontal hole segment. For other portions of a directional wellbore tilt rate 174 may increase during formation of respective portions of the wellbore such as a kick off segment. Bend length 204a may be a function of the distance between arm 94a contacting adjacent portions of wellbore 60 and the end of rotary drill bit 100a.

Bend length (L_{Bend}) may be used as one of the inputs to simulate forming portions of a wellbore in accordance with teachings of the present disclosure. Bend length or tilt length may be generally described as the distance from a fulcrum point of an associated bent subassembly to a furthest location on a "bit face" or "bit face profile" of an associated rotary drill bit. The furthest location may also be referred to as the extreme end of the associated rotary drill bit.

Some directional drilling techniques and systems may not include a bent subassembly. For such applications bend length may be taken as the distance from a first contact point between an associated bottom hole assembly with adjacent portions of the wellbore to an extreme end of a bit face on an associated rotary drill bit.

During formation of a kick off section or any other portion of a deviated wellbore, axial penetration of an associated drill bit will occur in response to weight on bit (WOB) and/or axial forces applied to the drill bit by a downhole drilling motor. Also, bit tilting motion relative to a bent sub, not side cutting or lateral penetration, will typically result from a side force or lateral force applied to the drill bit as a component of WOB and/or axial forces applied by a downhole drilling motor. Therefore, bit motion is usually a combination of bit axial penetration and bit tilting motion.

When bit axial penetration rate is very small (close to zero) and the distance from the bit to the bent sub or bend length is very large, side penetration or side cutting may be a dominated motion of the drill bit. The resulting bit motion may or may not be continuous when using a push-the-bit directional drilling system depending upon the weight on bit, revolutions per minute, applied side force and other parameters associated with rotary drill bit 100a.

FIGURE 4C is a schematic drawing showing one example of a rotary drill bit which may be designed in accordance with teachings of the present disclosure for optimum performance in a push-the-bit directional drilling system. For example, a three dimensional model such as shown in FIGURES 17A-17G may be used to design a rotary drill bit with optimum active and/or passive gage length for use with a push-the-bit directional drilling system. Rotary drill bit 100a may be generally described as a fixed cutter drill bit. For some applications rotary drill bit 100a may also be described as a matrix drill bit, steel body drill bit and/or a PDC drill bit.

Rotary drill bit 100a may include bit body 120a with shank 122a. The dimensions and configuration of bit body 120a and shank 122a may be substantially modified as appropriate for each rotary drill bit. See FIGURES 5C and 5D.

Shank 122a may include bit breaker slots 124a formed on the exterior thereof. Pin 126a may be formed as an integral part of shank 122a extending from bit body 120a. Various types of threaded connections, including but not limited to, API connections and premium threaded connections may be formed on the exterior of pin 126a.

A longitudinal bore (not expressly shown) may extend from end 121a of pin 126a through shank 122a and into bit body 120a. The longitudinal bore may be used to communicate drilling fluids from drilling string 32 to one or more nozzles (not expressly shown) disposed in bit body 120a. Nozzle outlet 150a is shown in FIGURE 4C.

A plurality of cutter blades 128a may be disposed on the exterior of bit body 120a. Respective junk slots or fluid flow slots 148a may be formed between adjacent blades 128a. Each blade 128 may include a plurality of cutting elements 130 formed from very hard materials associated with forming a wellbore in a downhole formation. For some applications cutting elements 130 may also be described as "face cutters".

Respective gage cutter 130g may be disposed on each blade 128a. For embodiments such as shown in FIGURE 4C rotary drill bit 100a may be described as having an active gage or active gage elements disposed on exterior portion of each blade 128a. Gage surface 154 of each blade 128a may also include a plurality of active gage elements 156. Active gage elements 156 may be formed from various types of hard abrasive materials sometimes referred to as "hardfacing". Active elements 156 may also be described as "buttons" or "gage inserts". As discussed later in more detail with respect to FIGURES 7B, 8A and 8B active gage elements may contact adjacent portions of a wellbore and remove some formation materials as a result of such contact.

Exterior portions of bit body 120a opposite from shank 122a may be generally described as a "bit face" or "bit face profile." As discussed later in more detail with respect to rotary drill bit 100e as shown in FIGURE 7A, a bit face profile may include a generally cone-shaped recess or indentation having a plurality of inner cutters and a plurality of shoulder cutters disposed on exterior portions of each blade 128a. One of the benefits of the present disclosure includes the ability to design a rotary drill bit having an optimum number of inner cutters, shoulder cutters and gage cutters to provide desired walk rate, bit steerability, and bit controllability.

FIGURE 5A shows portions of bottom hole assembly 90b disposed in a generally vertical section of wellbore 60a as rotary drill bit 100b begins to form kick off segment 60b. Bottom hole assembly 90b includes rotary drill bit steering unit 92b which may provide one portion of a point-the-bit directional drilling system.

Point-the-bit directional drilling systems typically form a directional wellbore using a combination of axial bit penetration, bit rotation and bit tilting. Point-the-bit directional drilling systems may not produce side penetration such as described with respect to steering unit 92b in FIGURE 5A. Therefore, bit side penetration is generally not created by point-the-bit directional drilling systems to form a directional wellbore. It is particularly advantageous to simulate forming a wellbore using a point-the-bit directional drilling system using a three dimensional model operable to consider bit tilting motion in accordance with teachings of the present disclosure. One example of a point-the-bit directional drilling system is the Geo-Pilot® Rotary Steerable System available from Sperry Drilling Services at Halliburton Company.

FIGURE 5B is a graphical representation showing various parameters associated with a point-the-bit directional drilling system. Steering unit 92b will generally include bent subassembly 96b. A wide variety of bent subassemblies may be satisfactorily used to allow drill string 32 to rotate drill bit 100c while bent subassembly 96b directs or points drill bit 100c at angle away from vertical axis 174. Some bent subassemblies have a constant "bent angle". Other bent subassemblies have a variable or adjustable "bent angle". Bend length 204b is a function of the dimensions and configurations of associated bent subassembly 96b.

As previously noted, side penetration of rotary drill bit will generally not occur in a point-the-bit directional drilling system. Arrow 200 represents the rate of penetration along rotational axis of rotary drill bit 100c. Additional features of a model used to simulate drilling of directional wellbores for push-the-bit directional drilling systems and point-the-bit directional drilling systems will be discussed with respect to FIGURES 9-13B.

FIGURE 5C is a schematic drawing showing one example of a rotary drill bit which may be designed in accordance with teachings of the present disclosure for optimum performance in a point-the-bit directional drilling system. For example, a three dimensional model such as shown in FIGURES 17A-17F may be used to design a rotary drill bit with an optimum ratio of inner cutters, shoulder cutters and gage cutters in forming a directional wellbore for use with a point-the-bit directional drilling system. Rotary drill bit 100c may be generally described as a fixed cutter drill bit. For some applications rotary drill bit 100c may also be described as a matrix drill bit steel body drill bit and/or a PDC drill bit. Rotary drill bit 100c may include bit body 120c with shank 122c.

Shank 122c may include bit breaker slots 124c formed on the exterior thereof. Shank 122c may also include extensions of associated blades 128c. As shown in FIGURE 5C blades 128c may extend at an especially large spiral or angle relative to an associated bit rotational axis.

One of the characteristics of rotary drill bits used with point-the-bit directional drilling systems may be increased length of associated gage surfaces as compared with push-the-bit directional drilling systems.

Threaded connection pin (not expressly shown) may be formed as part of shank 122c extending from bit body 120c. Various types of threaded connections, including but not limited to, API connections and premium threaded connections may be used to releasably engage rotary drill bit 100c with a drill string.

A longitudinal bore (not expressly shown) may extend through shank 122c and into bit body 120c. The longitudinal bore may be used to communicate drilling fluids from an associated drilling string to one or more nozzles 152 disposed in bit body 120c.

A plurality of cutter blades 128c may be disposed on the exterior of bit body 120c. Respective junk slots or fluid flow slots 148c may be formed between adjacent blades 128a. Each cutter blade 128c may include a plurality of cutters 130d. For some applications cutters 130d may also be described as "cutting inserts". Cutters 130d may be formed from very hard materials associated with forming a wellbore in a downhole formation. The exterior portions of bit body 120c opposite from shank 122c may be generally described as having a "bit face profile" as described with respect to rotary drill bit 100a.

FIGURE 5D is a schematic drawing showing one example of a rotary drill bit which may be designed in accordance with teachings of the present disclosure for optimum performance in a point-the-bit directional drilling system. Rotary drill bit 100d may be generally described as a fixed cutter drill bit. For some applications rotary drill bit 100d may also be described as a matrix drill bit and/or a PDC drill bit. Rotary drill bit 100d may include bit body 120d with shank 122d.

Shank 122d may include bit breaker slots 124d formed on the exterior thereof. Pin threaded connection 126d may be formed as an integral part of shank 122d extending from bit body 120d. Various types of threaded connections, including but not limited to, API connections and premium threaded connections may be formed on the exterior of pin 126d.

A longitudinal bore (not expressly shown) may extend from end 121d of pin 126d through shank 122c and into bit body 120d. The longitudinal bore may be used to communicate drilling fluids from drilling string 32 to one or more nozzles 152 disposed in bit body 120d.

A plurality of cutter blades 128d may be disposed on the exterior of bit body 120d. Respective junk slots or fluid flow slots 148d may be formed between adjacent blades 128d. Each cutter blade 128d may include a plurality of cutters 130f. Respective gage cutters 130g may also be disposed on each blade 128d. For some applications cutters 130f and 130g may also be described as "cutting inserts" formed from very hard materials associated with forming a wellbore in a downhole formation. The exterior portions of bit body 120d opposite from shank 122d may be generally described as having a "bit face profile" as described with respect to rotary drill bit 100a.

Blades 128 and 128d may also spiral or extend at an angle relative to the associated bit rotational axis. One of the benefits of the present disclosure includes simulating drilling portions of a directional wellbore to determine optimum blade length, blade width and blade spiral for a rotary drill bit which may be used to form all or portions of the directional wellbore. For embodiments represented by rotary drill bits 100a, 100c and 100d associated gage surfaces may be formed proximate one end of blades 128a, 128c and 128d opposite an associated bit face profile.

For some applications bit bodies 120a, 120c and 120d may be formed in part from a matrix of very hard materials associated with rotary drill bits. For other applications bit body 120a, 120c and 120d may be machined from various metal alloys satisfactory for use in drilling wellbores in downhole formations. Examples of matrix type drill bits are shown in U.S. Patents 4696354 and 5099929.

FIGURE 6A is a schematic drawing showing one example of a simulation of forming a directional wellbore using a directional drilling system such as shown in FIGURES 4A and 4B or FIGURES 5A and 5B. The simulation shown in FIGURE 6A may generally correspond with forming a transition from vertical segment 60a to kick off segment 60b of wellbore 60 such as shown in FIGURES 4A and 5B. This simulation may be based on several parameters including, but not limited to, bit tilting motion applied to a rotary drill bit during formation of kick off segment 60b. The resulting simulation provides a relatively smooth or uniform inside diameter as compared with the step hole simulation as shown in FIGURE 6C.

A rotary drill bit may be generally described as having three components or three portions for purposes of simulating forming a wellbore in accordance with teachings of the present disclosure. The first component or first portion may be described as "face cutters" or "face cutting elements" which may be primarily responsible for drilling action associated with removal of formation materials to form an associated wellbore. For some types of rotary drill bits the "face cutters" may be further divided into three segments such as "inner cutters," "shoulder cutters" and/or "gage cutters". See, for example, FIGURE 6B and 7A. Penetration force (F_p) is often the principal or primary force acting upon face cutters.

The second portion of a rotary drill bit may include an active gage or gages responsible for protecting face cutters and maintaining a relatively uniform inside diameter of an associated wellbore by removing formation materials adjacent portions of the wellbore. Active gage cutting elements generally contact and remove partially the sidewall portions of a wellbore.

The third component of a rotary drill bit may be described as a passive gage or gages which may be responsible for maintaining uniformity of the adjacent portions of the wellbore (typically the sidewall or inside diameter) by deforming formation materials in adjacent portions of the wellbore. For active and passive gages the primary force is generally a normal force which extends generally perpendicular to the associated gage face either active or passive.

Gage cutters may be disposed adjacent to active and/or passive gage elements. Gage cutters are not considered as part of an active gage or passive gage for purposes of simulating forming a wellbore as described in this application. However, teachings of the present disclosure may be used to conduct simulations which include gage cutters as part of an adjacent active gage or passive gage. The present disclosure is not limited to the previously described three components or portions of a rotary drill bit.

For some applications a three dimensional (3D) model incorporating teachings of the present disclosure may be operable to evaluate respective contributions of various components of a rotary drill bit to forces acting on the rotary drill bit. The 3D model may be operable to separately calculate or estimate the effect of each component on bit walk rate, bit steerability and/or bit controllability for a given set of downhole drilling parameters. As a result, a model such as shown in FIGURES 17A-17G may be used to design various portions of a rotary drill bit and/or to select a rotary drill bit from existing bit designs for use in forming a wellbore based upon directional behavior characteristics associated with changing face cutter parameters, active gage parameters and/or passive gage parameters. Similar techniques may be used to design or select components of a bottom hole assembly or other portions of a directional drilling system in accordance with teachings of the present disclosure.

FIGURE 6B shows some of the parameters which would be applied to rotary drill bit 100 during formation of a wellbore. Rotary drill bit 100 is shown by solid lines in FIGURE 6B during formation of a vertical segment or straight hole segment of a wellbore. Bit rotational axis 100a of rotary drill bit 100 will generally be aligned with the longitudinal axis of the associated wellbore, and a vertical axis associated with a corresponding bit hole coordinate system.

Rotary drill bit 100 is also shown in dotted lines in FIGURE 6B to illustrate various parameters used to simulate drilling kick off segment 60b in accordance with teachings of the present disclosure. Instead of using bit side penetration or bit side cutting motion, the simulation shown in FIGURE 6A is based upon tilting of rotary drill bit 100 as shown in dotted lines relative to vertical axis.

FIGURE 6C is a schematic drawing showing a typical prior simulation which used side cutting penetration as a step function to represent forming a directional wellbore. For the simulation shown in FIGURE 6C, the formation of wellbore 260 is shown as a series of step holes 260a, 260b, 260c, 260d and 260e. As shown in FIGURE 6D the assumption made during this simulation was that rotational axis 104a of rotary drill bit 100 remained generally aligned with a vertical axis during the formation of each step hole 260a, 260b, 260c, etc.

Simulations of forming directional wellbores in accordance with teachings of the present disclosure have indicated the influence of gage length on bit walk rate, bit steerability and bit controllability. Rotary drill bit 100e as shown in FIGURES 7A and 7B may be described as having both an active gage and a passive gage disposed on each blade 128e. Active gage portions of rotary drill bit 100e may include active elements formed from hardfacing or abrasive materials which remove formation material from adjacent portions of sidewall or inside diameter 63 of wellbore segment 60. See for example active gage elements 156 shown in FIGURE 4C.

Rotary drill bit 100e as shown in FIGURES 7A and 7B may be described as having a plurality of blades 128e with a plurality of cutting elements 130 disposed on exterior portions of each blade 128e. For some applications cutting elements 130 may have substantially the same configuration and design. For other applications various types of cutting elements and impact arrestors (not expressly shown) may also be disposed on exterior portions of blades 128e. Exterior portions of rotary drill bit 100e may be described as forming a "bit face profile".

The bit face profile for rotary drill bit 100e as shown in FIGURES 7A and 7B may include recessed portion or cone shaped section 132e formed on the end of rotary drill bit 100e opposite from shank 122e. Each blade 128e may include respective nose 134e which defines in part an extreme end of rotary drill bit 100e opposite from shank 122e. Cone section 132e may extend inward from respective noses 134e toward bit rotational axis 104e. A plurality of cutting elements 130i may be disposed on portions of each blade 128e between respective nose 134e and rotational axis 104e. Cutters 130i may be referred to as "inner cutters".

Each blade 128e may also be described as having respective shoulder 136e extending outward from respective nose 134e. A plurality of cutter elements 130s may be disposed on each shoulder 136e. Cutting elements 130s may sometimes be referred to as "shoulder cutters." Shoulder 136e and associated shoulder cutters 130s cooperate with each other to form portions of the bit face profile of rotary drill bit 100e extending outward from cone shaped section 132e.

A plurality of gage cutters 130g may also be disposed on exterior portions of each blade 128e. Gage cutters 130g may be used to trim or define inside diameter or sidewall 63 of wellbore segment 60. Gage cutters 130g and associated portions of each blade 128e form portions of the bit face profile of rotary drill bit 100e extending from shoulder cutters 130s.

For embodiments such as shown in FIGURE 7A and 7B each blade 128e may include active gage portion 138 and passive gage portion 139. Various types of hardfacing and/or other hard materials (not expressly shown) may be disposed on each active gage portion 138. Each active gage portion 138 may include a positive taper angle 158 as shown in FIGURE 7B. Each passive gage portion may include respective positive taper angle 159a as shown in FIGURE 7B. Active and passive gages on conventional rotary drill bits often have positive taper angles.

Simulations conducted in accordance with teachings of the present disclosure may be used to calculate side forces applied to rotary drill bit 100e by each segment or component of a bit face profile. For example inner cutters 130i, shoulder cutters 130s and gage cutters 130g may apply respective side forces to rotary drill bit 100e during formation of a directional wellbore. Active gage portions 138 and passive gage portions 139 may also apply respective side forces to rotary drill bit 100e during formation of a directional wellbore. A steering difficulty index may be calculated for each segment or component of a bit face profile to determine if design changes should be made to the respective component.

Simulations conducted in accordance with teachings of the present disclosure have indicated that forming a passive gage with a negative taper angle such as angle 159b shown in FIGURE 7B may provide improved or enhanced steerability when forming a directional wellbore. The size of negative taper angle 159b may be limited to prevent undesired contact between an associated passive gage and adjacent portions of a sidewall during drilling of a vertical wellbore or straight hole segments of a wellbore.

Since bend length associated with a push-the-bit directional drilling system is usually relatively large (greater than 20 times associated bit size), most of the cutting action associated with forming a directional wellbore may be a combination of axial bit penetration, bit rotation, bit side cutting and bit tilting. See FIGURES 4A, 4B and 13A. Simulations conducted in accordance with teachings of the present disclosure have indicated that an active gage with a gage gap such as gage gap 162 shown in FIGURES 7A and 7B may significantly reduce the amount of bit side force required to form a directional wellbore using a push-the-bit directional drilling system. A passive gage with a gage gap such as gage gap 164 shown in FIGURE 7A and 7B may also reduce required amounts of bit side force, but the effect is much less than that of an active gage with a gage gap.

Since bend length associated with a point-the-bit directional drilling system is usually relatively small (less than 12 times associated bit size), most of the cutting action associated with forming a directional wellbore may be a combination of axial bit penetration, bit rotation and bit tilting. See FIGURES 5A, 5B and 13B. Simulations conducted in accordance with teachings of the present disclosure have shown that rotary drill bits with positively tapered gages and/or gage gaps may be satisfactorily used with point-the-bit directional drilling systems. Simulations conducted in accordance with teachings of the present disclosure have further indicated that there is an optimum set of tapered gage angles and associated gage gaps depending upon respective bend length of each directional drilling system and required DLS for each segment of a directional wellbore.

Simulations conducted in accordance with teachings of the present disclosure have indicated that forming passive gage 139 with optimum negative taper angle 159b may result in contact between portions of passive gage 139 and adjacent portions of a wellbore to provide a fulcrum point to direct or guide rotary drill bit 100e during formation of a directional wellbore. The size of negative taper angle 159b may be limited to prevent undesired contact between passive gage 139 and adjacent portions of sidewall 63 during drilling of a vertical or straight hole segments of a wellbore. Such simulations have also indicated potential improvements in steerability and controllability by optimizing the length of passive gages with negative taper angles. For example, forming a passive gage with a negative taper angle on a rotary drill bit in accordance with teachings of the present disclosure may allow reducing the bend length of an associated rotary drill bit steering unit. The length of a bend subassembly included as part of the directional steering unit may be reduced as a result of having a rotary drill bit with an increased length in combination with a passive gage having a negative taper angle.

Simulations incorporating teachings of the present disclosure have indicated that a passive gage having a negative taper angle may facilitate tilting of an associated rotary drill bit during kick off drilling. Such simulations have also indicated benefits of installing one or more gage cutters at optimum locations on an active gage portion and/or passive gage portion of a rotary drill bit to remove formation materials from the inside diameter of an associated wellbore during a directional drilling phase. These gage cutters will typically not contact the sidewall or inside diameter of a wellbore while drilling a vertical segment or straight hole segment of the directional wellbore.

Passive gage 139 with an appropriate negative taper angle 159b and an optimum length may contact sidewall 63 during formation of an equilibrium portion and/or kick off portion of a wellbore. Such contact may substantially improve steerability and controllability of a rotary drill bit and associated steering difficulty index (SD_{index}). Such simulations have also indicated that multiple tapered gage portions and/or variable tapered gage portions may be satisfactorily used with both point-the-bit and push-the-bit directional drilling systems.

FIGURES 8A and 8B show interaction between active gage element 156 and adjacent portions of sidewall 63 of wellbore segment 60a. FIGURES 8C and 8D show interaction between passive gage element 157 and adjacent portions of sidewall 63 of wellbore segment 60a. Active gage element 156 and passive gage element 157 may be relatively small segments or portions of respective active gage 138 and passive gage 139 which contacts adjacent portions of sidewall 63. Active and passive gage elements may be used in simulations similar to previously described cutlets.

Arrow 180a represents an axial force (F_a) which may be applied to active gage element 156 as active gage element engages and removes formation materials from adjacent portions of sidewall 63 of wellbore segment 60a. Arrow 180p as shown in FIGURE 8C represents an axial force (F_a) applied to passive gage cutter 130p during contact with sidewall 63. Axial forces applied to active gage 130g and passive gage 130p may be a function of the associated rate of penetration of rotary drill bit 100e.

Arrow 182a associated with active gage element represents drag force (F_d) associated with active gage element 156 penetrating and removing formation materials from adjacent portions of sidewall 63. A drag force (F_d) may sometimes be referred to as a tangent force (F_t) which generates torque on an associate gage element, cutlet, or mesh unit. The amount of penetration in inches is represented by Δ as shown in FIGURE 8B.

Arrow 182p represents the amount of drag force (F_d) applied to passive gage element 130p during plastic and/or elastic deformation of formation materials in sidewall 63 when contacted by passive gage 157. The amount of drag force associated with active gage element 156 is generally a function of rate of penetration of associated rotary drill bit 100e and depth of penetration of respective gage element 156 into adjacent portions of sidewall 63. The amount of drag force associated with passive gage element 157 is generally a function of the rate of penetration of associated rotary drill bit 100e and elastic and/or plastic deformation of formation materials in adjacent portions of sidewall 63.

Arrow 184a as shown in FIGURE 8B represents a normal force (F_n) applied to active gage element 156 as active gage element 156 penetrates and removes formation materials from sidewall 63 of wellbore segment 60a. Arrow 184p as shown in FIGURE 8D represents a normal force (F_n) applied to passive gage element 157 as passive gage element 157 plastically or elastically deforms formation material in adjacent portions of sidewall 63. Normal force (F_n) is directly related to the cutting depth of an active gage element into adjacent portions of a wellbore or deformation of adjacent portions of a wellbore by a passive gage element. Normal force (F_n) is also directly related to the cutting depth of a cutter into adjacent portions of a wellbore.

The following algorithms may be used to estimate or calculate forces associated with contact between an active and passive gage and adjacent portions of a wellbore. The algorithms are based in part on the following assumptions:

> An active gage may remove some formation material from adjacent portions of a wellbore such as sidewall 63. A passive gage may deform adjacent portions of a wellbore such as sidewall 63. Formation materials immediately adjacent to portions of a wellbore such as sidewall 63 may be satisfactorily modeled as a plastic/elastic material.

For each cutlet or small element of an active gage which removes formation material:

$$F_n = ka_1 * \Delta_1 + ka_2 * \Delta_2$$

$$F_a = ka_3 * F_r$$

$$F_d = ka_4 * F_r$$

Where Δ_1 is the cutting depth of a respective cutlet (gage element) extending into adjacent portions of a wellbore, and Δ_2 is the deformation depth of hole wall by a respective cutlet.

ka_1, ka_2, ka_3 and ka_4 are coefficients related to rock properties and fluid properties often determined by testing of anticipated downhole formation material.

For each cutlet or small element of a passive gage which deforms formation material:

$$F_n = kp_1 * \Delta p$$

$$F_a = kp_2 * F_r$$

$$F_d = kp_3 * F_r$$

Where Δp is depth of deformation of formation material by a respective cutlet of adjacent portions of the wellbore.

kp_1, kp_2, kp_3 are coefficients related to rock properties and fluid properties and may be determined by testing of anticipated downhole formation material.

Many rotary drill bits have a tendency to "walk" or move laterally relative to a longitudinal axis of a wellbore while forming the wellbore. The tendency of a rotary drill bit to walk or move laterally may be particularly noticeable when forming directional wellbores and/or when the rotary drill bit penetrates adjacent layers of different formation material and/or inclined formation layers. An evaluation of bit walk rates requires consideration of all forces acting on rotary drill bit 100 which extend at an angle relative to tilt plane 170. Such forces include interactions between bit face profile active and/or passive gages associated with rotary drill bit 100 and adjacent portions of the bottom hole may be evaluated.

FIGURE 9 is a schematic drawing showing portions of rotary drill bit 100 in section in a two dimensional hole coordinate system represented by X axis 76 and Y axis 78. Arrow 114 represents a side force applied to rotary drill bit 100 from directional drilling system 20 in tilt plane 170. This side force generally acts normal to bit rotational axis 104a of rotary drill bit 100. Arrow 176 represents side cutting or side displacement (D_s) of rotary drill bit 100 projected in the hole coordinate system in response to interactions between exterior portions of rotary drill bit 100 and adjacent portions of a downhole formation. Bit walk angle 186 is measured from F_s to D_s.

When angle 186 is less than zero (opposite to bit rotation direction represented by arrow 178) rotary drill bit 100 will have a tendency to walk to the left of applied side force 114 and titling plane 170. When angle 186 is greater than zero (the same as bit rotation direction represented by arrow 178) rotary drill bit 100 will have a tendency to walk right relative to applied side force 114 and tilt plane 170. When bit walk angle 186 is approximately equal to zero (0), rotary drill bit 100 will have approximately a zero (0) walk rate or neutral walk tendency.

FIGURE 10 is a schematic drawing showing an alternative definition of bit walk angle when a side displacement (D_s) or side cutting motion represented by arrow 176a is applied to bit 100 during simulation of forming a directional wellbore. An associated force represented by arrow 114c required to act on rotary drill bit 100 to produce the applied side displacement (D_s) may be calculated and projected in the same hole coordinate system. Applied side displacement (D_s)represented by arrow 176a and calculated force (F_c) represented by arrow 114c form bit walk angle 186. Bit walk angle 186 is measured from F_c to D_s.

When angle 186 is less than zero (opposite to bit rotation direction represented by arrow 178), rotary drill bit 100 will have a tendency to walk to the left of calculated side force 176 and titling plane 170. When angle 186 is greater than zero (the same as bit rotation direction represented by arrow 178) rotary drill bit 100 will have a tendency to walk right relative to calculated side force 176 and tilt plane 170. When bit walk angle 186 is approximately equal to zero (0), rotary drill bit 100 will have approximately a zero (0) walk rate or neutral walk tendency.

As discussed later in this application both walk force (F_w) and walk moment or bending moment (M_w) along with an associated bit steer rate and steer force may be used to calculate a resulting bit walk rate. However, the value of walk force and walk moment are generally small compared to an associated steer force and therefore need to be calculated accurately. Bit walk rate may be a function of bit geometry and downhole drilling conditions such as rate of penetration, revolutions per minute, lateral penetration rate, bit tilting rate or steer rate and downhole formation characteristics.

Simulations of forming a directional wellbore based on a 3D model incorporating teachings of the present disclosure indicate that for a given axial penetration rate and a given revolutions per minute and a given bottom hole assembly configuration that there is a critical tilt rate. When the tilt rate is greater than the critical tilt rate, the associated drill bit may begin to walk either right or left relative to the associated wellbore. Simulations incorporating teachings of the present disclosure indicate that transition drilling through an inclined formation such as shown in FIGURES 14A, 14B and 14C may change a bit walk tendencies from bit walk right to bit walk left.

For some applications the magnitude of bit side forces required to achieve desired DLS or tilt rates for a given set of drilling equipment parameters and downhole drilling conditions may be used as an indication of associated bit steerability or controllability. See FIGURE 11 for one example. Fluctuations in the amount of bit side force, torque on bit (TOB) and/or bit bending moment may also be used to provide an evaluation of bit controllability or bit stability during the formation of various portions of a directional wellbore. See FIGURE 12 for one example.

FIGURE 11 is a schematic drawing showing rotary drill bit 100 in solid lines in a first position associated with forming a generally vertical section of a wellbore. Rotary drill bit 100 is also shown in dotted lines in FIGURE 11 showing a directional portion of a wellbore such as kick off segment 60a. The graph shown in FIGURE 11 indicates that the amount of bit side force required to produce a tilt rate corresponding with the associated dogleg severity (DLS) will generally increase as the dogleg severity of the deviated wellbore increases. The shape of curve 194 as shown in FIGURE 11 may be a function of both rotary drill bit design parameters and associated downhole drilling conditions.

As previously noted fluctuations in drilling parameters such as bit side force, torque on bit and/or bit bending moment may also be used to provide an evaluation of bit controllability or bit stability.

FIGURE 12 is a graphical representation showing variations in torque on bit with respect to revolutions per minute during the tilting of rotary drill bit 100 as shown in FIGURE 12. The amount of variation or the ΔTOB as shown in FIGURE 12 may be used to evaluate the stability of various rotary drill bit designs for the same given set of downhole drilling conditions. The graph shown in FIGURE 11 is based on a given rate of penetration, a given RPM and a given set of downhole formation data.

For some applications steerability of a rotary drill bit may be evaluated using the following steps. Design data for the associated drilling equipment may be inputted into a three dimensional model incorporating teachings of the present disclosure. For example design parameters associated with a drill bit may be inputted into a computer system (see for example FIGURE 1C) having a software application such as shown and described in FIGURES 17A-17G. Alternatively, rotary drill bit design parameters may be read into a computer program from a bit design file or drill bit design parameters such as International Association of Drilling Contractors (IADC) data may be read into the computer program.

Drilling equipment operating data such as RPM, ROP, and tilt rate for an associated rotary drill bit may be selected or defined for each simulation. A tilt rate or

DLS may be defined for one or more formation layers and an associated inclination angle for adjacent formation layers. Formation data such as rock compressive strength, transition layers and inclination angle of each transition layer may also be defined or selected.

Total run time, total number of bit rotations and/or respective time intervals per the simulation may also be defined or selected for each simulation. 3D simulations or modeling using a system such as shown in FIGURE 1C and software or computer programs as outlined in FIGURES 17A-17G may then be conducted to calculate or estimate various forces including side forces acting on an associated rotary drill bit or other associated downhole drilling equipment.

The preceding steps may be conducted by changing DLS or tilt rate and repeated to develop a curve of bit side forces corresponding with each value of DLS. A curve of side force versus DLS may then be plotted (See FIGURE 11) and bit steerability calculated. Another set of rotary drill bit operating parameters may then be inputted into the computer and steps 3 through 7 repeated to provide additional curves of side force (F_s) versus dogleg severity (DLS). Bit steerability may then be defined by the set of curves showing side force versus DLS.

FIGURE 13A may be described as a graphical representation showing portions of a bottom hole assembly and rotary drill bit 100a associated with a push-the-bit directional drilling system. A push-the-bit directional drilling system may be sometimes have a bend length greater than 20 to 35 times an associated bit size or corresponding bit diameter in inches. Bend length 204a associated with a push-the-bit directional drilling system is generally much greater than length 206a of rotary drill bit 100a. Bend length 204a may also be much greater than or equal to the diameter D_{B1} of rotary drill bit 100a.

FIGURE 13B may be generally described as a graphical representation showing portions of a bottom hole assemble and rotary drill bit 100c associated with a point-the-bit directional drilling system. A point-the-bit directional drilling system may sometimes have a bend length less than or equal to 12 times the bit size. For the example shown in FIGURE 13B, bend length 204c associated with a point-the-bit directional drilling system may be approximately two or three times greater than length 206c of rotary drill bit 100c. Length 206c of rotary drill bit 100c may be significantly greater than diameter D_{B2} of rotary drill bit 100c. The length of a rotary drill bit used with a push-the-bit drilling system will generally be less than the length of a rotary drill bit used with a point-the-bit directional drilling system.

Due to the combination of tilting and axial penetration, rotary drill bits may have side cutting motion. This is particularly true during kick off drilling. However, the rate of side cutting is generally not a constant for a drill bit and is changed along drill bit axis. The rate of side penetration of rotary drill bits 100a and 100c is represented by arrow 202. The rate of side penetration is generally a function of tilting rate and associated bend length 204a and 204d. For rotary drill bits having a relatively long bit length and particularly a relatively long gage length such as shown in FIGURE 5C, the rate of side penetration at point 208 may be much less than the rate of side penetration at point 210. As the length of a rotary drill bit increases the side penetration rate decreases from the shank as compared with the extreme end of the rotary drill bit. The difference in rate of side penetration between point 208 and 210 may be small, but the effects on bit steerability may be very large.

Simulations conducted in accordance with teachings of the present disclosure may be used to calculate bit walk rate. Walk force (F_W) may be obtained by simulating forming a directional wellbore as a function of drilling time. Walk force (F_W) corresponds with the amount of force which is applied to a rotary drill bit in a plane extending generally perpendicular to an associated azimuth plane or tilt plane. A model such as shown in FIGURES 17A-17G may then be used to obtain the total bit lateral force (F_{lat}) as a function of time.

FIGURES 14A, 14B and 14C are schematic drawings showing representations of various interactions between rotary drill bit 100 and adjacent portions of first formation 221 and second formation layer 222. Software or computer programs such as outlined in FIGURES 17A-17G may be used to simulate or model interactions with multiple or laminated rock layers forming a wellbore.

For some applications first formation layer may have a rock compressibility strength which is substantially larger than the rock compressibility strength of second layer 222. For embodiments such as shown in FIGURES 14A, 14B and 14C first layer 221 and second layer 222 may be inclined or disposed at inclination angle 224 (sometimes referred to as a "transition angle") relative to each other and relative to vertical. Inclination angle 224 may be generally described as a positive angle relative associated vertical axis 74.

Three dimensional simulations may be performed to evaluate forces required for rotary drilling bit 100 to form a substantially vertical wellbore extending through first layer 221 and second layer 222. See FIGURE 14A. Three dimensional simulations may also be performed to evaluate forces which must be applied to rotary drill bit 100 to form a directional wellbore extending through first layer 221 and second layer 222 at various angles such as shown in FIGURES 14B and 14C. A simulation using software or a computer program such as outlined in FIGURE 17A-17G may be used calculate the side forces which must be applied to rotary drill bit 100 to form a wellbore to tilt rotary drill bit 100 at an angle relative to vertical axis 74.

FIGURE 14D is a schematic drawing showing a three dimensional meshed representation of the bottom hole or end of wellbore segment 60a corresponding with rotary drill bit 100 forming a generally vertical or horizontal wellbore extending therethrough as shown in FIGURE 14A. Transition plane 226 as shown in FIGURE 14D represents a dividing line or boundary between rock formation layer and rock formation layer 222. Transition plane 226 may extend along inclination angle 224 relative to vertical.

The terms "meshed" and "mesh analysis" may describe analytical procedures used to evaluate and study complex structures such as cutters, active and passive gages, other portions of a rotary drill bit, other downhole tools associated with drilling a wellbore, bottom hole configurations of a wellbore and/or other portions of a wellbore. The interior surface of end 62 of wellbore 60a may be finely meshed into many small segments or "mesh units" to assist with determining interactions between cutters and other portions of a rotary drill bit and adjacent formation materials as the rotary drill bit removes formation materials from end 62 to form wellbore 60. See FIGURE 14D. The use of mesh units may be particularly helpful to analyze distributed forces and variations in cutting depth of respective mesh units or cutlets as an associated cutter interacts with adjacent formation materials.

Three dimensional mesh representations of the bottom of a wellbore and/or various portions of a rotary drill bit and/or other downhole tools may be used to simulate interactions between the rotary drill bit and adjacent portions of the wellbore. For example cutting depth and cutting area of each cutting element or cutlet during one revolution of the associated rotary drill bit may be used to calculate forces acting on each cutting element. Simulation may then update the configuration or pattern of the associated bottom hole and forces acting on each cutter. For some applications the nominal configuration and size of a unit such as shown in FIGURE 14D may be approximately 0.5 mm per side. However, the actual configuration size of each mesh unit may vary substantially due to complexities of associated bottom hole geometry and respective cutters used to remove formation materials.

Systems and methods incorporating teachings of the present disclosure may also be used to simulate or model forming a directional wellbore extending through various combinations of soft and medium strength formation with multiple hard stringers disposed within both soft and/or medium strength formations. Such formations may sometimes be referred to as "interbedded" formations. Simulations and associated calculations may be similar to simulations and calculations as described with respect to FIGURES 14A-14D.

Spherical coordinate systems such as shown in FIGURES 15A-15C may be used to define the location of respective cutlets, gage elements and/or mesh units of a rotary drill bit and adjacent portions of a wellbore. The location of each mesh unit of a rotary drill bit and associated wellbore may be represented by a single valued function of angle phi (φ), angle theta (θ) and radius rho (ρ) in three dimensions (3D) relative to Z axis 74. The same Z axis 74 may be used in a three dimensional Cartesian coordinate system or a three dimensional spherical coordinate system.

The location of a single point such as center 198 of cutter 130 may be defined in the three dimensional spherical coordinate system of FIGURE 15A by angle φ and radius ρ. This same location may be converted to a Cartesian hole coordinate system of X_h, Y_h, Z_h using radius r and angle theta (θ) which corresponds with the angular orientation of radius r relative to X axis 76. Radius r intersects Z axis 74 at the same point radius ρ intersects Z axis 74. Radius r is disposed in the same plane as Z axis 74 and radius ρ. Various examples of algorithms and/or matrices which may be used to transform data in a Cartesian coordinate system to a spherical coordinate system and to transform data in a spherical coordinate system to a Cartesian coordinate system are discussed later in this application.

As previously noted, a rotary drill bit may generally be described as having a "bit face profile" which includes a plurality of cutters operable to interact with adjacent portions of a wellbore to remove formation materials therefrom. Examples of a bit face profile and associated cutters are shown in FIGURES 2A, 2B, 4C, 5C, 5D, 7A and 7B. The cutting edge of each cutter on a rotary drill bit may be represented in three dimensions using either a Cartesian coordinate system or a spherical coordinate system.

FIGURES 15B and 15C show graphical representations of various forces associated with portions of cutter 130 interacting with adjacent portions of bottom hole 62 of wellbore 60. For examples such as shown in FIGURE 15B cutter 130 may be located on the shoulder of an associated rotary drill bit.

FIGURE 15B and 15C also show one example of a local cutter coordinate system used at a respective time step or interval to evaluate or interpolate interaction between one cutter and adjacent portions of a wellbore. A local cutter coordinate system may more accurately interpolate complex bottom hole geometry and bit motion used to update a 3D simulation of a bottom hole geometry such as shown in FIGURE 14D based on simulated interactions between a rotary drill bit and adjacent formation materials. Numerical algorithms and interpolations incorporating teachings of the present disclosure may more accurately calculate estimated cutting depth and cutting area of each cutter.

In a local cutter coordinate system there are two forces, drag force (F_d) and penetration force (F_p), acting on cutter 130 during interaction with adjacent portions of wellbore 60. When forces acting on each cutter 130 are projected into a bit coordinate system there will be three forces, axial force (F_a), drag force (F_d) and penetration force (F_p). The previously described forces may also act upon impact arrestors and gage cutters.

For purposes of simulating cutting or removing formation materials adjacent to end 62 of wellbore 60 as shown in FIGURE 15B, cutter 130 may be divided into small elements or cutlets 131a, 131b, 131c and 131d. Forces represented by arrows F_e may be simulated as acting on cutlet 131a-131d at respective points such as 191 and 200. For example, respective drag forces may be calculated for each cutlet 131a-131d acting at respective points such as 191 and 200. The respective drag forces may be summed or totaled to determine total drag force (F_d) acting on cutter 130. In a similar manner, respective penetration forces may also be calculated for each cutlet 131a-131d acting at respective points such as 191 and 200. The respective penetration forces may be summed or totaled to determine total penetration force (F_p) acting on cutter 130.

FIGURE 15C shows cutter 130 in a local cutter coordinate system defined in part by cutter axis 198. Drag force (F_d) represented by arrow 196 corresponds with the summation of respective drag forces calculated for each cutlet 131a-131d. Penetration force (F_p) represented by arrow 192 corresponds with the summation of respective penetration forces calculated for each cutlet 131a-131d.

FIGURE 16 shows portions of bottom hole 62 in a spherical hole coordinate system defined in part by Z axis 74 and radius R_h. The configuration of a bottom hole generally corresponds with the configuration of an associated bit face profile used to form the bottom hole. For example, portion 62i of bottom hole 62 may be formed by inner cutters 130i. Portion 62s of bottom hole 62 may be formed by shoulder cutters 130s. Side wall 63 may be formed by gage cutters 130g.

Single point 200 as shown in FIGURE 16 is located on the exterior of cutter 130s. In the hole coordinate system, the location of point 200 is a function of angle φ_h and radius ρ_h. FIGURE 16 also shows the same single point 200 on the exterior of cutter 130s in a local cutter coordinate system defined by vertical axis Z_c and radius R_c. In the local cutter coordinate system, the location of point 200 is a function of angle φ_c and radius ρ_c. Cutting depth 212 associated with single point 200 and associated removal of formation material from bottom hole 62 corresponds with the shortest distance between point 200 and portion 62s of bottom hole 62.

Simulating Straight Hole Drilling (Path B, Algorithm A)

The following algorithms may be used to simulate interaction between portions of a cutter and adjacent portions of a wellbore during removal of formation materials proximate the end of a straight hole segment. Respective portions of each cutter engaging adjacent formation materials may be referred to as cutting elements or cutlets. Note that in the following steps y axis represents the bit rotational axis. The x and z axes are determined using the right hand rule. Drill bit kinematics in straight hole drilling is fully defined by ROP and RPM.

Given ROP, RPM, current time t, dt, current cutlet position (x_i, y_i, z_i) or $(\theta_i, \varphi_i, \rho_i)$

(1) Cutlet position due to penetration along bit axis Y may be obtained

$$x_p = x_i \;;\quad y_p = y_i + rop*d_t;\quad z_p = z_i$$

(2) Cutlet position due to bit rotation around the bit axis may be obtained as follows:

N_rot = {0 1 0 }

Accompany matrix:

$$M_{rot} = \begin{matrix} 0 & -N\_rot(3) & N\_rot(2) \\ N\_rot(3) & 0 & -N\_rot(1) \\ -N\_rot(2) & N\_rot(1) & 0 \end{matrix}$$

The transform matrix is:

R_rot = cosωt I + (1- cos ωt) N_rot N_rot′ + sin ωt M_rot,

where I is 3x3 unit matrix and ω is bit rotation speed.

New cutlet position after bit rotation is:

$$\begin{matrix} x_{i+1} \\ y_{i+1} \\ z_{i+1} \end{matrix} = R_{rot} \begin{matrix} x_p \\ y_p \\ z_p \end{matrix}$$

(3) Calculate the cutting depth for each cutlet by comparing $(x_{i+1}, y_{i+1}, z_{i+1})$ of this cutlet with hole coordinate (x_h, y_h, z_h) where $X_h = x_{i+1}$ & $z_h = z_{i+1}$, and $d_p = y_{i+1} - y_h$;

(4) Calculate the cutting area of this cutlet

A cutlet $= d_p * d_r$

where d_r is the width of this cutlet.

(5) Determine which formation layer is cut by this cutlet by comparing y_{i+1} with hole coordinate y_h, if $y_{i+1} < y_h$ then layer A is cut. y_h may be solved from the equation of the transition plane in Cartesian coordinate:

$$l(x_h-x_1) + m(y_h-y_1) + n(z_h-z_1) = 0$$

where (x_1, y_1, z_1) is any point on the plane and $\{l,m,n\}$ is normal direction of the transition plane.

(6) Save layer information, cutting depth and cutting area into 3D matrix at each time step for each cutlet for force calculation.

(7) Update the associated bottom hole matrix removed by the respective cutlets or cutters.

Simulating Kick Off Drilling (Path C)

The following algorithms may be used to simulate interaction between portions of a cutter and adjacent portions of a wellbore during removal of formation materials proximate the end of a kick off segment. Respective portions of each cutter engaging adjacent formation materials may be referred to as cutting elements or cutlets. Note that in the following steps, y axis is the bit axis, x and z are determined using the right hand rule. Drill bit kinematics in kick-off drilling is defined by at least four parameters: ROP, RPM, DLS and bend length.

Given ROP, RPM, DLS and bend length, L_{bend}, current time t, dt, current cutlet position (x_i, y_i, z_i) or $(\theta_i, \varphi_i, \rho_i)$

(1) Transform the current cutlet position to bend center:

$$x_i = x_i;$$
$$y_i = y_i - L_{bend}$$
$$z_i = z_i;$$

(2) New cutlet position due to tilt may be obtained by tilting the bit around vector N_tilt an angle γ:

$$N\_tilt = \{\sin\alpha \quad 0.0 \quad \cos\alpha\}$$

Accompany matrix:

$$M_{tilt} = \begin{matrix} 0 & -N\_tilt(3) & N\_tilt(2) \\ N\_tilt(3) & 0 & -N\_tilt(1) \\ -N\_tilt(2) & N\_tilt(1) & 0 \end{matrix}$$

The transform matrix is:

R_tilt = cosγ I + (1- cosγ) N_tilt N_tilt′ + sinγ M_tilt

where I is the 3x3 unit matrix.

New cutlet position after tilting is:

$$\begin{matrix} x_t \\ y_t \\ z_t \end{matrix} = R_{Tilt} \begin{matrix} x_i \\ y_i \\ z_i \end{matrix}$$

(3) Cutlet position due to bit rotation around the new bit axis may be obtained as follows:

N_rot = {sinγcosθ cos γ sinγsinθ }

Accompany matrix:

$$M_{rot} = \begin{matrix} 0 & -N\_rot(3) & N\_rot(2) \\ N\_rot(3) & 0 & -N\_rot(1) \\ -N\_rot(2) & N\_rot(1) & 0 \end{matrix}$$

The transform matrix is:

R_rot = cosωt I + (1- cos ωt) N_rot N_rot′ + sin ωt M_rot,

I is 3x3 unit matrix and ω is bit rotation speed

New cutlet position after tilting is:

$$\begin{matrix} x_r \\ y_r \\ z_r \end{matrix} = R_{rot} \begin{matrix} x_t \\ y_t \\ z_t \end{matrix}$$

(4) Cutlet position due to penetration along new bit axis may be obtained

d_p = rop x dt;

$$x_{i+1} = x_r + d_{p}\_x$$
$$y_{i+1} = y_r + d_{p}\_y$$
$$z_{i+1} = z_r + d_{p}\_z$$

With d_p_x, d_p_y and d_p_z being projection of d_p on X, Y, Z.

(5) Transfer the calculated cutlet position after tilting, rotation and penetration into spherical coordinate and get $(\theta_{i+1}, \varphi_{i+1}, \rho_{i+1})$

(6) Determine which formation layer is cut by this cutlet by comparing Y_{i+1} with hole coordinate y_h, if $y_{i+1} < y_h$ first layer is cut (this step is the same as Algorithm A).

(7) Calculate the cutting depth of each cutlet by comparing $(\theta_{i+1}, \varphi_{i+1}, \rho_{i+1})$ of the cutlet and $(\theta_h, \varphi_h, \rho_h)$ of the hole where $\theta_h = \theta_{i+1}$ & $\varphi_h = \varphi_{i+1}$. Therefore $d_\rho = \rho_{i+1} - \rho_h$. It is usually difficult to find point on hole $(\theta_h, \varphi_h, \rho_h)$, an interpretation is used to get an approximate ρ_h:

$$\rho_h = \text{interp2}(\theta_h, \varphi_h, \rho_h, \theta_{i+1}, \varphi_{i+1})$$

where θ_h, φ_h, ρ_h is sub-matrices representing a zone of the hole around the cutlet. Function interp2 is a MATLAB function using linear or nonlinear interpolation method.

(8) Calculate the cutting area of each cutlet using $d\varphi$, $d\rho$ in the plane defined by ρ_i, ρ_{i+1}. The cutlet cutting area is

$$A = 0.5^* \, d\varphi^*(\rho_{i+1}\hat{}2 - (\rho_{i+1} - d\rho)\hat{}2)$$

(9) Save layer information, cutting depth and cutting area into 3D matrix at each time step for each cutlet for force calculation.

(10) Update the associated bottom hole matrix removed by the respective cutlets or cutters.

Simulating Equilibrium Drilling (Path D)

The following algorithms may be used to simulate interaction between portions of a cutter and adjacent portions of a wellbore during removal of formation materials in an equilibrium segment. Respective portions of each cutter engaging adjacent formation materials may be referred to as cutting elements or cutlets. Note that in the following steps, y represents the bit rotational axis. The x and z axes are determined using the right hand rule. Drill bit kinematics in equilibrium drilling is defined by at least three parameters: ROP, RPM and DLS.

Given ROP, RPM, DLS, current time t, selected time interval dt, current cutlet position (x_i, y_i, z_i) or (θ_i, φ_i, ρ_i),

(1) Bit as a whole is rotating around a fixed point O_w, the radius of the well path is calculated by

R = 5730*12 / DLS (inch)

and angle

γ = DLS*rop/100.0 /3600 (deg/sec)

(2) The new cutlet position due to rotation γ may be obtained as follows:

Axis: N_1 = {0 0 -1}

Accompany matrix:

$$M_1 = \begin{matrix} 0 & -N\_1(3) & N\_1(2) \\ N\_1(3) & 0 & -N\_1(1) \\ -N\_1(2) & N\_1(1) & 0 \end{matrix}$$

The transform matrix is:

R_1 = cosγ I + (1- cosγ) N_1 N_1′ + sinγ M1
where I is 3x3 unit matrix

New cutlet position after rotating around O_w is:

$$\begin{matrix} x_t \\ y_t \\ z_t \end{matrix} = R_1 \begin{matrix} x_i \\ y_i \\ z_i \end{matrix}$$

(3) Cutlet position due to bit rotation around the new bit axis may be obtained as follows:

N_rot = {sinγcosα cos γ sinγsinα}
where α is the azimuth angle of the well path

Accompany matrix:

$$M_{rot} = \begin{matrix} 0 & -N\_rot(3) & N\_rot(2) \\ N\_rot(3) & 0 & -N\_rot(1) \\ -N\_rot(2) & N\_rot(1) & 0 \end{matrix}$$

The transform matrix is:

R_rot = cos θ I + (1- cos θ) N_rot N_rot′ + sin θ M_rot,
where I is 3x3 unit matrix

New cutlet position after bit rotation is:

$$\begin{matrix} x_{i+1} \\ y_{i+1} \\ z_{i+1} \end{matrix} = R_{rot} \begin{matrix} x_t \\ y_t \\ z_t \end{matrix}$$

(4) Transfer the calculated cutlet position into spherical coordinate and get (θ_{i+1}, φ_{i+1}, ρ_{i+1}).

(5) Determine which formation layer is cut by this cutlet by comparing y_{i+1} with hole coordinate y_h, if $y_{i+1} < y_h$ first layer is cut (this step is the same as Algorithm A).

(6) Calculate the cutting depth of each cutlet by comparing (θ_{i+1}, φ_{i+1}, ρ_{i+1}) of the cutlet and (θ_h, φ_h, ρ_h) of the hole where $\theta_h = \theta_{i+1}$ & $\varphi_h = \varphi_{i+1}$. Therefore $d_\rho = \rho_{i+1} - \rho_h$. It is usually difficult to find point on hole (θ_h, φ_h, ρ_h), an interpretation is used to get an approximate ρ_h:

$$\rho_h = \text{interp2}(\theta_h,\ \varphi_h,\ \rho_h,\ \theta_{i+1},\ \varphi_{i+1})$$

where θ_h, φ_h, ρ_h is sub-matrices representing a zone of the hole around the cutlet. Function interp2 is a MATLAB function using linear or nonlinear interpolation method.

(7) Calculate the cutting area of each cutlet using $d\varphi$, $d\rho$ in the plane defined by ρ_i , ρ_{i+1}. The cutlet cutting area is:

$$A = 0.5 * d\varphi * (\rho_{i+1}\hat{\ }2 - (\rho_{i+1} - d\rho)\hat{\ }2)$$

(8) Save layer information, cutting depth and cutting area into 3D matrix at each time step for each cutlet for force calculation.

(9) Update the associated bottom hole matrix for portions removed by the respective cutlets or cutters.

<u>An Alternative Algorithm to Calculate Cutting Area of A Cutter</u>

The following steps may also be used to calculate or estimate the cutting area of the associated cutter. See FIGURE 15C and 16.

(1) Determine the location of cutter center O_c at current time in a spherical hole coordinate system, see FIGURE 16.

(2) Transform three matrices φ_H, θ_H and ρ_H to Cartesian coordinate in hole coordinate system and get X_h, Y_h and Z_h;

(3) Move the origin of X_h, Y_h and Z_h to the cutter center O_c located at (φ_C, θ_C and ρ_C);

(4) Determine a possible cutting zone on portions of a bottom hole interacted by a respective cutlet for this cutter and subtract three sub-matrices from X_h, Y_h and Z_h to get x_h, y_h and z_h;

(5) Transform x_h, y_h and z_h back to spherical coordinate and get φ_h, θ_h and ρ_h for this respective subzone on bottom hole;

(6) Calculate spherical coordinate of cutlet B: φ_B, θ_B and ρ_B in cutter local coordinate;

(7) Find the corresponding point C in matrices φ_h, θ_h and ρ_h with condition $\varphi_C = \varphi_B$ and $\theta_C=\theta_B$;

(8) If $\rho_B > \rho_C$, replacing ρ_C with ρ_B and matrix ρ_h in cutter coordinate system is updated;

(9) Repeat the steps for all cutlets on this cutter;

(10) Calculate the cutting area of this cutter;

(11) Repeat steps 1-10 for all cutters;

(12) Transform hole matrices in local cutter coordinate back to hole coordinate system and repeat steps 1-12 for next time interval.

Force Calculations in Different Drilling Modes

The following algorithms may be used to estimate or calculate forces acting on all face cutters of a rotary drill bit.

(1) Summarize all cutlet cutting areas for each cutter and project the area to cutter face to get cutter cutting area, A_c

(2) Calculate the penetration force (F_p) and drag force (F_d) for each cutter using, for example, AMOCO Model (other models such as SDBS model, Shell model, Sandia Model may be used).

$$F_p = \sigma * A_c * (0.16 * \mathrm{abs}(\beta e) - 1.15))$$

$$F_d = F_d * F_p + \sigma * A_c * (0.04 * \mathrm{abs}(\beta e) + 0.8))$$

where σ is rock strength, βe is effective back rake angle and F_d is drag coefficient (usually F_d=0.3)

(3) The force acting point M for this cutter is determined either by where the cutlet has maximal cutting depth or the middle cutlet of all cutlets of this cutter which are in cutting with the formation. The direction of F_p is from point M to cutter face center O_c. F_d is parallel to cutter axis. See for example FIGURES 15B and 15C.

One example of a computer program or software and associated method steps which may be used to simulate forming various portions of a wellbore in accordance with teachings of the present disclosure is shown in FIGURES 17A-17G. Three dimensional (3D) simulation or modeling of forming a wellbore may begin at step 800. At step 802 the drilling mode, which will be used to simulate forming a respective segment of the simulated wellbore, may be selected from the group consisting of straight hole drilling, kick off drilling or equilibrium drilling. Additional drilling modes may also be used depending upon characteristics of associated downhole formations and capabilities of an associated drilling system.

At step 804a bit parameters such as rate of penetration and revolutions per minute may be inputted into the simulation if straight hole drilling was selected. If kickoff drilling was selected, data such as rate of penetration, revolutions per minute, dogleg severity, bend length and other characteristics of an associated bottom hole assembly may be inputted into the simulation at step 804b. If equilibrium drilling was selected, parameters such as rate of penetration, revolutions per minute and dogleg severity may be inputted into the simulation at step 804c.

At steps 806, 808 and 810 various parameters associated with configuration and dimensions of a first rotary drill bit design and downhole drilling conditions may be inputted into the simulation. Appendix A provides examples of such data.

At step 812 parameters associated with each simulation, such as total simulation time, step time, mesh size of cutters, gages, blades and mesh size of adjacent portions of the wellbore in a spherical coordinate system may be inputted into the model. At step 814 the model may simulate one revolution of the associated drill bit around an associated bit axis without penetration of the rotary drill bit into the adjacent portions of the wellbore to calculate the initial (corresponding to time zero) hole spherical coordinates of all points of interest during the simulation. The location of each point in a hole spherical coordinate system may be transferred to a corresponding Cartesian coordinate system for purposes of providing a visual representation on a monitor and/or print out.

At step 816 the same spherical coordinate system may be used to calculate initial spherical coordinates for each cutlet of each cutter and each gage portions which will be used during the simulation.

At step 818 the simulation will proceed along one of three paths based upon the previously selected drilling mode. At step 820a the simulation will proceed along path A for straight hole drilling. At step 820b the simulation will proceed along path B for kick off hole drilling. At step 820c the simulation will proceed along path C for equilibrium hole drilling.

Steps 822, 824, 828, 830, 832 and 834 are substantially similar for straight hole drilling (Path A), kick off hole drilling (Path B) and equilibrium hole drilling (Path C). Therefore, only steps 822a, 824a, 828a, 830a, 832a and 834a will be discussed in more detail.

At step 822a a determination will be made concerning the current run time, the ΔT for each run and the total maximum amount of run time or simulation which will be conducted. At step 824a a run will be made for each cutlet and a count will be made for the total number of cutlets used to carry out the simulation.

At step 826a calculations will be made for the respective cutlet being evaluated during the current run with respect to penetration along the associated bit axis as a result of bit rotation during the corresponding time interval. The location of the respective cutlet will be determined in the Cartesian coordinate system corresponding with the time the amount of penetration was calculated. The information will be transferred from a corresponding hole coordinate system into a spherical coordinate system.

At step 828a the model will determine which layer of formation material has been cut by the respective cutlet. A calculation will be made of the cutting depth, cutting area of the respective cutlet and saved into respective matrices for rock layer, depth and area for use in force calculations.

At step 830a the hole matrices in the hole spherical coordinate system will be updated based on the recently calculated cutlet position at the corresponding time. At step 832a a determination will be made to determine if the current cutter count is less than or equal to the total number of cutlets which will be simulated. If the number of the current cutter is less than the total number, the simulation will return to step 824a and repeat steps 824a through 832a.

If the cutlet count at step 832a is equal to the total number of cutlets, the simulation will proceed to step 834a. If the current time is less than the total maximum time selected, the simulation will return to step 822a and repeat steps 822a through 834a. If the current time is equal to the previously selected total maximum amount of time, the simulation will proceed to steps 840 and 860.

As previously noted, if a simulation proceeds along path C as shown in FIGURE 17D corresponding with kick off hole drilling, the same steps will be performed as described with respect to path B for straight hole drilling except for step 826b. As shown in FIGURE 17D, calculations will be made at step 826b corresponding with location and orientation of the new bit axis after tilting which occurred during respective time interval dt.

A calculation will be made for the new Cartesian coordinate system based upon bit tilting and due to bit rotation around the location of the new bit axis. A calculation will also be made for the new Cartesian coordinate system due to bit penetration along the new bit axis. After the new Cartesian coordinate systems have been calculated, the cutlet location in the Cartesian coordinate systems will be determined for the corresponding time interval. The information in the Cartesian coordinate time interval will then be transferred into the corresponding spherical coordinate system at the same time. Path C will then proceed through steps 828b, 830b, 832b and 834b as previously described with respect to path B.

If equilibrium drilling is being simulated, the same functions will occur at steps 822c and 824c as previously described with respect to path B. For path D as shown in FIGURE 17E, the simulation will proceed through steps 822c and 824c as previously described with respect to steps 822a and 824a of path B. At step 826a a calculation will be made for the respective cutlet during the respective time interval based upon the radius of the corresponding wellbore segment. A determination will be made based on the center of the path in a hole coordinate system. A new Cartesian coordinate system will be calculated after bit rotation has been entered based on the amount of DLS and rate of penetration along the Z axis passing through the hole coordinate system. A calculation of the new Cartesian coordinate system will be made due to bit rotation along the associated bit axis. After the above three calculations have been made, the location of a cutlet in the new Cartesian coordinate system will be determined for the appropriate time interval and transferred into the corresponding spherical coordinate system for the same time interval. Path D will continue to simulate equilibrium drilling using the same functions for steps 828c, 830c, 832c and 834c as previously described with respect to Path B straight hole drilling.

When selected path B, C or D has been completed at respective step 834a, 834b or 834c the simulation will then proceed to calculate cutter forces including impact arrestors for all step times at step 840 and will calculate associated gage forces for all step times at step 860. At step 842 a respective calculation of forces for a respective cutter will be started.

At step 844 the cutting area of the respective cutter is calculated. The total forces acting on the respective cutter and the acting point will be calculated.

At step 846 the sum of all the cutting forces in a bit coordinate system is summarized for the inner cutters and the shoulder cutters. The cutting forces for all active gage cutters may be summarized. At step 848 the previously calculated forces are projected into a hole coordinate system for use in calculating associated bit walk rate and steerability of the associated rotary drill bit.

At step 850 the simulation will determine if all cutters have been calculated. If the answer is NO, the model will return to step 842. If the answer is YES, the model will proceed to step 880.

At step 880 all cutter forces and all gage blade forces are summarized in a three dimensional bit coordinate system. At step 882 all forces are summarized into a hole coordinate system.

At step 884 a determination will be made concerning using only bit walk calculations or only bit steerability calculations. If bit walk rate calculations will be used, the simulation will proceed to step 886b and calculate bit steer force, bit walk force and bit walk rate for the entire bit. At step 888b the calculated bit walk rate will be compared with a desired bit walk rate. If the bit walk rate is satisfactory at step 890b, the simulation will end and the last inputted rotary drill bit design will be selected. If the calculated bit walk rate is not satisfactory, the simulation will return to step 806.

If the answer to the question at step 884 is NO, the simulation will proceed to step 886a and calculate bit steerability using associated bit forces in the hole coordinate system. At step 888a a comparison will be made between calculated steerability and desired bit steerability. At step 890a a decision will be made to determine if the calculated bit steerability is satisfactory. If the answer is YES, the simulation will end and the last inputted rotary drill bit design at step 806 will be selected. If the bit steerability calculated is not satisfactory, the simulation will return to step 806.

FIGURE 18 is a schematic drawing showing one comparison of bit steerability versus tilt rate for a rotary drill bit when used with point-the-bit drilling system and push-the-bit drilling system, respectively.

The curves shown in FIGURE 18 are based upon a constant rate of penetration of thirty feet per hour, a constant RPM of 120 revolutions per minute, and a uniform rock strength of 18000 PSI. The simulations used to form the graphs shown in FIGURE 18 along with other simulations conducted in accordance with teachings of the present disclosure indicates that bit steerability or required steer force is generally a nonlinear function of the DLS or tilt rate. The drilling bit when used in point-the-bit drilling system required much less steer force than with the push-the-bit drilling system. The graphs shown in FIGURE 18 provide a similar result with respect to evaluating steerability as calculations represented by bit steer force as a function of bit tilt rate. The effect of downhole drilling conditions on varying the steerability of a rotary drill bit have previously been generally unnoticed by the prior art.

Bit Steerability Evaluation

The steerability of a rotary drill may be evaluated using the following steps.

(1) Input bit geometry parameters or read bit file from bit design software such as UniGraphics or Pro-E;

(2) Define bit motion: a rotation speed (RPM) around bit axis, an axial penetration rate (ROP, ft/hr), DLS or tilting rate (deg/ 100 ft) at an azimuth angle (to define the bit tilt plane);

(3) Define formation properties: rock compressive strength, rock transition layer, inclination angle;

(4) Define simulation time or total number of bit rotations and time interval;

(5) Run 3D PDC bit drilling simulator and calculate bit forces including bit side force;

(6) Change DLS and repeat step 5 to get bit side force corresponding to the given DLS;

(7) Plot a curve using (DLS, F_s) and calculate bit steerability; The steerability may be represented by the slop of the curve if the curve is close to a line, or the steerability may be represented by the first derivative of the nonlinear curve.

(8) Giving another set of bit operational parameters (ROP, RPM) and repeat step 3 to 7 to get more curves;

(9) Bit steerability is defined by a set of curves or their first derivative or slop.

The steerability of various rotary drill bit designs may be compared and evaluated by calculating a steering difficulty for each rotary drill bit.

Steering Difficulty Index may be defined using steer force as follows:

$$SD_{index} = F_{steer} \ / \ \text{Tilt Rate}$$

Steering Difficulty Index may also be defined using steer moment as follows:

$$SD_{index} = M_{steer} \ / \ \text{Steer Rate}$$
$$\text{Steer Rate} = \text{Tilt Rate}$$

A steering difficulty index may also be calculated for any zone of part on the drill bit. For example, when the steer force, F_{steer}, is contributed only from the shoulder cutters, then the associated SD_{index} represents the difficulty level of the shoulder cutters. In accordance with teachings of the present disclosure, the steering difficulty index for each zone of the drilling bit may be evaluated. By comparing the steering difficulty index of each zone, a bit designer may more easily identify which zone or zones are more difficult to steer and design modifications may be focused on the difficult zone or zones.

The calculation of steerability index for each zone may be repeated and design changes made until the calculation of steerability for each zone is satisfactory and/or the steerability index for the overall drill bit design is satisfactory.

Bit Walk Rate Evaluation

Bit walk rate may be calculated using bit steer force, tilt rate and walk force:

$$\text{Walk Rate} = (\text{Steer Rate} / F_{steer}) * F_{walk}$$

Bit walk rate may also be calculated using bit steer moment, tilt rate and walk moment:

$$\text{Walk Rate} = (\text{Steer Rate} / M_{steer}) * M_{walk}$$

The walk rate may be applied to any zone of part on the drill bit. For example, when the steer force, F_{steer} and walk force, F_{walk}, are contributed only from the shoulder cutters, then the associated walk rate represents the walk rate of the shoulder cutters. In accordance with teachings of the present disclosure, the walk rate for each zone of the drilling bit can be evaluated. By comparing the walk rate of each zone, the bit designer can easily identify which zone is the easiest zone to walk and modifications may be focused on that zone.

Although the present disclosure and its advantages have been described in detail, it should be understood that various changes, substitutions and alternations may be made herein without departing from the spirit and scope of the disclosure as defined by the following claims.

APPENDIX A

EXAMPLES OF DRILLING EQUIPMENT DATA		EXAMPLES OF WELLBORE DATA	EXAMPLES OF FORMATION DATA
Design Data	**Operating Data**		
active gage	axial bit penetration rate	azimuth angle	compressive strength
bend (tilt) length	bit ROP	bottom hole configuration	down dip angle
bit face profile	bit rotational speed	bottom hole pressure	first layer
bit geometry	bit RPM	bottom hole temperature	formation plasticity
blade (length, number, spiral, width)	bit tilt rate	directional wellbore	formation strength
bottom hole assembly	equilibrium drilling	dogleg severity (DLS)	inclination
cutter (type, size, number)	kick off drilling	equilibrium section	lithology
cutter density	lateral penetration rate	horizontal section	number of layers
cutter location (inner, outer, shoulder)	rate of penetration (ROP)	inside diameter	porosity
cutter orientation (back rake, side rake)	revolutions per minute (RPM)	kick off section	rock pressure
cutting area	side penetration azimuth	profile	rock strength
cutting depth	side penetration rate	radius of curvature	second layer
cutting structures	steer force	side azimuth	shale plasticity
drill string	steer rate	side forces	up dip angle

APPENDIX A - CONTINUED

EXAMPLES OF DRILLING EQUIPMENT DATA		EXAMPLES OF WELLBORE DATA	EXAMPLES OF FORMATION DATA
Design Data	**Operating Data**		
fulcrum point	straight hole drilling	slant hole	
gage gap	tilt rate	straight hole	
gage length	tilt plane	tilt rate	
gage radius	tilt plane azimuth	tilting motion	
gage taper	torque on bit (TOB)	tilt plane azimuth angle	
IADC Bit Model	walk angle	trajectory	
impact arrestor (type, size, number)	walk rate	vertical section	
passive gage	weight on bit (WOB)		
worn (dull) bit data			

EXAMPLES OF MODEL PARAMETERS FOR SIMULATING DRILLING A DIRECTIONAL WELLBORE
Mesh size for portions of downhole equipment interacting with adjacent portions of a wellbore.
Mesh size for portions of a wellbore.
Run time for each simulation step.
Total simulation run time.
Total number of revolutions of a rotary drill bit per simulation.

WHAT IS CLAIMED IS:

1. A method for determining bit walk rate of a rotary drill bit comprising:

applying a set of drilling conditions to the bit including at least bit rotational speed, rate of penetration along a bit rotational axis, and at least one characteristics of an earth formation;

applying a steer rate to the bit;

simulating, for a time interval, drilling of the earth formation by the bit under the set of drilling conditions, including calculating a steer force applied to the bit and an associated walk force;

calculating a walk rate based on the bit steer rate, the steer force, and the walk force;

repeating simulating drilling the earth formation for another time interval, and recalculating the steer force, the walk force and walk rate;

repeating the simulating successively for a predefined number of time intervals; and

calculating an average walk rate of the bit using an average steer force and an average walk force over the simulated time interval.

2. The method of Claim 1 wherein applying the steer rate further comprises applying the steer rate in a vertical plane passing through the bit rotational axis.

3. The method of Claim 1 wherein calculating the walk rate further comprises:

determining respective three dimensional locations of all cutting edges of all cutters and all gauge portions in a hole coordinate system;

determining respective interactions of all cutting edges of the cutters and gauge portions with the bottom hole of the formation;

calculating a cutting depth for each cutting edge and a cutting area for each cutting element;

calculating respective three dimensional forces of the cutters and projecting the forces into a hole coordinate system;

summing all of the cutter forces projected in the hole coordinate system;

projecting the summed forces into the vertical tilting plane; and

calculating the steer force in the vertical tilting plane and perpendicular to bit rotational axis

4. The method of Claim 1 wherein calculating the walk rate further comprises:

determining respective three dimensional locations of all cutting edges of all cutters and all gauge portions in a hole coordinate system;

determining respective interactions of all cutting edges of the cutters and gauge portions with the bottom hole of the formation;

calculating a cutting depth for each cutting edge and a cutting area for each cutting element;

calculating respective three dimensional forces of the cutters and projecting the forces into a hole coordinate system;

summing all of the cutter forces projected in the hole coordinate system;

projecting the summed forces into a plane perpendicular to the vertical tilting plane; and

calculating the walk force in the plane perpendicular to the vertical tilting plane and perpendicular to bit rotational axis

5. The method as defined in Claim 1, the walk rate, at time t, of the bit is calculated by:

$$\text{Walk Rate} = (\text{Steer Rate} / \text{Steer Force}) \times \text{Walk Force}$$

6. The method of Claim 1 further comprising:

determining a bit walk angle of a rotary drill bit by calculating the average bit walk rate over a pre-defined time interval under a pre-defined drilling conditions where at least the magnitude of the given steer rate is not equal to zero;

if the average bit walk rate is negative, bit walk left;

if the average bit walk rate is positive, bit walk right; and

if the average bit walk rate is substantially close to zero, bit does not walk;

7. A method for determining bit walk rate of a rotary drill bit comprising:

applying a set of drilling conditions to the bit including at least bit rotational speed, rate of penetration along a bit rotational axis, and at least one characteristics of an earth formation;

applying a steer rate to the bit;

simulating, for a time interval, drilling of the earth formation by the bit under the set of drilling conditions, including calculating a steer moment applied to the bit and an associated walk moment;

calculating a walk rate based on the bit steer rate, the steer moment, and the walk moment;

repeating simulating drilling the earth formation for another time interval, and recalculating the steer moment, the walk moment and walk rate;

repeating the simulating successively for a predefined number of time intervals; and

calculating an average walk rate of the bit using an average steer moment and an average walk moment over the simulated time interval.

8. The method of Claim 7 wherein applying the steer rate further comprises applying the steer rate in a vertical plane passing through the bit rotational axis.

9. The method of Claim 7 wherein calculating the walk rate further comprises:

determining respective three dimensional locations of all cutting edges of all cutters and all gauge portions in a hole coordinate system;

determining respective interactions of all cutting edges of the cutters and gauge portions with the bottom hole of the formation;

calculating a cutting depth for each cutting edge and a cutting area for each cutting element;

calculating respective three dimensional forces of the cutters;

calculating the three dimensional moments of the cutting elements around a predefined point on bit axis, and projecting the moments into a hole coordinate system;

summing all of the cutter moments projected in the hole coordinate system;

projecting the summed moments into the vertical tilting plane; and

calculating the walk moment in the vertical tilting plane and perpendicular to bit rotational axis

10. The method of Claim 7 wherein calculating the walk rate further comprises:

determining respective three dimensional locations of all cutting edges of all cutters and all gauge portions in a hole coordinate system;

determining respective interactions of all cutting edges of the cutters and gauge portions with the bottom hole of the formation;

calculating a cutting depth for each cutting edge and a cutting area for each cutting element;

calculating respective three dimensional forces of the cutters;

calculating the three dimensional moments of the cutting elements around a predefined point on bit axis, and projecting the moments into a hole coordinate system;

summing all of the cutter moments projected in the hole coordinate system;

projecting the summed moments into a plane perpendicular to the vertical tilting plane; and

calculating the steer moment in the plane perpendicular to the vertical tilting plane and perpendicular to bit rotational axis.

11. The method as defined in Claim 7, the walk rate, at time t, of the bit is calculated by:

$$\text{Walk Rate} = (\text{Steer Rate} / \text{Steer Moment}) \times \text{Walk Moment}$$

12. A method to design a rotary drill bit with a desired bit walk rate comprising:

(a) determining the drilling conditions and the formation characteristics to be drilled by the bit;

(b) simulating drilling at least one portion of a wellbore using the drilling conditions;

(c) calculating the average bit walk rate;

(d) comparing the calculated bit walk rate to the desired walk rate;

(e) if the calculated walk rate does not approximately equal the desired walk rate, modifying at least one bit geometry of the rotary drill bit selected from the group consisting of bit profile, cutter location, cutter orientation, cutter density, gauge length, gage diameter; and

(f) repeating steps (a) through (e) until the calculated walk rate approximately equals the desired walk rate.

13. The method of Claim 12 further comprising:

checking the calculation of the walk rate by changing at least one of the drilling conditions; and

repeating steps (a) to (e), if necessary.

14. The method of Claim 12 further comprising designing an energy balanced fixed cutter drill bit.

15. The method of Claim 12 further comprising calculating the walk rate using walk force and steer force, and calculating the walk rate using walk moment and steer moment.

16. A method to design a rotary drill bit with a desired bit walk rate comprising:

(a) determining the drilling conditions and the formation characteristics to be drilled by the bit;

(b) simulating drilling at least one portion of a wellbore using the drilling conditions;

(c) calculating the average bit walk rate;

(d) comparing the calculated bit walk rate to the desired walk rate;

(e) if the calculated bit walk rate does not approximately equal the desired walk rate, performing the following steps:

(f) dividing the bit body into at least inner zone, shoulder zone, gage zone, active gauge zone and passive gauge zone;

(g) calculating the walk rate of each zone;

(h) calculating the walk rate of combined inner zone and shoulder zone to get walk rate of face cutters;

(i) calculating the walk rate of active gauge and passive gauge to get walk rate of the gauge;

(j) modifying the structure within one zone, or one combined zone which has the maximal magnitude of walk rate or has the minimal magnitude of the walk rate; and

(k) repeating steps (b) through (j) until the calculated walk rate approximately equals the desired walk rate.

17. The method of claim 16, wherein the modifying the structure within the inner zone including at least the cone angle, the number of blades, the number of cutters, the location of cutters, the size of cutters and the back rake and side rake angles of each cutter.

18. The method of claim 16, wherein the modifying the structure within the shoulder zone including at least the number of blades, the number of cutters, the location of cutters, the size of cutters and the back rake and side rake angles of each cutter.

19. The method of claim 16, wherein the modifying the structure within the gage zone including at least the number of gage cutters, the location of gage cutters, the size of cutters and the back rake and side rake angles of each cutter.

20. The method of claim 16, wherein the modifying the structure within the active gauge zone including at least the length of the active gauge, the number of blades, the width of each blade, the spiral angle of each blade, the diameter of the active gauge and the aggressiveness of the active gauge;

21. The method of claim 16, wherein the modifying the structure within the passive gauge zone including at least the length of the passive gauge, the number of blades, the width of each blade, the spiral angle of each blade, the diameter of the passive gauge, the number of steps of passive gauge and the taper angle of the passive gauge.

22. A method to find and optimize operational parameters to control bit walk of a rotary drill bit during drilling of at least one portion of a wellbore comprising:

(a) determining a bit path deviation for the at least one portion of the wellbore;

(b) determining a desired bit walk rate to compensate for the bit path deviation;

(c) determining downhole formation properties at a first location and at a second location ahead of the first location in the at least one portion of the wellbore;

(d) simulating drilling with the rotary drill bit between the first location and the second location;

(e) during the simulation applying to the rotary drill bit an initial set of bit operational parameters selected from the group consisting of ROP, RPM and steer rate;

(f) calculating a walk rate of the rotary drill bit and comparing the calculated walk rate with the desired walk rate; and

(g) changing at least one set of the bit operational parameters and repeating steps (d) through (f) until the calculated walk rate approximately equals the desired walk rate.

23. The method of Claim 22 further comprising determining optimum operational parameters to control bit walk rate of a fixed cutter rotary drill bit.

24. The method of Claim 20 further comprising applying a second set of bit operational parameters to the rotary drill bit and continuing to simulate drilling.

25. The method of Claim 22 further comprising repeating steps (a) through (g) for another portion of the wellbore.

26. The method of Claim 22 further comprising designing a passive gauge with an optimum taper and optimum length to reduce steer force and/or walk force on the rotary drill bit while drilling a directional well bore.

27. The method of Claim 22 further comprising forming a passive gauge having a taper of approximately two degrees of the rotary drill bit.

28. A method to select a rotary drill bit to drill at least one portion of a wellbore having at least one desired trajectory comprising:

(a) determining a desired walk rate to compensate for the desired trajectory of the at least one portion of the wellbore;

(b) determining at least one formation property of the at least one portion of the wellbore;

(c) determining a first set of bit operational parameters according to capability of an associated drilling system and experience gained by drilling other wellbores with similar formation properties;

(d) choosing a first rotary drill bit;

(e) calculating a walk rate for the first rotary drill bit under the first set of bit operational parameters and comparing the calculated walk rate with the desired walk rate;

(f) choosing a second rotary drill bit; and

(g) repeating steps (e) and (f) until the calculated walk angle for at least one rotary drill bit is approximately equal to the desired walk rate under the first set of bit operational parameters.

29. The method of Claim 28 further comprising:

monitoring the trajectory of the at least one rotary drill bit during simulated drilling of the at least one portion of the wellbore; and

if the simulated trajectory of the at least one rotary drill bit does not correspond with the desired trajectory, finding an optimal set of bit operational parameters by repeating steps (c) through (g) of Claim 28 for the at least one rotary drill bit.

30. The method of Claim 28 further comprising selecting a fixed cutter rotary drill bit from existing fixed cutter rotary drill bit designs.

31. A method for designing a rotary drill bit having a gauge comprising:

(a) determining formation properties such as transition layer strength and inclination angle for use in simulating drilling with the rotary drill bit;

(b) determining drilling conditions for use in simulating drilling with the rotary drill bit;

(c) determining if the rotary drill bit will be used with a point-the-bit or push-the-bit drilling system;

(d) simulating applying a steering motion, a relative shorter bent length, axial penetration and rotation forces to the rotary drill bit when used with a point-the-bit drilling system;

(e) simulating applying steering motion, a relative longer bent length, axial penetration and rotation forces to the rotary drill bit when used with a push-the-bit drilling system;

(f) calculating a walk rate based on the simulated drilling;

(g) comparing the calculated walk rate with a desired walk rate;

(h) if the calculated walk rate is not approximately equal to the desired walk rate, changing a bit geometry such as bit profile, cutter locations and orientations, cutter density or changing a geometric parameter of the gauge such as gauge length, gauge radius, gauge taper angle and gauge blade spiral angle; and

(i) repeating steps (c) to (h) until the calculated walk rate approximately equals the desired walk rate.

32. The method of Claim 31 further comprising:

checking the calculation of the walk rate by changing at least one drilling condition according to variations of actual drilling conditions; and

repeating step (c) to (h) of Claim 31, if necessary.

33. The method of Claim 31 further comprising calculating the walk rate based on steer force and walk force.

34. The method of Claim 31 further comprising calculating the walk rate based on steer moment and walk moment.

35. The method of Claim 31 further comprising calculating the walk rate based on an average of the walk rate calculated from steer force and walk force, and the walk rate calculated from steer moment and walk moment.

36. A rotary drill bit with desired walk characteristics comprising:

a bit face profile designed for use in a directional drilling system;

the bit face profile defined in part by a plurality of blades with a plurality of cutters disposed on each blade;

the bit face profile further defined by a recessed portion disposed on one end of the rotary drill bit;

a nose disposed adjacent to the recessed portion with a shoulder portion extending outward from the nose portion;

a plurality of inner cutters disposed within the recessed portion and a plurality of cutters disposed on the shoulder portion of the rotary drill bit; and

the ratio between the number of inner cutters and the number of outer cutters based upon calculation and comparison of various walk rates for the rotary drill bit corresponding with respective ratios of inner cutters and shoulder cutters.

37. The drill bit of Claim 36 further comprising:

a gage portion disposed on the exterior of the rotary drill bit adjacent to the shoulder portion;

a plurality of gage cutters disposed on the blades adjacent to the gage portion; and

the number, location and type of gage cutters based upon comparing the results of one or more simulations of forming a directional wellbore using the rotary drill bit.

38. The drill bit of Claim 36 further comprising a passive gage portion having a negative taper angle optimized for use in forming a directional wellbore.

39. The drill bit of Claim 36 further comprising the bit face profile providing means for optimizing use of the drill bit with a push-the-bit steerable drilling system.

40. The drill bit of Claim 36 further comprising the bit face profile providing means for optimizing use of the drill bit with a point the bit steerable drilling system.

41. A rotary drill bit with a walk rate comprising:

a bit body having a plurality of blades extending therefrom;

each blade having a plurality of cutters disposed thereon; and

the location, number, size and type of cutter disposed on each blade providing means for optimizing the walk rate of the rotary drill bit while forming a directional wellbore.

42. The drill bit of Claim 41 further comprising at least one feature selected from the group consisting of bit face profile, cutter size and location, cutter orientation(back rake and side rake), number of blades and number of cutters, geometric parameters of an associated active or passive gage including gage length, gage taper angle and blade spiral angle designed to provide at least part of the means for optimizing the walk rate of the rotary drill bit.

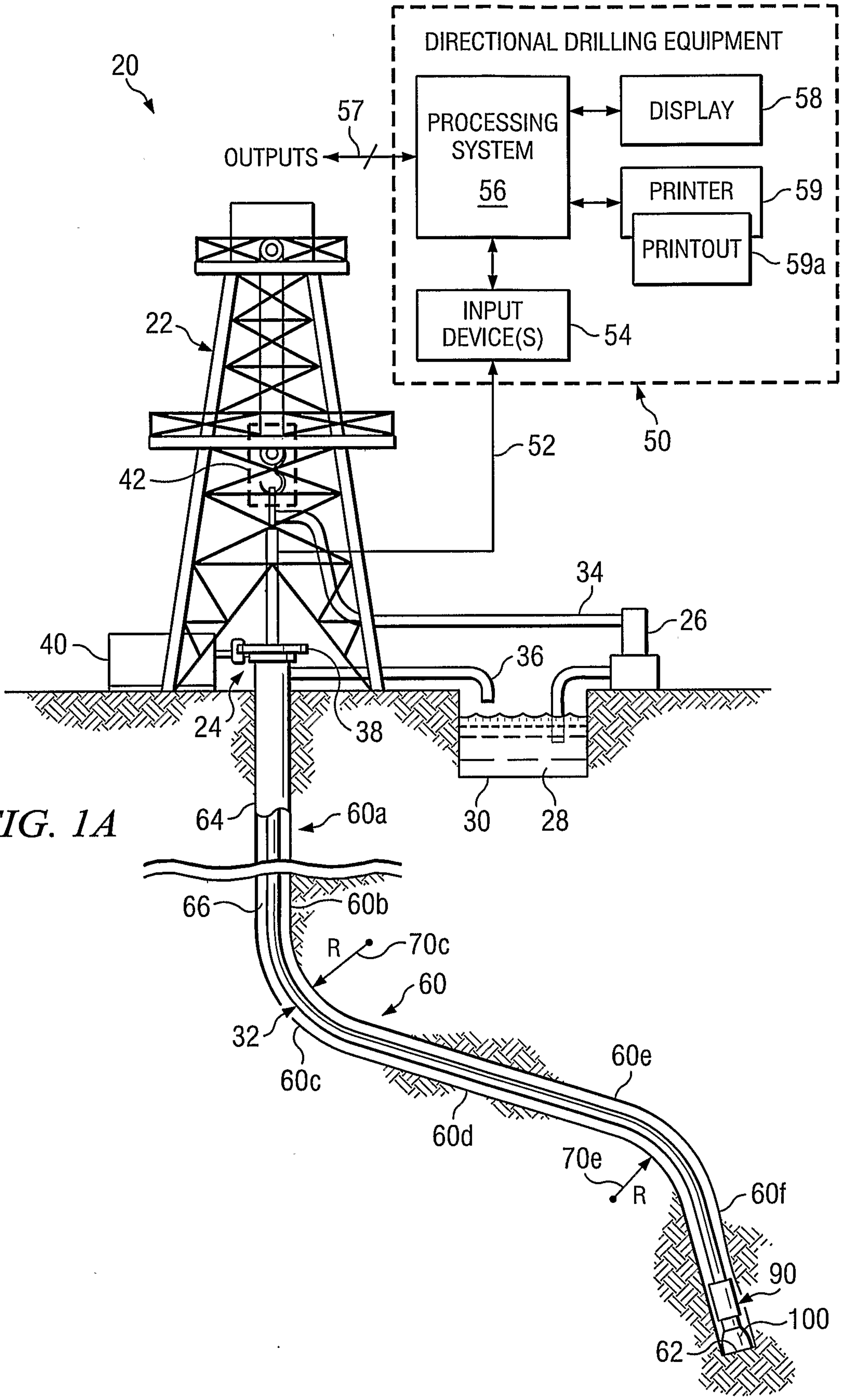

DIRECTIONAL DRILLING EQUIPMENT
PROCESSING SYSTEM
56
DISPLAY
58
PRINTER
59
PRINTOUT
59a
INPUT DEVICE(S)
54
OUTPUTS
57
50
52
20
22
42
34
26
40
36
24
38
30
28
64
60a
66
60b
R
70c
60
32
60c
60d
60e
70e
R
60f
90
100
62

FIG. 1A

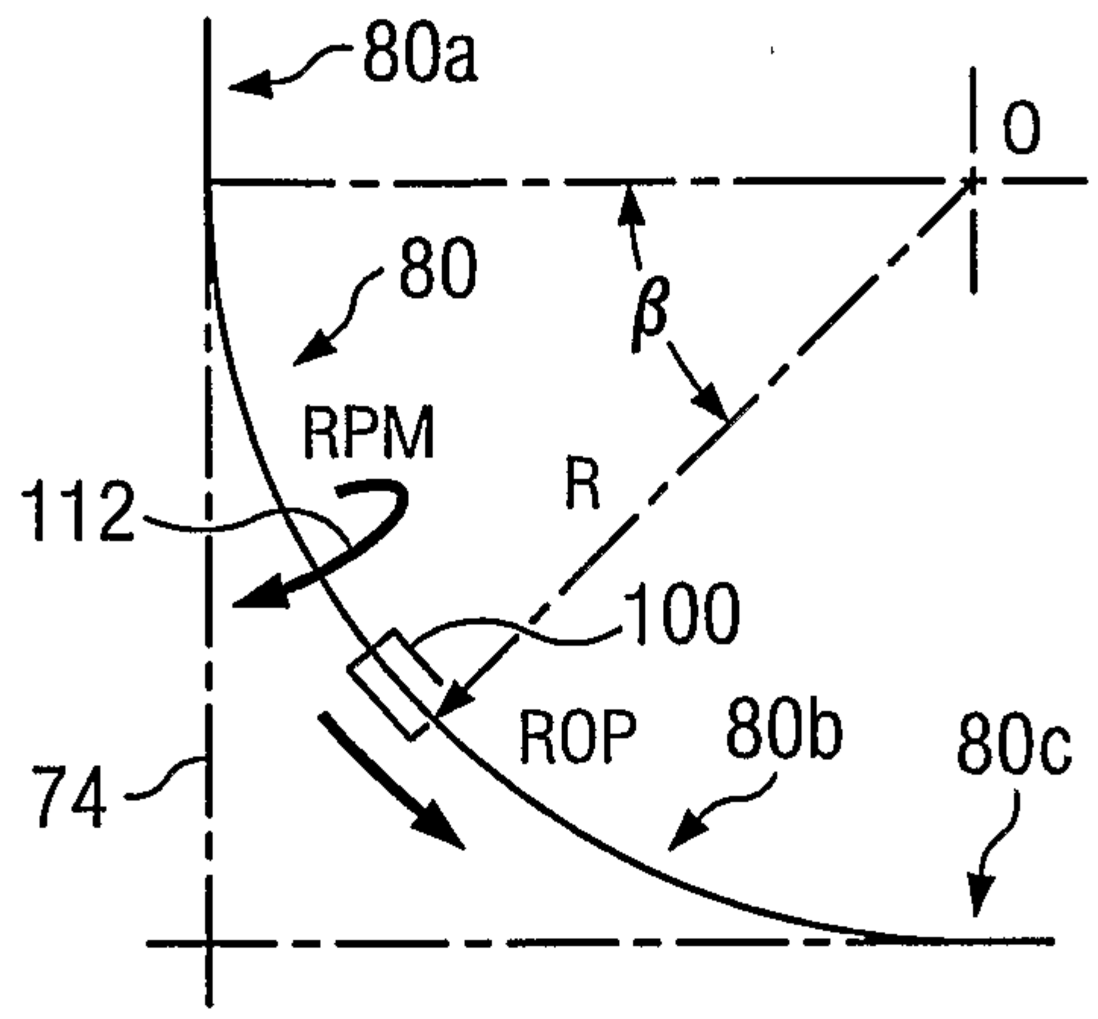

80a
0
80
β
RPM
R
112
100
ROP
80b
80c
74

FIG. 1B

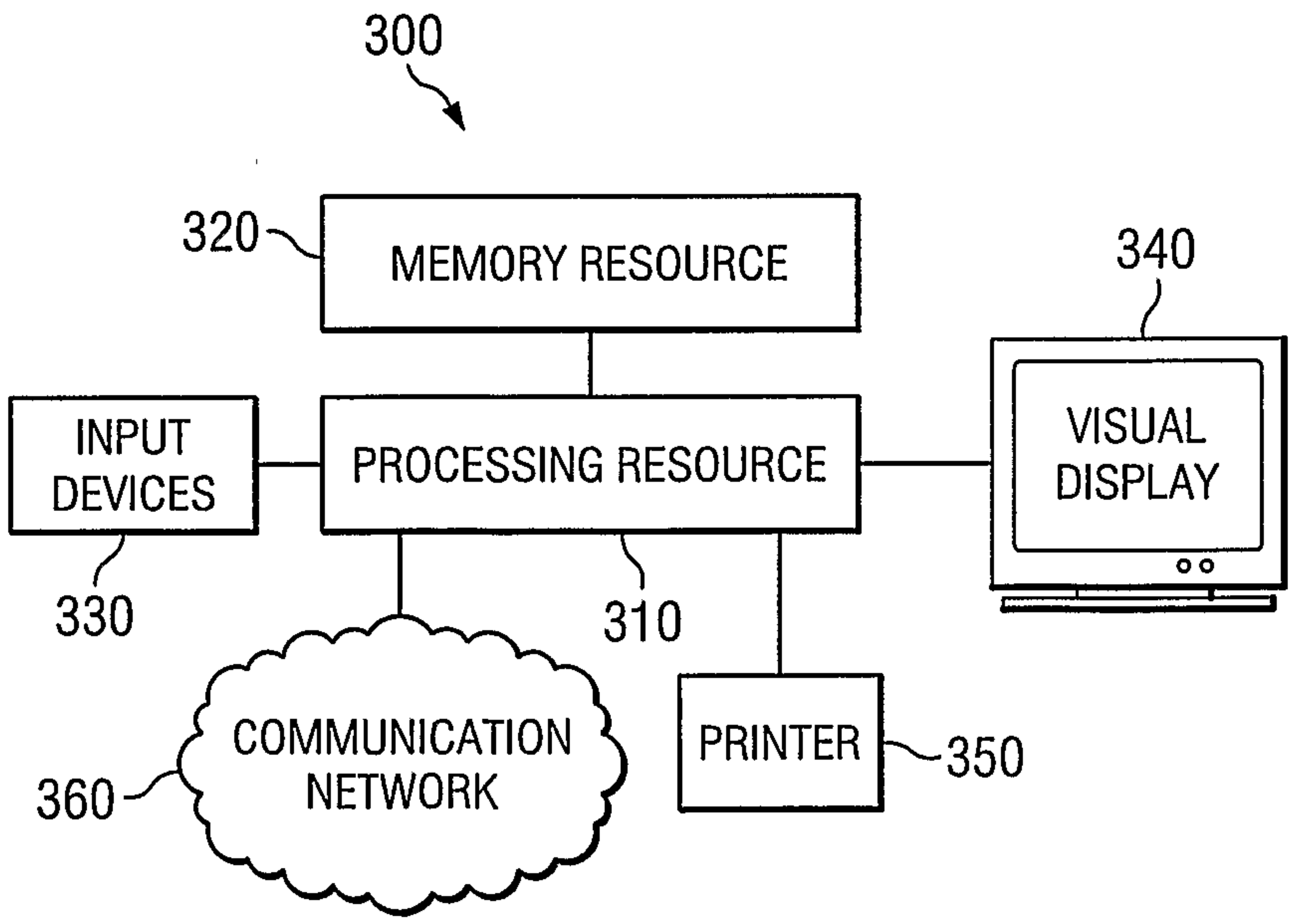

300
320
MEMORY RESOURCE
340
INPUT DEVICES
PROCESSING RESOURCE
VISUAL DISPLAY
330
310
COMMUNICATION NETWORK
PRINTER
350
360

FIG. 1C

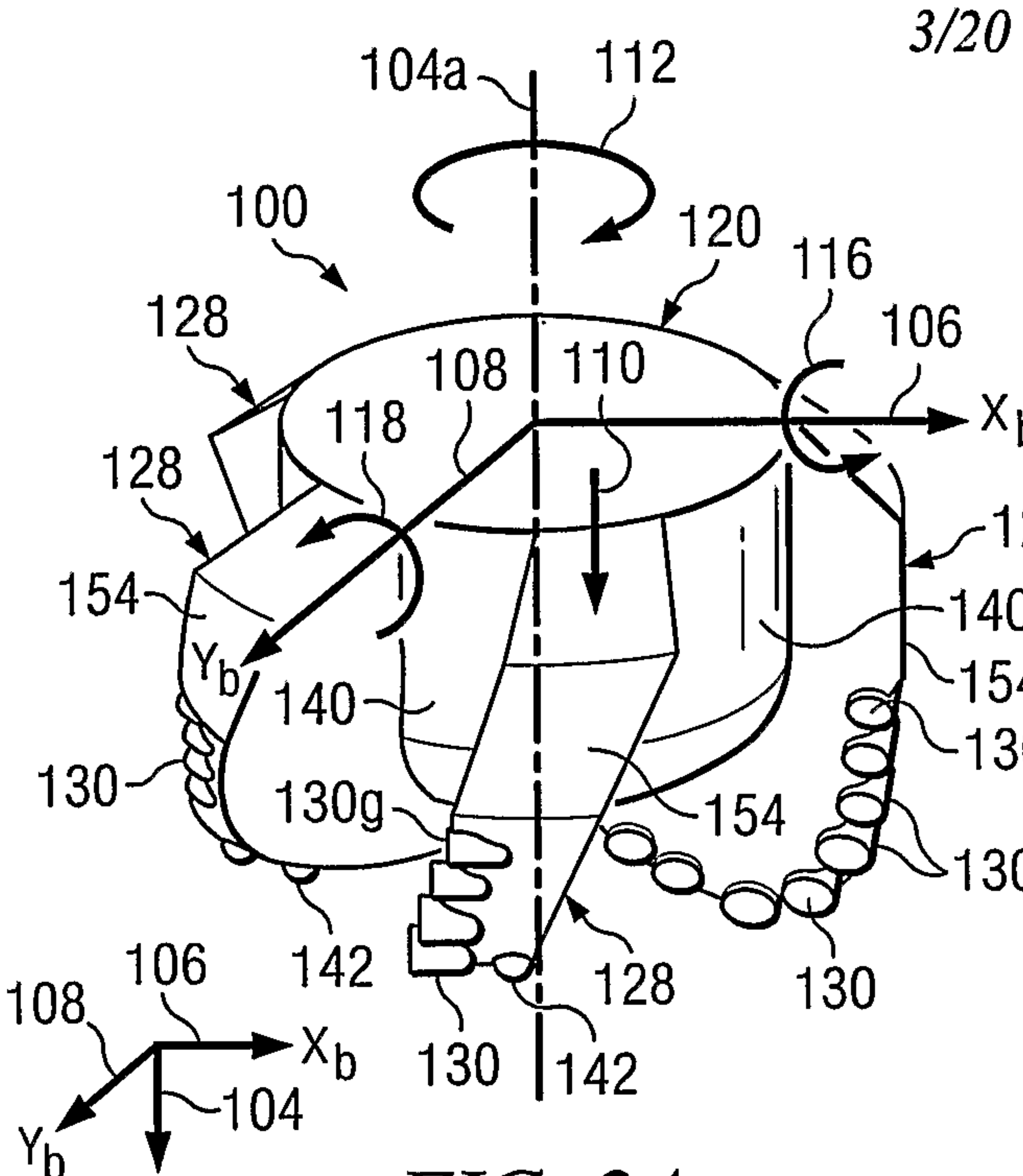


FIG. 2A

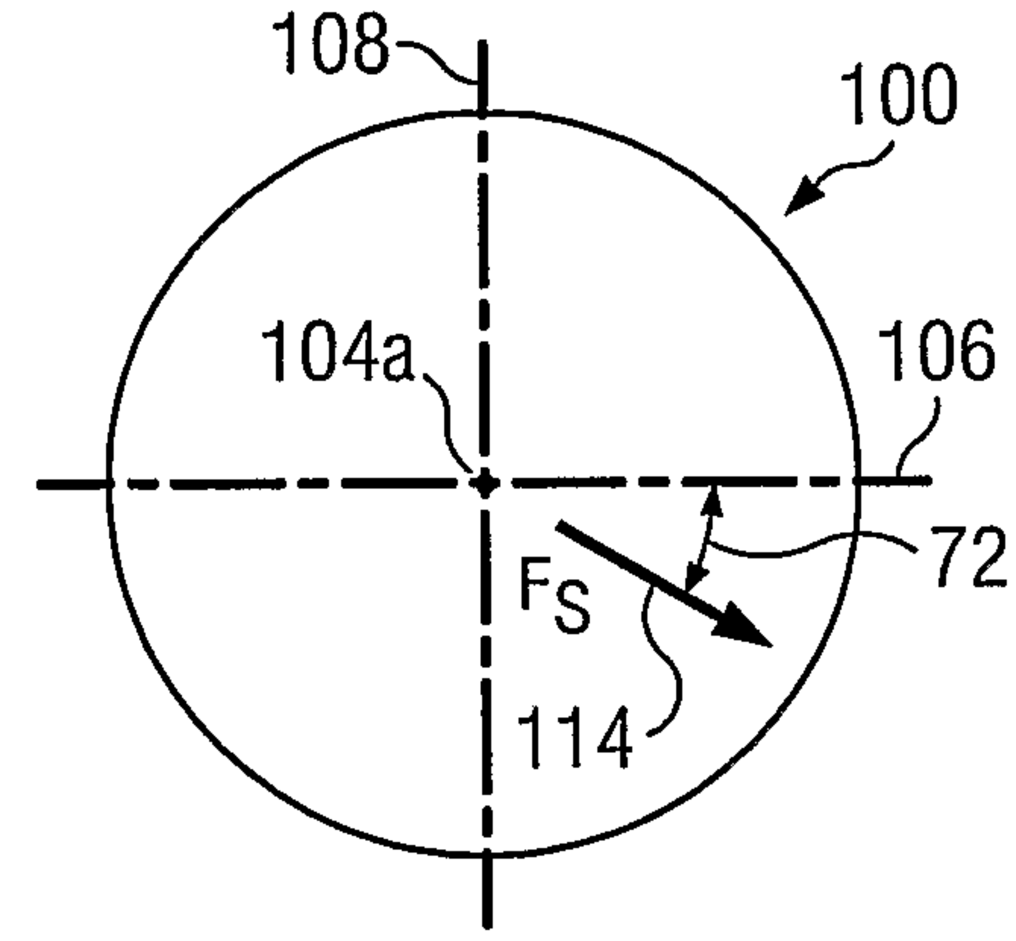


FIG. 3A

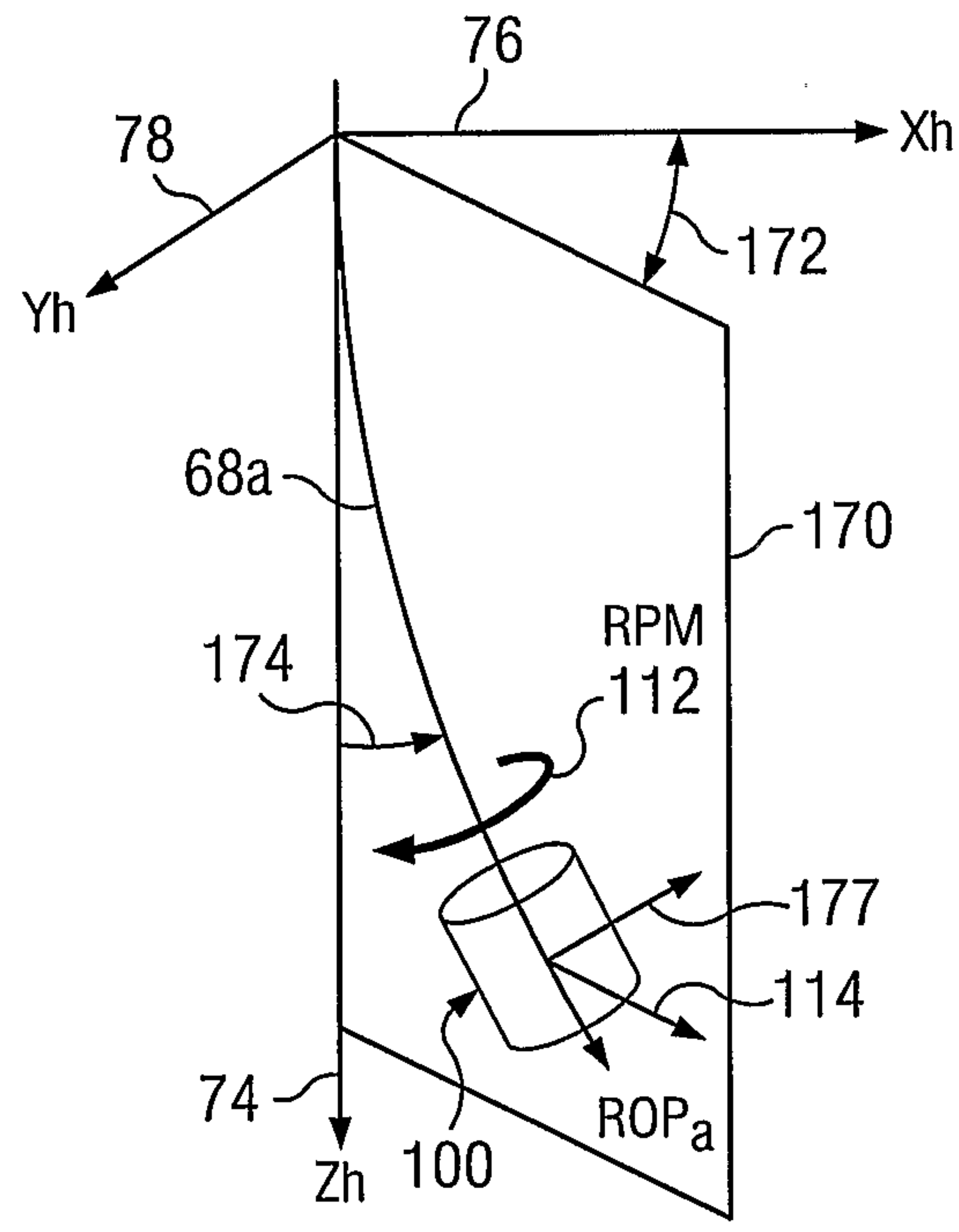


FIG. 3B

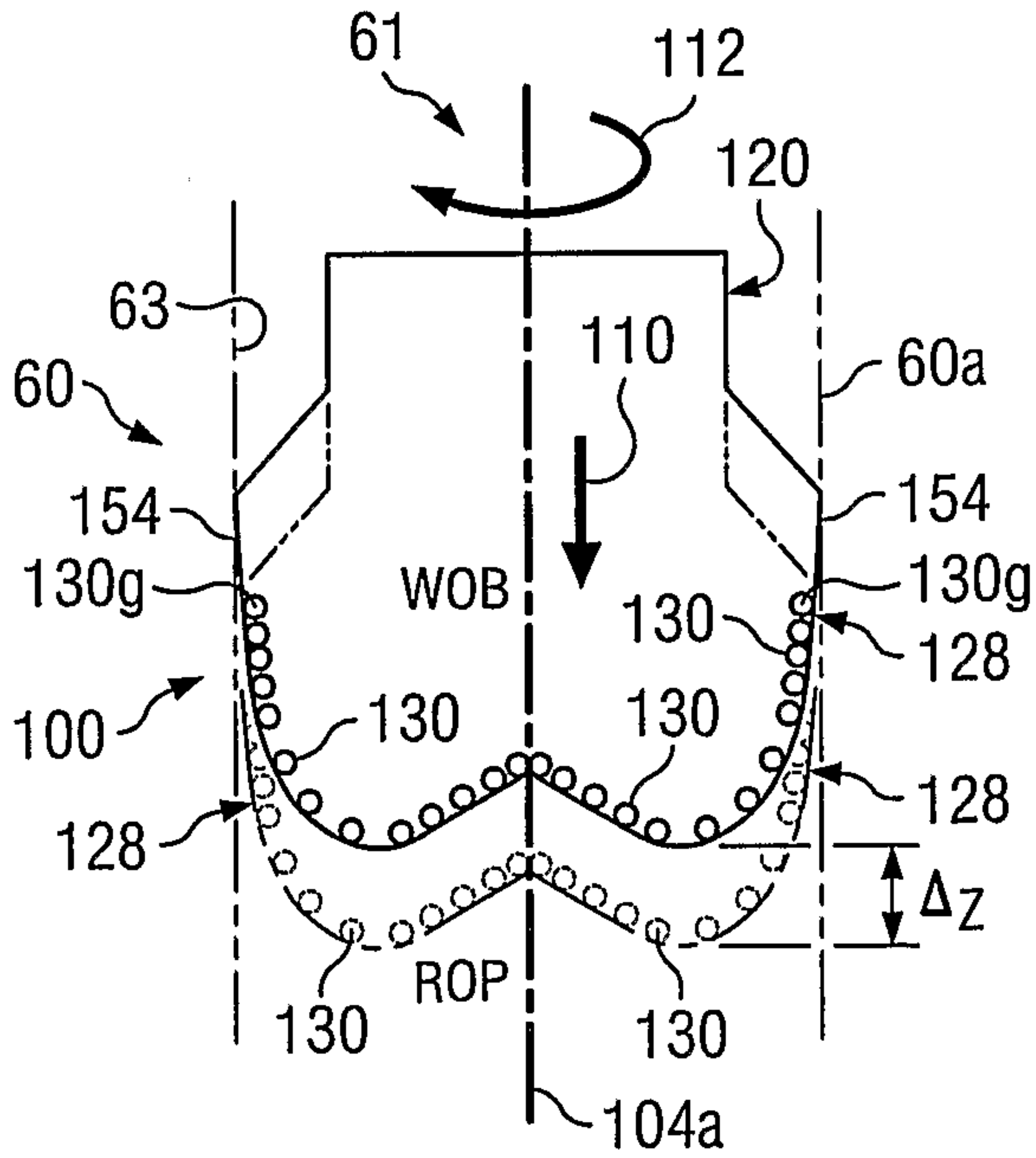


FIG. 2B

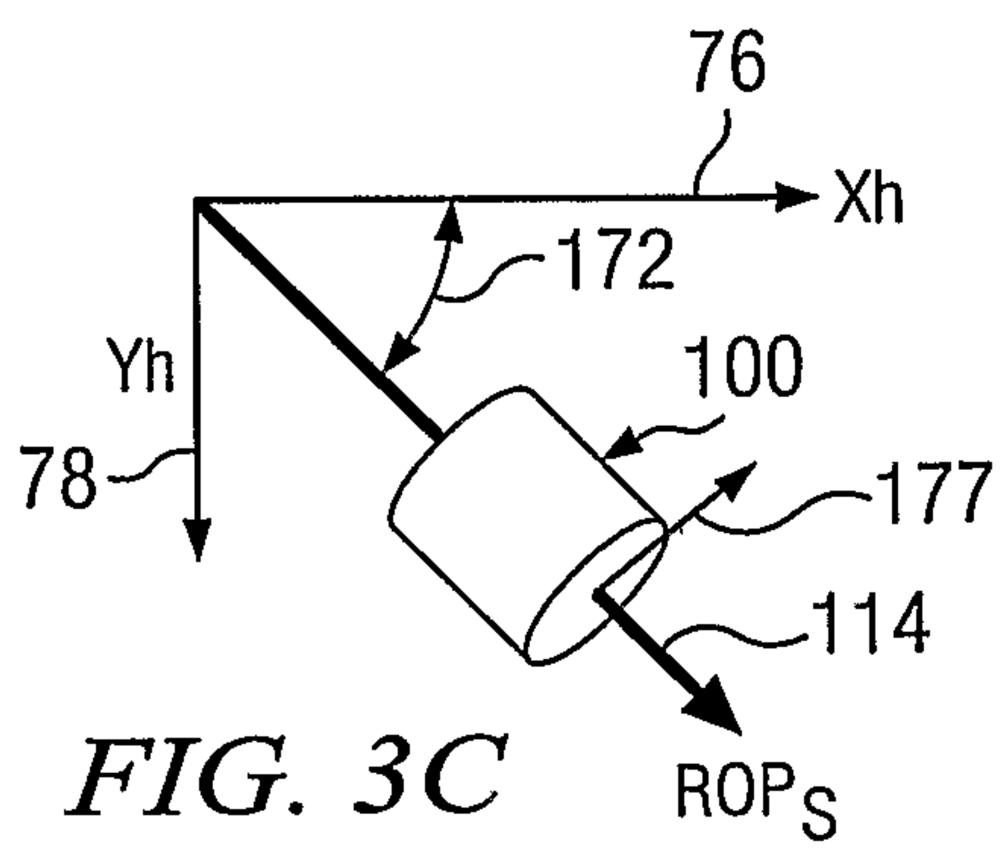


FIG. 3C

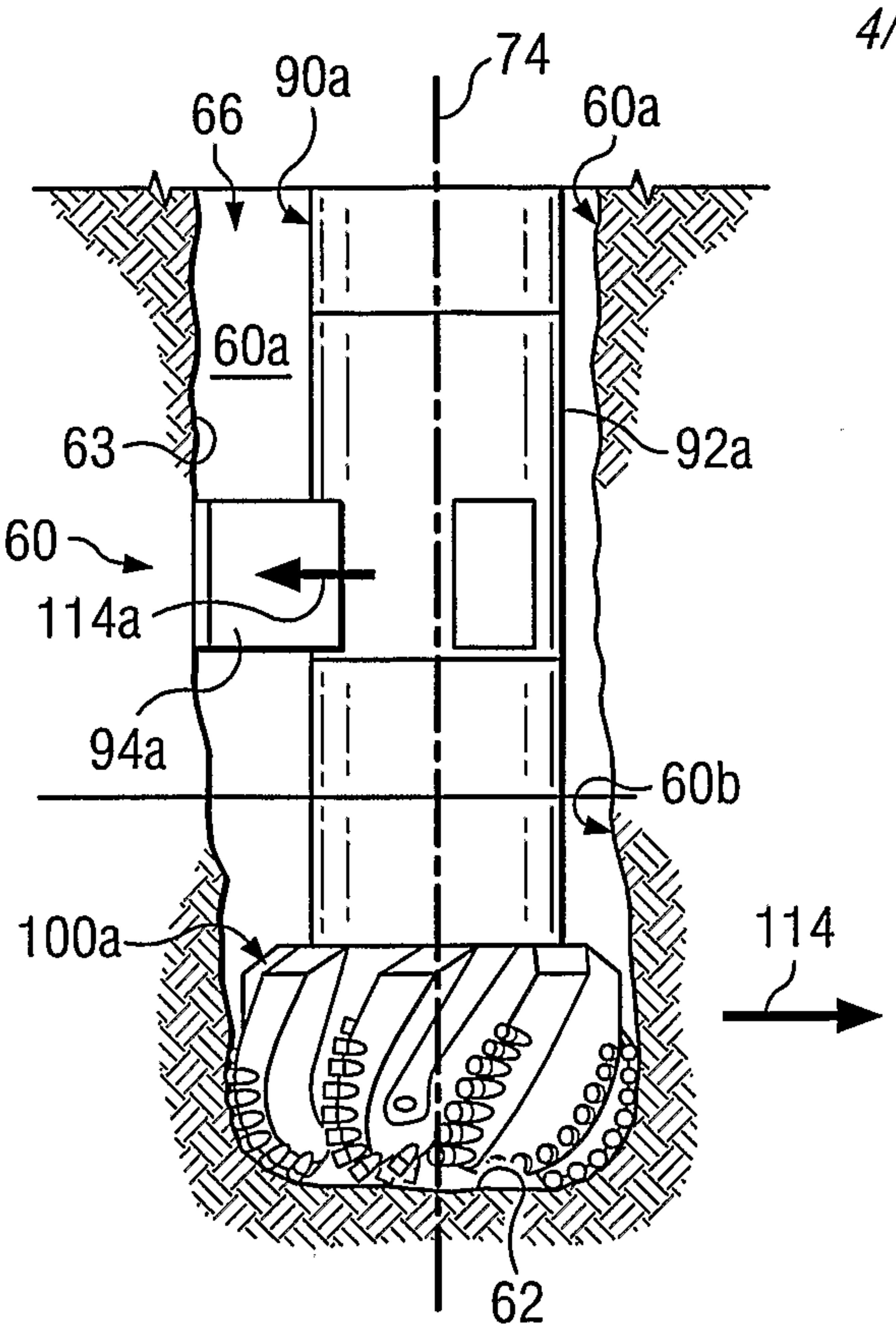


FIG. 4A

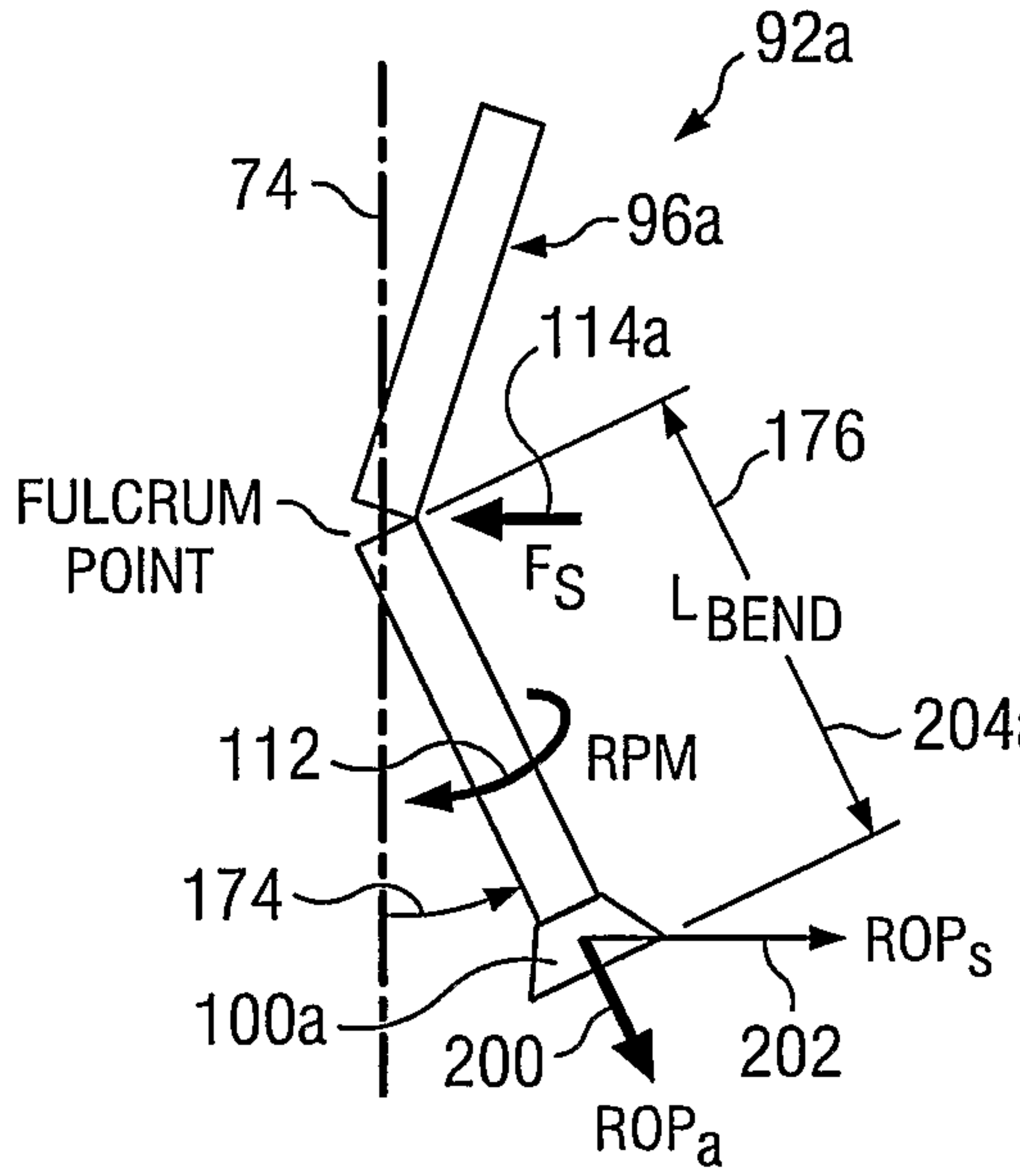


FIG. 4B

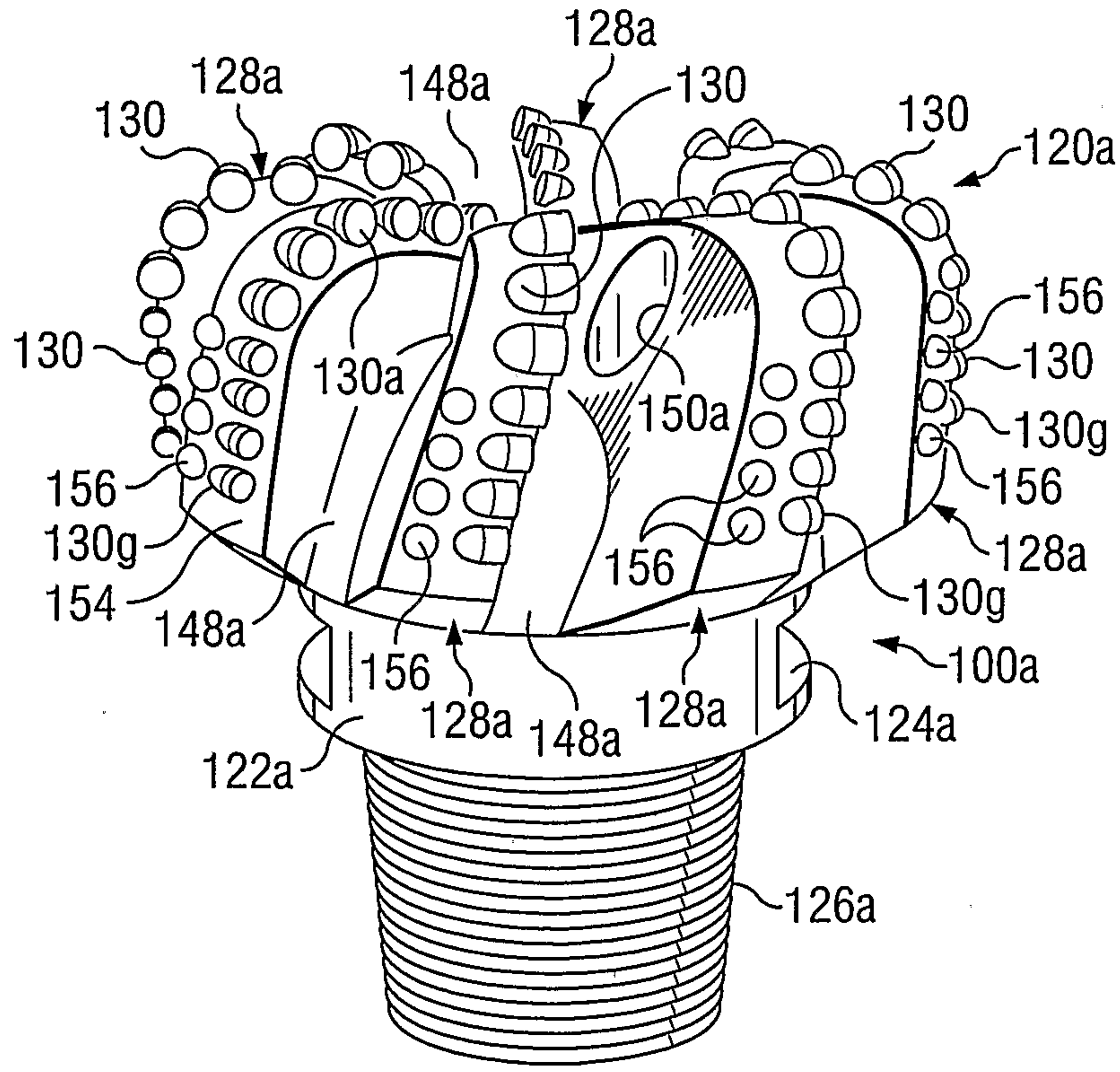


FIG. 4C

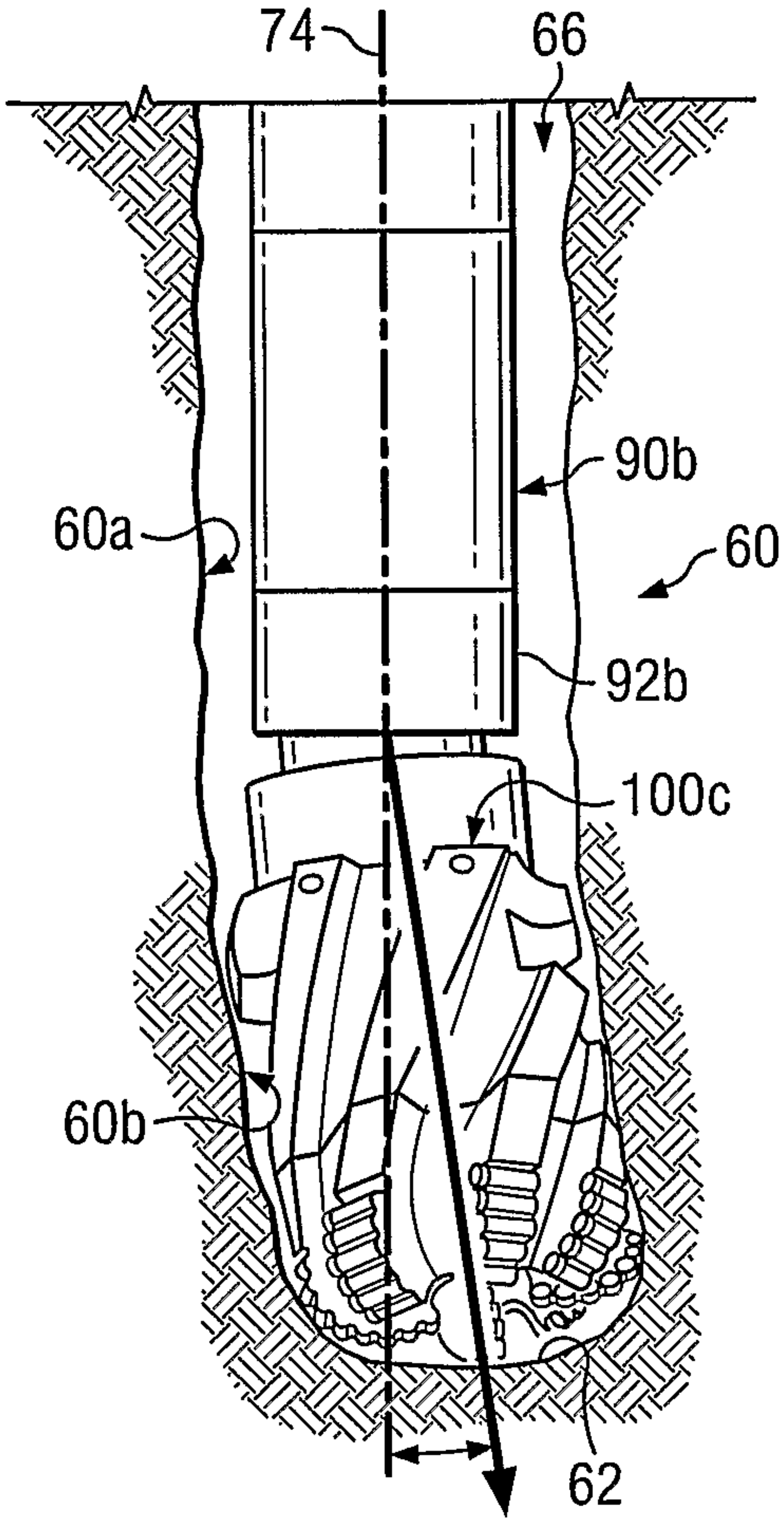


FIG. 5A

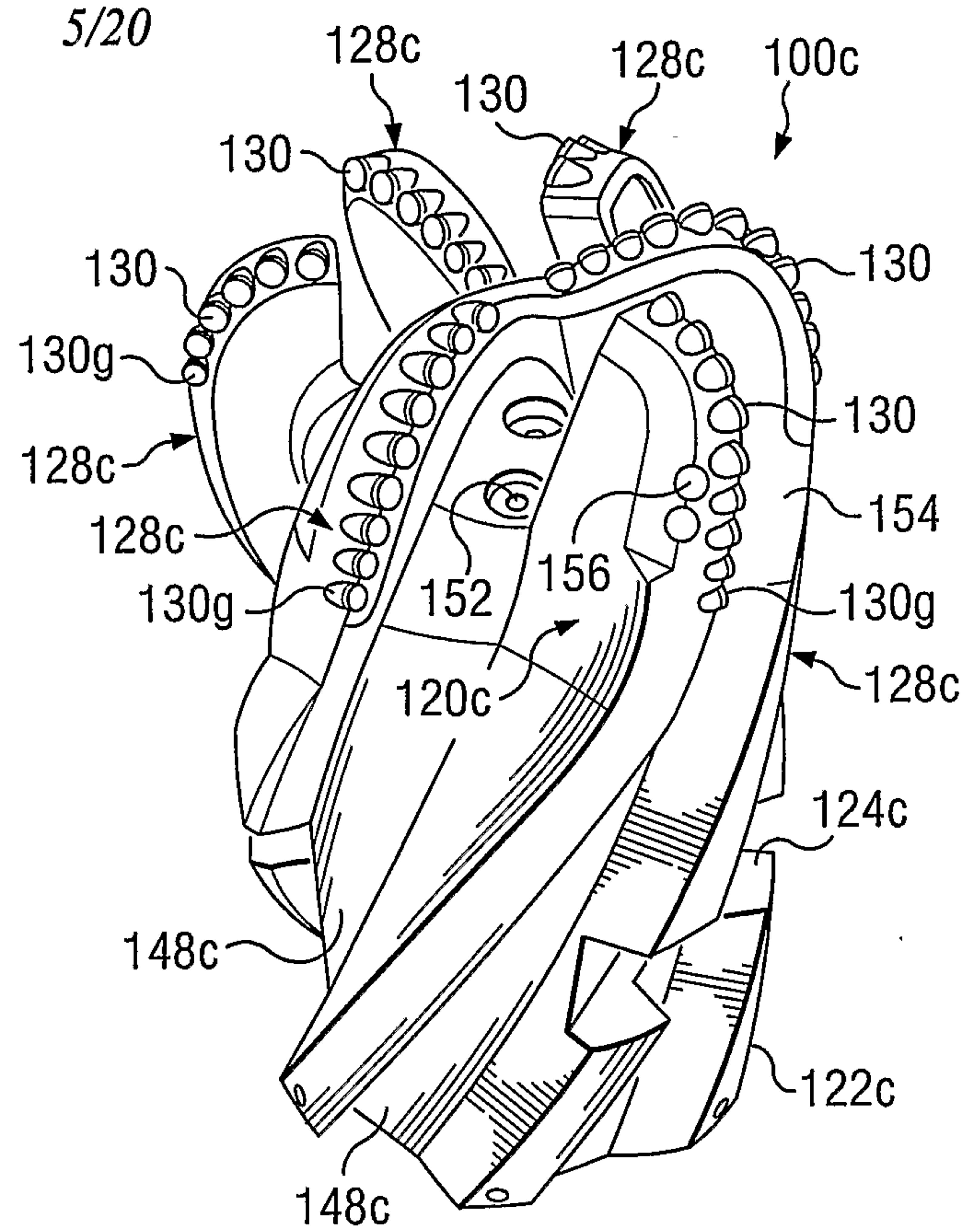


FIG. 5C

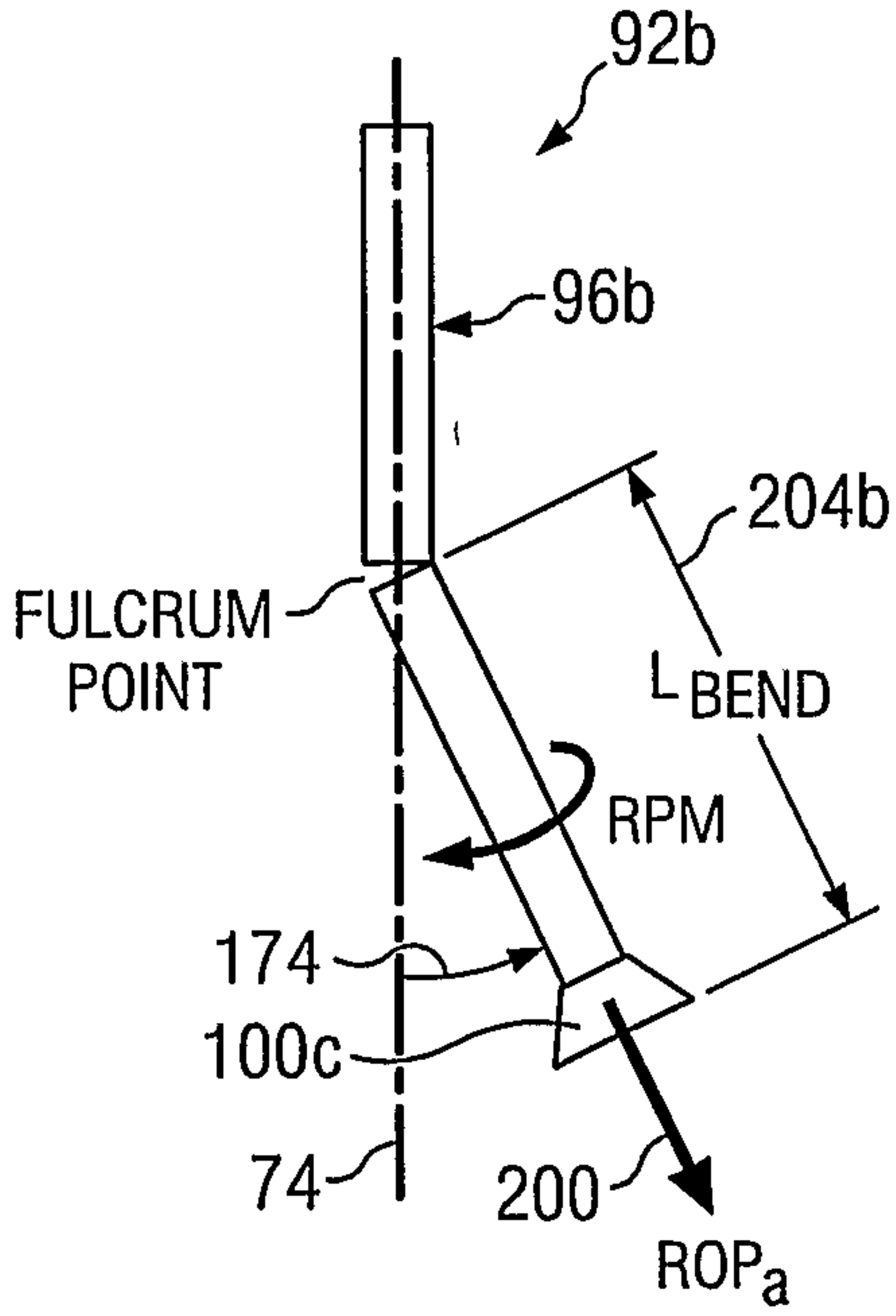


FIG. 5B

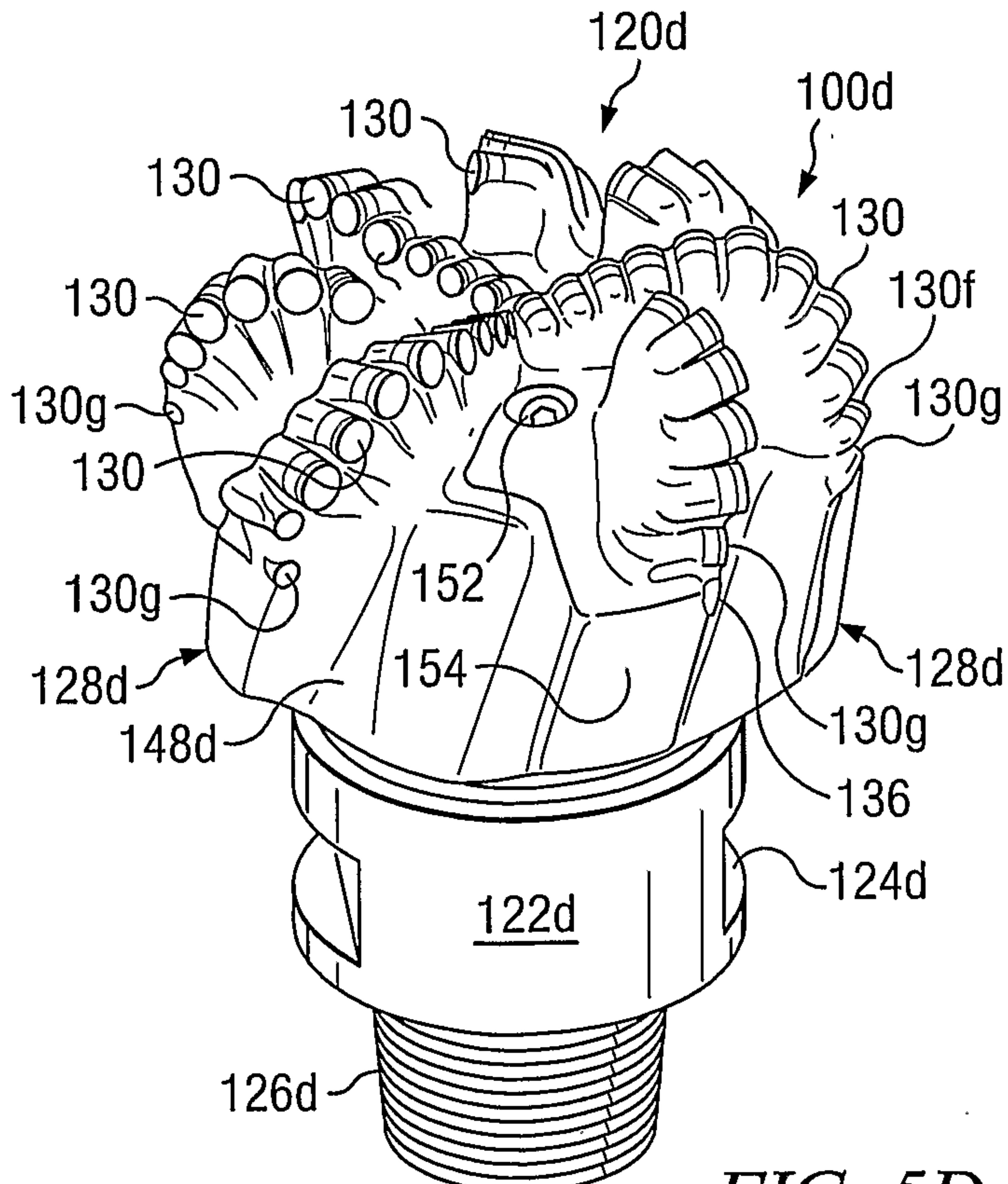


FIG. 5D

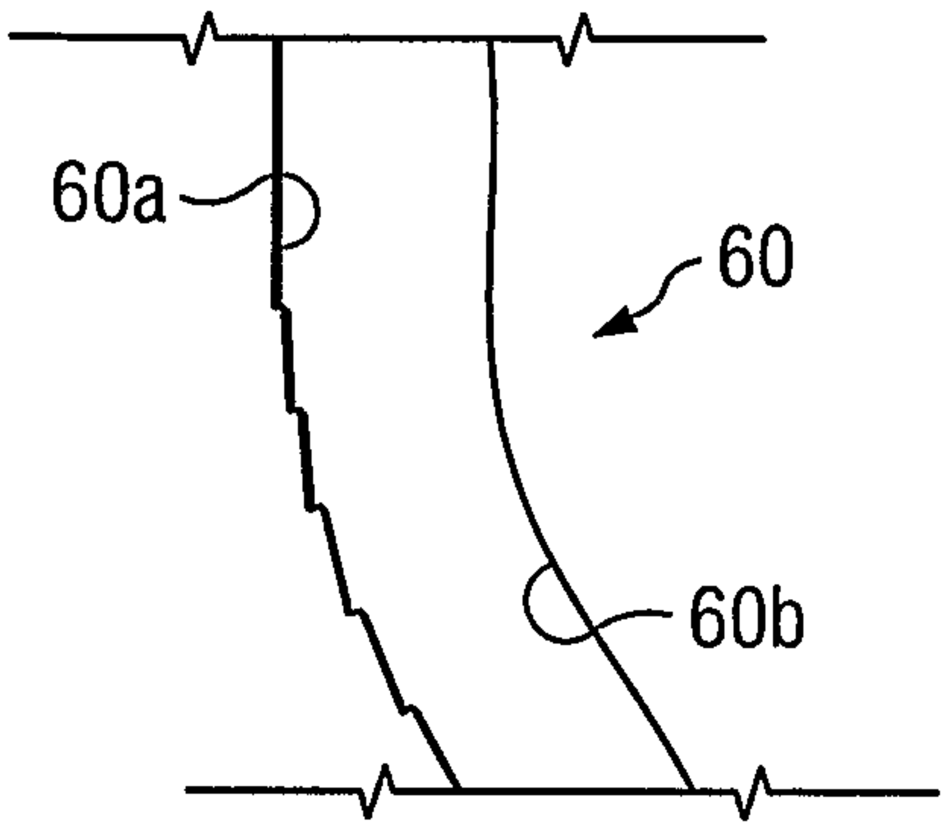


FIG. 6A

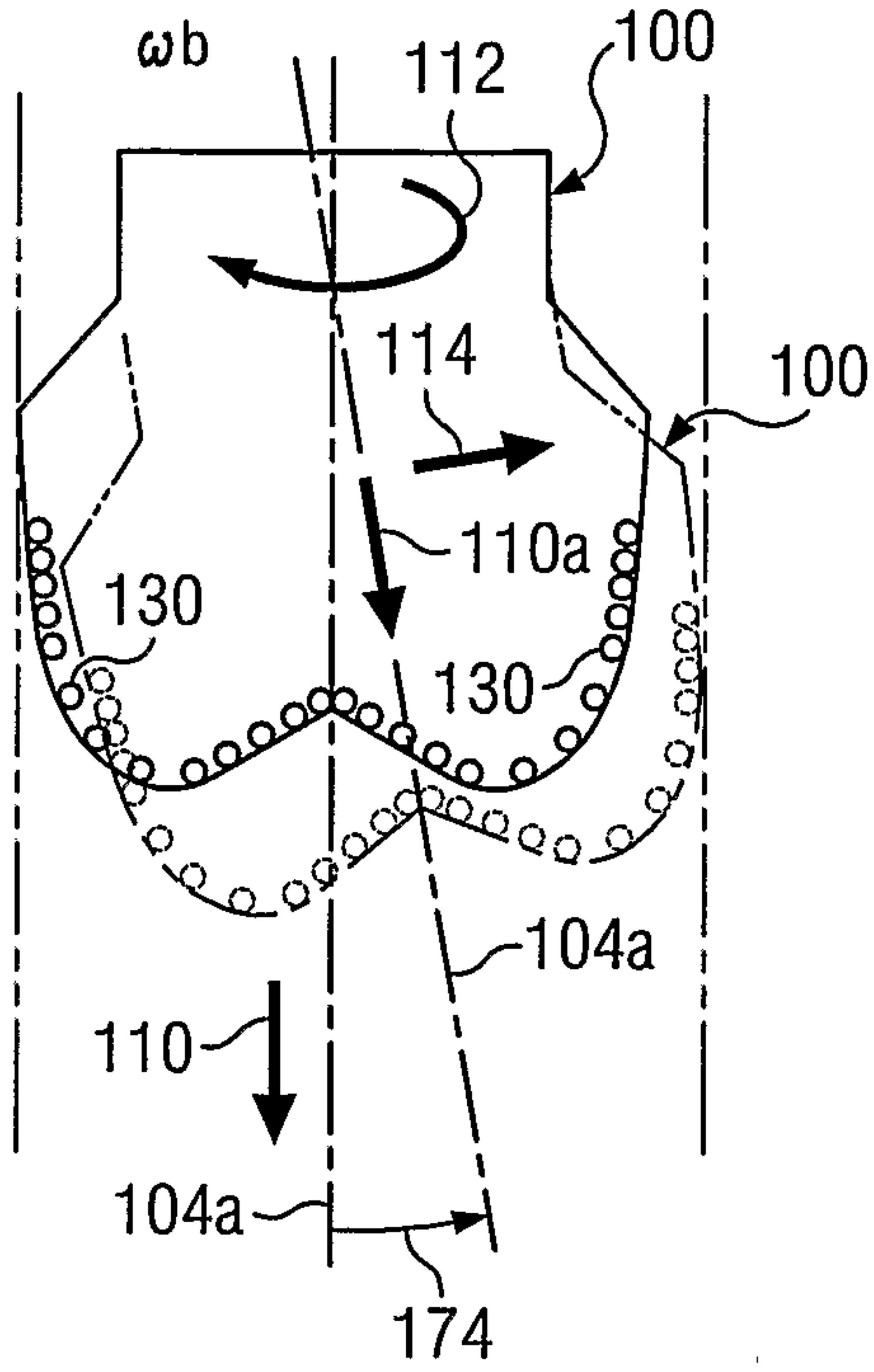


FIG. 6B

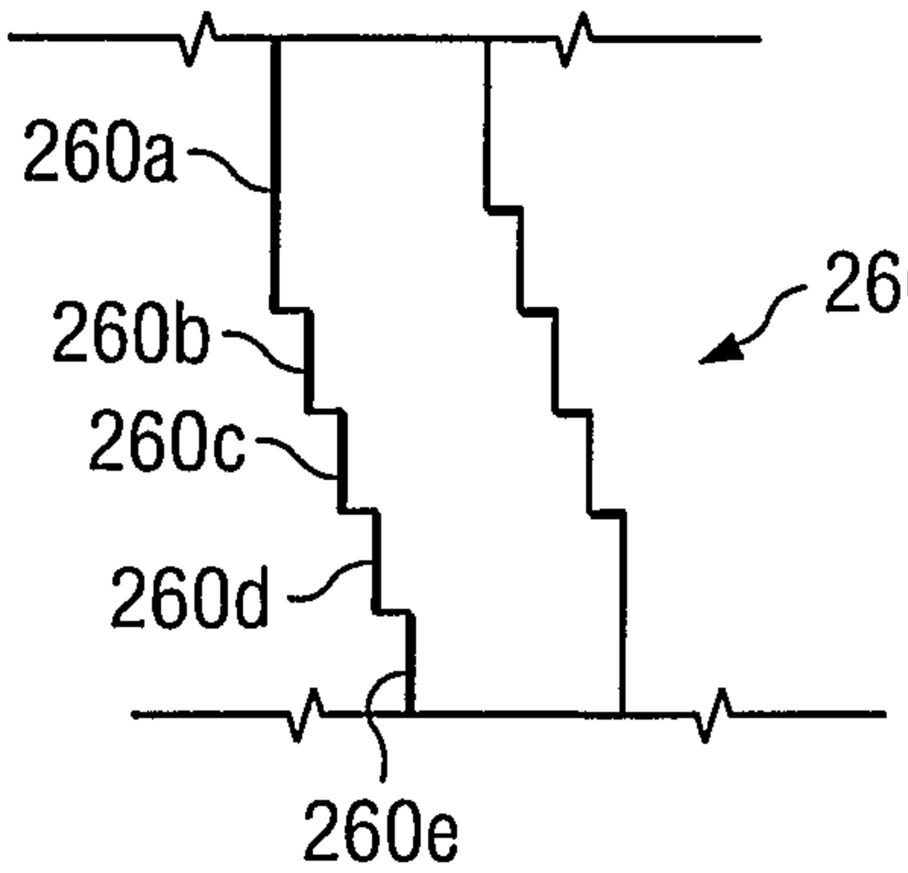


FIG. 6C

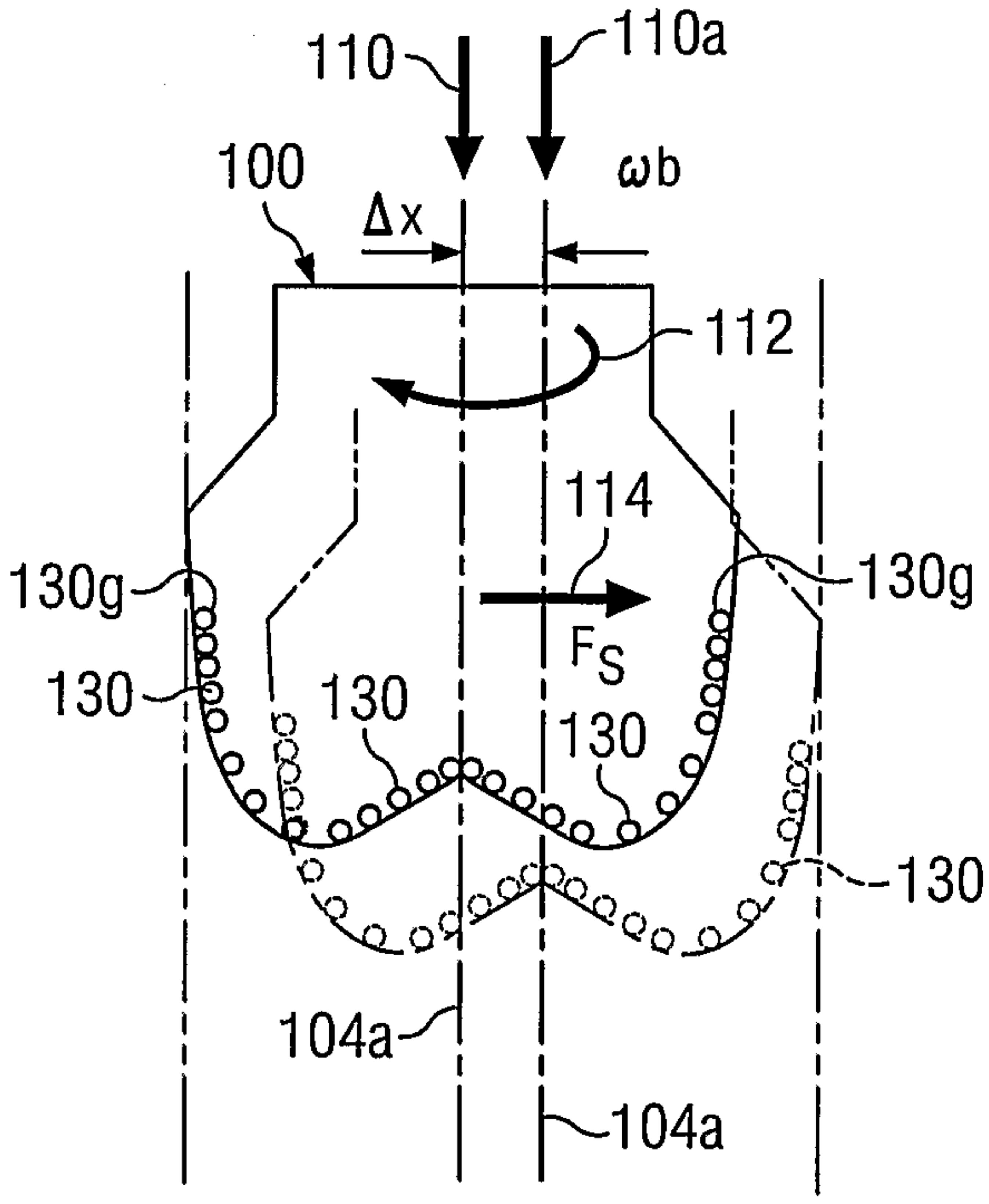


FIG. 6D

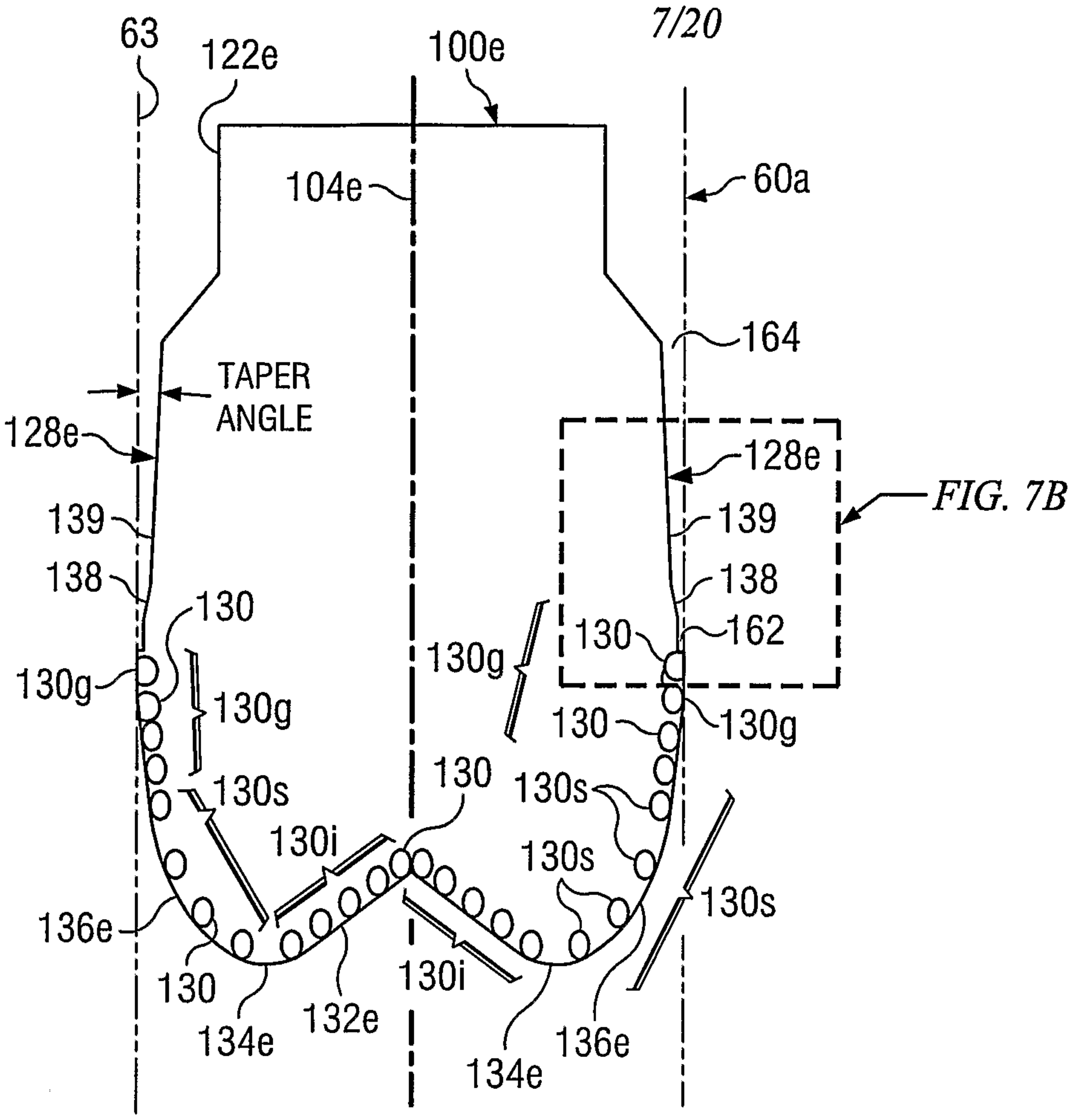


FIG. 7B

FIG. 7A

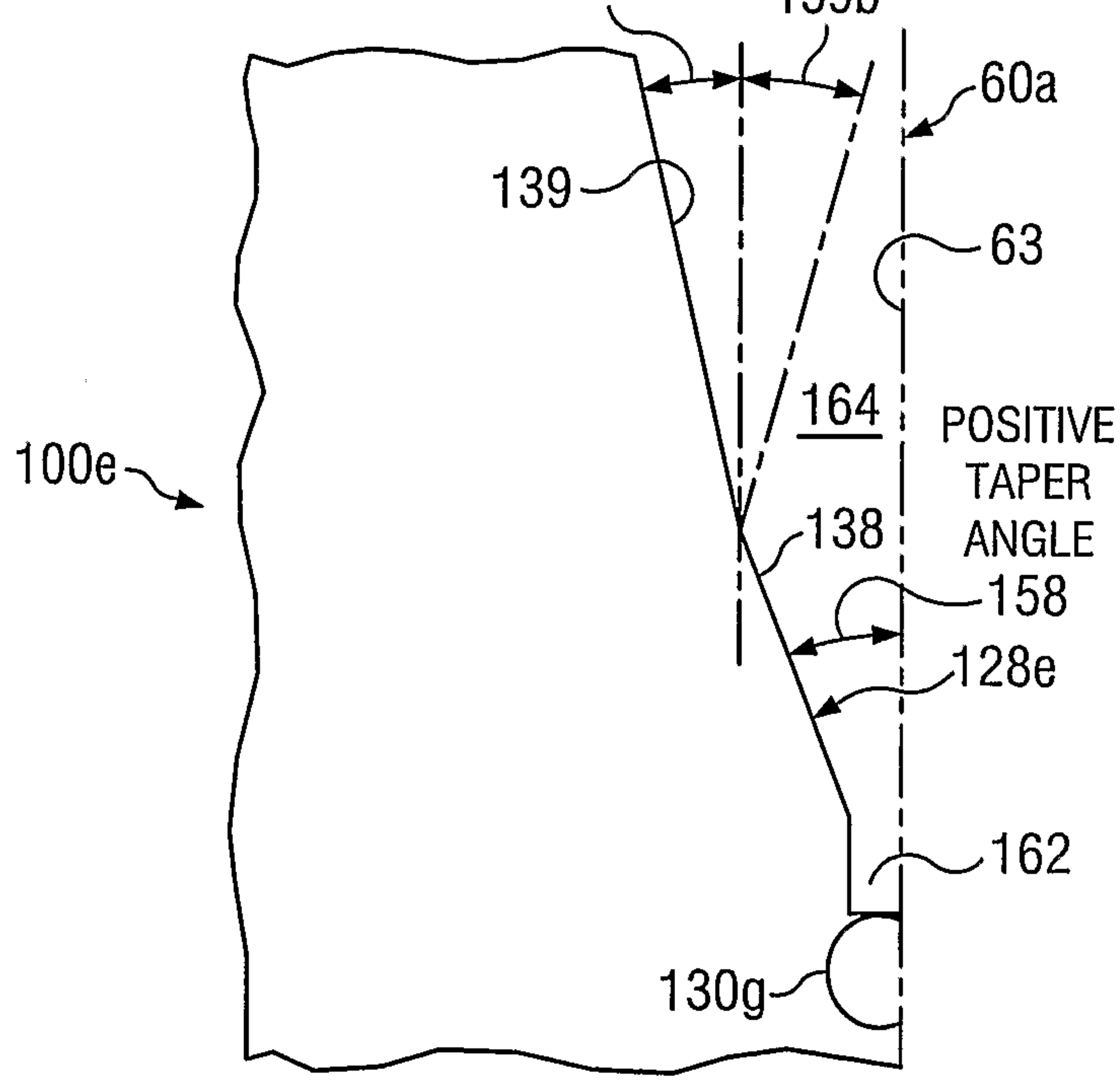


FIG. 7B

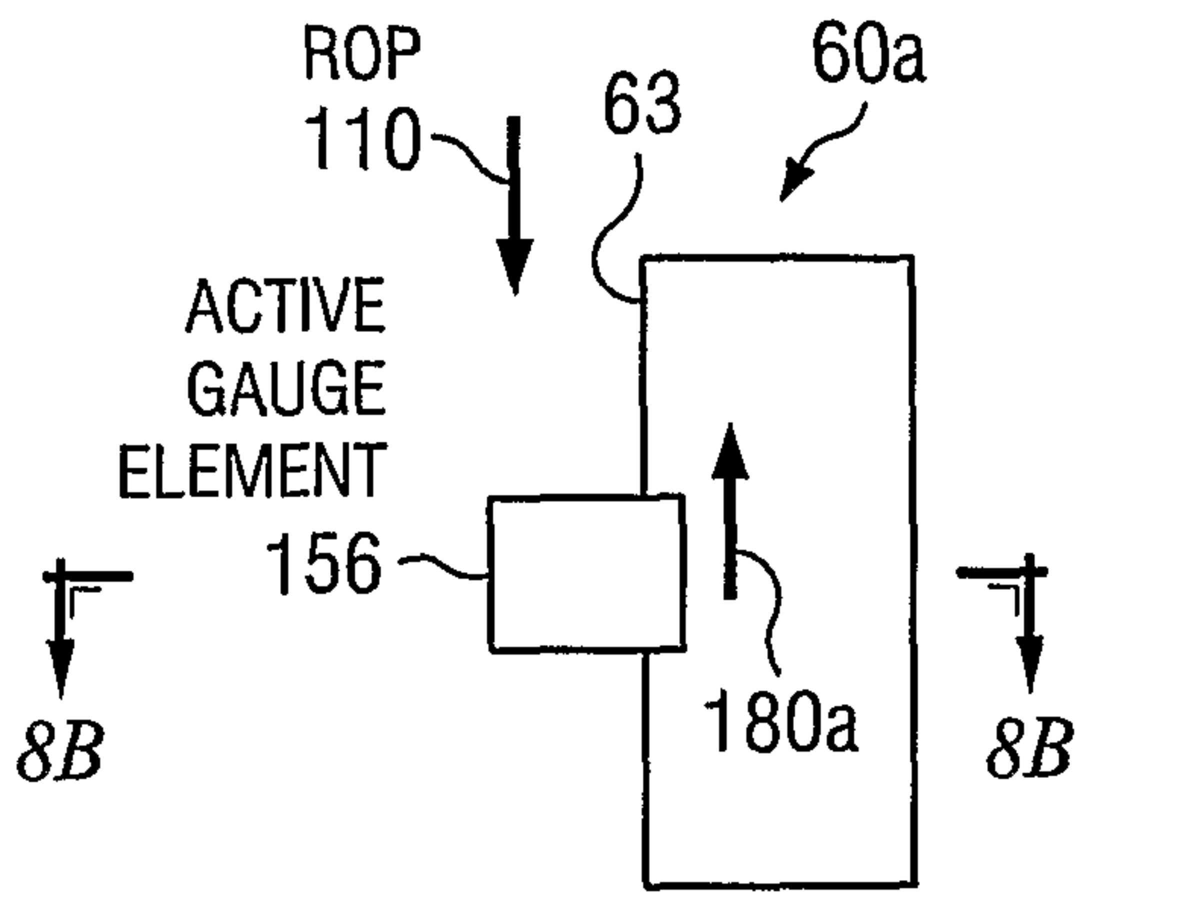


FIG. 8A

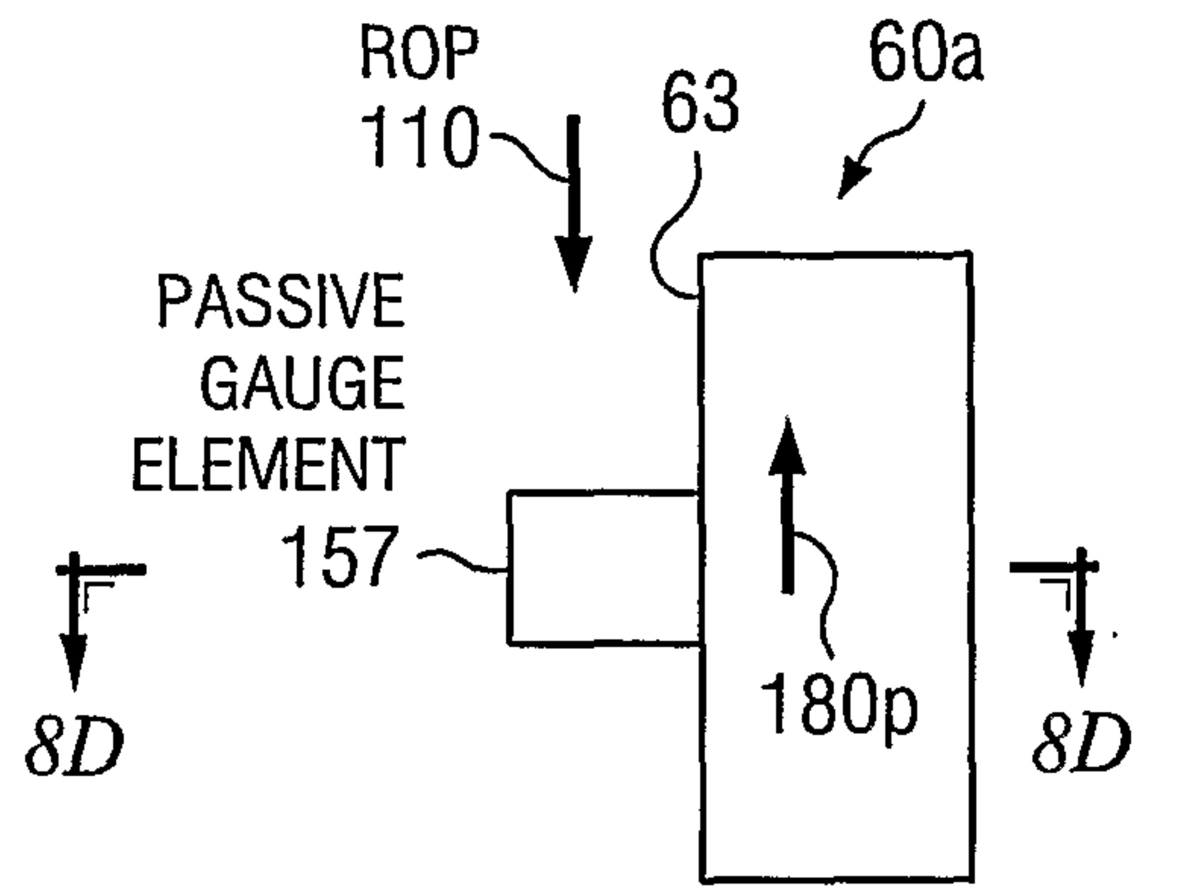


FIG. 8C

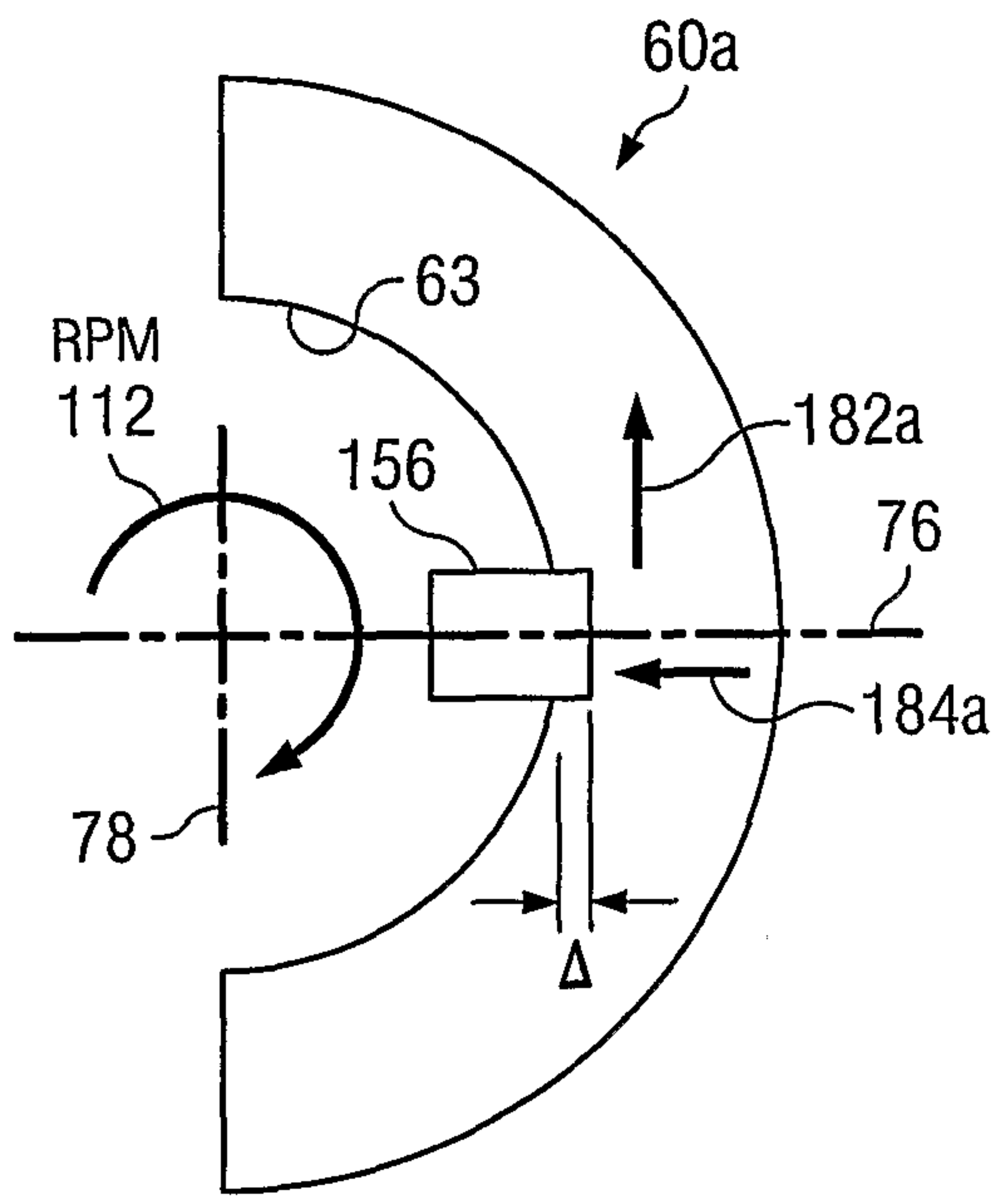


FIG. 8B

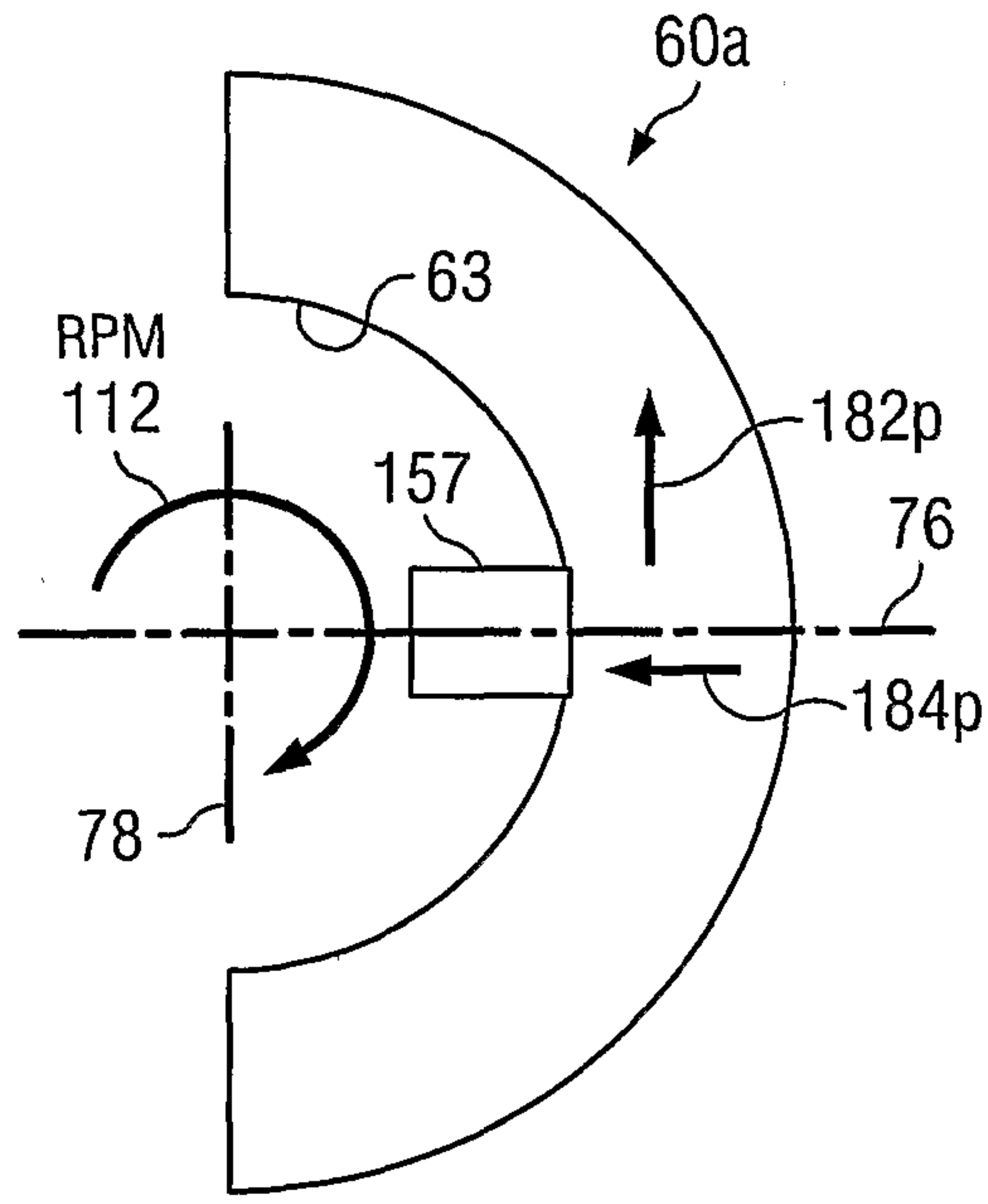


FIG. 8D

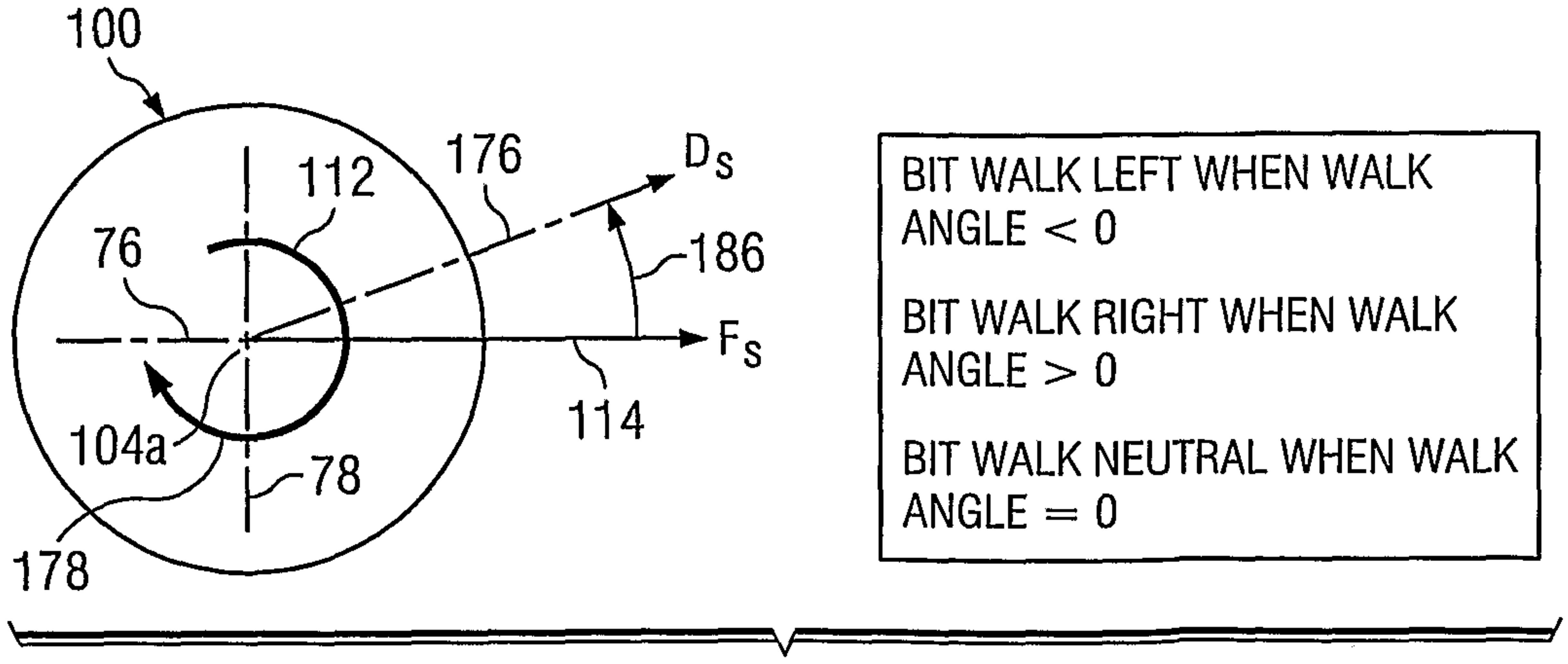


FIG. 9

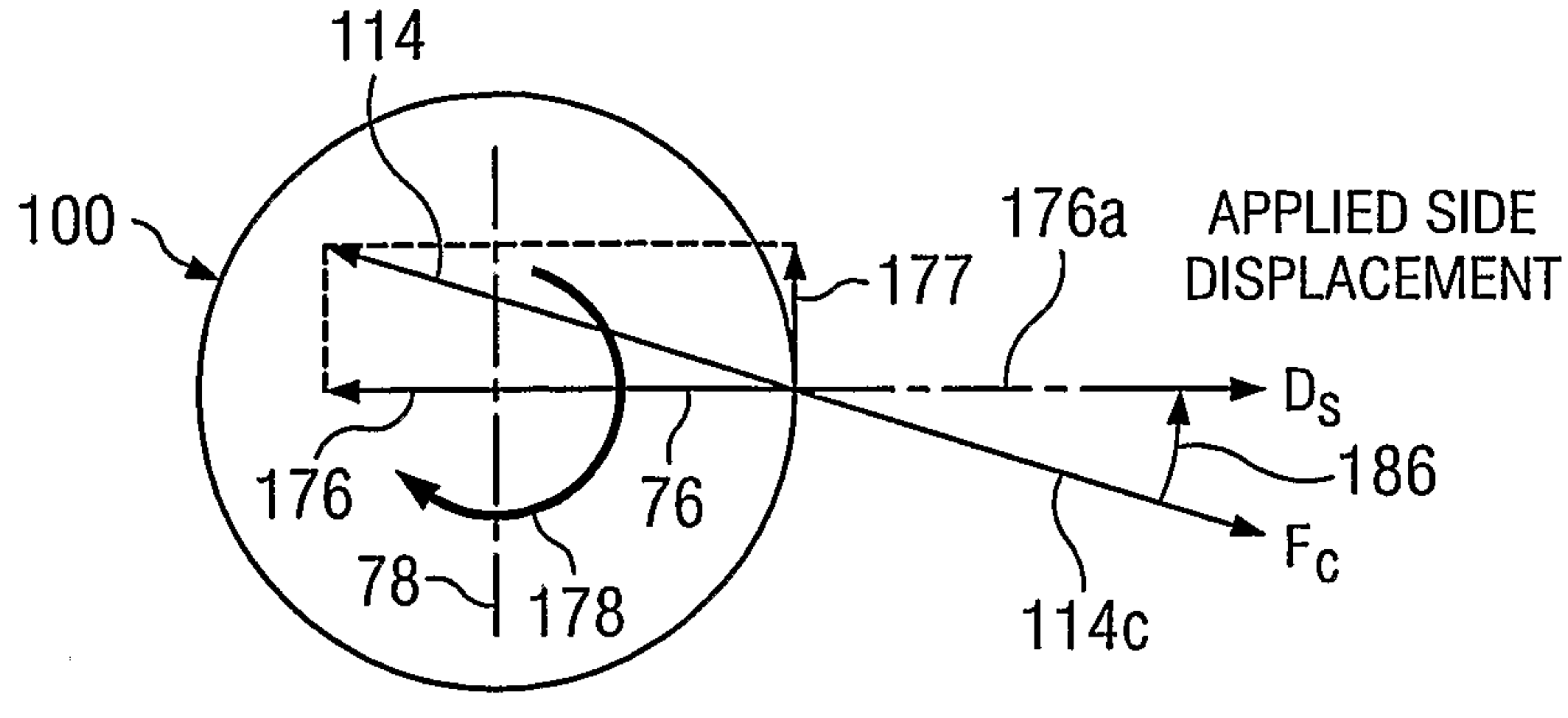


FIG. 10

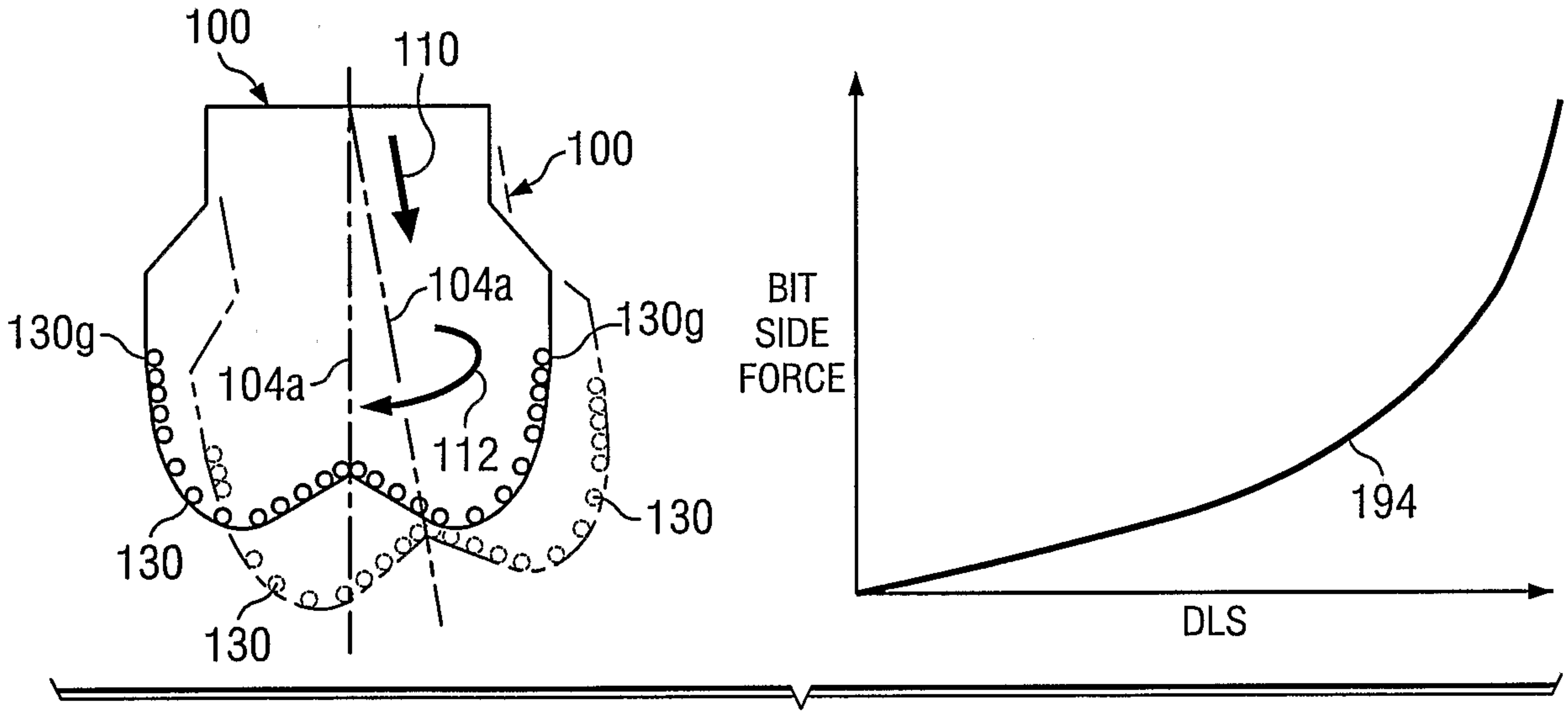


FIG. 11

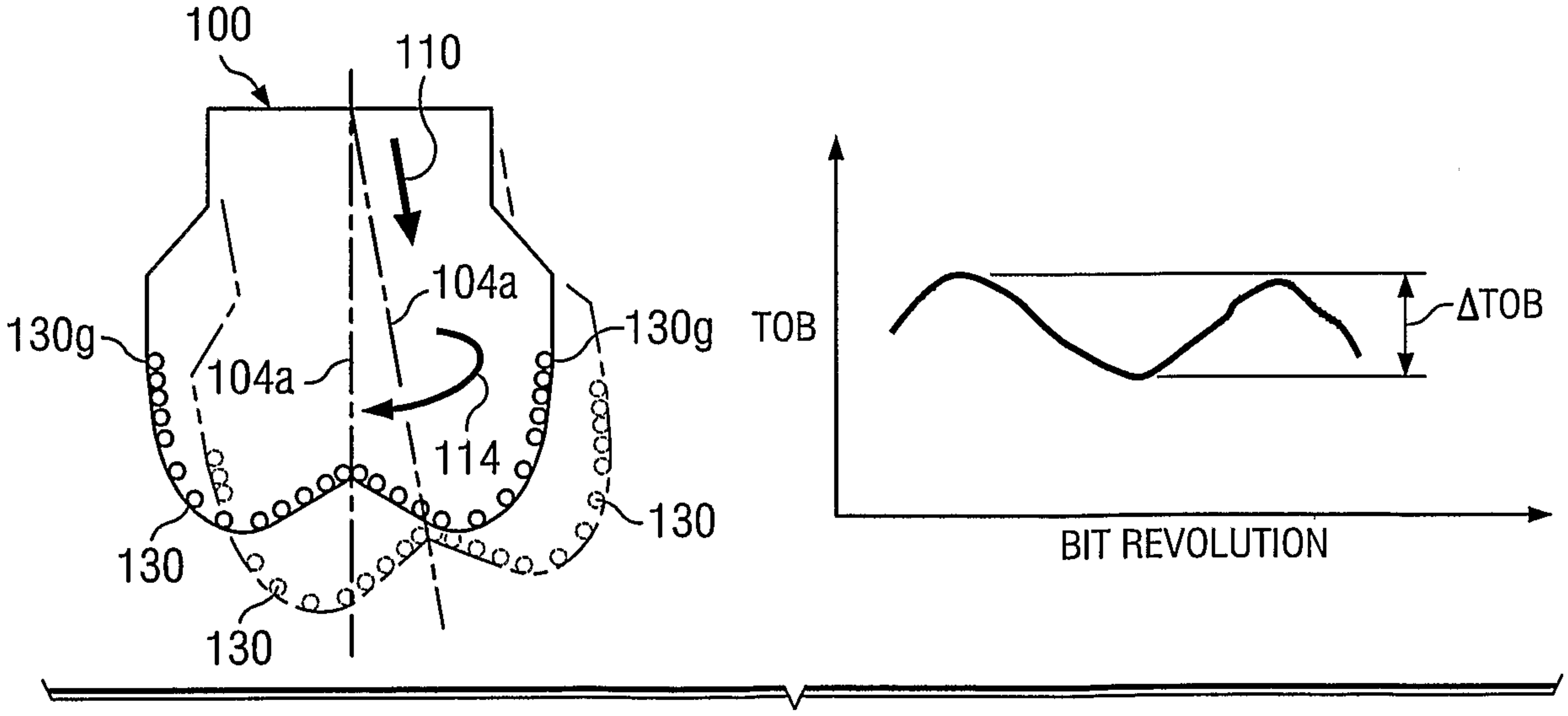


FIG. 12

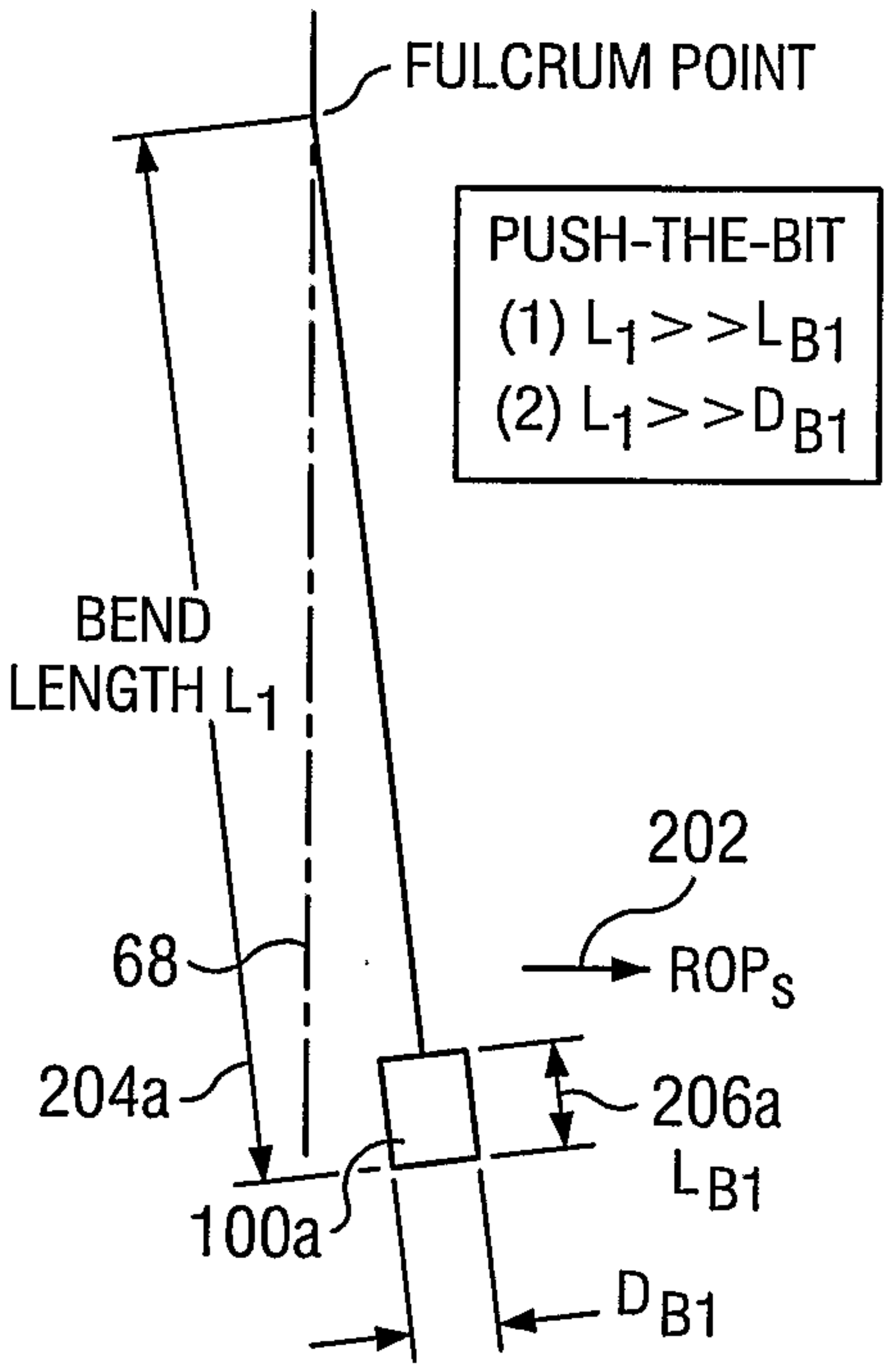


FIG. 13A

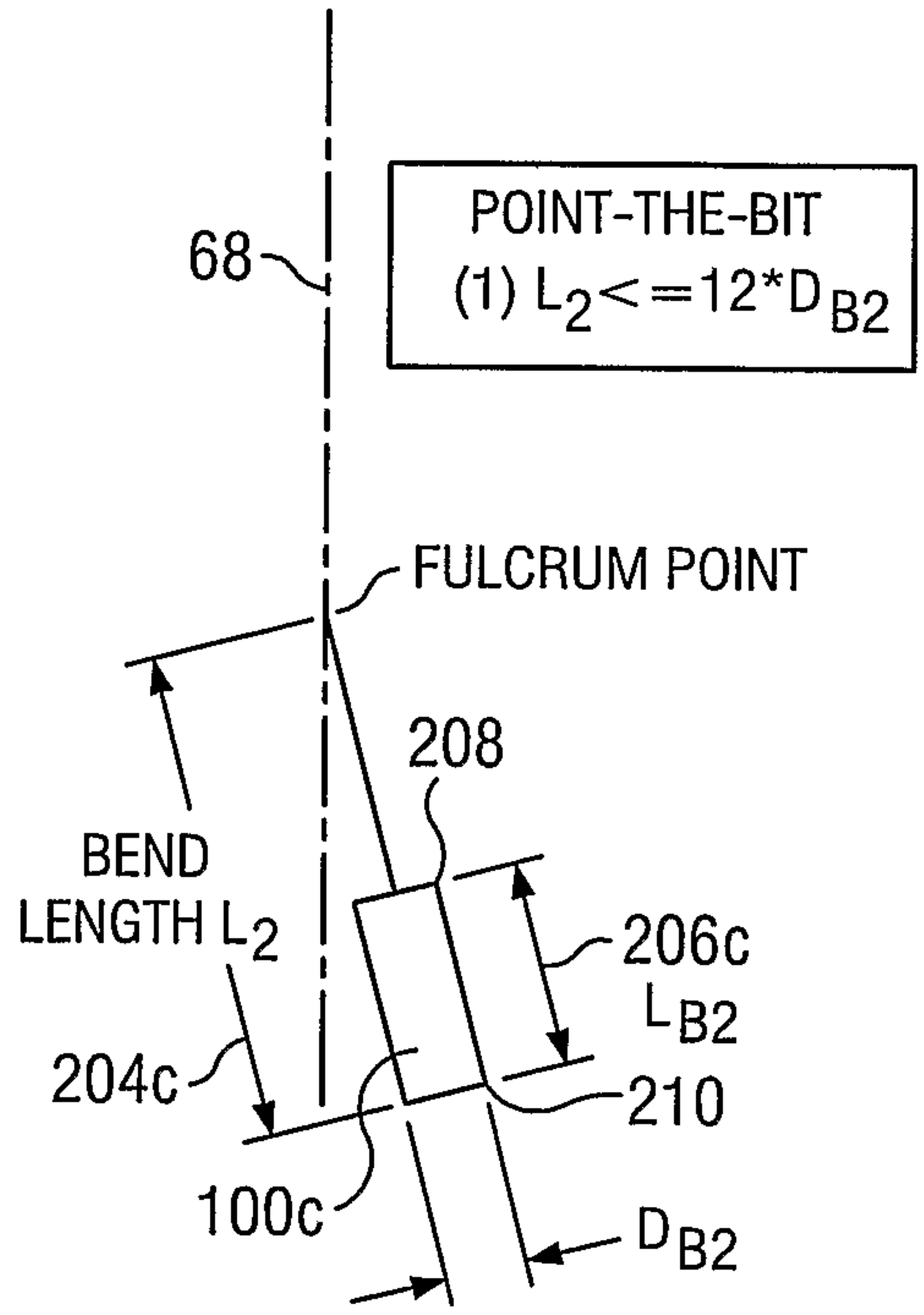


FIG. 13B

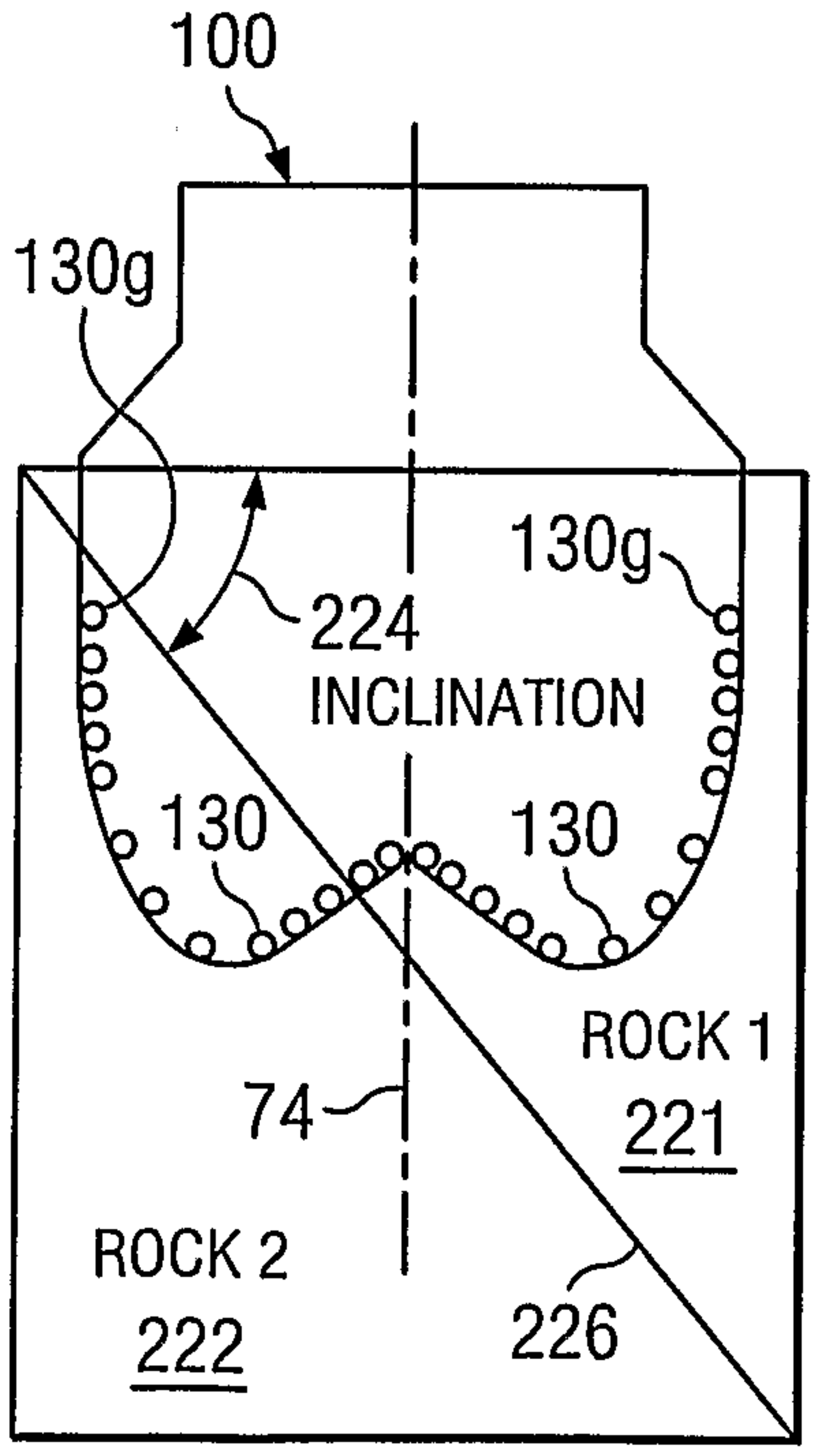


FIG. 14A

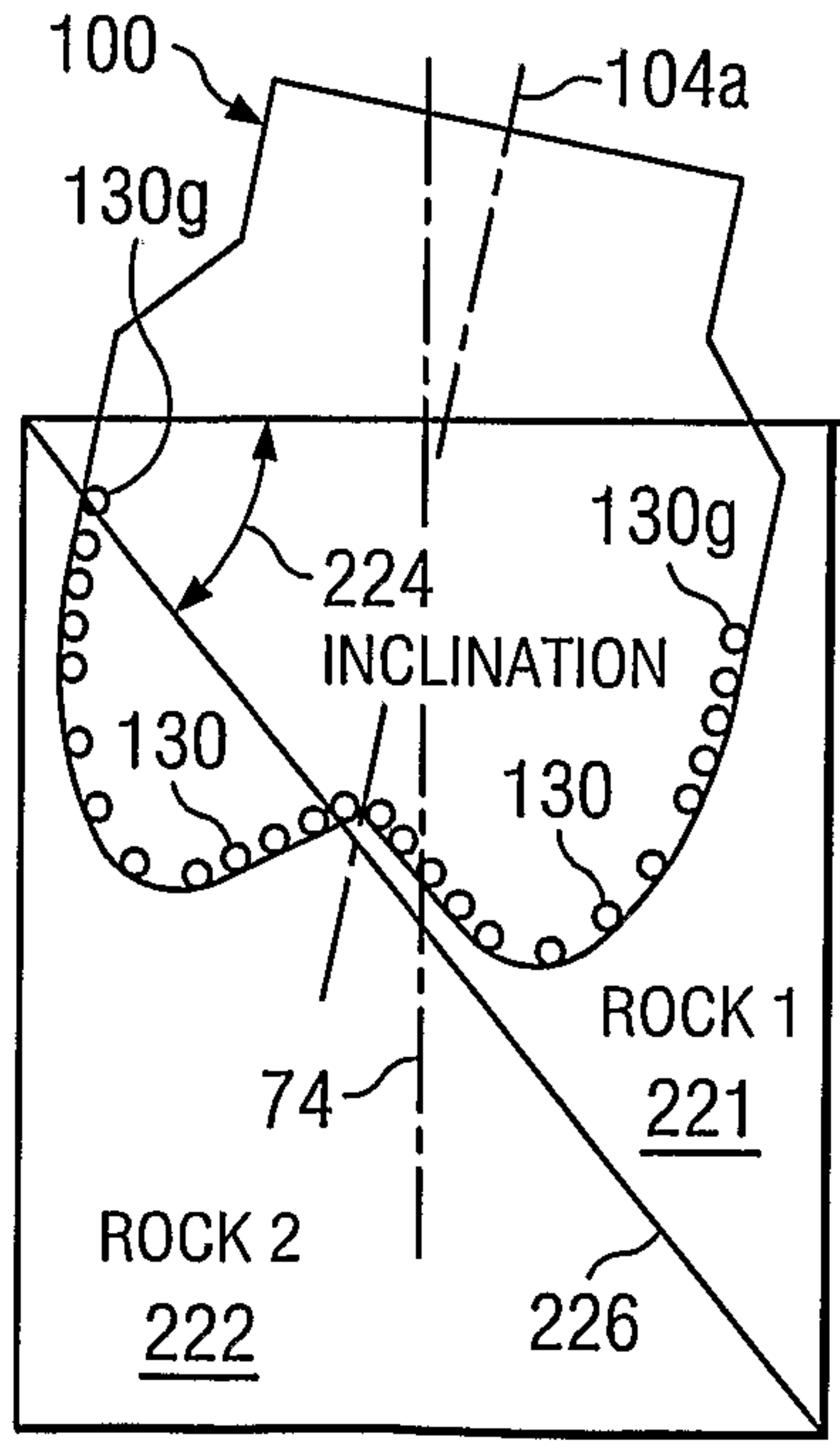


FIG. 14B

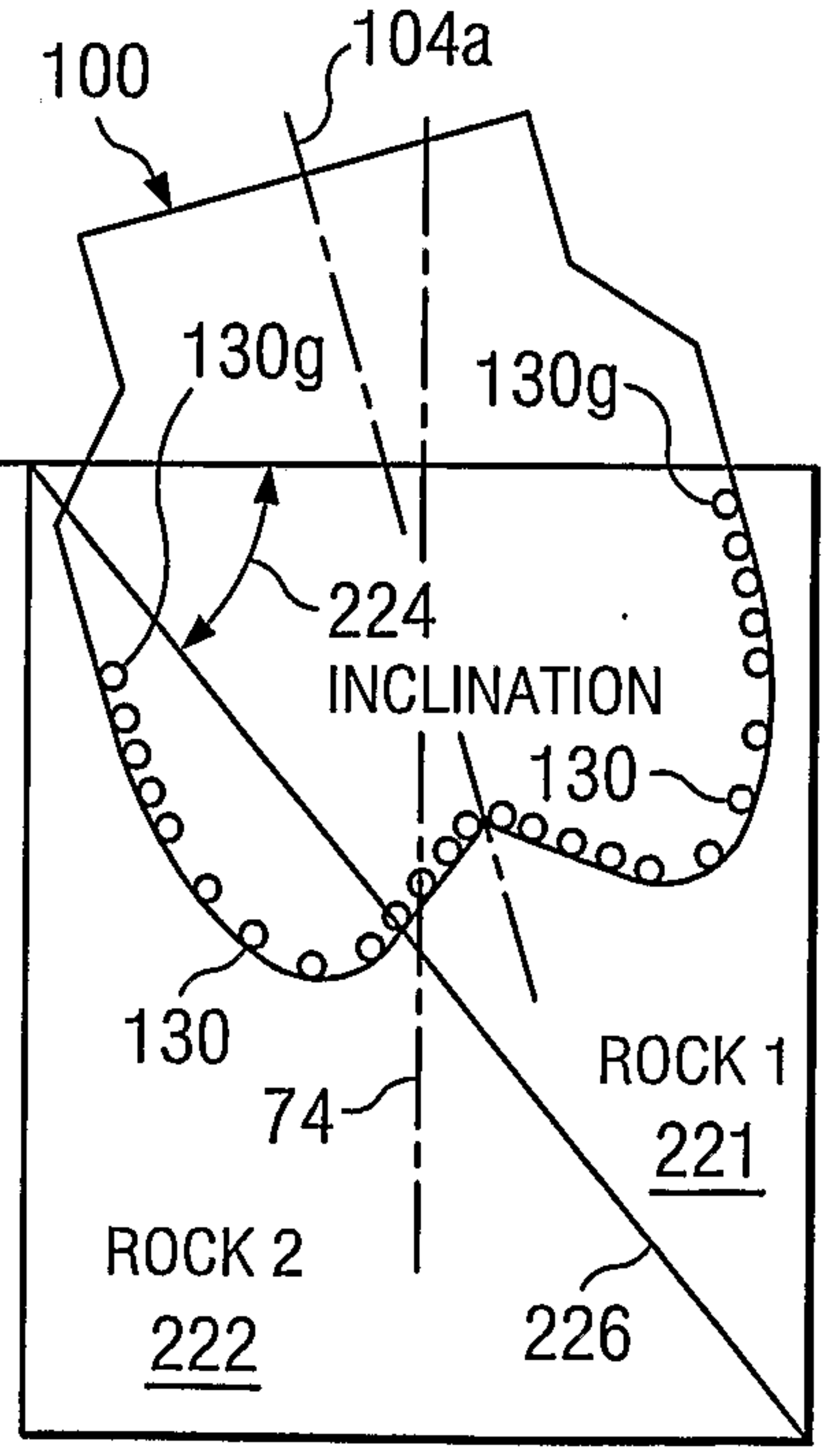


FIG. 14C

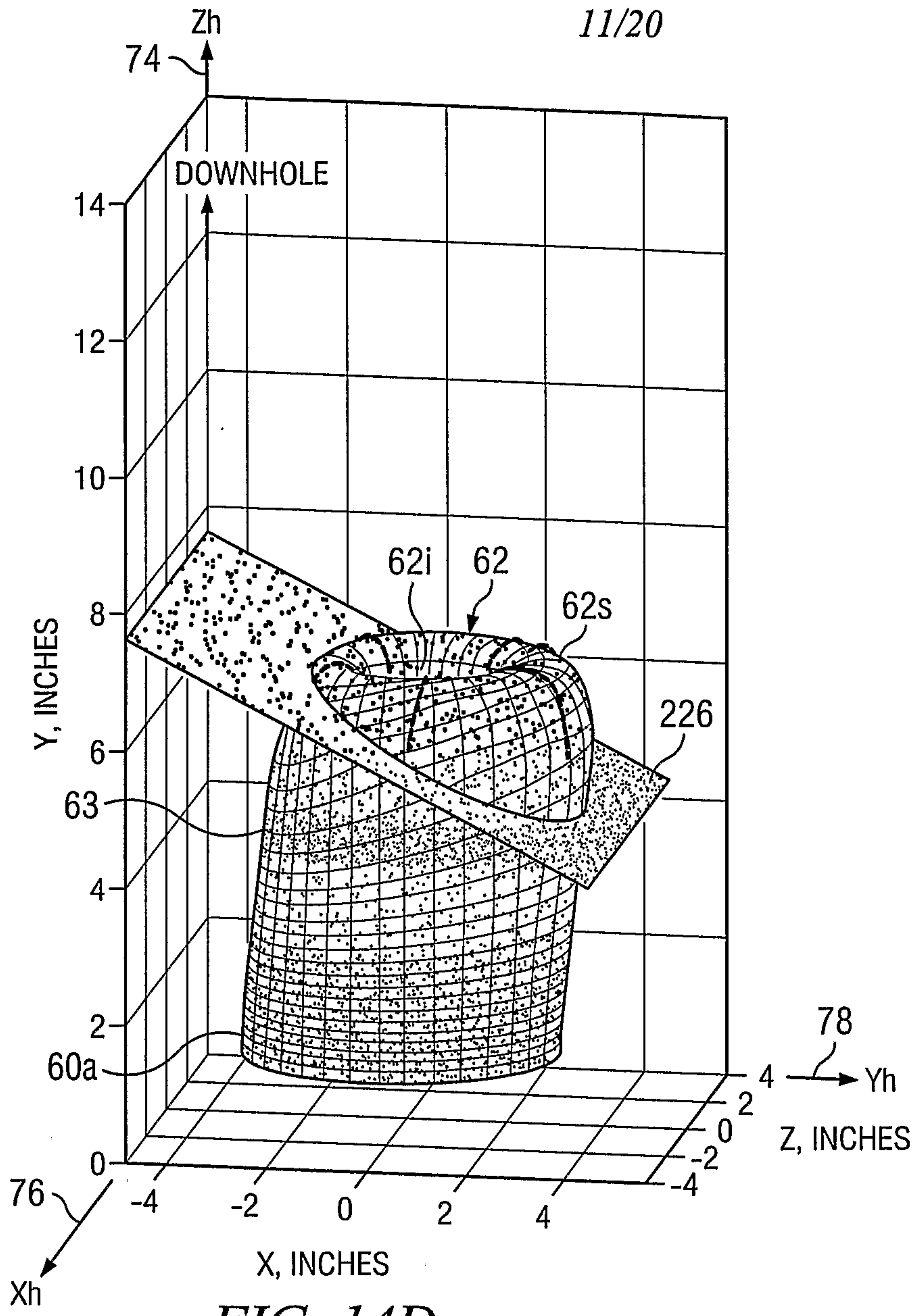


FIG. 14D

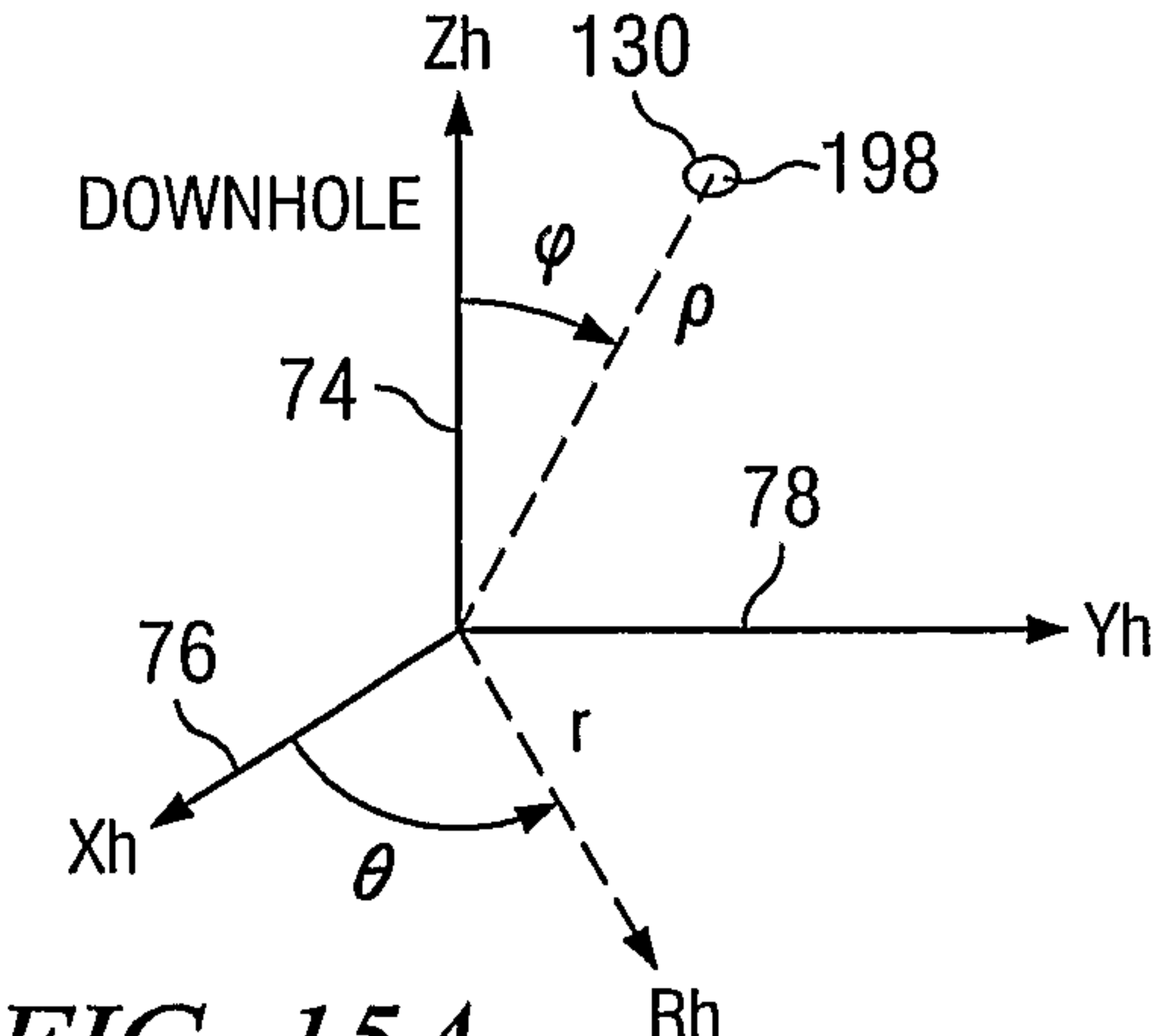


FIG. 15A

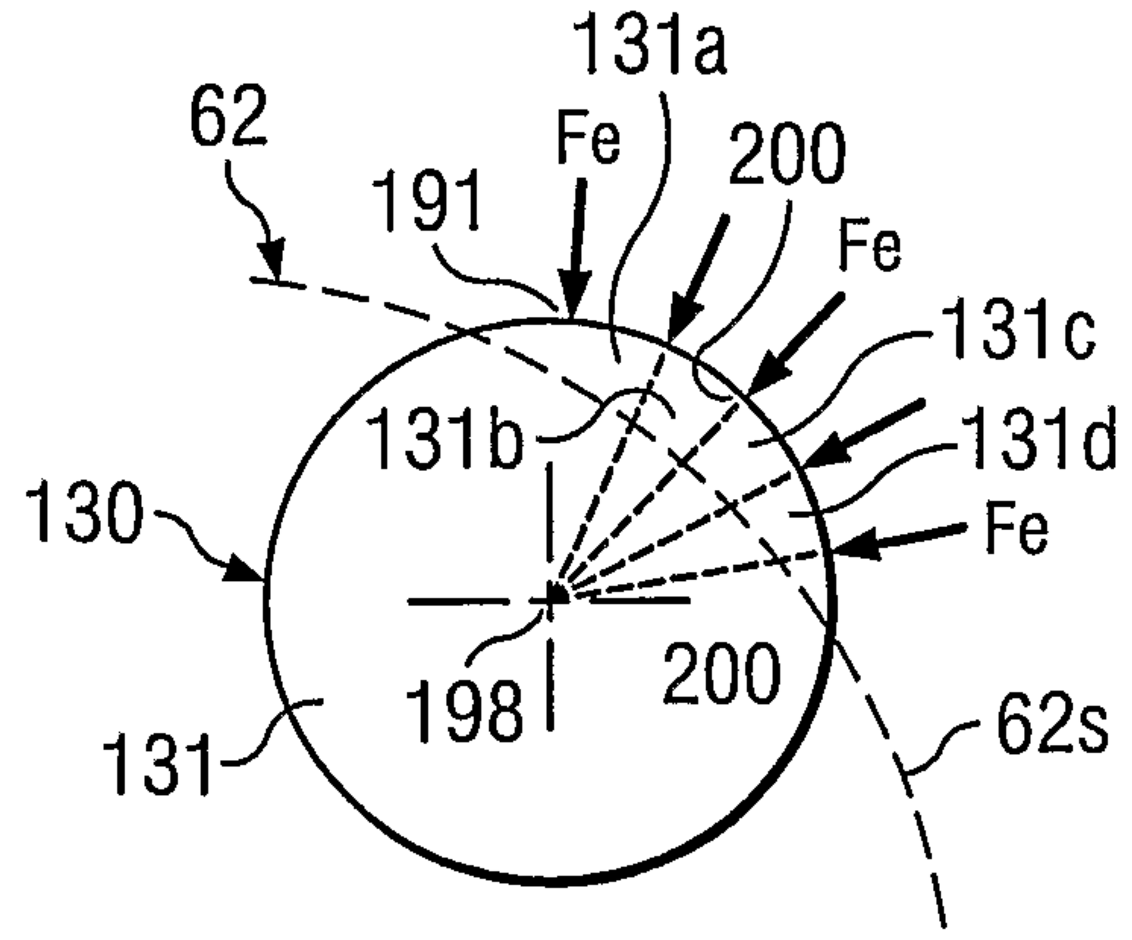


FIG. 15B

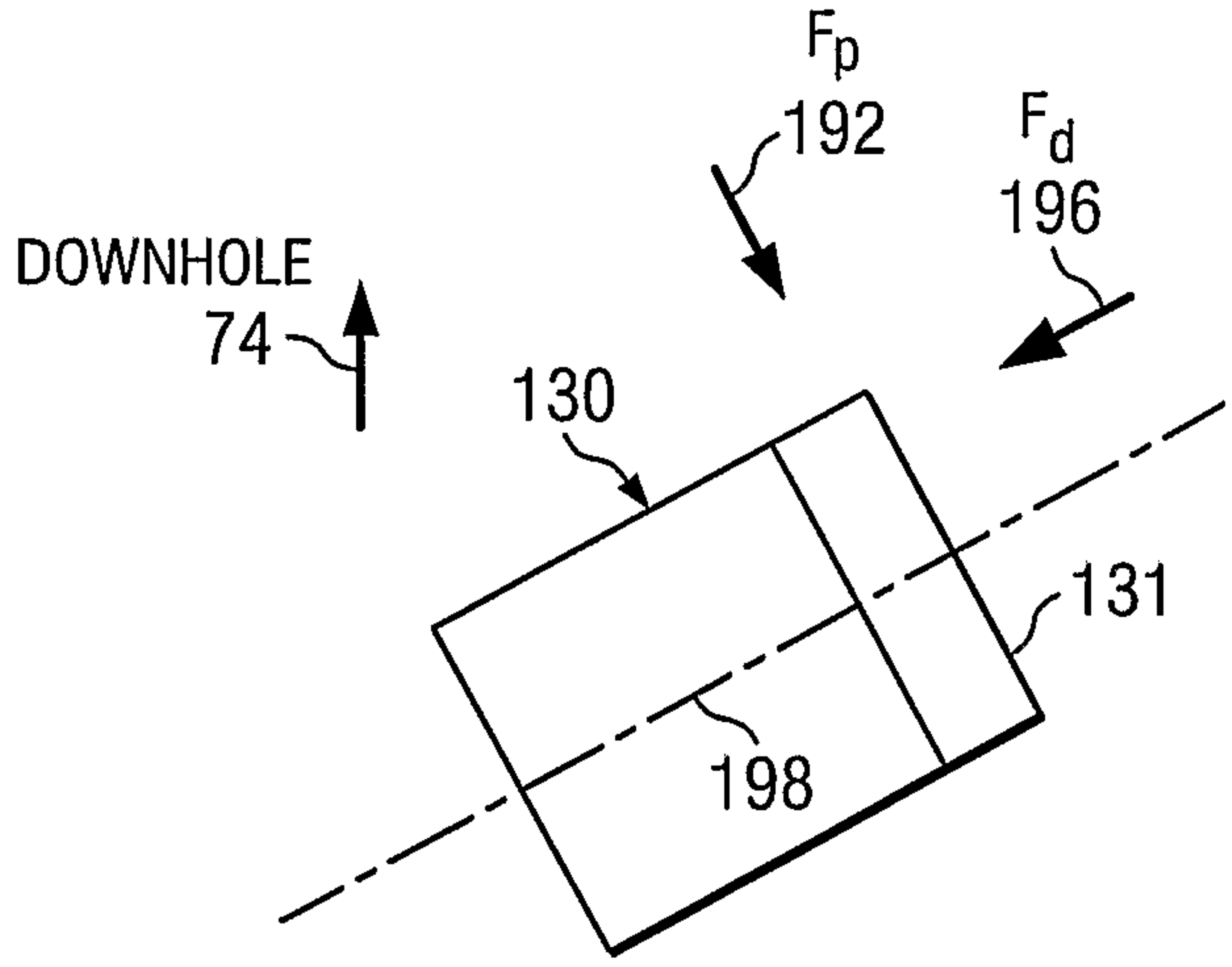


FIG. 15C

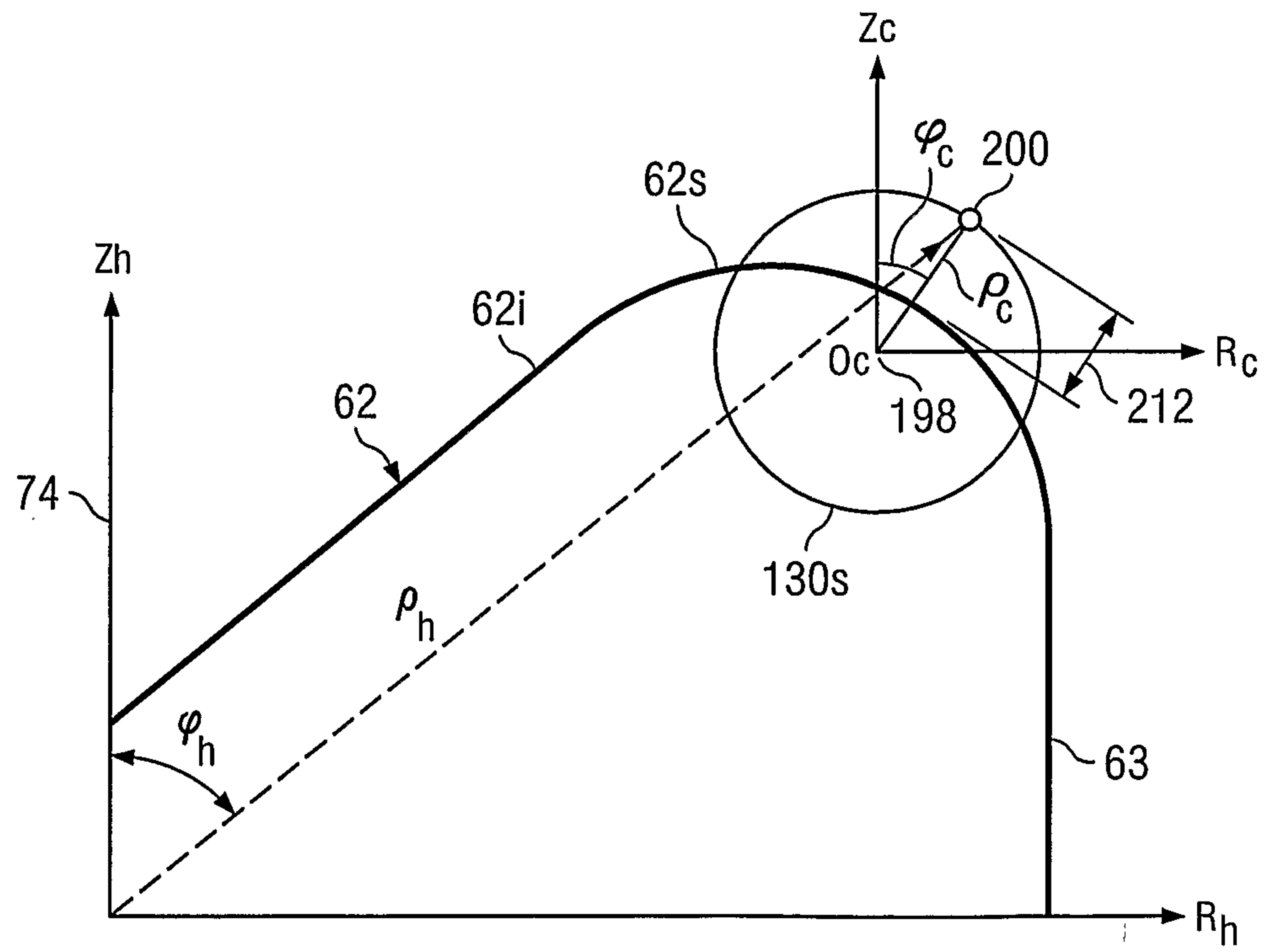


FIG. 16

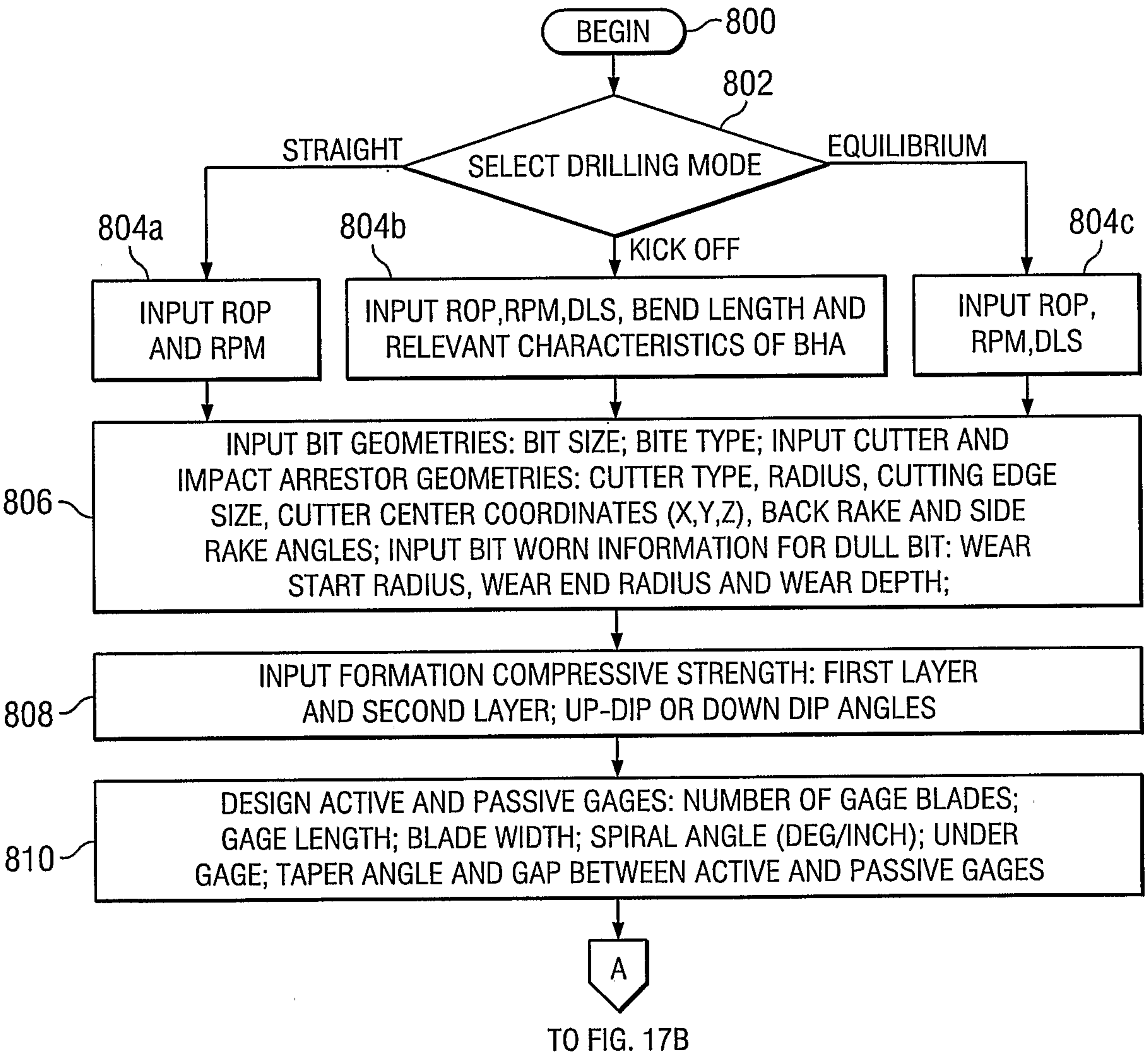

BEGIN
800
802
SELECT DRILLING MODE
STRAIGHT
KICK OFF
EQUILIBRIUM
804a
804b
804c
INPUT ROP AND RPM
INPUT ROP,RPM,DLS, BEND LENGTH AND RELEVANT CHARACTERISTICS OF BHA
INPUT ROP, RPM,DLS
806
INPUT BIT GEOMETRIES: BIT SIZE; BITE TYPE; INPUT CUTTER AND IMPACT ARRESTOR GEOMETRIES: CUTTER TYPE, RADIUS, CUTTING EDGE SIZE, CUTTER CENTER COORDINATES (X,Y,Z), BACK RAKE AND SIDE RAKE ANGLES; INPUT BIT WORN INFORMATION FOR DULL BIT: WEAR START RADIUS, WEAR END RADIUS AND WEAR DEPTH;
808
INPUT FORMATION COMPRESSIVE STRENGTH: FIRST LAYER AND SECOND LAYER; UP-DIP OR DOWN DIP ANGLES
810
DESIGN ACTIVE AND PASSIVE GAGES: NUMBER OF GAGE BLADES; GAGE LENGTH; BLADE WIDTH; SPIRAL ANGLE (DEG/INCH); UNDER GAGE; TAPER ANGLE AND GAP BETWEEN ACTIVE AND PASSIVE GAGES
A
TO FIG. 17B

FIG. 17A

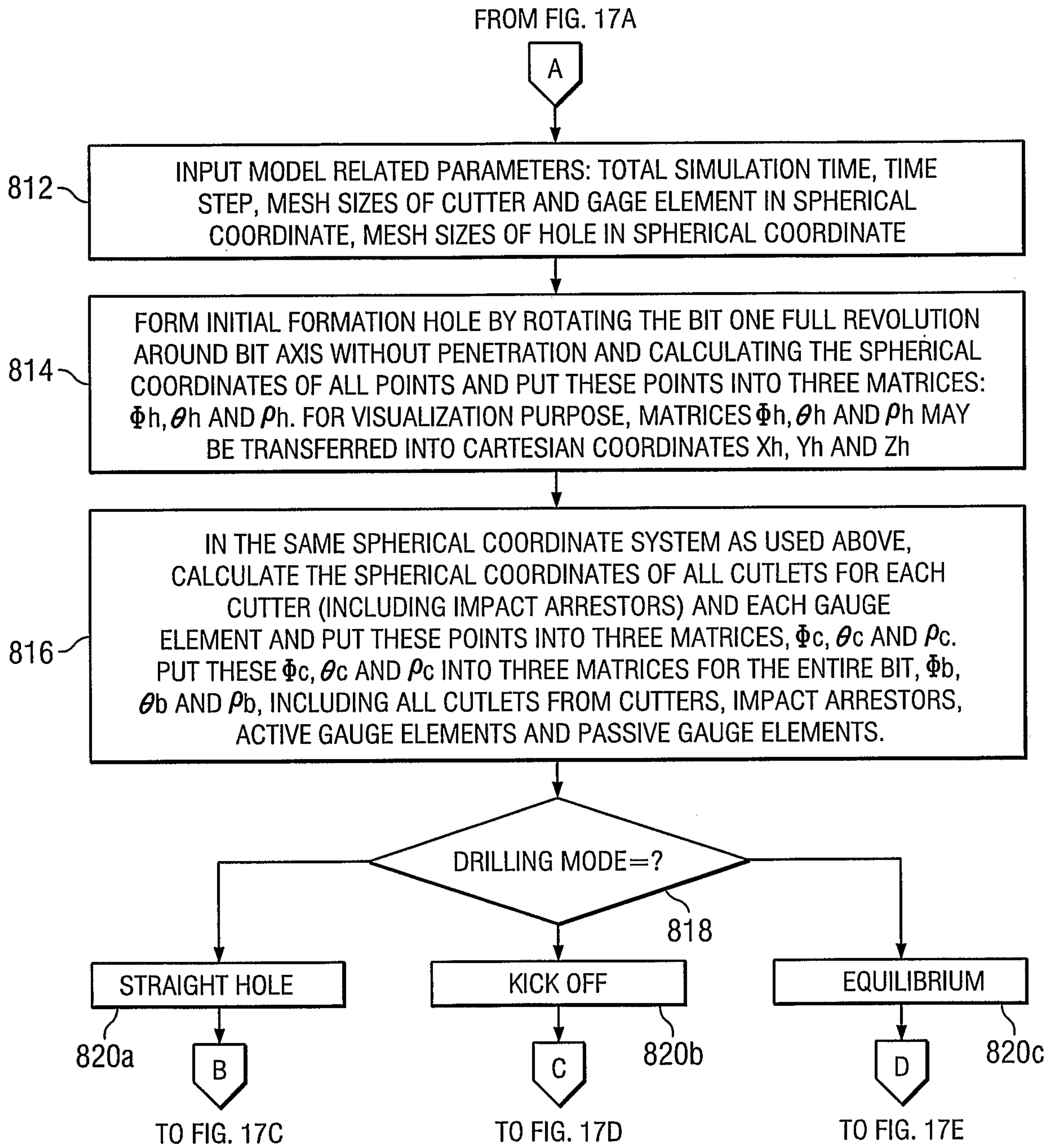

FROM FIG. 17A
A
812
INPUT MODEL RELATED PARAMETERS: TOTAL SIMULATION TIME, TIME STEP, MESH SIZES OF CUTTER AND GAGE ELEMENT IN SPHERICAL COORDINATE, MESH SIZES OF HOLE IN SPHERICAL COORDINATE
814
FORM INITIAL FORMATION HOLE BY ROTATING THE BIT ONE FULL REVOLUTION AROUND BIT AXIS WITHOUT PENETRATION AND CALCULATING THE SPHERICAL COORDINATES OF ALL POINTS AND PUT THESE POINTS INTO THREE MATRICES: Φh, θh AND ρh. FOR VISUALIZATION PURPOSE, MATRICES Φh, θh AND ρh MAY BE TRANSFERRED INTO CARTESIAN COORDINATES Xh, Yh AND Zh
816
IN THE SAME SPHERICAL COORDINATE SYSTEM AS USED ABOVE, CALCULATE THE SPHERICAL COORDINATES OF ALL CUTLETS FOR EACH CUTTER (INCLUDING IMPACT ARRESTORS) AND EACH GAUGE ELEMENT AND PUT THESE POINTS INTO THREE MATRICES, Φc, θc AND ρc. PUT THESE Φc, θc AND ρc INTO THREE MATRICES FOR THE ENTIRE BIT, Φb, θb AND ρb, INCLUDING ALL CUTLETS FROM CUTTERS, IMPACT ARRESTORS, ACTIVE GAUGE ELEMENTS AND PASSIVE GAUGE ELEMENTS.
DRILLING MODE=?
818
STRAIGHT HOLE
KICK OFF
EQUILIBRIUM
820a
820b
820c
B
C
D
TO FIG. 17C
TO FIG. 17D
TO FIG. 17E

FIG. 17B

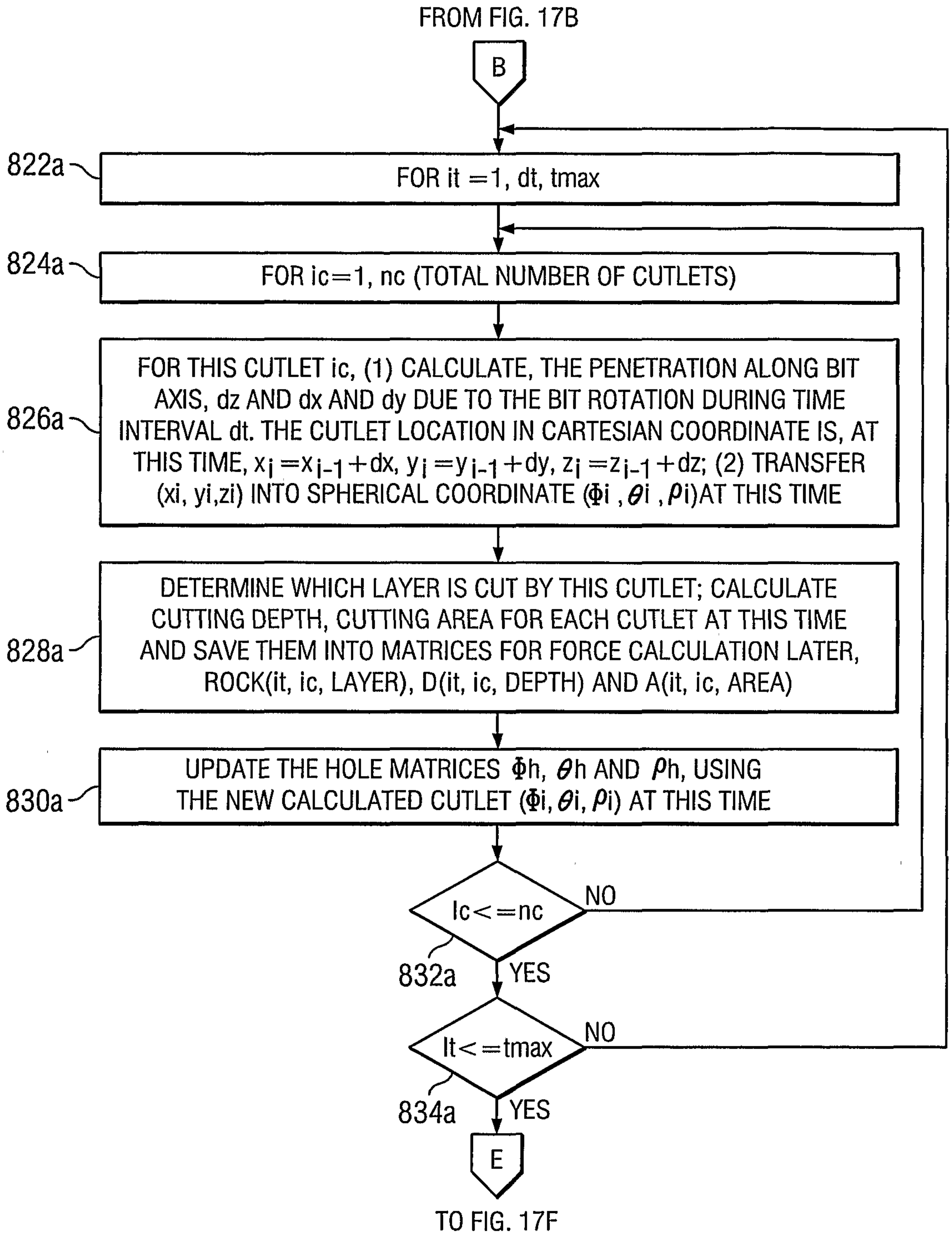

FROM FIG. 17B
B
822a
FOR it =1, dt, tmax
824a
FOR ic=1, nc (TOTAL NUMBER OF CUTLETS)
826a
FOR THIS CUTLET ic, (1) CALCULATE, THE PENETRATION ALONG BIT AXIS, dz AND dx AND dy DUE TO THE BIT ROTATION DURING TIME INTERVAL dt. THE CUTLET LOCATION IN CARTESIAN COORDINATE IS, AT THIS TIME, $x_i = x_{i-1} + dx$, $y_i = y_{i-1} + dy$, $z_i = z_{i-1} + dz$; (2) TRANSFER (xi, yi,zi) INTO SPHERICAL COORDINATE (Φi , θi , ρi)AT THIS TIME
828a
DETERMINE WHICH LAYER IS CUT BY THIS CUTLET; CALCULATE CUTTING DEPTH, CUTTING AREA FOR EACH CUTLET AT THIS TIME AND SAVE THEM INTO MATRICES FOR FORCE CALCULATION LATER, ROCK(it, ic, LAYER), D(it, ic, DEPTH) AND A(it, ic, AREA)
830a
UPDATE THE HOLE MATRICES Φh, θh AND ρh, USING THE NEW CALCULATED CUTLET (Φi, θi, ρi) AT THIS TIME
Ic<=nc
NO
832a
YES
It<=tmax
NO
834a
YES
E
TO FIG. 17F

FIG. 17C

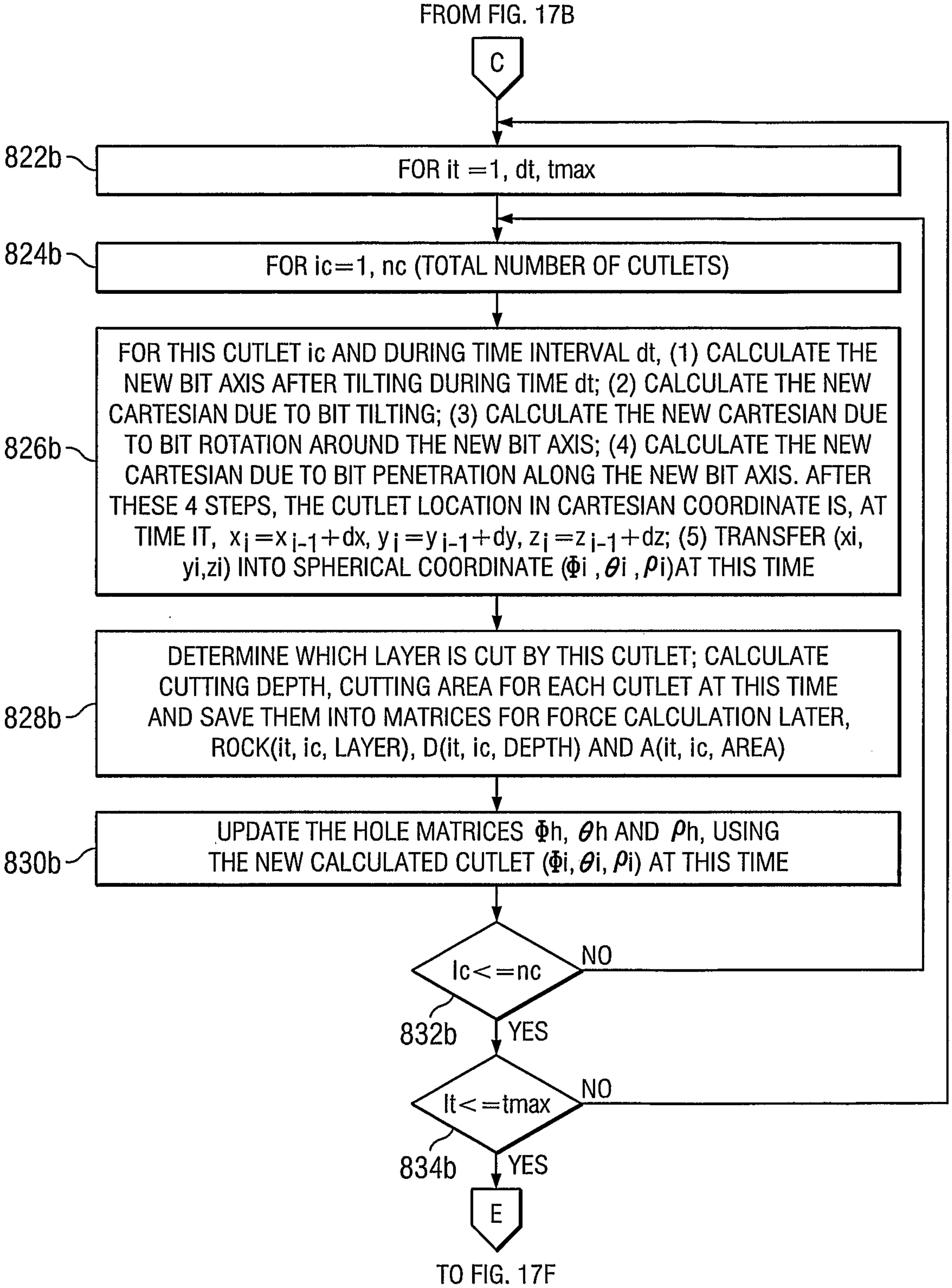

FROM FIG. 17B
C
822b
FOR it =1, dt, tmax
824b
FOR ic=1, nc (TOTAL NUMBER OF CUTLETS)
826b
FOR THIS CUTLET ic AND DURING TIME INTERVAL dt, (1) CALCULATE THE NEW BIT AXIS AFTER TILTING DURING TIME dt; (2) CALCULATE THE NEW CARTESIAN DUE TO BIT TILTING; (3) CALCULATE THE NEW CARTESIAN DUE TO BIT ROTATION AROUND THE NEW BIT AXIS; (4) CALCULATE THE NEW CARTESIAN DUE TO BIT PENETRATION ALONG THE NEW BIT AXIS. AFTER THESE 4 STEPS, THE CUTLET LOCATION IN CARTESIAN COORDINATE IS, AT TIME IT, $x_i = x_{i-1} + dx$, $y_i = y_{i-1} + dy$, $z_i = z_{i-1} + dz$; (5) TRANSFER (xi, yi,zi) INTO SPHERICAL COORDINATE (Φi ,θi ,ρi)AT THIS TIME
828b
DETERMINE WHICH LAYER IS CUT BY THIS CUTLET; CALCULATE CUTTING DEPTH, CUTTING AREA FOR EACH CUTLET AT THIS TIME AND SAVE THEM INTO MATRICES FOR FORCE CALCULATION LATER, ROCK(it, ic, LAYER), D(it, ic, DEPTH) AND A(it, ic, AREA)
830b
UPDATE THE HOLE MATRICES Φh, θh AND ρh, USING THE NEW CALCULATED CUTLET (Φi, θi, ρi) AT THIS TIME
Ic<=nc
NO
832b
YES
It<=tmax
NO
834b
YES
E
TO FIG. 17F

FIG. 17D

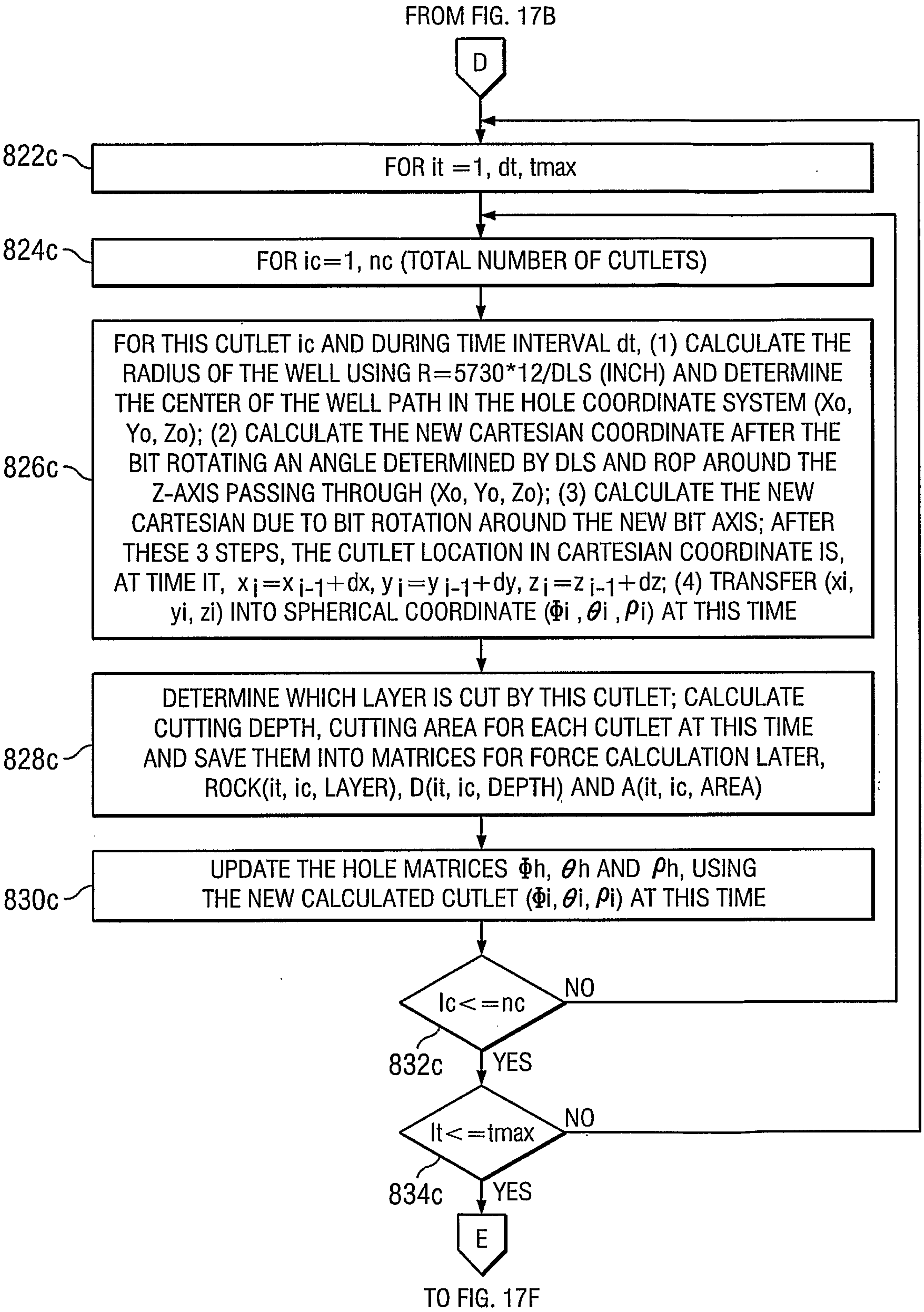

FROM FIG. 17B
D
822c
FOR it =1, dt, tmax
824c
FOR ic=1, nc (TOTAL NUMBER OF CUTLETS)
826c
FOR THIS CUTLET ic AND DURING TIME INTERVAL dt, (1) CALCULATE THE RADIUS OF THE WELL USING R=5730*12/DLS (INCH) AND DETERMINE THE CENTER OF THE WELL PATH IN THE HOLE COORDINATE SYSTEM (Xo, Yo, Zo); (2) CALCULATE THE NEW CARTESIAN COORDINATE AFTER THE BIT ROTATING AN ANGLE DETERMINED BY DLS AND ROP AROUND THE Z-AXIS PASSING THROUGH (Xo, Yo, Zo); (3) CALCULATE THE NEW CARTESIAN DUE TO BIT ROTATION AROUND THE NEW BIT AXIS; AFTER THESE 3 STEPS, THE CUTLET LOCATION IN CARTESIAN COORDINATE IS, AT TIME IT, $x_i=x_{i-1}+dx$, $y_i=y_{i-1}+dy$, $z_i=z_{i-1}+dz$; (4) TRANSFER (xi, yi, zi) INTO SPHERICAL COORDINATE (Φi , θi , ρi) AT THIS TIME
828c
DETERMINE WHICH LAYER IS CUT BY THIS CUTLET; CALCULATE CUTTING DEPTH, CUTTING AREA FOR EACH CUTLET AT THIS TIME AND SAVE THEM INTO MATRICES FOR FORCE CALCULATION LATER, ROCK(it, ic, LAYER), D(it, ic, DEPTH) AND A(it, ic, AREA)
830c
UPDATE THE HOLE MATRICES Φh, θh AND ρh, USING THE NEW CALCULATED CUTLET (Φi, θi, ρi) AT THIS TIME
Ic<=nc
NO
YES
832c
It<=tmax
NO
YES
834c
E
TO FIG. 17F

FIG. 17E

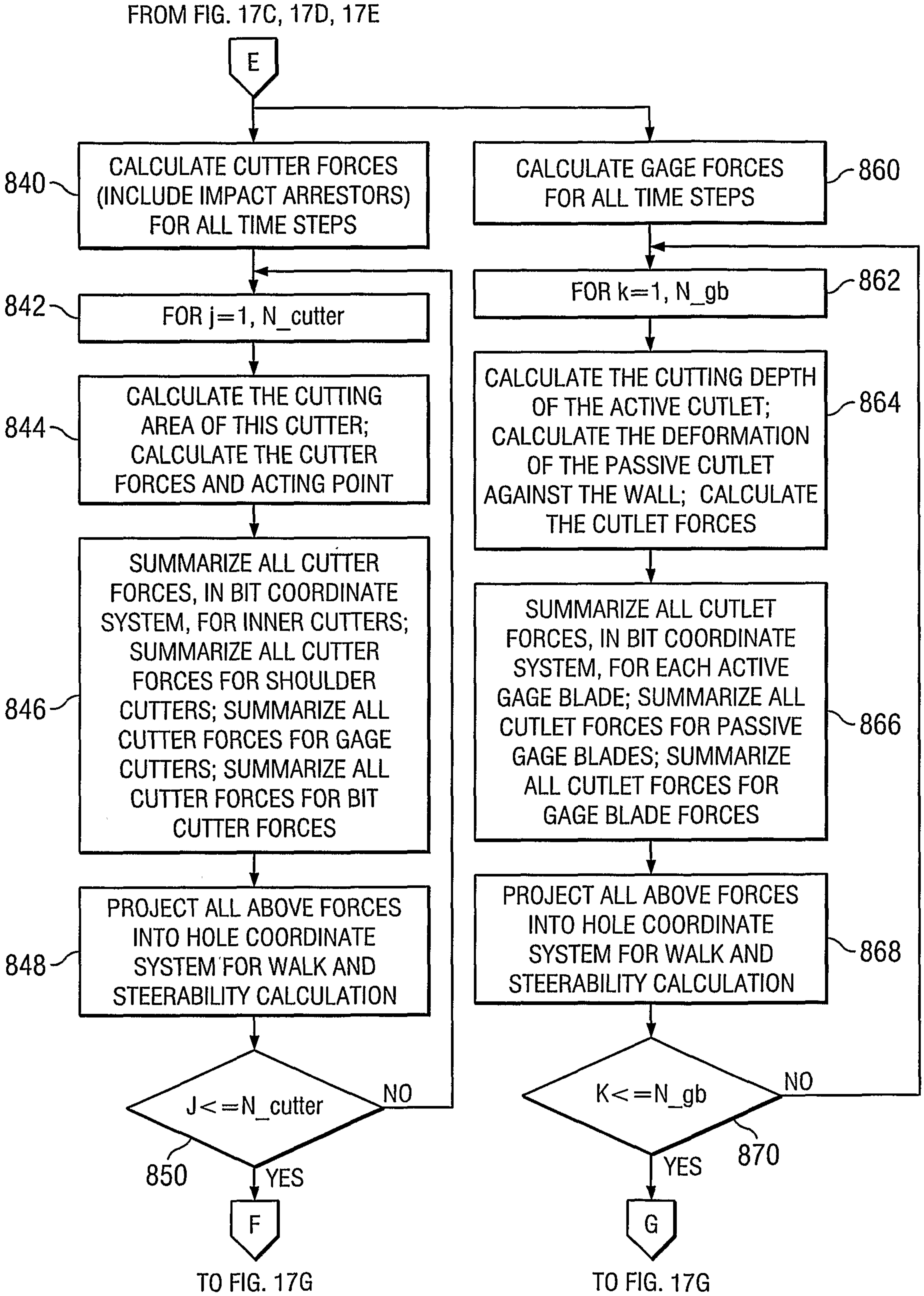

FROM FIG. 17C, 17D, 17E
E
840
CALCULATE CUTTER FORCES (INCLUDE IMPACT ARRESTORS) FOR ALL TIME STEPS
842
FOR j=1, N_cutter
844
CALCULATE THE CUTTING AREA OF THIS CUTTER; CALCULATE THE CUTTER FORCES AND ACTING POINT
846
SUMMARIZE ALL CUTTER FORCES, IN BIT COORDINATE SYSTEM, FOR INNER CUTTERS; SUMMARIZE ALL CUTTER FORCES FOR SHOULDER CUTTERS; SUMMARIZE ALL CUTTER FORCES FOR GAGE CUTTERS; SUMMARIZE ALL CUTTER FORCES FOR BIT CUTTER FORCES
848
PROJECT ALL ABOVE FORCES INTO HOLE COORDINATE SYSTEM FOR WALK AND STEERABILITY CALCULATION
J<=N_cutter
NO
850
YES
F
TO FIG. 17G
860
CALCULATE GAGE FORCES FOR ALL TIME STEPS
862
FOR k=1, N_gb
864
CALCULATE THE CUTTING DEPTH OF THE ACTIVE CUTLET; CALCULATE THE DEFORMATION OF THE PASSIVE CUTLET AGAINST THE WALL; CALCULATE THE CUTLET FORCES
866
SUMMARIZE ALL CUTLET FORCES, IN BIT COORDINATE SYSTEM, FOR EACH ACTIVE GAGE BLADE; SUMMARIZE ALL CUTLET FORCES FOR PASSIVE GAGE BLADES; SUMMARIZE ALL CUTLET FORCES FOR GAGE BLADE FORCES
868
PROJECT ALL ABOVE FORCES INTO HOLE COORDINATE SYSTEM FOR WALK AND STEERABILITY CALCULATION
K<=N_gb
NO
870
YES
G
TO FIG. 17G

FIG. 17F

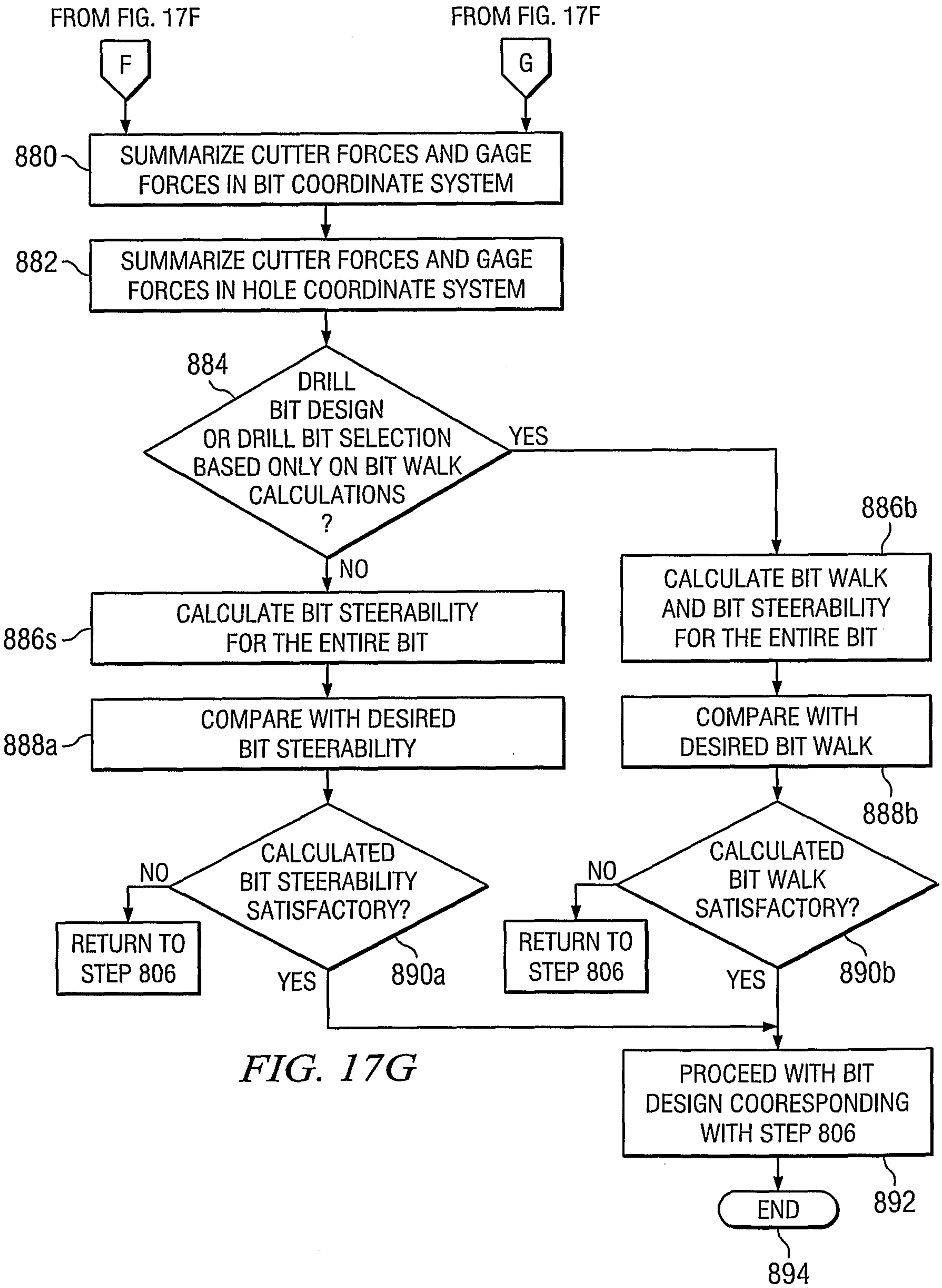

FROM FIG. 17F
F
FROM FIG. 17F
G
880
SUMMARIZE CUTTER FORCES AND GAGE FORCES IN BIT COORDINATE SYSTEM
882
SUMMARIZE CUTTER FORCES AND GAGE FORCES IN HOLE COORDINATE SYSTEM
884
DRILL BIT DESIGN OR DRILL BIT SELECTION BASED ONLY ON BIT WALK CALCULATIONS ?
YES
NO
886b
CALCULATE BIT WALK AND BIT STEERABILITY FOR THE ENTIRE BIT
886s
CALCULATE BIT STEERABILITY FOR THE ENTIRE BIT
888a
COMPARE WITH DESIRED BIT STEERABILITY
COMPARE WITH DESIRED BIT WALK
888b
CALCULATED BIT STEERABILITY SATISFACTORY?
NO
RETURN TO STEP 806
YES
890a
CALCULATED BIT WALK SATISFACTORY?
NO
RETURN TO STEP 806
YES
890b
PROCEED WITH BIT DESIGN COORESPONDING WITH STEP 806
892
END
894

FIG. 17G

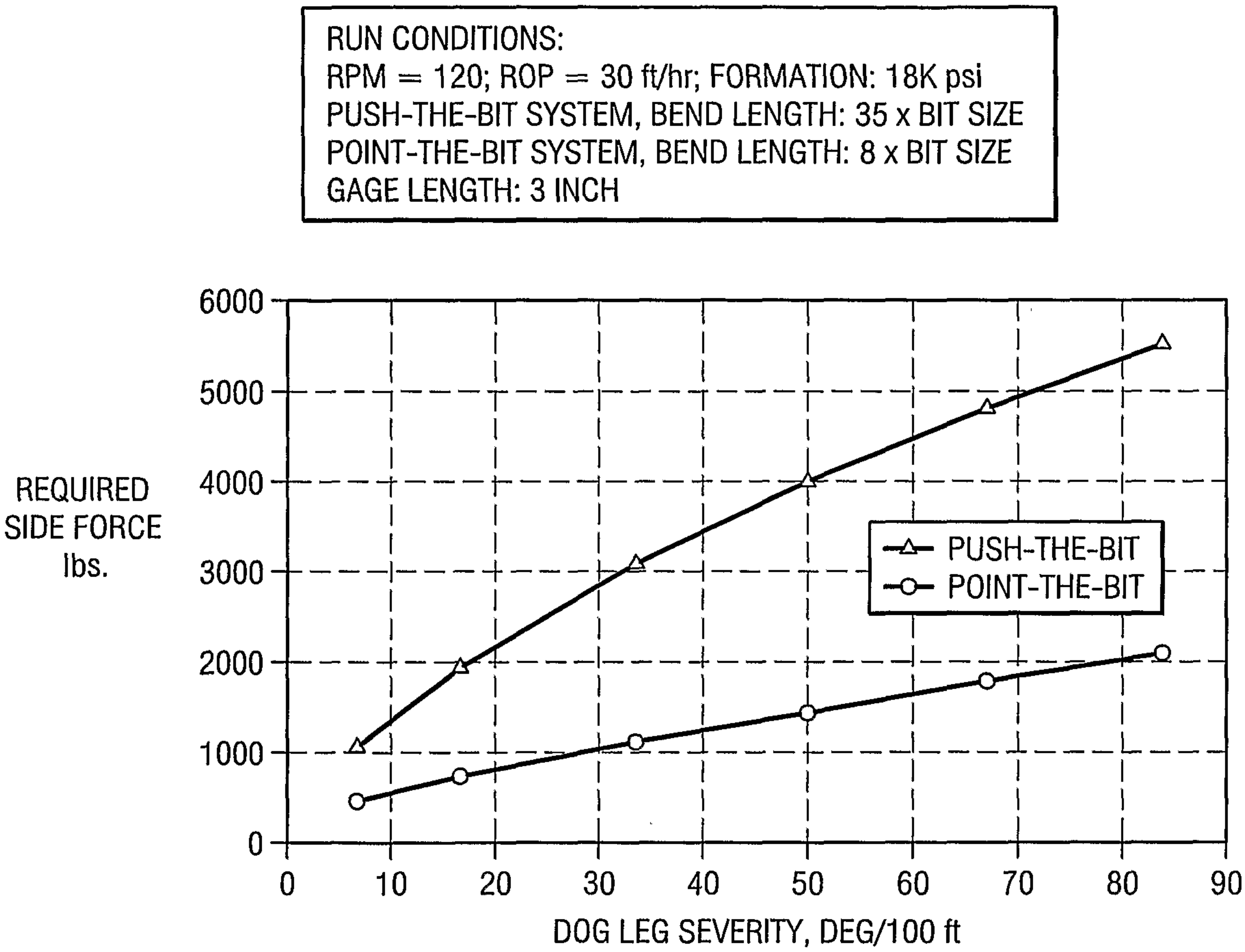
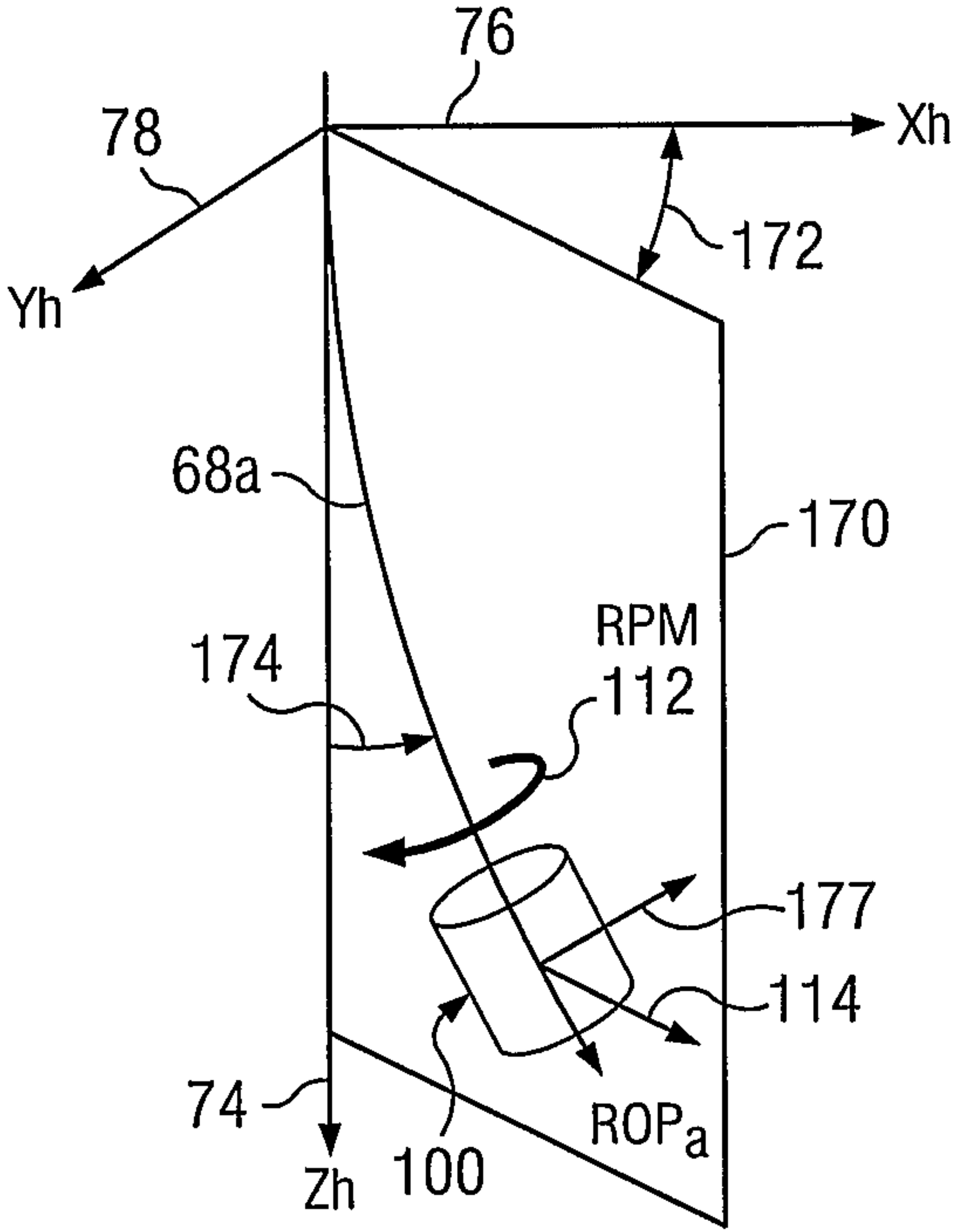

RUN CONDITIONS:
RPM = 120; ROP = 30 ft/hr; FORMATION: 18K psi
PUSH-THE-BIT SYSTEM, BEND LENGTH: 35 x BIT SIZE
POINT-THE-BIT SYSTEM, BEND LENGTH: 8 x BIT SIZE
GAGE LENGTH: 3 INCH
REQUIRED SIDE FORCE lbs.
6000
5000
4000
3000
2000
1000
0
0
10
20
30
40
50
60
70
80
90
DOG LEG SEVERITY, DEG/100 ft
PUSH-THE-BIT
POINT-THE-BIT

FIG. 18


76
78
Xh
Yh
172
68a
170
RPM
174
112
177
114
74
ROPa
100
Zh