Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2973027 A1 2018/02/03

(21) 2 973 027

(12) **DEMANDE DE BREVET CANADIEN**
CANADIAN PATENT APPLICATION

(13) **A1**

(22) **Date de dépôt/Filing Date:** 2017/07/11

(41) **Mise à la disp. pub./Open to Public Insp.:** 2018/02/03

(30) **Priorités/Priorities:** 2016/08/03 (US62/370,524); 2017/07/06 (US15/643,202)

(51) **Cl.Int./Int.Cl.** *E21B 19/02* (2006.01), *E21B 19/06* (2006.01)

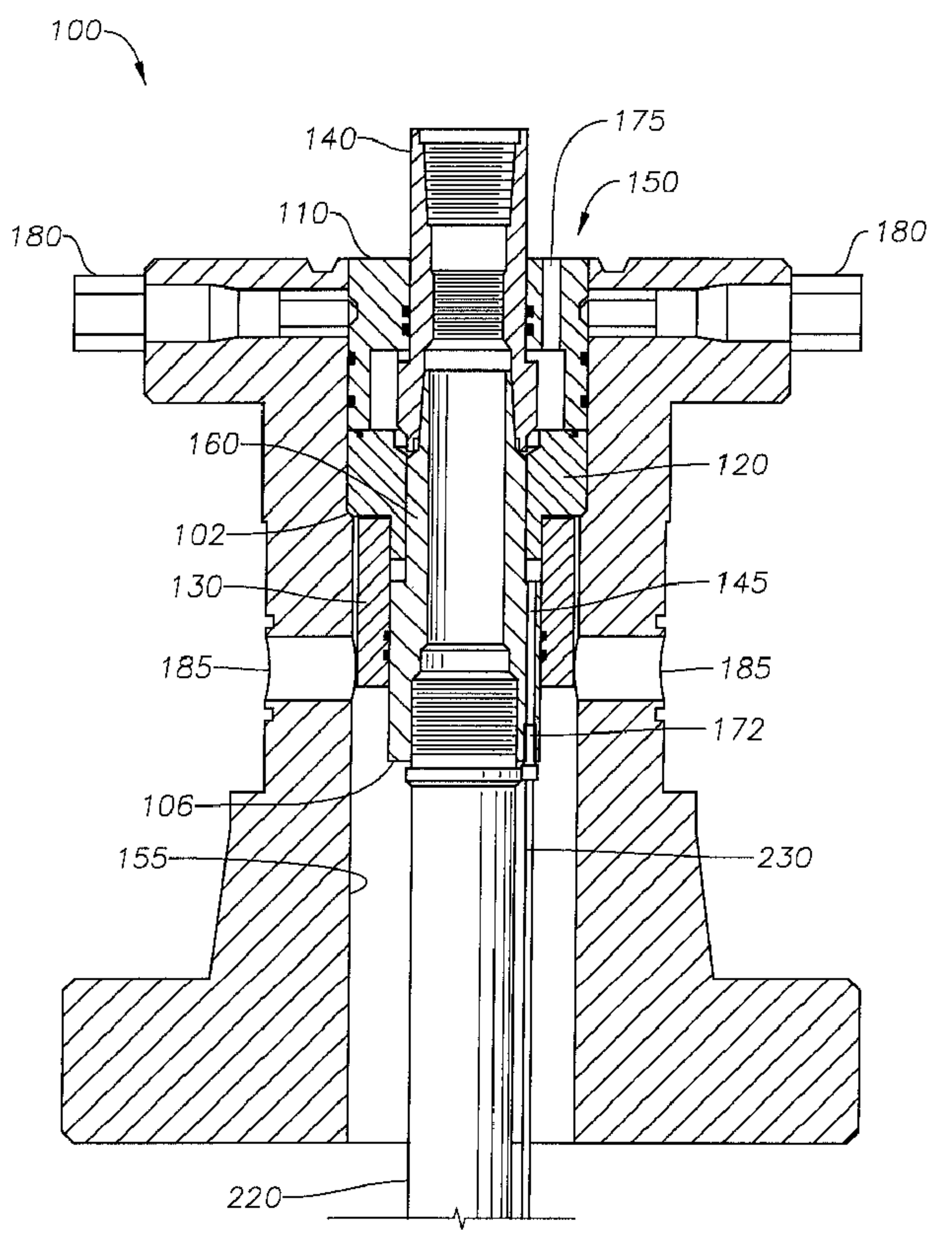
(71) **Demandeur/Applicant:**
ROSS, JERRY D., US

(72) **Inventeurs/Inventors:**
ROSS, STEPHEN C., US;
HINDS, ORLAND J., US...

(74) **Agent:** G. RONALD BELL & ASSOCIATES

(54) **Titre :** SYSTEME DE COLLIER A COINS POUR TUBES DE PRODUCTION, ET METHODE DE MISE SOUS TENSION DE TUBES DE PRODUCTION DANS UN TROU DE FORAGE

(54) **Title:** TUBING HANGER SYSTEM, AND METHOD OF TENSIONING PRODUCTION TUBING IN A WELLBORE



(57) **Abrégé/Abstract:**
A tubing hanger system for suspending a tubing string within a wellbore is provided. The system is designed to place the tubing string in tension. The tubing hanger system comprises a tubing hanger and a tubing anchor. Both the tubing hanger and the tubing

(21) 2 973 027

(13) A1

(57) Abrégé(suite)/Abstract(continued):
anchor are designed to reside in series with the production tubing. The tubing hanger is threadedly connected to the tubing string at the top of the wellbore. The tubing anchor is also threadedly connected to the tubing string but is configured to be set within a string of casing downhole. Beneficially, the tubing hanger and the tubing anchor is each uniquely configured to be set through a rotation of the tubing string that is less than one full rotation. This enables use of a stainless steel chemical injection line extending from the tubing hanger to the tubing anchor. A method for hanging a string of production tubing in a wellbore, in tension, is also provided herein.

ABSTRACT

A tubing hanger system for suspending a tubing string within a wellbore is provided. The system is designed to place the tubing string in tension. The tubing hanger system comprises a tubing hanger and a tubing anchor. Both the tubing hanger and the tubing anchor are designed to reside in series with the production tubing. The tubing hanger is threadedly connected to the tubing string at the top of the wellbore. The tubing anchor is also threadedly connected to the tubing string but is configured to be set within a string of casing downhole. Beneficially, the tubing hanger and the tubing anchor is each uniquely configured to be set through a rotation of the tubing string that is less than one full rotation. This enables use of a stainless steel chemical injection line extending from the tubing hanger to the tubing anchor. A method for hanging a string of production tubing in a wellbore, in tension, is also provided herein.

CA 2973027 2017-07-11

TUBING HANGER SYSTEM, AND METHOD OF TENSIONING PRODUCTION TUBING IN A WELLBORE

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of U.S. Serial No. 62/370,524 filed August 03, 2016. That application is entitled "Tubing Hanger System, And Method Of Tensioning Production Tubing In A Wellbore," and is incorporated herein in its entirety by reference.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

THE NAMES OF THE PARTIES TO A JOINT RESEARCH AGREEMENT

[0003] Not applicable.

BACKGROUND OF THE INVENTION

[0004] This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

Field of the Invention

[0005] The present disclosure relates to the field of hydrocarbon recovery operations. More specifically, the present invention relates to a system for hanging a string of production tubing in a wellbore without applying appreciable torque to a banded chemical injection line downhole. The invention also relates to a method of hanging production tubing in a wellbore, in tension.

Technology in the Field of the Invention

[0006] In the drilling of oil and gas wells, a wellbore is formed using a drill bit that is urged downwardly at a lower end of a drill string. The drill bit is rotated while force is applied through the drill string and against the rock face of the formation being drilled. After drilling to a predetermined depth, the drill string and bit are removed and the wellbore is lined with a string of casing. An annular area is thus formed between the string of casing and the formation. A cementing operation is typically conducted in order to fill or "squeeze" the annular area with cement. The combination of cement and casing strengthens the wellbore and facilitates the isolation of zones behind the casing for the production of hydrocarbons.

[0007] It is common to place several strings of casing having progressively smaller outer diameters into the wellbore. In this respect, the process of drilling and then cementing progressively smaller strings of casing is repeated several times until the well has reached total depth. The final string of casing, referred to as a production casing, is typically cemented into place.

[0008] As part of the completion process, the production casing is perforated at a desired level. Alternatively, a sand screen may be employed in the event of an open hole completion. Either option provides fluid communication between the wellbore and a selected zone in a formation. In addition, production equipment such as a string of production tubing, a packer and a pump may be installed within the wellbore.

[0009] As part of the completion process, a wellhead is installed at the surface. The wellhead includes a tubing-hanger used to gravitationally support the production tubing. Fluid gathering and processing equipment such as pipes, valves and separators are also provided. Production operations may then commence.

[0010] During the production process, the production tubing may experience thermal expansion over time. This is due to the presence of warm production fluids being produced up through the pipe and to the surface. To offset the anticipated expansion, it is known to place the production tubing under some degree of tension when the well is completed. This will maintain the production tubing in a linear state even while the pipe string relaxes in response to thermal expansion.

[0011] Typically, the tubing string may be tensioned approximately one inch for every 1,000 feet of tubing in order to minimize buckling. This way the travel distance associated with the expansion will be less than the distance the tubing is stretched during tensioning. Thus, even when the tubing expands over time, the tubing does not buckle within the wellbore during the production process but remains somewhat taut. This is of particular benefit when the wellbore is being rod pumped as pre-tensioning minimizes frictional engagement between the rod string and the surrounding production tubing.

[0012] In connection with hanging the tubing in the wellbore, it is also sometimes desirable to provide a fluid supply line such as a chemical injection line into the well. The chemical injection line extends from the tubing hanger at the surface, and down to a packer or pump downhole. Most existing tubing tensioning arrangements prevent the use of a fluid supply line that will descend through and below the tubing hanger. Moreover, known tubing hangers generally require that the tubing string be rotated or turned five or more times in connection with setting the tubing anchor and locking the tubing hanger. However, stainless steel chemical injection lines cannot tolerate the stress and tension induced by rotation of the tubing string.

[0013] Accordingly, a need exists for a tubing hanger that enables hanging tubing from a tubing head at the surface with less than one complete rotation of the production string from the surface. Further, a need exists for a tubing hanging system that is able to accommodate a chemical injection line being run down to the tubing anchor within the wellbore. Still further, a need exists for a tubing anchor / catcher that allows slips to be actuated to engage the surrounding casing with less than a full tubing rotation

SUMMARY OF THE INVENTION

[0014] A tubing hanger system for suspending a tubing string within a wellbore is provided. The system is designed to hold the tubing string in tension within the wellbore. The tubing hanger system comprises a tubing hanger and a separate tubing anchor. Both the tubing hanger and the tubing anchor are designed to reside in series with the production tubing.

[0015] The tubing hanger is threadedly connected to the tubing string at an upper end of the tubing string, and is configured to reside within a tubing head over the wellbore. The tubing hanger comprises a short tubular assembly having an inner diameter, an outer diameter, and a bore extending along its length. The tubing hanger also has a beveled shoulder along the outer diameter which is configured to land on a matching conical surface machined along the tubing head. Upon landing, the tubing hanger gravitationally supports the tubing string in tension.

[0016] The tubing anchor is also threadedly connected to the tubing string. Specifically, the tubing anchor is threadedly connected to the tubing string proximate a lower end of the tubing string. Thus, the tubing anchor resides within a string of production casing downhole. The result is that the tubing hanger is at the upper end of the tubing string and the tubing hanger is proximate a lower end of the tubing string.

[0017] Beneficially, the tubing hanger and the tubing anchor are each configured to be set through a rotation of the tubing string that is less than one full rotation. The tubing hanger is set in the tubing head, while the tubing anchor is set downhole in production casing. This enables use of a stainless steel chemical injection line extending from the tubing hanger to the tubing anchor.

[0018] In one aspect, the tubing hanger comprises a tubular assembly and a mandrel assembly. The tubular assembly comprises:

- a cylindrical interlocking top ring,

- a cylindrical interlocking bottom ring configured to reside below the interlocking top ring, and having a series of splines extending down from an inner diameter thereof; and

- a cylindrical chemical injection ring configured to generally reside below the interlocking bottom ring and around the series of splines.

[0019] Of interest, the beveled shoulder resides along a bottom end of the interlocking bottom ring.

[0020] The mandrel assembly defines a tubular body that is configured to be slidably received within the bore of the tubular assembly. In one aspect, the mandrel assembly comprises:

- an upper end having female threads and configured to extend above the tubular assembly when the tubing hanger lands on the conical surface of the tubing head;

- a lower end also having female threads and configured to be threadedly connected to an upper joint of the tubing string; and

- angled shoulders spaced radially around an outer diameter of the mandrel assembly configured to pass between the splines of the tubular assembly, but to receive and interlock with individual splines of the series of splines when the mandrel assembly is rotated the less than one full rotation, and then set down.

[0021] In one embodiment, the mandrel assembly comprises:

- a top mandrel providing the female threads at the upper end; and

- a separate bottom mandrel providing the female threads at the lower end;

wherein the angled shoulders reside about a cylindrical body forming the top mandrel.

[0022] During completion, the tubular assembly is placed along an inner diameter of the tubing head. As noted, the beveled shoulder of the tubular assembly will land on the conical surface machined into the inner diameter of the tubing head. The tubular assembly is then rotationally locked into place.

[0023] Next, the mandrel assembly is secured to the top joint of the production tubing. The mandrel assembly with connected production tubing is then lowered into the wellbore until the tubing anchor is at a desired location downhole. The tubing anchor is then set.

[0024] Next, the mandrel assembly is moved back up the wellbore in order to apply the desired tension to the production tubing. The angled shoulders of the bottom mandrel are lifted along the spaces provided between the splines of the cylindrical interlocking bottom ring. Once the angled shoulders have cleared the splines, the mandrel assembly is rotated less than 180 degrees, and the mandrel assembly is then set down onto the splines in order to lock the mandrel assembly and gravitationally supported tubing string in place. Preferably, a rotation of the mandrel assembly and connected tubing string by less than 180 degrees comprises a rotation of the mandrel assembly by a one-quarter turn clockwise relative to the bore of the tubular assembly.

[0025] The tubing hanger system may also comprise a channel machined through each of the interlocking top ring and the bottom mandrel along a longitudinal axis. The channel is designed to carry an injection fluid. A fitting may be provided at a lower end of the channel. The fitting is machined into the bottom mandrel for sealingly receiving a top end of a chemical injection line. The chemical injection line extends downhole from the fitting to the tubing anchor. In this way, a chemical treatment fluid may be injected into the channel and then into the chemical injection line, where it is transmitted downhole to the tubing anchor.

[0026] As noted, the tubing hanger assembly also includes a tubing anchor. In one aspect, the tubing anchor comprises:

- an upper box connector for threadedly connecting the tubing anchor to the tubing string;

- a lower pin connector for threadedly connecting the tubing anchor to the tubing string;

- slips between the upper box connector and the lower pin connector configured to be mechanically actuated by applying tension to the tubing string; and

- a locking body having profiles configured to receive a pin and to hold the slips in engagement with the surrounding production casing upon rotation of the tubing string by less than 180 degrees;

wherein the locking body comprises a channel along an outer diameter dimensioned to mechanically connect to a lower end of the chemical injection line.

[0027] A method for hanging a string of production tubing in a wellbore, in tension, is also provided herein. The method employs the tubing hanger system as described above, in any of its various embodiments.

[0028] The method first includes providing a tubing hanger system. The tubing hanger system includes the tubing hanger and the tubing anchor, wherein the tubing hanger and the tubing anchor are each configured to be set through a rotation that is less than one full rotation.

[0029] The method also includes threadedly connecting a joint of production tubing to the tubing anchor. The method then includes running a string of production tubing into the wellbore, joint-by-joint, wherein the tubing anchor is threadedly connected to the production tubing proximate a lower end of the production tubing.

[0030] As part of the method, a steel chemical injection line is banded or clamped to the o.d. of the tubing joints. An upper end of the chemical injection line is connected to the channel at the lower end of the bottom mandrel. This may be by means of a compression fitting.

[0031] The method additionally includes threadedly connecting the tubing hanger to the string of production tubing at an upper end of the production tubing. The method then includes lowering the tubing hanger so as to land the tubing hanger onto a landing surface of the tubing head above the wellbore. Preferably, the landing surface of the tubing head comprises an inner conical surface machined into the inner diameter of the tubing head. In any instance, the tubing hanger gravitationally supports the production tubing.

[0032] The method further comprises setting the tubing anchor within a string of surrounding production casing within the wellbore. The method then includes applying tension to the tubing string.

[0033] In accordance with embodiments of the invention, the method additionally comprises setting the tubing hanger within a tubing head at a surface above the wellbore. In operation, a rotation of the mandrel assembly within the bore of the tubular assembly while the angled shoulders of the top mandrel are above the splines of the cylindrical interlocking bottom ring locks the tubing anchor in place within the production casing. This is followed by a rotation of the mandrel assembly and connected tubing string by less than 180 degrees, but sufficient to lock the mandrel assembly from further longitudinal movement within the wellbore.

[0034] The method may then include producing hydrocarbon fluids to the tubing hanger at the surface.

BRIEF DESCRIPTION OF THE DRAWINGS

[0035] So that the manner in which the present inventions can be better understood, certain illustrations, charts and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[0036] Figure 1 is a cut-away view of a known tubing head for supporting a string of production tubing from the surface. Residing within an inner diameter of the tubing head is a tubing hanger of the present invention, in one embodiment. Also visible is a chemical injection line in fluid communication with the tubing hanger.

[0037] Figure 2 is a cross-sectional view of an illustrative wellbore. The tubing head of Figure 1 is provided over the wellbore at the surface while a tubing anchor is schematically shown downhole.

[0038] Figure 3 is a perspective view of components of the tubing hanger of Figure 1, in exploded-apart relation, in one embodiment.

[0039] Figure 4A is a cross-sectional view of the interlocking top ring of the tubing hanger of Figure 3, in one embodiment.

[0040] Figure 4B is an end view of the interlocking top ring of Figure 8A as viewed from a top or proximal end.

[0041] Figure 5A is a side view of the interlocking bottom ring of the tubing hanger of Figure 3, in one embodiment.

[0042] Figure 5B is a cross-sectional view of the interlocking bottom ring of Figure 6A.

[0043] Figure 5C is an end view of the interlocking bottom ring of Figure 6A as viewed from a top or proximal end.

[0044] Figure 6 is a cross-sectional view of the chemical transfer ring of the tubing hanger of Figure 3, in one embodiment.

[0045] Figure 7A is a cross-sectional view of the top mandrel of the tubing hanger of Figure 3, in one embodiment.

[0046] Figure 7B is an end view of the top mandrel of Figure 5A as viewed from the top, or proximal end.

[0047] Figure 7C is a side view of the top mandrel of Figure 5A.

[0048] Figure 8 is a cross-sectional view of the bottom mandrel of the tubing hanger of Figure 3, in one embodiment. A channel for communicating a chemical treatment fluid is seen along the body.

[0049] Figure 9 is a perspective view of a tubing anchor as may be used in connection with the tubing hanger system of the present invention, in one embodiment.

[0050] Figure 10A is a perspective view of the cone of the tubing anchor of Figure 9, in one embodiment.

[0051] Figure 10B is an end view of the cone of Figure 10A as viewed from a bottom or distal end.

[0052] Figure 11A is a cross-sectional view of a J-lock control body of the tubing anchor of Figure 9, in one embodiment.

[0053] Figure 11B is a perspective view of the J-lock control body of Figure 11A.

[0054] Figure 12A is a perspective view of the control body ring of the tubing anchor of Figure 9.

[0055] Figure 12B is a side view of the control body ring of Figure 12A.

[0056] Figure 12C is an end view of the control body ring of Figure 12A as viewed from a top or proximal end.

[0057] Figure 13 is a perspective view of a lower slip body as used in the tubing anchor of Figure 9, in one embodiment.

4836-2127-5463 v1
2937581-000001 06/30/2017

CA 2973027 2017-07-11

DETAILED DESCRIPTION OF CERTAIN EMBODIMENTS

Definitions

[0058] For purposes of the present application, it will be understood that the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur.

[0059] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions, or at ambient condition. Hydrocarbon fluids may include, for example, oil, natural gas, coalbed methane, shale oil, pyrolysis oil, pyrolysis gas, a pyrolysis product of coal, and other hydrocarbons that are in a gaseous or liquid state.

[0060] As used herein, the terms "produced fluids," "reservoir fluids" and "production fluids" refer to liquids and/or gases removed from a subsurface formation, including, for example, an organic-rich rock formation. Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids. Production fluids may include, but are not limited to, oil, natural gas, pyrolyzed shale oil, synthesis gas, a pyrolysis product of coal, oxygen, carbon dioxide, hydrogen sulfide and water.

[0061] As used herein, the term "fluid" refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, combinations of liquids and solids, and combinations of gases, liquids, and solids.

[0062] As used herein, the term "wellbore fluids" means water, hydrocarbon fluids, formation fluids, or any other fluids that may be within a wellbore during a production operation.

[0063] As used herein, the term "gas" refers to a fluid that is in its vapor phase.

[0064] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[0065] As used herein, the term "formation" refers to any definable subsurface region regardless of size. The formation may contain one or more hydrocarbon-containing layers, one or more non-hydrocarbon containing layers, an overburden, and/or an underburden of any geologic formation. A formation can refer to a single set of related geologic strata of a specific rock type, or to a set of geologic strata of different rock types that contribute to or are encountered in, for example, without limitation, (i) the creation, generation and/or entrapment of hydrocarbons or minerals, and (ii) the execution of processes used to extract hydrocarbons or minerals from the subsurface.

[0066] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shapes. The term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore." When used in connection with a drilling process, the term "bore" refers to the diametric opening formed in the subsurface.

Description of Selected Specific Embodiments

[0067] A tubing hanger system is provided herein. The tubing hanger system includes a tubing hanger (or "tensioner") configured to reside at the wellhead, and a tubing anchor (or "catcher") configured to reside downhole. Ideally, the tubing anchor is positioned just above or adjacent a fluid pump. Together, the tubing hanger and the tubing anchor hold a string of production tubing in tension during the production of hydrocarbon fluids.

[0068] **Figure 1** is a cut-away view of a tubing head **100** for supporting a string of production tubing **220**. The tubing head **100** is designed to reside at a surface. The surface may be a land surface; alternatively, the surface may be an ocean bottom or a lake bottom, or a production platform offshore. The tubing head **100** is designed to be part of a larger wellhead (not shown, but well-familiar to those of ordinary skill in the art) used to control and direct production fluids and to enable access to the "back side" of the tubing **220**. The tubing head **100** provides an inner diameter, or bore **155**, through which the string of production tubing **220** and downhole hardware are run.

[0069] Residing within the inner diameter **155** of the tubing head **100** is a tubing hanger **150** of the present invention, in one embodiment. The tubing hanger **150** is designed to gravitationally support the string of production tubing **220** from the surface. It is understood by those of ordinary skill in the art that by suspending the tubing string **220** from the surface, at least an upper portion of the tubing string **220** will reside in a state of tension.

[0070] It is observed that in long strings of jointed tubing, and particularly those in which a reciprocating pump is used, the portion of the tubing string **220** closest to a downhole tubing anchor will rest on an anchored pump barrel. This causes at least the lower portion of the tubing string **220** to go into compression. As thermal expansion occurs during the production of hot reservoir fluids, the string of production tubing **220** is further induced into compression. As noted above, this compression causes buckling along the wellbore which, in turn, causes premature wear of the rods and tubing during pump reciprocation. Accordingly, operators will pull the tubing string **220** into slight tension before "hanging," and then lock the tubing string **220** into place using the tubing hanger **150**. In known systems, this locking procedure requires multiple rotations of the tubing string **220**.

[0071] In the arrangement of **Figure 1**, the tubing hanger **150** includes a series of components. These components include an interlocking top ring **110**, an interlocking bottom ring **120**, a chemical transfer ring **130**, a top mandrel **140** and a bottom mandrel **160**. These components are shown in exploded apart relation in **Figure 3**, and are discussed below. Beneficially, these components permit the tubing string **220** to be locked in tension without multiple rotations.

[0072] It is noted that the tubing head **100** includes opposing lock pins **180**. The lock pins **180** help secure the tubing string **220** in place within the bore **155**. More specifically, the pins **180** lock in the interlocking top ring **110** which operatively supports the tubing string

220. This then allows a mandrel assembly (top mandrel **140** and bottom mandrel **160**) to travel relative to a bore **205** of the well **200** (shown in **Figure 2**) and relative to the bore **155** of the tubing head **100**.

[0073] The tubing head **100** also includes one or more side outlets **185**. The side outlets **185** are used during production to control annulus fluids and to allow access to the annulus by regulators during testing. Additionally, the tubing head **100** includes an injection conduit **175** for a treating fluid. The treating fluid may be, for example, a corrosion inhibitor. The injection conduit is in fluid communication with a chemical injection line **230** using, for example, a compression fitting **172**.

[0074] The chemical injection line **230** is preferably a small-diameter, stainless steel tubing. The injection line **230** extends down into the wellbore **200** and terminates near the pump inlet. In this way, treating fluid is delivered proximate the reciprocating pump (not shown) below the anchor **900** to treat the downhole hardware.

[0075] The chemical injection line **230** is banded to joints of production tubing during run-in. Banding helps protect the chemical injection line **230**.

[0076] **Figure 2** is a cross-sectional view of an illustrative wellbore **200**. The wellbore **200** defines a bore **205** that extends from a surface **201**, and into the earth's subsurface **210**. The wellbore **200** has been formed for the purpose of producing hydrocarbon fluids for commercial sale. A string of production tubing **220** is provided in the bore **205** to transport production fluids from a subsurface formation **250** up to the surface **201**. In the illustrative arrangement of **Figure 2**, the surface is a land surface.

[0077] The wellbore **200** includes a wellhead. Only the tubing head **100** (or "spool") of **Figure 1** is shown, along with the liner hanger **150** therein. However, it is understood that the wellhead will include a production valve that controls the flow of production fluids from the production tubing **220** to a flow line, and a back side valve that controls the flow of gases from the tubing-casing annulus **208** up to the flow line. In addition, a subsurface safety valve (not shown) is typically placed along the tubing string **220** below the surface **201** to block the flow of fluids from the subsurface formation **250** in the event of a rupture or catastrophic event at the surface **201** or otherwise above the subsurface safety valve.

[0078] The wellbore **200** will also have a pump (not shown) within or just above the subsurface formation **250**. The pump may be either a reciprocating pump or a progressive cavity pump. The pump, of course, is used to artificially lift production fluids up to the tubing head **100**. In the case of a reciprocating pump, the pump will be cycled up and down by means of a mechanical "pump jack" or by means of a hydraulic or pneumatic rod pumping system residing at the surface **201** over the wellbore **200**.

[0079] An anchor is set at the lower end of the production tubing **220**. The anchor prevents a corresponding axial movement of the pump barrel during reciprocation of the rod string. In the event a progressive cavity pump (or "PCP") is used, the rod string is used to rotate a rotor within a stator in the progressive cavity pump to pump hydrocarbon fluids to the surface.

[0080] In **Figure 2**, the wellbore **200** has been completed by setting a series of pipes into the subsurface **210**. These pipes include a first string of casing **202**, sometimes known as surface casing. These pipes also include at least a second string of casing **204**, and frequently a third string of casing (not shown). The casing string **204** is an intermediate casing string that provides support for walls of the wellbore **200**. Intermediate casing strings may be hung from the surface **201**, or they may be hung from a next higher casing string using an expandable liner or a liner hanger. It is understood that a pipe string that does not extend back to the surface is normally referred to as a "liner."

[0081] The wellbore **200** is completed with a final string of casing, known as production casing **206**. The production casing **206** extends down to the subsurface formation **250**. The casing string **206** includes perforations **215** which provide fluid communication between the bore **205** and the surrounding subsurface formation **250**. In some instances, the final string of casing is a liner.

[0082] Each string of casing **202**, **204**, **206** is set in place through cement (not shown). The cement is "squeezed" into the annular regions around the respective casing strings, and serves to isolate the various formations of the subsurface **210** from the wellbore **200** and each other. In some instances, a production casing is not used and the subsurface formation is left "open." In this instance, a sand screen or a slotted liner may be used to filter fines and solids while permitting formation fluids to enter the wellbore **200**.

[0083] The wellbore **200** further includes a string of production tubing **220**. The production tubing **220** has a bore **228** that extends from the surface **201** down into the subterranean region **250**. The production tubing **220** serves as a conduit for the production of reservoir fluids, such as hydrocarbon liquids. An annular region **208** is formed between the production tubing **220** and the surrounding tubular casing body **206**.

[0084] It is observed that the present inventions are not limited to the type of casing arrangement used or the type of pump used. However, the inventions are beneficial for applying tension to the tubing string **220** while also accommodating a chemical injection line. Thus, **Figure 2** shows not only the tubing hanger **150**, but also a tubing anchor **900** along the tubing string, and a chemical injection line **230**.

[0085] **Figure 3** is a perspective view of components of the tubing hanger **150**, in exploded-apart relation. Visible in this view are the interlocking top ring **110**, the interlocking bottom ring **120**, the chemical transfer ring **130**, the top mandrel **140** and the bottom mandrel **160**. The interlocking top ring **110**, the interlocking bottom ring **120** and the chemical transfer ring **130** are secured together, along with appropriate o-rings, through bolts **111**, **121**. At the same time, the interlocking top ring **110**, the interlocking bottom ring **120** and the chemical transfer ring **130** slidably receive the top **140** and bottom **160** mandrels. The top mandrel **140** includes a set of angled shoulders **148** along an outer diameter, shown more fully in **Figure 7C**, which slide between fixed splines **128** of the interlocking bottom ring **120**, seen more fully in **Figure 5B**.

4836-2127-5463 v1
2937581-000001 06/30/2017

CA 2973027 2017-07-11

[0086] **Figure 4A** is a cross-sectional view of the interlocking top ring **110** of the tubing hanger **150** of **Figure 1**, in one embodiment. The interlocking top ring **110** defines a short tubular body **116** having a proximal (or top) end **112** and a distal (or bottom) end **114**. The generally cylindrical body **116** forms a bore **115** dimensioned to receive the proximal end **142** of the top mandrel **140**.

[0087] **Figure 4B** is an end view of the interlocking top ring **110** of **Figure 8A** as viewed from the proximal end **112**. It is observed that four recesses **119** are provided equidistantly about the body **116** of the ring **110**. These recesses **119** are dimensioned to receive bolts (seen at **111** in **Figure 3**). The bolts **111** allow the interlocking top ring **110** to be secured to the interlocking bottom ring **120**. Each bolt **111** is followed by an optional cap **113**.

[0088] The interlocking top ring **110** is configured to reside within the bore **155** of the tubing head **100**. Various seals or o-rings (seen in **Figure 3** at **117'**) may be placed about an outer diameter of the interlocking top ring **110**. These help maintain a fluid seal between the interlocking top ring **110** and the surrounding bore **155**. In addition, seals **117''** (also seen in **Figure 3**) may reside along the inner diameter of the body **116** to provide a fluid seal between the upper mandrel **140** and the surrounding interlocking top ring **110** upon assembly.

[0089] It is observed that the body **116** of the interlocking top ring **110** provides a small through-channel **475**. The through-channel **475** runs the length of the body **116**. Upon assembly, the through-channel **475** is aligned with conduit **175**. The through-channel **475** serves as a conduit for passing the fluid chemical treatment from conduit **175** down to injection line **230**.

[0090] The body **116** of the of the interlocking top ring **110** also includes a radial indentation, or reduced outer diameter portion **111**. The reduced outer diameter portion **111** is configured to receive the opposing lock pins **180**. When the lock pins **180** are screwed into the tubing head **100**, they may be further tightened down onto the reduced outer diameter portion **111** to rotationally hold the interlocking top ring **110**.

[0091] **Figure 5A** is a side view of the interlocking bottom ring **120** of the tubing hanger **150** of **Figure 3**, in one embodiment. The interlocking bottom ring **120** is also configured to reside within the bore **155** of the tubing head **100** just below the interlocking top ring **110**. The interlocking bottom ring **120** also defines a short tubular body **126** having a proximal (or top) end **122** and a distal (or bottom) end **124**. Extending from the distal end **124** are four splines **128**. The splines **128** are spaced apart radially and equi-distantly and extend from the inner diameter of the body **126**.

[0092] **Figure 5B** is a cross-sectional view of the interlocking bottom ring **120** of **Figure 5A**. **Figure 5C** is an end view of the interlocking bottom ring **120** of **Figure 5A** as viewed from the proximal end **122**. A bore **125** (shown in **Figure 3**) is formed within the body **126**. The bore **125** is sized to receive the proximal end **142** of the top mandrel **160**. In addition, spaces **123** reserved between the splines **128** are dimensioned to slidably receive the angled shoulders **148** of the top mandrel **140** when the mandrel assembly **140** / **160** is moved up and down within the tubular assembly **110** / **120** / **130**.

[0093] **Figure 5C** also shows a plurality of through-openings **127**. The through-openings **127** receive bolts **121**. **Figure 5C** further shows the radial spacing of the splines **128** and the spaces **123** there between.

[0094] The distal end **124** of the body **126** comprises a beveled shoulder **129**. The beveled shoulder **129** rests on a conical surface (seen at **102** in **Figure 1**) within the tubing head **100**, or "spool." In one embodiment, more o-rings are placed on a shoulder **123** at the proximate end **122** of the ring **120**. This helps maintain a fluid seal between the bottom ring **120** and the surrounding tubing head **100**.

[0095] In operation, the tubular assembly comprising the chemical injection ring **130**, the interlocking bottom ring **120** and the interlocking top ring **110** are lowered into the tubing head **100** together. The beveled shoulder **129** of the bottom ring **120** lands on the matching conical shoulder **102** of the tubing head **100**. Then, lock pins **180** are tightened down onto the interlocking top ring **110** to prevent rotation.

[0096] Next, the tubing anchor **900** is set (discussed below). The mandrel assembly (top mandrel **140** and bottom mandrel **160**) and connected production tubing **220** are raised up and located along the interlocking bottom ring **120**. With the angled shoulders **148** above the splines **128**, the mandrel assembly **140** / **160** (and connected tubing string **220**) is then rotated about a quarter turn, and the mandrel assembly **140** / **160** is dropped in order to lock the angled shoulders **148** onto the splines **128**. This fixes the tubing string **220** (both longitudinally and rotationally) in tension.

[0097] As noted, the tubing hanger **150** also includes a chemical transfer ring **130**. **Figure 6** is a cross-sectional view of the chemical transfer ring **130** of the tubing hanger **150** of **Figure 3**, in one embodiment. The chemical transfer ring **130** is configured to reside within the bore **155** of the tubing head **100** just below the bottom interlocking ring **120**. The chemical transfer ring **130** defines a short tubular body **136** having a proximal (or top) end **132** and a distal (or bottom) end **134**. The generally cylindrical body **136** forms a bore **135** that is dimensioned to receive the proximal end **142** of the top mandrel **140**.

[0098] It is also noted that recesses **139** are formed along the body **136** at the proximal end **132**. The recesses **139** are threaded and are dimensioned to receive bolts (shown at **121** in **Figure 3**). This secures the interlocking bottom ring **120** to the chemical transfer ring **130**.

[0099] Also of interest, the illustrative chemical transfer ring **130** has two or more o-rings (seen at **137** in **Figure 3**). These are actually installed along the outer diameter of the body **136** to provide a fluid seal between the chemical transfer ring **130** and adjacent hardware assembly. Separate o-rings **137''** may be used to provide a seal between the bottom mandrel **160** and the surrounding chemical transfer ring **130**.

[00100] The interlocking top ring **110**, the interlocking bottom ring **120** and the chemical transfer ring **130** together form a tubular assembly. The tubular assembly resides along the inner diameter (or bore **155**) of the tubing head **100**. Preferably, the tubular assembly **110** / **120** / **130** is installed when the last (or uppermost) joint of production tubing **220** has been run into the wellbore **200**, and before the top **140** and bottom **160** mandrels are connected.

4836-2127-5463 v1
2937581-000001 06/30/2017

CA 2973027 2017-07-11

The conical beveled shoulder **129** of the interlocking bottom ring **120** is landed on the conical surface **102** within the tubing head **100**.

[00101] **Figure 7A** is a cross-sectional view of the top mandrel **140** of the tubing hanger **150** of **Figure 3**, in one embodiment. The top mandrel **140** also defines a generally tubular body **146** having a proximal end **142** and a distal end **144**. A bore **145** is formed within the body **146** which is sized to receive the proximal end **162** of the bottom mandrel **160**.

[00102] **Figure 7B** is an end view of the top mandrel **140** of **Figure 5A** as viewed from the top, or proximal end **142**. **Figure 7C** is a side view of the top mandrel **140** of **Figure 5A**. Visible here are angled shoulders **148**. In the arrangement of **Figures 7A**, **7B** and **7C**, four separate angled shoulders **148** are spaced radially and equi-distantly apart.

[00103] **Figure 8** is a cross-sectional view of the bottom mandrel **160** of the tubing hanger **150** of **Figure 3**, in one embodiment. The bottom mandrel **160** defines a generally tubular body **166** having a proximal end **162** and a distal end **164**. A bore **165** is formed within the body **166** which transports production fluids through the tubing head **100**.

[00104] During well completion, the proximal end **162** of the bottom mandrel **160** is threadedly connected to the distal end **144** of the top mandrel **140** using a 2-7/8" EUE 8 round thread. The distal end **164** of the bottom mandrel **160** defines female threads that connect with the pin end of the uppermost joint of production tubing **220**. Once the connection with the string of production tubing **220** is made, the top mandrel **140** and the bottom mandrel **160** are lowered in the wellhead **100** together until the tubing anchor 900 is at a desired depth within the production casing **206**. The entire tubing hanger **150** is now in place.

[00105] It is again observed that the top mandrel **140** and the bottom mandrel **160** together form a mandrel assembly. The dimensions of the top **140** and bottom **160** mandrels may be changed to accommodate the size of the tubing head **100** and the tubular assembly

[00106] As noted, the tubing hanger system also includes a tubing anchor **900**. **Figure 9** is an enlarged perspective view of a tubing anchor **900** as may be used in connection with the tubing hanger system of the present invention, in one embodiment. **Figure 9** demonstrates that the tubing anchor **900** is made up of several components. These include an upper female box connector **902**, an upper slip body **910**, a cone **920**, a J-lock control body **930** (with an integral lower slip body **938**), slips **940**, a threaded stop member **950** and a lower pin connector **904**. In the view of **Figure 9**, the slips **940** have not been actuated and the tubing anchor **900** has not been set in the surrounding casing **220**.

[00107] It is observed that the tubing anchor **900** defines a generally tubular body having a proximal end **912** and a distal end **914**. A bore **905** is provided along the length of the tubing anchor **900**. This allows production fluids to flow up the production tubing **220** and to the tubing head **100** at the surface **201**.

[00108] The upper tubing connector **902** resides at the proximal, or top end **912**. The tubing connector **902** provides a female "box" connection that receives a male "pin end" of a jointed tubing **220**. In one aspect, the female connection has a 2-7/8" outer diameter and 2-1/2" ACME threads along the inner diameter.

[00109] The tubing anchor **900** is intended to be run into the wellbore **200** near the bottom of the tubing string **220**. Below the tubing anchor **900**, perhaps less than 100 feet, is a downhole pump (not shown). The pump, or at least the standing valve portion, is installed along the tubing string **220** using, for example, a tap-type puller having an anvil.

[00110] In practice, a first joint of tubing string **220** is lowered into the well **205** while keeping the proximal (or top) end **902** of the tubing anchor **900** still at the surface **201**. Another section of pipe is connected to the tubing connector **902**. From that point, a check valve (not shown) connected to the 1/4" chemical injection line **230** is banded to the joint of pipe. The check valve prevents chemical treatment fluid and wellbore fluids from running up the chemical injection line **230**.

[00111] As joints of pipe **220** are added and depth increases, banding of the 1/4' line **230** continues. Once the desired depth is achieved for setting the tubing anchor **900**, the tubular assembly **110** / **120** / **130** of the tubing hanger **150** is placed inside of the tubing spool **100** at the surface **201**. Next, the mandrel assembly (top mandrel **140** and bottom mandrel **160**) of the tubing hanger **150** is connected to the string of pipe **220** and is lowered towards the tubing head **100**. Preferably, a tubular landing sub (not shown) is connected to the proximal (or top) end **142** of the top mandrel **140**. The tubing string **220** is then further lowered to a position where the tubing anchor **900** is to be set in the production casing **106**.

[00112] It is again observed here that the bottom mandrel **160** threads into the top mandrel **140** with a 2-7/8" EUE 8 round thread. Threads are shown in **Figure 8**. The threaded connection ensures that the bottom mandrel **160** is connected to the top mandrel **140** so that they move together as a mandrel assembly.

[00113] The top mandrel **140** is landed on the interlocking bottom ring **120**. The conical beveled shoulder **129** of the interlocking bottom ring **120** rests on the conical surface **102** within the tubing head **100**. The production tubing **220** is now gravitationally hanging in tension due to the weight of the tubing string **220**. The lock pins **180** from the tubing head **100**, or "spool," are then rotated to engage with the cylindrical interlocking top ring **110**. Specifically, the lock pins **180** tighten down into the recessed outer diameter portion **111**.

[00114] The top mandrel **140** may be turned into and out of its locked position. When the top mandrel **140** is out of its locked position, it can freely float within the well bore **205**. In this unlocked position, the angled shoulders **148** slide vertically through the spaces **123** between the splines **128** of the interlocking bottom ring **120**. The tubing string **220** is then lowered and comes to a position where the tubing anchor **900** will be set.

[00115] The tubing anchor **900** also includes slips **940**. The slips **940** define a set of opposing slip segments representing upper **945U** and lower **945L** segments. Actuation of the slips **940** causes the tubing anchor **900** to be set in the production casing **106**.

[00116] The tubing anchor **900** also comprises upper and lower slip bodies. The upper slip body is an independent tubular body shown at **910** in **Figures 9** and **13**. The lower slip body is integral to the J-lock control body **930** and is shown at **938** in **Figures 9** and **11B**.

[00117] A slot **911** in the upper slip body **910** (seen in **Figure 13**) locks into or receives an upper slip segment **945U**. The upper **945U** and lower **945L** slip segments ride upon respective upper and lower slip sleeves (not seen) when actuated at the point of setting.

[00118] Of interest, and as discussed further below in connection with **Figure 13**, a groove **915** resides along the upper slip body **910**. The groove **915** is dimensioned to receive a distal end of the chemical injection line **230**. A keeper tab **917** snaps over the chemical injection line **230** to help hold the line **230** in place. The keeper tab **917** is secured onto the recess **919** by screws.

[00119] The groove arrangement **915** allows the chemical injection line **230** to reside within the wellbore **200** without being damaged during run-in and without interfering with operation of the anchor **900** during setting. This unique arrangement enables a downhole pump and other downhole hardware to receive inhibitors that prevent build-up of paraffin, wax and corrosive elements that can lead to failure.

[00120] It is observed that the chemical injection line **230** need not terminate at the tubing anchor / catcher **900**, but may continue on past the anchor **900** to the pump inlet.

[00121] Around the slips **940** is a cone **920**. **Figure 10A** is a perspective view of the cone **920** of the tubing anchor **900** of **Figure 9**, in one embodiment. As can be seen, the cone **920** defines a generally tubular member having a proximal end **922** and a distal end **924**. The cone **920** comprises a body **926** that has a groove **929** running substantially the length thereof. The groove **929** is configured to receive the chemical injection line **230** below the channel **915**. Upon assembly of the tubing anchor **900**, groove **929** aligns with groove **915**.

[00122] **Figure 10B** is an end view of the cone **940** of **Figure 10A** as viewed from the bottom or distal end **924**. The profile of the groove **929** is more clearly seen. Also visible is

a bore **925** formed by the body **926**. In practice, the cone **920** threadedly connects opposing slip segments **945** of the slips **940** while providing a means of traverse for the chemical injection line **230**.

[00123] **Figure 11A** is a cross-sectional view of the J-lock control body **930** of the tubing anchor **900** of **Figure 9**, in one embodiment. **Figure 11B** is a perspective view of the control body **930** of **Figure 11A**. The J-lock control body **930** will be discussed with reference to each of these figures together.

[00124] The J-lock control body **930** is a generally tubular wall **936** having a proximal end **932** and a distal end **934**. A channel **939** is preserved along the shoulder to accommodate the chemical injection line **230**. In addition, a bore **935** is formed within the wall **936** for the transport of production fluids en route to the surface **201**.

[00125] The proximal end **932** comprises the lower slip body **938**. The slip body **938** has radially disposed slots **937**. The slots **937** latch into the lower slip segment **945L**. In addition, the wall **936** of the control body **930** includes opposing J-lock profiles **933**. Action of a pin (not shown) along the J-lock profiles **933** allows the operator to actuate the slip segments **945** into biting engagement with the surrounding casing string **206**.

[00126] It is noted that the J-Lock control body **930** is a modified version of a known tubing anchor / catcher. The known tubing anchor catcher will have certain components not seen in **Figures 11A** and **11B** but which are understood by those of ordinary skill in the art to be present. Such features may include a J-pin ring residing along the J-lock control body **930**, a bottom sleeve, and one or more shear pins. U.S. Patent No. 4,605,063 entitled "Chemical Injection Tubing Anchor-Catcher" is referred to and incorporated by reference in its entirety herein. The '063 describes the setting of a rotationally-set anchor-catcher.

[00127] During run-in, the J-pin ring is attached to a bottom sleeve (not shown) by shear pins. The shear pins temporarily fix the bottom sleeve along the body **936**. Shearing of the pins allows the bottom sleeve to slide out of a landing position and to start actuation of the slip segments **945**. It is noted though that the pins are only sheared when pulling up on the tubing, causing the slips to release. Turn to the right will not release the slips.

[00128] During setting of the tubing anchor **900**, the tubing string **220** with connected anchor **900** is turned clockwise. This positions the J-pin ring into a diagonal portion of the J-slot **933**. The string **220** is then lowered the distance of the J-slot **933**. A lower slip sleeve (not visible) is connected to the lower slip body **938**, which houses the two slips (upper **945U** and lower **945L** slip segments). A releasing slip is provided in both the upper **945U** and the lower **945L** slip segments, where each has three segments in which two hold and one releases. Both the lower slip sleeve and the lower slip body **938** begin sliding on the outside diameter of the tubing anchor body **936**. Once engaged by the top sub connected to the proximal end **932**, the lower slip body **938** begins a downward descent relative to the wellbore **200**. The upper slip segment **945U** and upper slip body **938** come into contact with a notch that is on the tubing anchor body **936**. This action pins the sleeve and the lower slip body **938** between the notch and the top sub.

[00129] The sleeve and the lower slip body **938** now come into contact with the cone **920**. The cone **920** is connected to the lower slip segment **945L**. With the string **220** still moving downward, the cone **920** that is now in contact with the lower slips **945L** force the cone **920** and lower slips **945L** to come in contact with the slips **945** that are being housed in the upper end **932** of the J-Lock control body **930**. Setting of the slips **945** is caused by pulling up on the anchor body, which causes the springs **933** to drag along the tubing to be turned to the left 1/8 (45°) turn. This action causes the slips **945U**, **945L** in the J-Lock control body **930** to grip the casing internal diameter. As the J-Pin approaches the end of the J-slot **933**, the string **220** makes a counter-clockwise turn to prepare to set. Once the J-Pin is in position, the string **220** is pulled back up slightly to set the anchor **900** in place.

[00130] It is observed that the tubing anchor **900** is uniquely configured to lock into the casing slips **945** using only the a 1/8 (45°) turn. In contrast, known tubing anchors use several turns to lock and set. Tubing anchors that need several turns to set can result in entanglement of any chemical tubing lines, causing them to bend and break. Further, some tubing anchors are set through use of the pressure of the chemicals or hydraulic pressure in the 1/4" line, which actuates the slips. The draw back to chemical or hydraulic pressure is that the tubing anchor may not hold tightly in the casing. Also, splices that connect the main line together in order for the tubing anchor to actuate often fail to hold pressure, and leak. In contrast, the present tubing anchor design **900** does not require such splices; instead, the present tubing anchor **900** is actuated merely by pulling back up on the tubing string **220**, allowing drag of the springs **933** to pull the control body **930** and shear pins, followed by the 1/8th turn clockwise.

[00131] **Figure 12A** is a perspective view of the J-control body ring **950** of the tubing anchor **900** of **Figure 9**. **Figure 12B** is a side view of the control body ring **950** of **Figure 12A**. **Figure 12C** is an end view of the control body ring of **Figure 12A** as viewed from the top or proximal end **952**. The J-control body ring **950** will be discussed with reference to each of these three figures.

[00132] The J-control body ring **950** comprises a generally circular body **956** having a proximal end **952** and a distal end **954**. The ring **950** serves as a "no-go" gauge that keeps the anchor **900** from being lowered into crushed casing. A short bore **955** is formed there through. The distal end **954** is flanged, with the flange preserving a channel **959** to receive the chemical injection line **230**.

[00133] A plurality of holes **953** are formed radially through the body **956**. The holes **953** reside equi-distantly about the body **956**. The holes **953** are dimensioned to receive bolts (not shown) that secure the body **956** to the body **936** of the J-lock control body **930**.

[00134] Finally, **Figure 13** is a perspective view of the upper slip body **910**. The upper slip body **910** comprises a generally tubular body **956**. The upper slip body **910** includes a slot **911** that receives a portion of the upper slip segment **945U**. The upper slip body **910** also includes channel **915**. The channel **915** is dimensioned to accommodate the chemical injection line **230**. It is also seen that a recess is milled out and two holes are drill and tapped for a machined tab **917** to fit, which is held down by screws (not shown).

[00135] As can be seen, an improved tubing hanger assembly is provided. The tubing hanger assembly includes a tubing hanger **150** and a tubing anchor **900**, each of which is set in a wellbore using less than a full rotation, and in a preferred embodiment, less than a 180° rotation.

[00136] Using the tubing hanger assembly **150** / **900**, a method for hanging a string of production tubing in a wellbore is also provided herein. The method employs the tubing hanger system as described above, in any of its various embodiments.

[00137] The method first includes providing a tubing hanger system. The tubing hanger system includes the tubing hanger and the tubing anchor, wherein the tubing hanger and the tubing anchor are each configured to be set through a rotation that is less than one full rotation.

[00138] The method also includes threadedly connecting a joint of production tubing to the tubing anchor. The method then includes running a string of production tubing into the wellbore, joint-by-joint, wherein the tubing anchor is threadedly connected to the production tubing proximate a lower end of the production tubing.

[00139] The method additionally includes threadedly connecting the tubing hanger to the string of production tubing at an upper end of the production tubing. The method then includes lowering the tubing hanger so as to position the tubing anchor at a desired depth downhole.

[00140] The method further comprises setting the tubing anchor within a string of surrounding production casing within the wellbore. The method then includes applying tension to the tubing string. Applying tension to the tubing string means pulling on the production tubing from the surface.

[00141] In accordance with embodiments of the invention, the method additionally comprises setting the tubing hanger within a tubing head at a surface above the wellbore. This first comprises landing a tubular assembly within the bore of a tubing head forming a portion of the wellhead. The tubing hanger has a beveled shoulder along the outer diameter which is configured to land on a matching conical surface machined along the tubing head. This also includes threadedly connecting a mandrel assembly to the upper end of the production tubing.

[00142] The method further comprises banding a chemical injection line **230** to the production tubing **220**, joint-by-joint, during run-in. An upper end of the injection line **230** is connected to a lower end of the bottom mandrel **160**, such as through use of a compression fitting **172**. In this way, a channel within the interlocking top ring **110** and the bottom mandrel **160** are in sealed fluid communication with the injection line **230**. The chemical injection line **230** extends downhole from the fitting **172** to the tubing anchor **900**. In this way, a chemical treatment fluid may be injected into the channel and then into the chemical injection line **230**, where it is transmitted downhole to the tubing anchor **900**.

[00143] In operation, the mandrel assembly (top mandrel **140** and bottom mandrel **160**) of the tubing hanger **150** is lowered into the bore **205** in order to set the tubing anchor **900**. Material for the hanger **150** is determined by the well conditions. After the tubing anchor **900** is set, the mandrel assembly (top mandrel **140** and bottom mandrel **160**) and connected tubing string **220** are raised back up to pass through the bore **135** of the chemical transfer ring **130** and the bore **125** of the interlocking bottom ring **120**. This involves moving the angled shoulders **148** of the top mandrel **140** up through the spaces **123** between the splines **128** until the mandrel assembly **140** / **160** comes to a stop within the interlocking top ring **110**. The angled shoulders **148** have now cleared the splines **128** and the string of production tubing **220** in tension.

[00144] The mandrel assembly (top mandrel **140** and bottom mandrel **160**) is then rotated 1/4 turn clockwise relative to the bore **115** while the angled shoulders **148** are above the splines **128**. The method then includes lowering the mandrel assembly **140** / **160** back down along the tubular assembly **110** / **12** / **130** in order to lock the tubing hanger within the surrounding production casing. This prevents further rotational and longitudinal movement of the mandrel assembly **140** / **160** within the wellbore **200**.

[00145] Beneficially, the tubing hanger is set by pulling tension on the production tubing **220** and the connected chemical injection line **230** without undue torsional stress. Chemicals can now be supplied to the wellbore **205** through the injection conduit **175**. Chemicals are then flushed through the splines **128** of the interlocking bottom ring **120**. The chemical injection tubing **230** preferably terminates proximate a downhole pump below the tubing anchor within the wellbore.

[00146] In one embodiment of the method, an adapter is placed above the tubing hanger. More specifically, an adapter is threadedly connected to the top mandrel **140**. A pocket is provided at the bottom of the adapter that is configured to receive the top mandrel **140** and seals the well.

[00147] At the upper end, the adapter provides a connection for a valve, a pumping tee or other hardware that is part of the well head. This top connection can be either threaded or studded with a ring groove.

[00148] The adapter includes a first port that allows for the injection of the chemical treatment fluid into the tubing hanger. This first port provides fluid access to the channel **175** in the interlocking top ring **110** and down to the channel **163** in the bottom mandrel **160**. The adapter also includes second and third ports that enable testing of the seals on both the chemical channels **175**, **163** and the tubing hanger body.

[00149] The adapter is an optional feature. It typically is not needed with low producing wells where the operator produces from the top connection of the tubing hanger. In any event, the method then includes producing hydrocarbon fluids to the tubing hanger at the surface, through the production tubing **220**.

[00150] As can be seen, a tubing hanger system is provided that includes both a novel tubing hanger **150** and a novel tubing anchor **900**. The tubing hanger system provides an assembly of engineered parts that enable a method of pulling tension in the tubing string **220** from the surface **201**, and then holding that tension by means of a locking design. Once in the locking position, chemicals (such as corrosion inhibitors) can be pumped through the tubing hanger **150** and down an injection line **230**. In one aspect, the system is able to hold tension without use of shear pins and springs, saving considerable manufacturing costs.

[00151] Another advantage of the tubing hanger system presented herein is the ability to transfer downward force created from the gravitational force on the tubing string **220**, and lock the top mandrel body **140** within the tubing head **100**. This, in turn, prevents further rotation about the longitudinal axis of the casing strings **202**, **204**, **206** within the wellbore **200**.

[00152] Still another advantage of the tension hanger system is in the method of delivering chemicals that treat the pump or that treat the formation. Such chemicals may include steam, corrosion inhibitors, foam and water. Chemicals are able to be delivered downhole under minimal pressure while the tubing hanger is in its locked position and while maintaining a seal within the tubing hanger itself. Further, a seal is maintained within the casing spool where the tubing hanger suspends from the tubing head.

[00153] While it will be apparent that the inventions herein described are well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the inventions are susceptible to modification, variation and change without departing from the spirit thereof.

CLAIMS

What is claimed is:

1. A tubing hanger system for suspending a production tubing string within a wellbore, comprising:

a tubing hanger threadedly connected to the tubing string at an upper end of the tubing string, and configured to reside within a tubing head over the wellbore and to gravitationally support the tubing string in tension; and

a tubing anchor threadedly connected to the tubing string proximate a lower end of the tubing string, and configured to be set within a string of production casing downhole;

wherein:

the tubing hanger comprises a tubular assembly having an inner diameter and an outer diameter, with a beveled shoulder along the outer diameter dimensioned to land on an inner conical surface of the tubing head; and

the tubing hanger and the tubing anchor are each configured to be set in the wellbore through a rotation of the tubing string that is less than one full rotation.

2. The tubing hanger system of claim 1, further comprising:

a stainless steel chemical injection line having an upper end and a lower end, wherein:

the upper end is in sealed fluid communication with a fluid channel extending along the tubing hanger and configured to receive an injection chemical from the surface; and

the lower end extends to at least the tubing anchor.

3. The tubing hanger system at claim 2, wherein:

the lower end of the chemical injection line extends below the tubing anchor; and

the chemical injection line passes through a channel along an outer diameter of the tubing anchor as the chemical injection line extends below the tubing anchor.

4836-2127-5463 v1
2937581-000001 06/30/2017

CA 2973027 2017-07-11

4. The tubing hanger system of claim 3, wherein the chemical injection line terminates proximate a downhole pump within the wellbore.

5. The tubing hanger system of claim 2, wherein the tubular hanger comprises:

a series of splines extending down from an inner diameter of the tubular assembly, and

a mandrel assembly defining a tubular body configured to be slidably received within a bore of the tubular assembly, the mandrel assembly comprising:

an upper end having female threads and configured to extend above the tubular assembly when the tubing hanger lands on the conical surface of the tubing head;

a lower end also having female threads and configured to be threadedly connected to an uppermost joint of the tubing string; and

angled shoulders spaced radially around an outer diameter of the mandrel assembly configured to pass between the splines of the tubular assembly when the mandrel assembly and connected tubing string are moved vertically in the wellbore, but to receive and interlock with individual splines of the series of splines when the tubing hanger is rotated the less than one full rotation, and then set down.

6. The tubing hanger system of claim 5, wherein the tubular assembly further comprises:

a cylindrical interlocking top ring,

a cylindrical interlocking bottom ring configured to reside below the interlocking top ring and support the series of splines; and

a cylindrical chemical injection ring configured to generally reside below the interlocking bottom ring and around the series of splines;

and wherein the splines extend down from an inner diameter of the interlocking bottom ring, and the beveled shoulder resides along an outer diameter of the interlocking bottom ring.

7. The tubing hanger system of claim 6, wherein the mandrel assembly further comprises:

a top mandrel defining a cylindrical body; and

a bottom mandrel also defining a cylindrical body;

wherein the angled shoulders reside about the cylindrical body forming the top mandrel.

8. The tubing hanger system of claim 7, further comprising:

a channel machined through a body of each of the interlocking top ring and the bottom mandrel along a longitudinal axis for carrying an injection fluid from the surface; and

a fitting at a lower end of the channel machined into the chemical injection ring for mechanically connecting to and sealingly receiving a top end of a chemical injection line.

9. The tubing hanger system of claim 8, wherein:

the tubing string is threadedly connected to and supports the tubing anchor.

the bottom mandrel is threadedly connected to the top mandrel;

a rotation of the mandrel assembly and connected tubing string within the bore of the tubular assembly while the angled shoulders are above the splines locks the tubing anchor within the surrounding production casing; and

thereafter, a rotation of the mandrel assembly by less than 180 degrees, followed by setting down the mandrel assembly onto the splines, locks the mandrel assembly and connected tubing string from further rotational and longitudinal movement within the wellbore.

10. The tubing hanger system of claim 9, wherein:

the chemical injection line is fabricated from stainless steel; and

a rotation of the tubing string by less than 180 degrees comprises a rotation of the mandrel assembly by a one-quarter turn clockwise relative to the bore of the tubular assembly.

11. The tubing hanger system of claim 9, wherein the tubing anchor comprises:

an upper box connector for threadedly connecting the tubing anchor to the tubing string;

a lower pin connector for threadedly connecting the tubing anchor to the tubing string;

slips between the upper box connector and the lower pin connector configured to be mechanically actuated by applying tension to the tubing string; and

a locking body having profiles configured to receive a pin and to hold the slips in engagement with the surrounding production casing upon rotation of the tubing string by less than 180 degrees; and

wherein the locking body comprises a channel along an outer diameter dimensioned to accommodate the chemical injection line.

12. The tubing hanger system of claim 11, wherein the tubing anchor further comprises:

a cone slidably residing over the slips;

an upper slip body configured to urge actuation of the upper slip segments in response to the shearing of a shear pin; and

a lower slip body configured to urge actuation of the lower slip segments in response to a force provided by movement of the cone; and

wherein the cone, the upper slip body and the lower slip body each comprise a channel along an outer diameter dimensioned to accommodate the chemical injection line, with the respective channels of the locking body, the cone, the upper slip body and the lower slip body being aligned along the tubing anchor.

13. The tubing hanger system of claim 12, wherein:

the tubing anchor further comprises springs extending along the lower slip body, wherein upward movement of the production tubing causes the springs to drag along an inner diameter of the surrounding production casing and to shear one or more pins, thereby releasing the cone for its sliding movement; and

upon shearing of the one or more pins, the production tubing may be rotated by a 1/8 quarter turn (45°) to lock the casing slips.

14. The tubing hanger system of claim 1, wherein the tubing anchor comprises:

an upper box connector for threadedly connecting the tubing anchor to the tubing string;

a lower pin connector for threadedly connecting the tubing anchor to the tubing string;

slips between the upper box connector and the lower pin connector configured to be mechanically actuated by applying tension to the tubing string; and

a locking body having profiles configured to receive a pin and to hold the slips in engagement with the surrounding production casing upon rotation of the tubing string by less than 180 degrees; and

wherein the locking body comprises a channel along an outer diameter dimensioned to accommodate the chemical injection line.

15. The tubing hanger system of claim 14, wherein the tubing anchor further comprises:

a cone slidably residing over the slips;

an upper slip body configured to urge actuation of the upper slip segments in response to the shearing of a shear pin; and

a lower slip body configured to urge actuation of the lower slip segments in response to a force provided by movement of the cone; and

wherein the cone, the upper slip body and the lower slip body each comprise a channel along an outer diameter dimensioned to accommodate the chemical injection line, with the respective channels of the locking body, the cone, the upper slip body and the lower slip body being aligned along the tubing anchor.

16. A method of hanging a string of production tubing within a wellbore, in tension, comprising:

threadedly connecting a tubing anchor to a joint of production tubing;

running the string of production tubing into the wellbore, joint-by-joint, wherein the tubing anchor is placed adjacent a string of production casing at a selected depth;

threadedly connecting a tubing hanger to the string of production tubing at an upper end of the tubing string, wherein the tubing hanger comprises:

a tubular assembly having an inner diameter and an outer diameter, with a beveled shoulder along the outer diameter dimensioned to land on an inner conical surface of a tubing head above the wellbore; and

a mandrel assembly defining a tubular body and configured to be slidably received within a bore formed by the tubular assembly, wherein an uppermost joint of the string of production tubing is threadedly connected to a lower end of the mandrel assembly;

setting the tubing anchor within the string of surrounding production casing by applying tension to the production casing and then rotating the production casing less than one full rotation; and

setting the tubing hanger within the tubing head by further applying tension to the tubing string to raise the mandrel assembly within the tubular assembly, and rotating the mandrel assembly and connected tubing string less than one full rotation.

17. The method of claim 16, wherein:

setting the tubing anchor within the string of surrounding production casing comprises rotating the string of production tubing by less than 180°; and

setting the tubing hanger within the tubing head comprises rotating the string of production tubing by less than 180° while applying tension to the string of production tubing.

18. The method of claim 17, wherein:

the tubular assembly further comprises a series of radially-disposed splines extending down from the inner diameter of the tubular assembly and forming spaces there between; and

the mandrel assembly further comprises a series of radially-disposed angled shoulders along an outer diameter of the mandrel assembly;

raising the mandrel assembly within the tubular assembly comprises raising the angled shoulders up through the spaces of the tubular assembly so that the angled shoulders are above the splines before the mandrel assembly and connected tubing string are rotated; and

setting the tubing hanger within the tubing head further comprises setting the angled shoulders down onto the respective splines to rotationally and longitudinally lock the tubing string within the tubing head.

19. The method of claim 18, further comprising:

clamping a stainless steel chemical injection line along the string of production tubing while the string of production tubing string is being run into the wellbore, joint by joint;

and wherein:

the stainless steel chemical injection line has an upper end and a lower end,

the upper end is in sealed fluid communication with a fluid channel extending along the tubing hanger and is configured to receive an injection chemical from the surface, and

the lower end extends at least to the tubing anchor.

20. The method of claim 19, wherein:

the chemical injection line passes through a channel along an outer diameter of the tubing anchor as the chemical injection line extends below the tubing anchor, and

the chemical injection line terminates proximate a downhole pump within the wellbore.

4836-2127-5463 v1
2937581-000001 06/30/2017

CA 2973027 2017-07-11

21. The method of claim 19, wherein:

the mandrel assembly further comprises:

an upper end having female threads and configured to extend above the tubular assembly when the tubing hanger lands on the conical surface of the tubing head;

a lower end also having female threads;

a bore extending from the upper end to the lower end, axially aligned with a bore of the tubing head; and

threadedly connecting the tubing hanger to the string of production tubing comprises threadedly connecting the uppermost joint of the string of production tubing to the lower end of the mandrel assembly.

22. The method of claim 21, wherein the tubular assembly further comprises:

a cylindrical interlocking top ring,

a cylindrical interlocking bottom ring configured to reside below the interlocking top ring and supporting the series of splines; and

a cylindrical chemical injection ring configured to generally reside below the interlocking bottom ring and around the splines;

and wherein the splines extend down from an inner diameter of the interlocking bottom ring, and the beveled shoulder resides along an outer diameter of the interlocking bottom ring.

23. The method of claim 22, wherein the mandrel assembly comprises:

a top mandrel defining a cylindrical body; and

a bottom mandrel also defining a cylindrical body;

and wherein the angled shoulders reside about an outer diameter of the cylindrical body forming the top mandrel.

24. The method of claim 23, wherein the tubular assembly further comprises:

a channel machined through each of the interlocking top ring and the bottom mandrel along a longitudinal axis for carrying an injection fluid; and

a fitting at a lower end of the channel machined into the chemical injection ring for sealingly receiving a top end of a chemical injection line;

and wherein the method further comprises injecting a chemical treatment fluid from the surface through the channel in the interlocking top ring, flushing the splines in the interlocking bottom ring, through the channel in the bottom mandrel, through the fitting, and into the chemical injection line.

25. The method of claim 24, wherein setting the tubing hanger within the tubing head at the surface further comprises:

placing the tubular assembly of the tubing hanger within the inner diameter of the tubing head such that the beveled outer shoulder of the interlocking bottom ring lands on the conical inner surface of the tubing head;

running the mandrel assembly with connected string of production tubing through the bore of the tubular assembly;

after the tubing anchor is set, raising the mandrel assembly and connected tubing string back up to pass through the bore of the chemical transfer ring until the mandrel assembly hits the interlocking top ring, thereby placing the string of production tubing in tension and positioning the angled shoulders over the splines;

rotating the mandrel assembly within the bore of the tubular assembly one-quarter turn clockwise while the angled shoulders are above the splines; and

setting down the mandrel assembly in order to lock the tubing hanger and connected tubing string within the surrounding production casing and prevent further longitudinal movement of the mandrel assembly within the wellbore.

26. The method of claim 25, wherein the tubing anchor comprises:

an upper box connector for threadedly connecting the tubing anchor to the tubing string;

a lower pin connector for threadedly connecting the tubing anchor to the tubing string;

slips between the upper box connector and the lower pin connector configured to be mechanically actuated by applying tension to the tubing string; and

a locking body having profiles configured to receive a pin and to hold the slips in engagement with the surrounding production casing upon rotation of the tubing string by less than 180 degrees; and

wherein the locking body comprises a channel along an outer diameter dimensioned to accommodate the chemical injection line.

27. The method of claim 26, wherein the tubing anchor further comprises:

a cone slidably residing over the slips;

an upper slip body configured to urge actuation of the upper slip segments in response to the shearing of a shear pin; and

a lower slip body configured to urge actuation of the lower slip segments in response to a force provided by movement of the cone; and

wherein the cone, the upper slip body and the lower slip body each comprise a channel along an outer diameter dimensioned to accommodate the chemical injection line, with the respective channels of the locking body, the cone, the upper slip body and the lower slip body being aligned along the tubing anchor.

28. The method of claim 27, wherein:

the tubing anchor further comprises springs extending along the lower slip body, wherein upward movement of the production tubing causes the springs to drag along an inner diameter of the surrounding production casing and to shear one or more pins, thereby releasing the cone for its sliding movement; and

upon shearing of the one or more pins, the production tubing may be rotated by a 1/8 quarter turn (45°) to lock the casing slips.

4836-2127-5463 v1
2937581-000001 06/30/2017

CA 2973027 2017-07-11

29. The method of claim 28, wherein the chemical injection tubing terminates proximate a downhole pump below the tubing anchor within the wellbore.

30. The method of claim 18 further comprising:

producing hydrocarbon fluids through the string of production tubing and up to the tubing anchor.

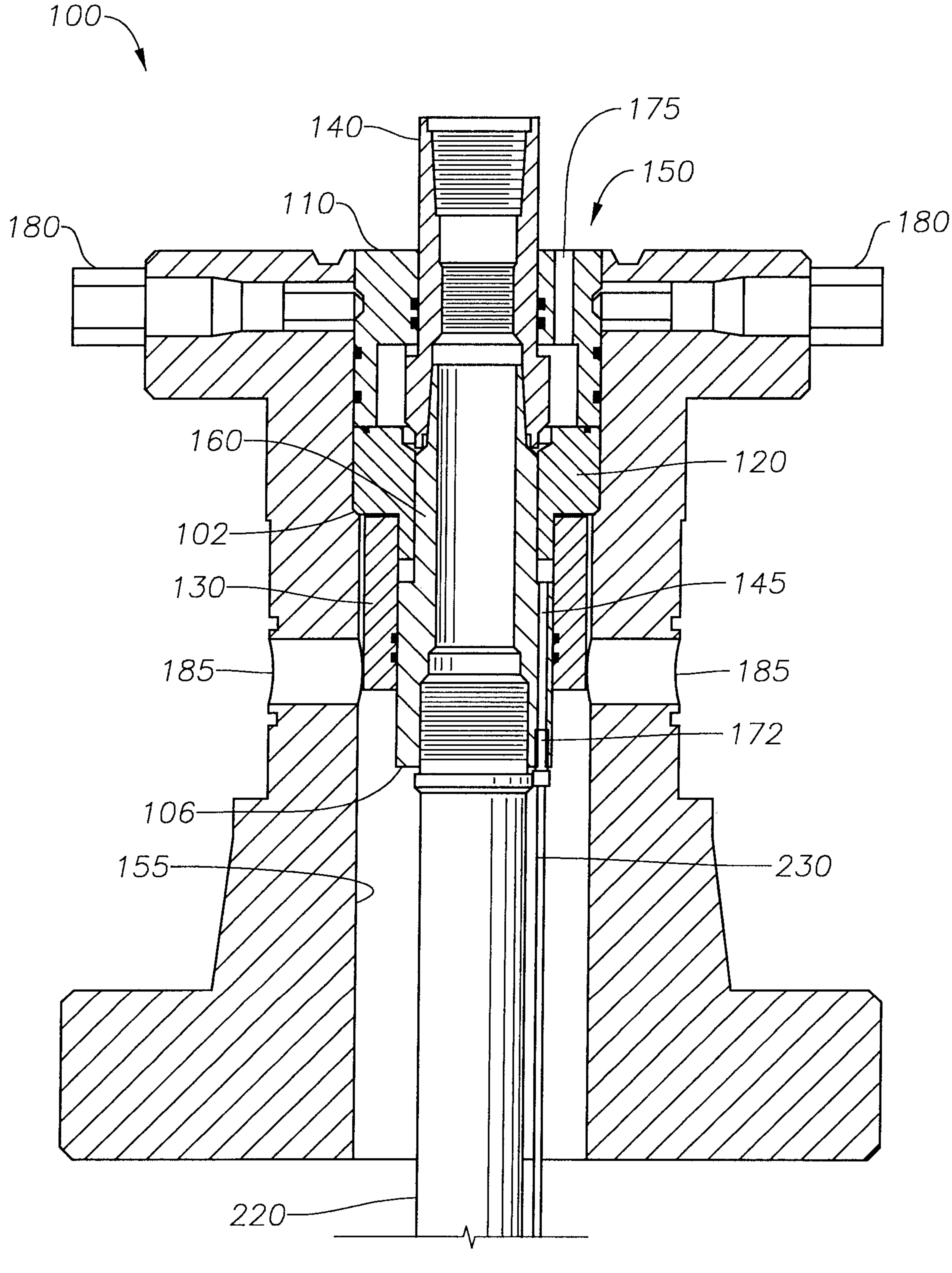

100
140
175
150
110
180
180
160
120
102
130
145
185
185
172
106
155
230
220

FIG. 1

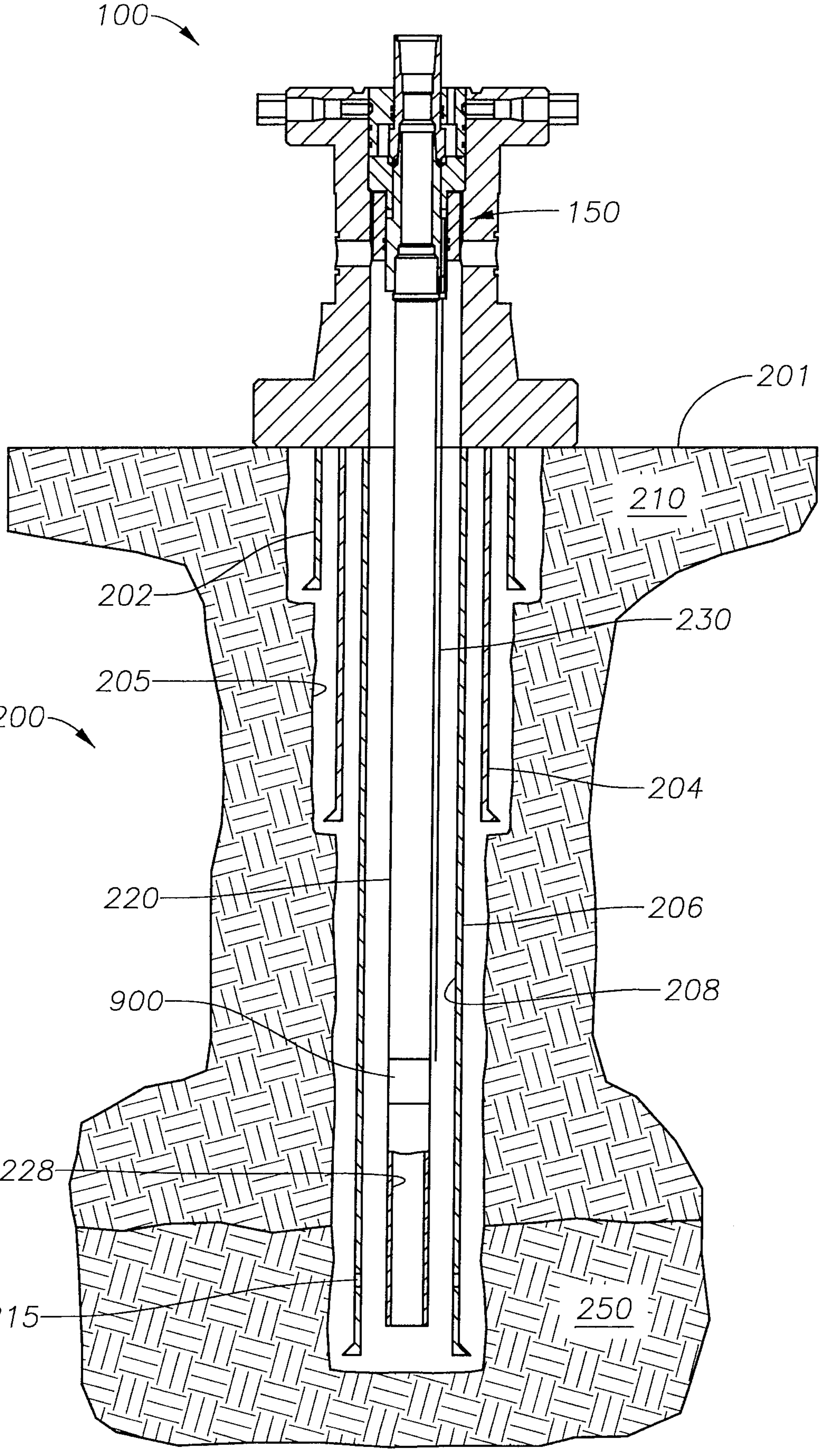


FIG. 2

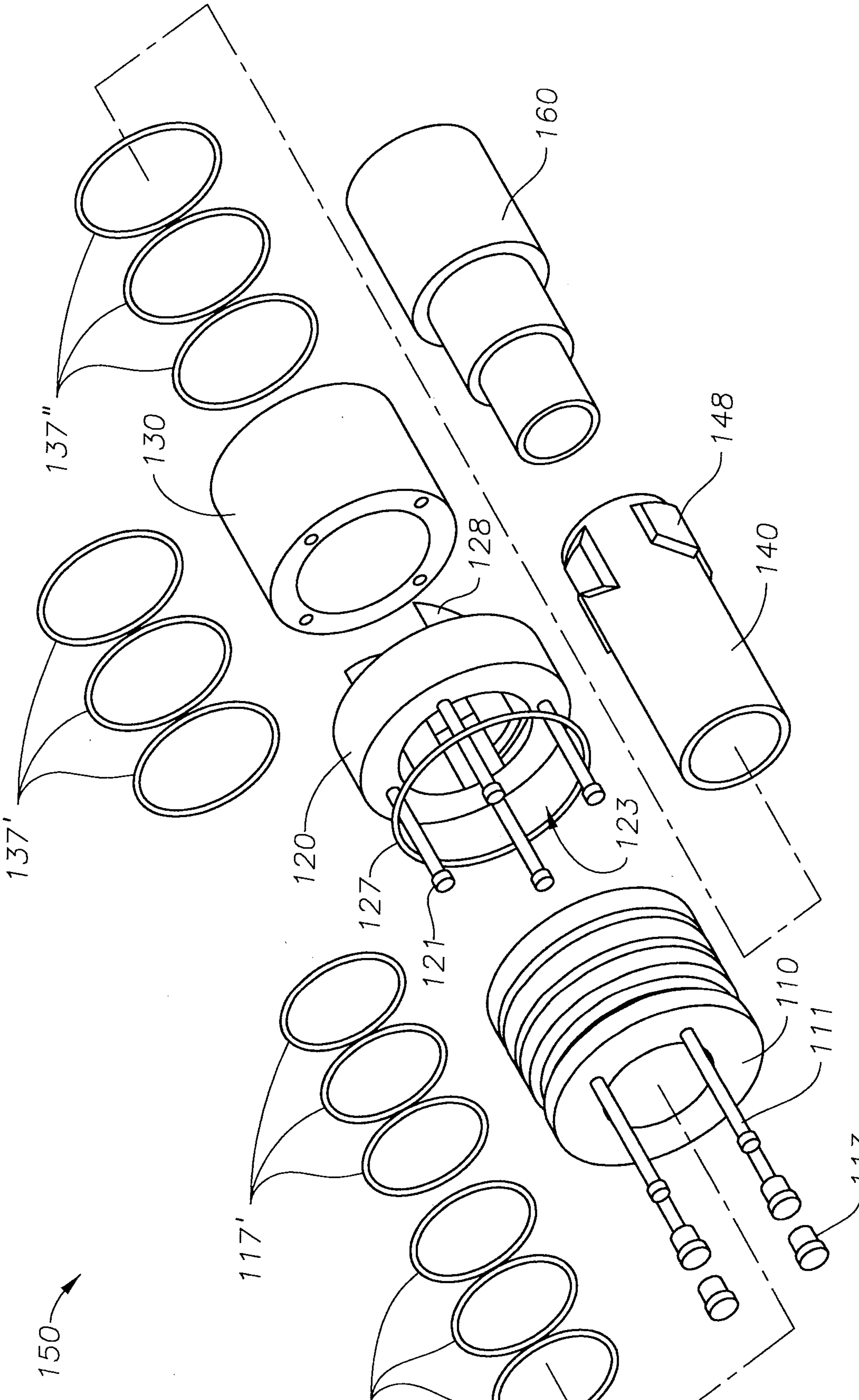

160
148
140
130
128
137"
137'
120
123
127
121
110
111
113
117'
117"
150

FIG. 3

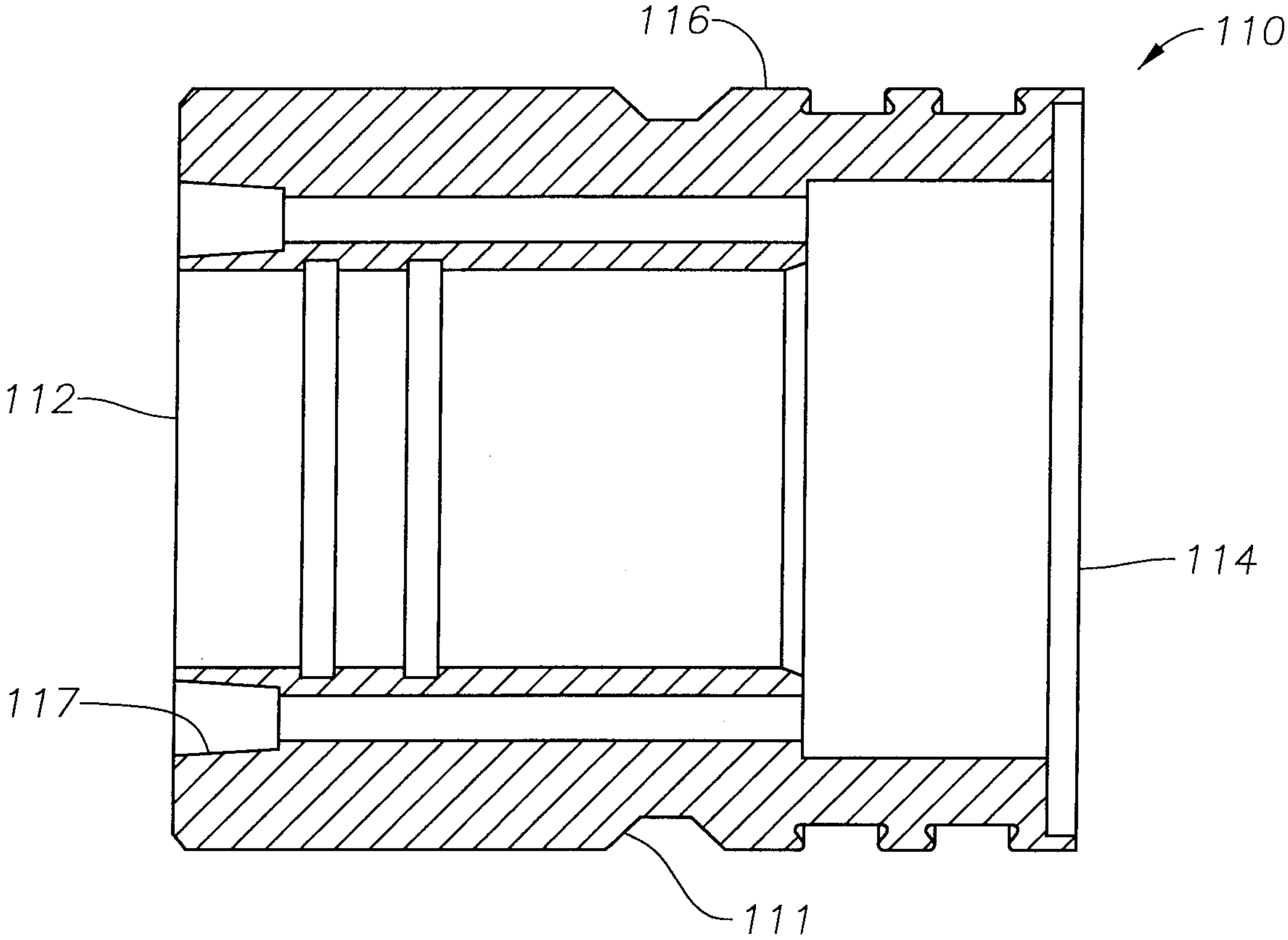


FIG. 4A

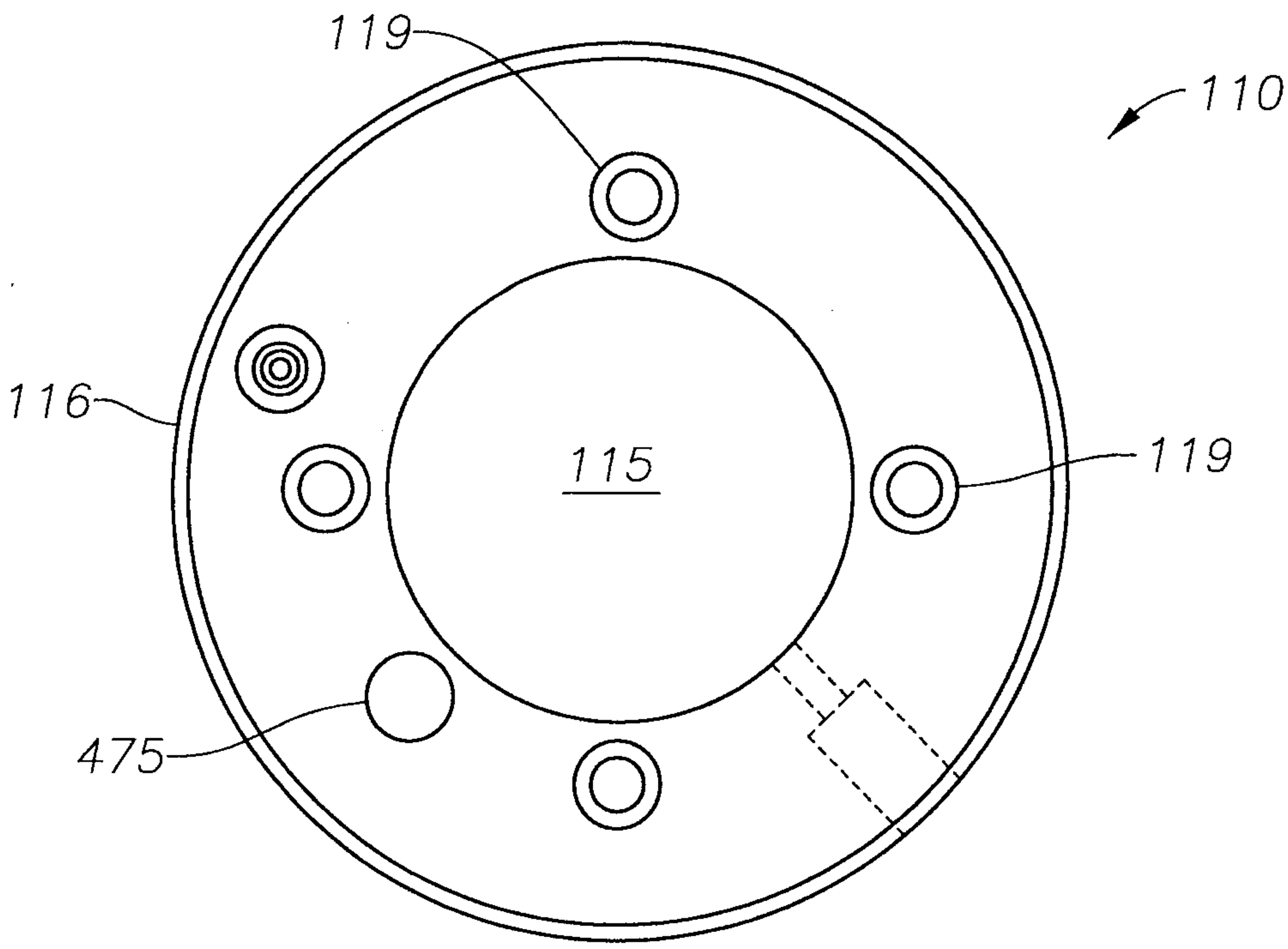


FIG. 4B

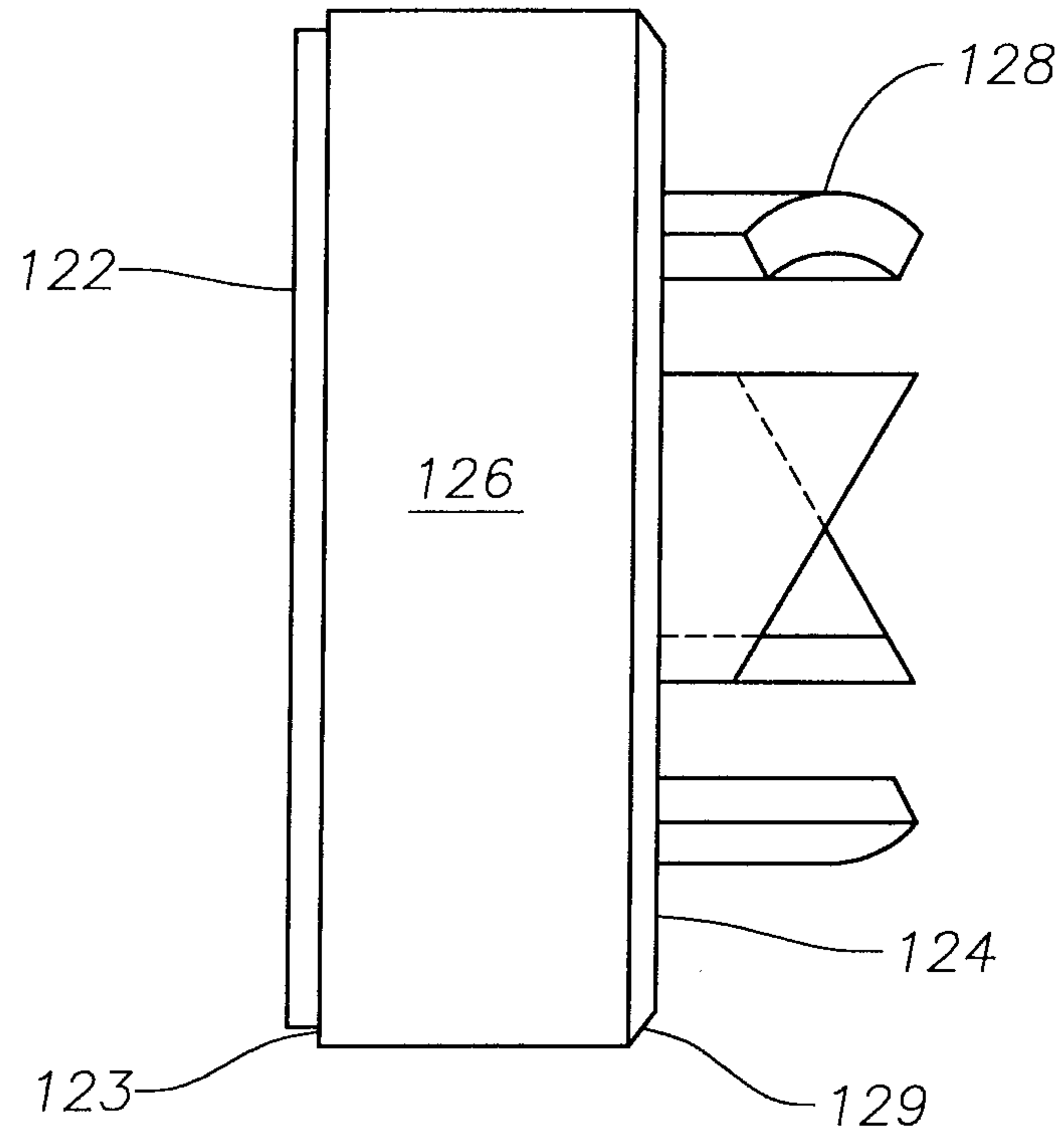


FIG. 5A

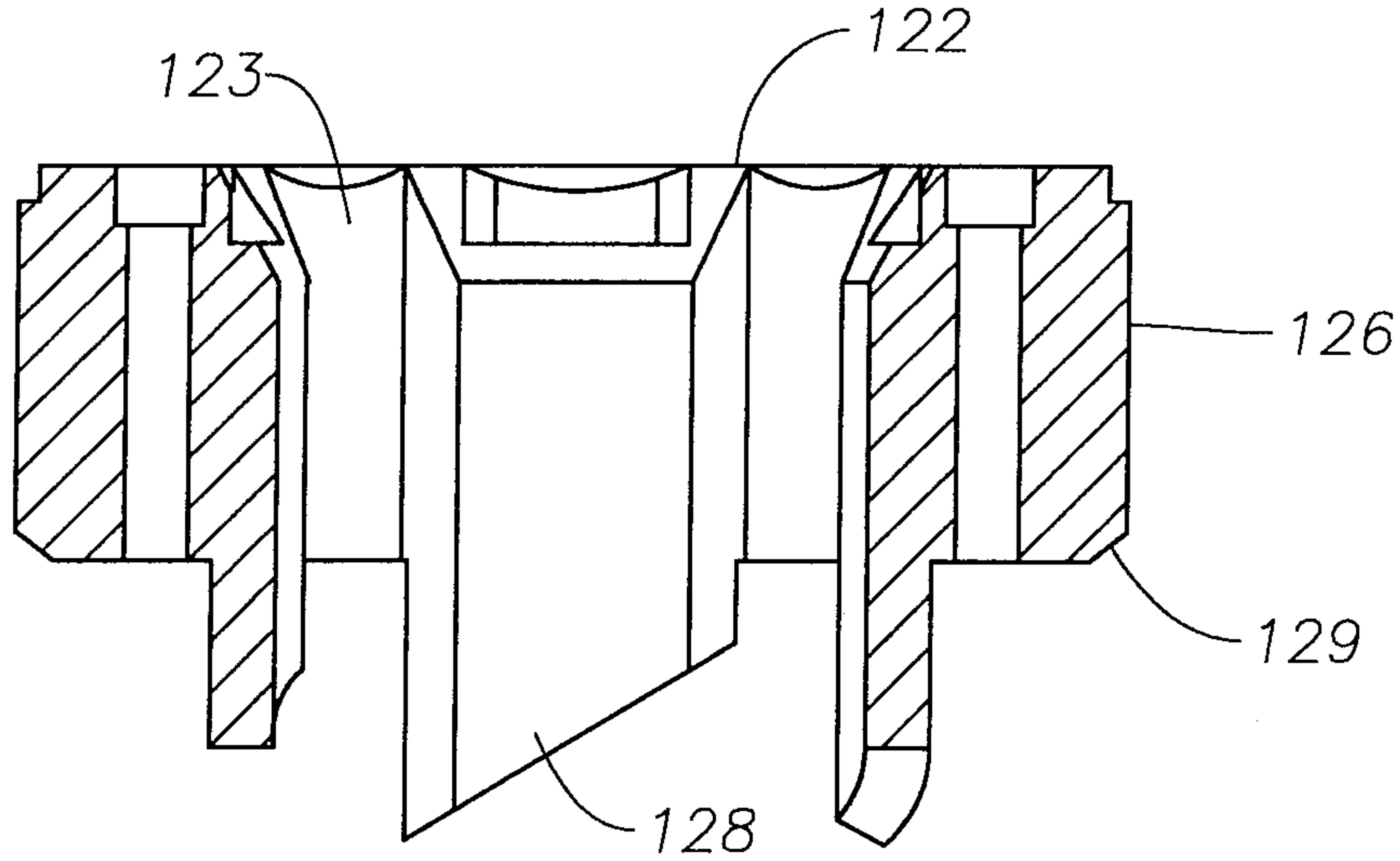


FIG. 5B

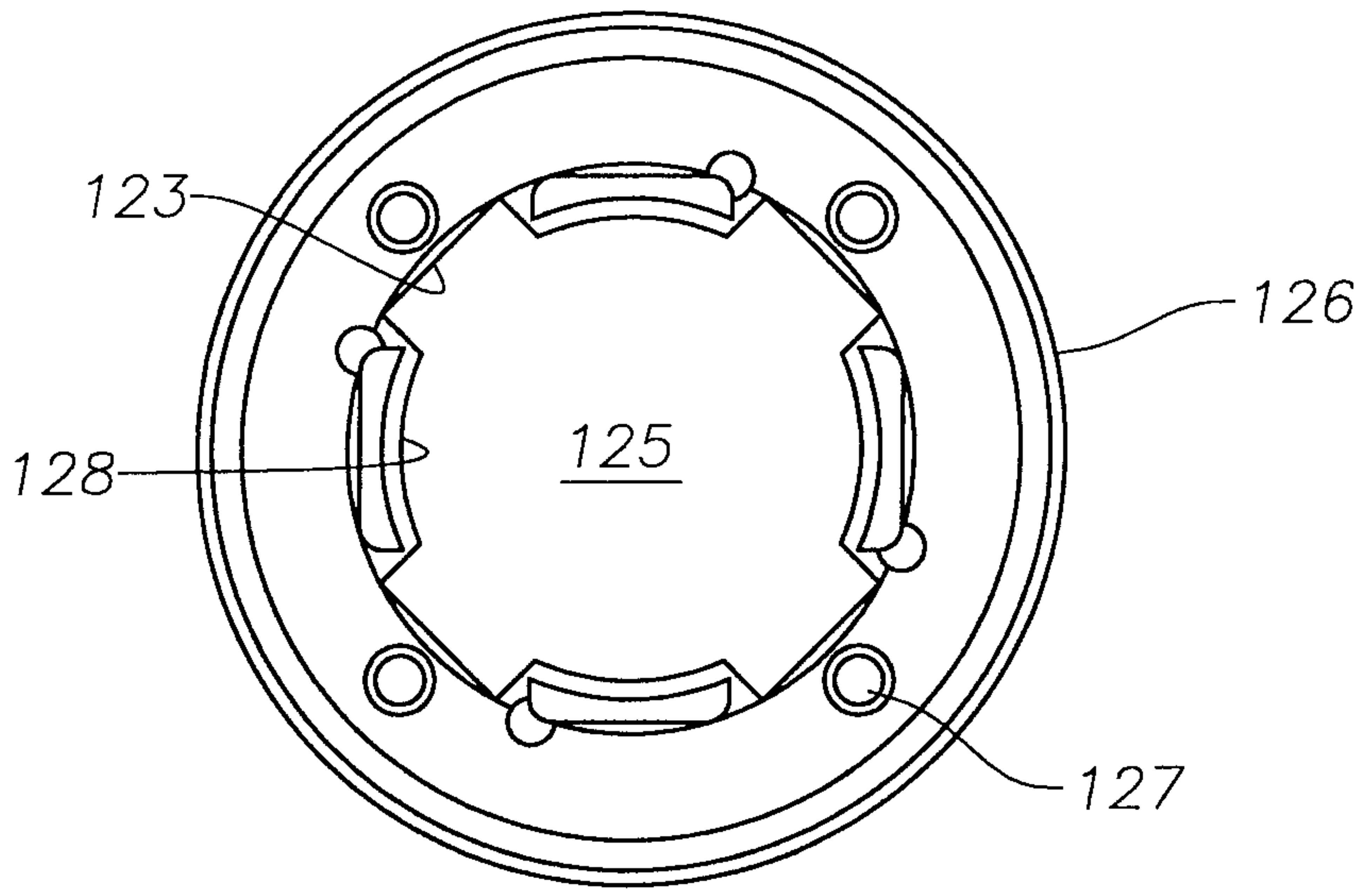


FIG. 5C

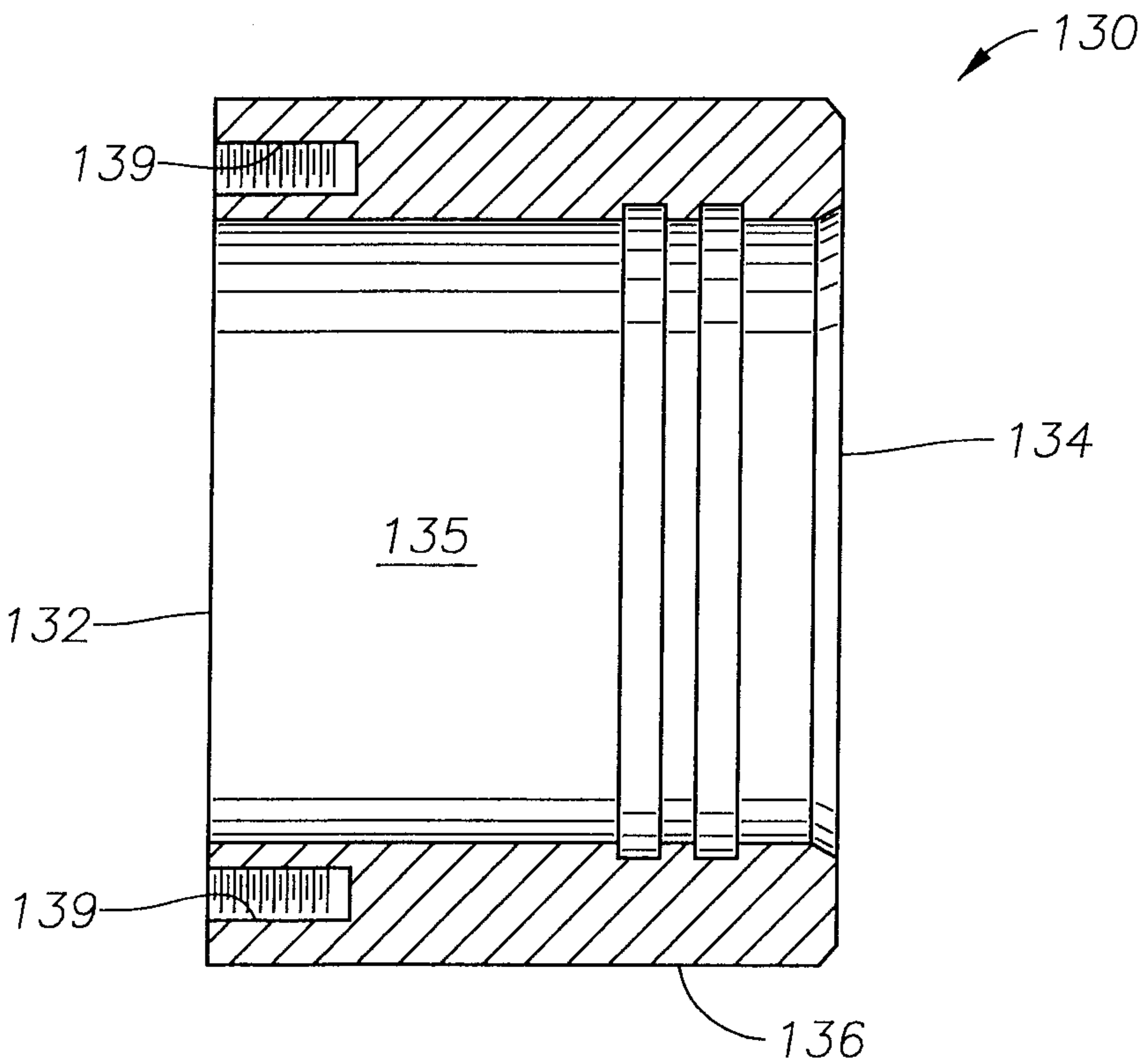


FIG. 6

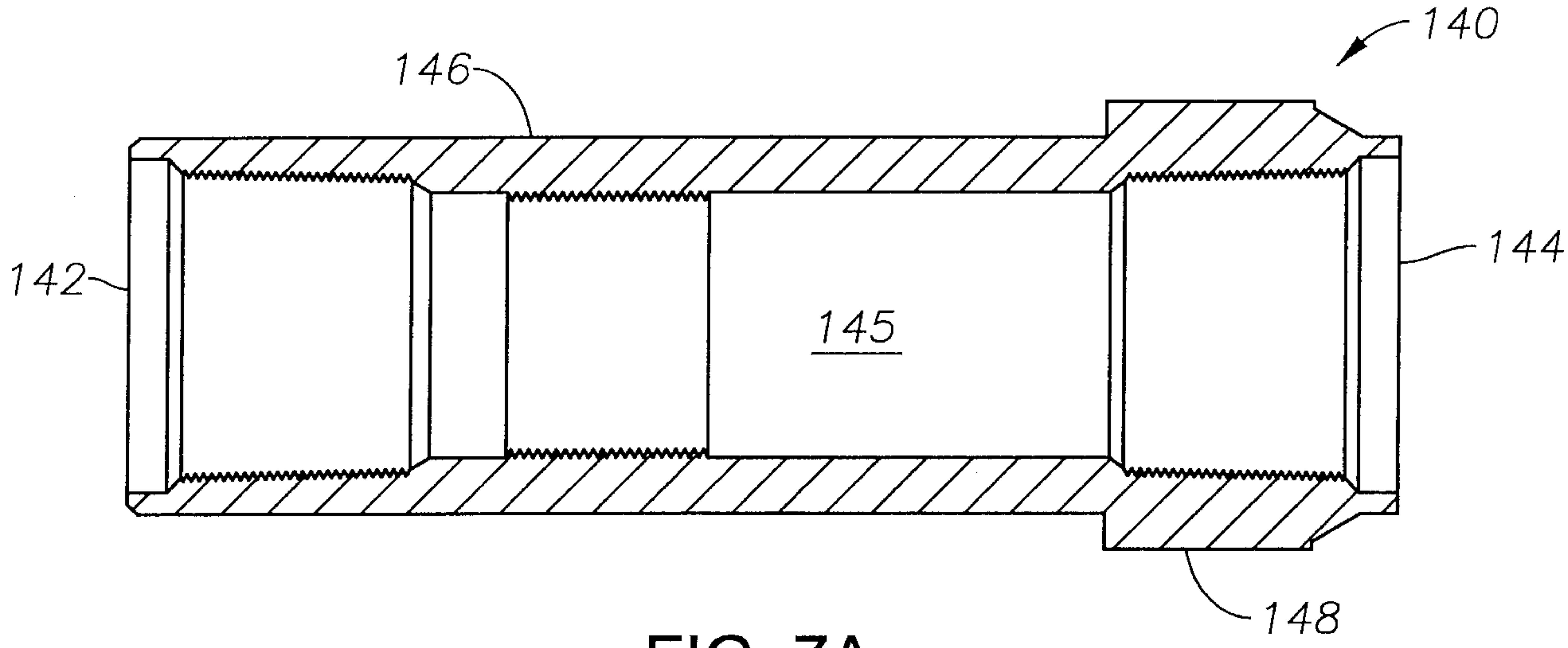


FIG. 7A

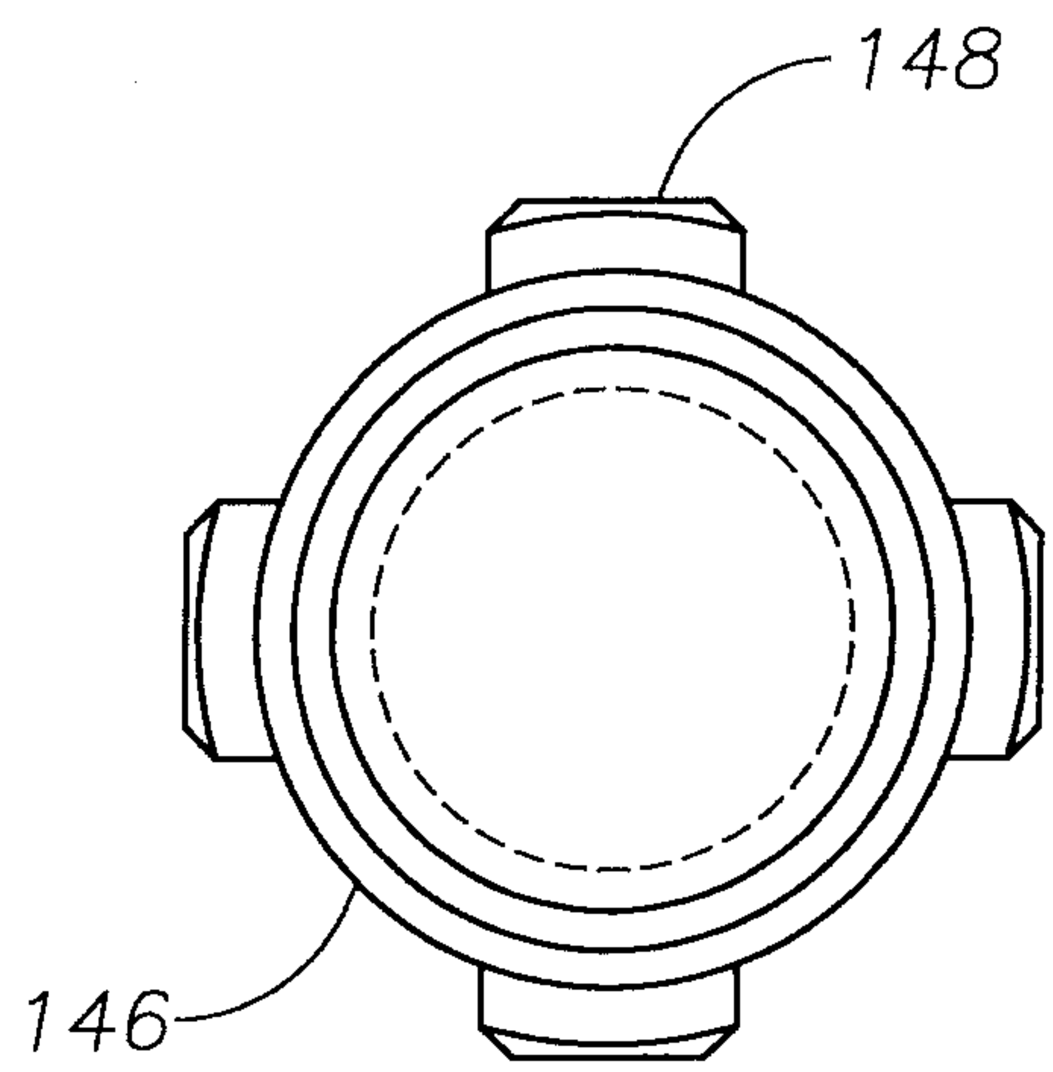


FIG. 7B

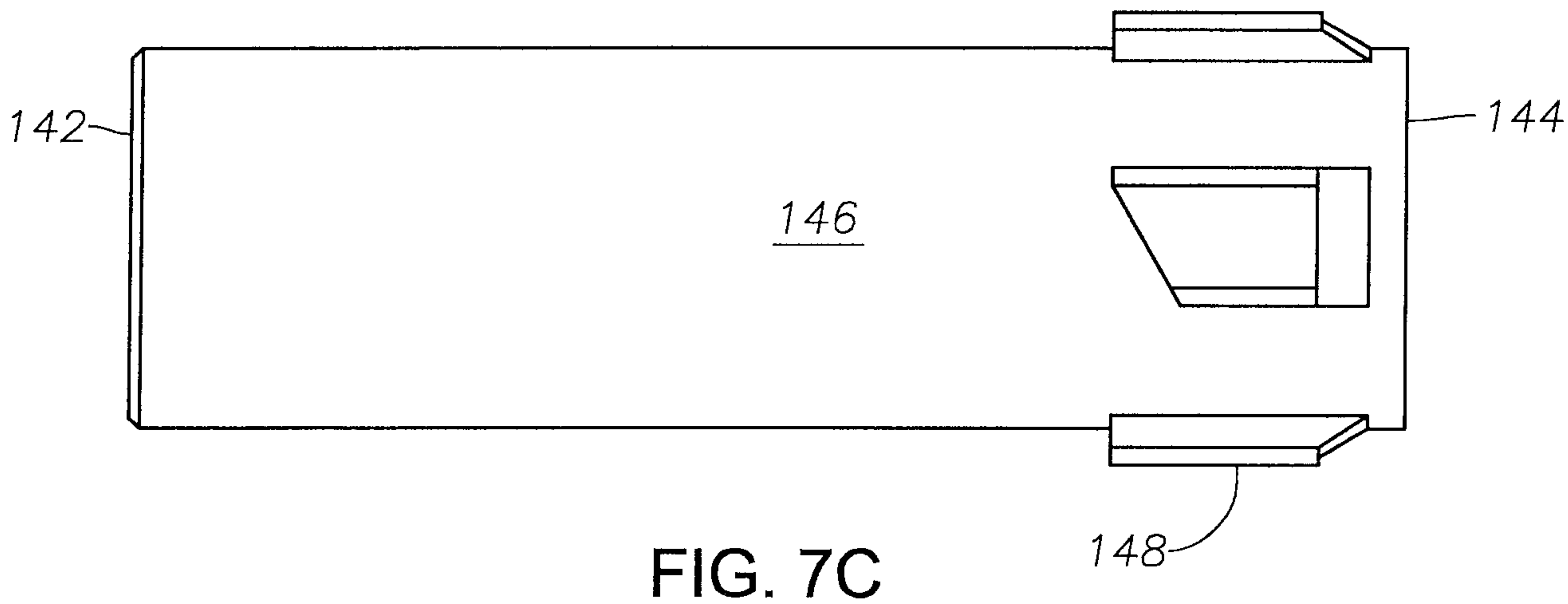


FIG. 7C

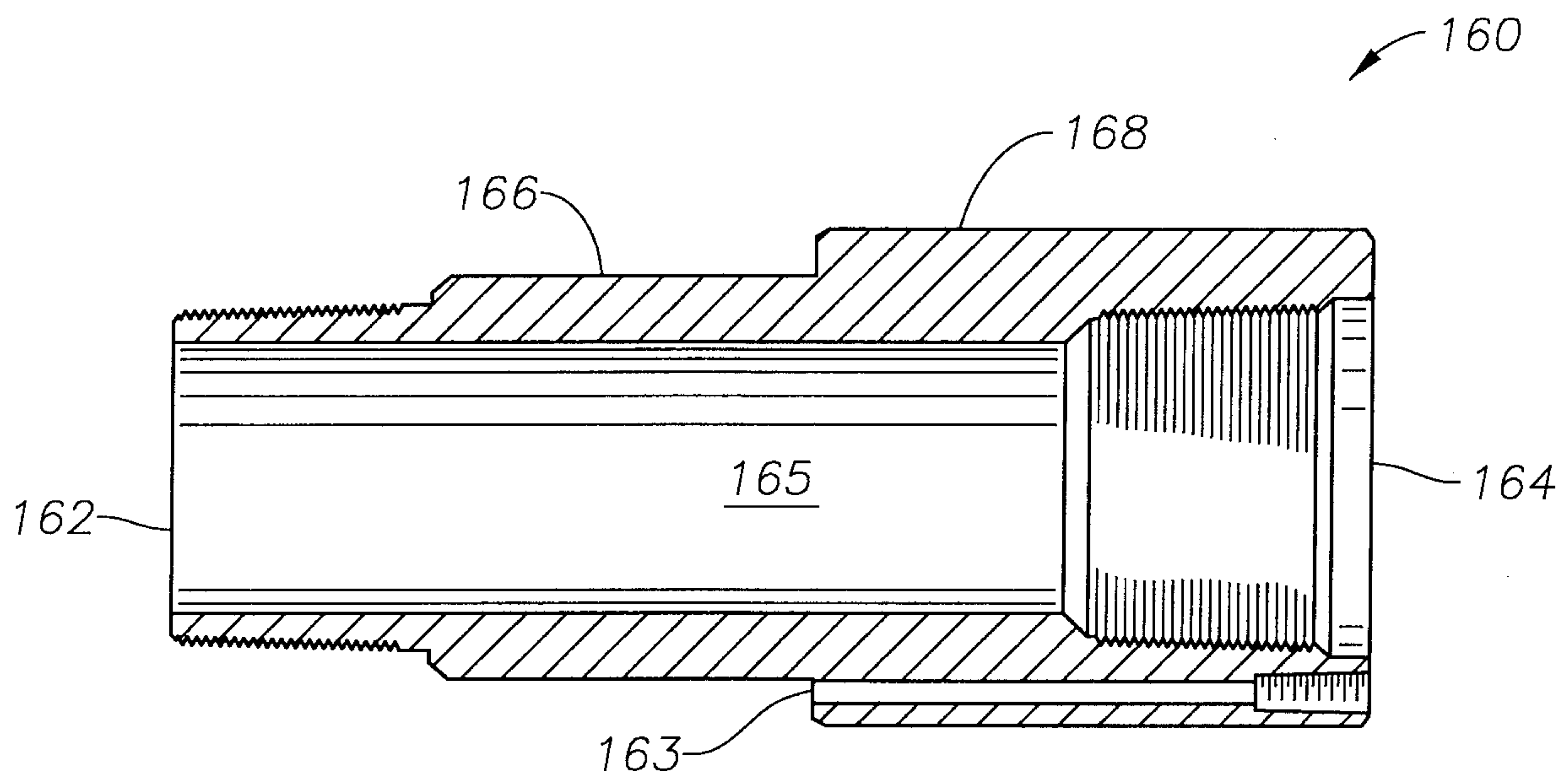


FIG. 8

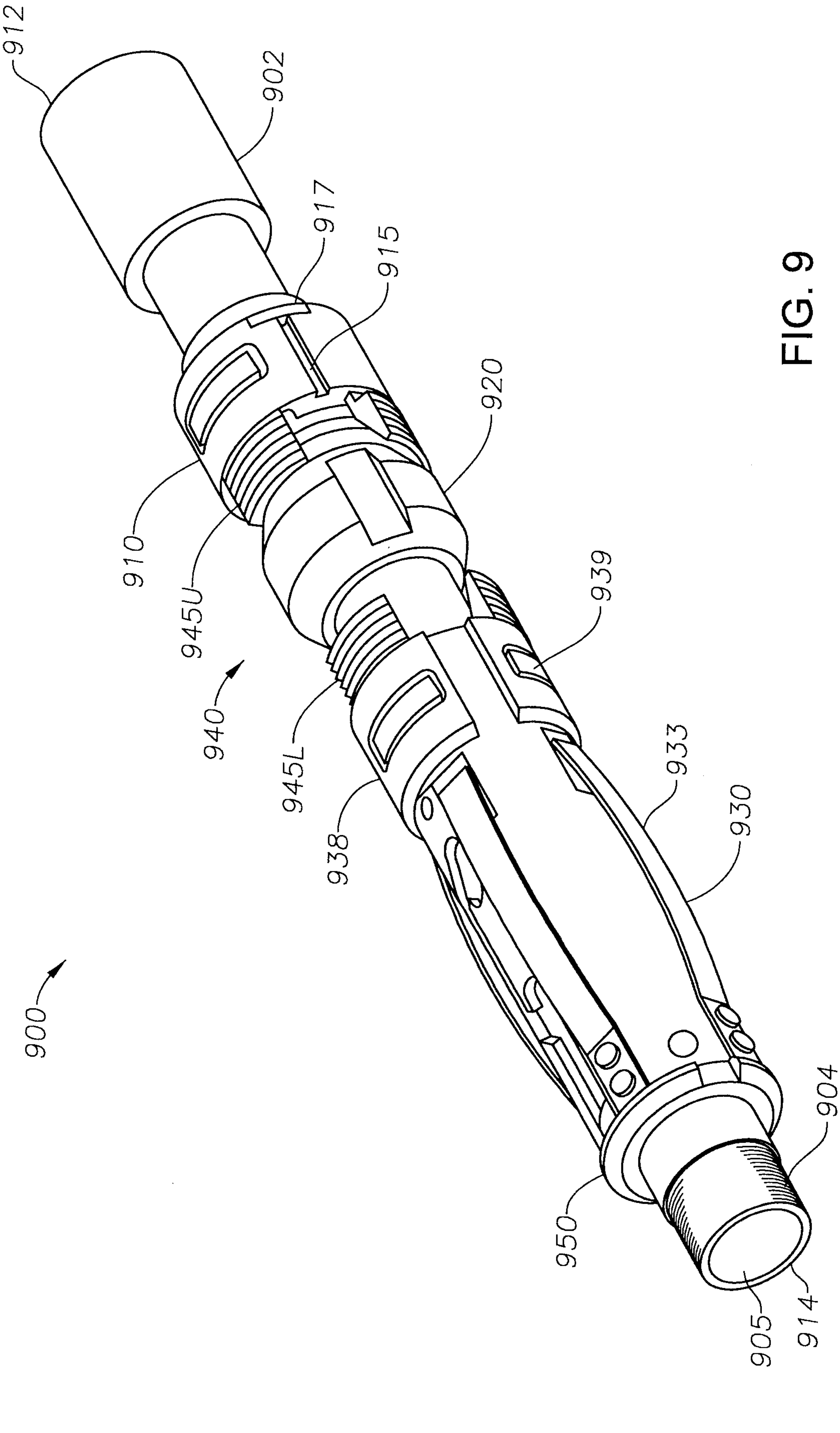

912
902
917
915
920
910
945U
939
940
945L
933
930
938
900
904
950
905
914

FIG. 9

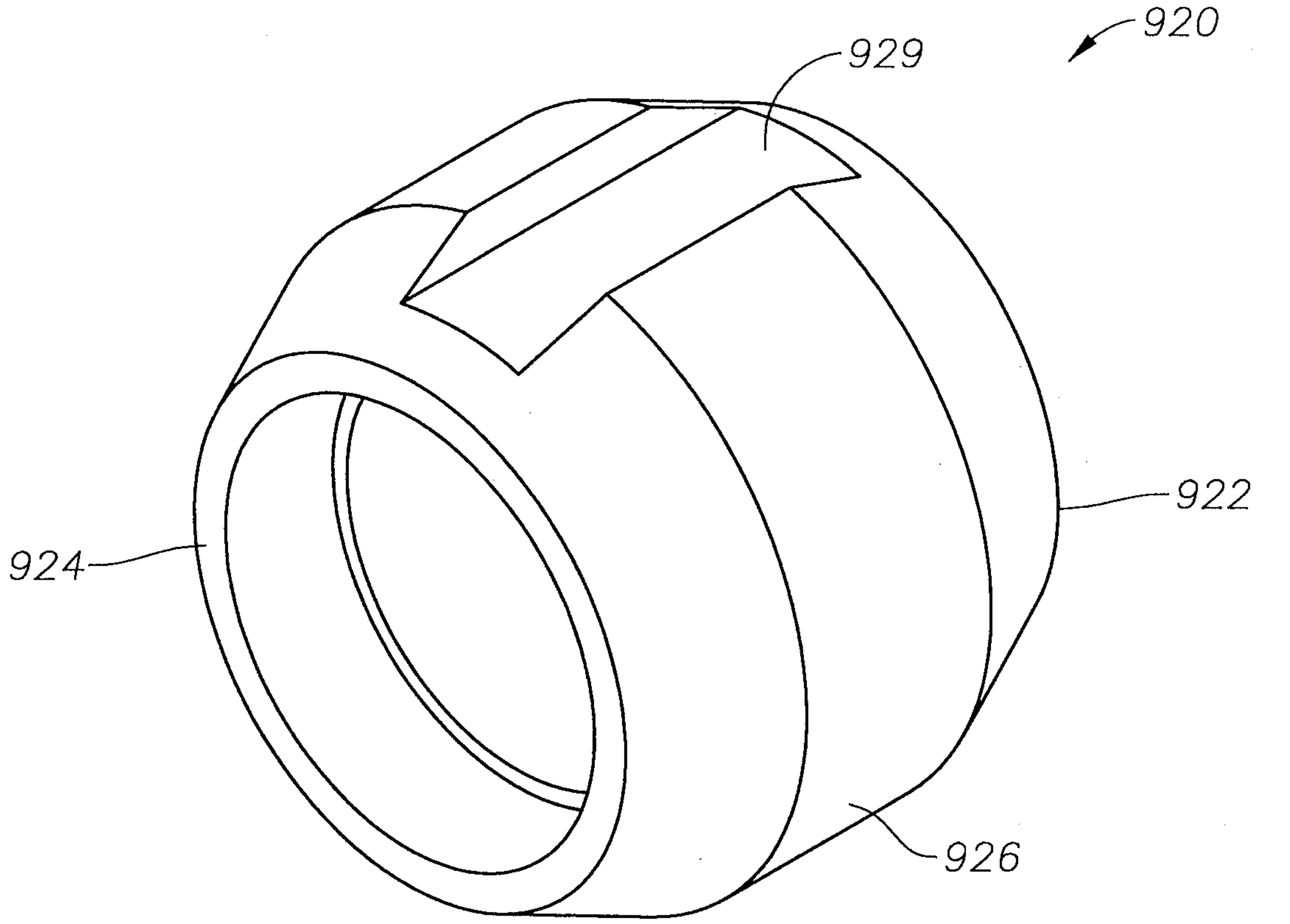


FIG. 10A

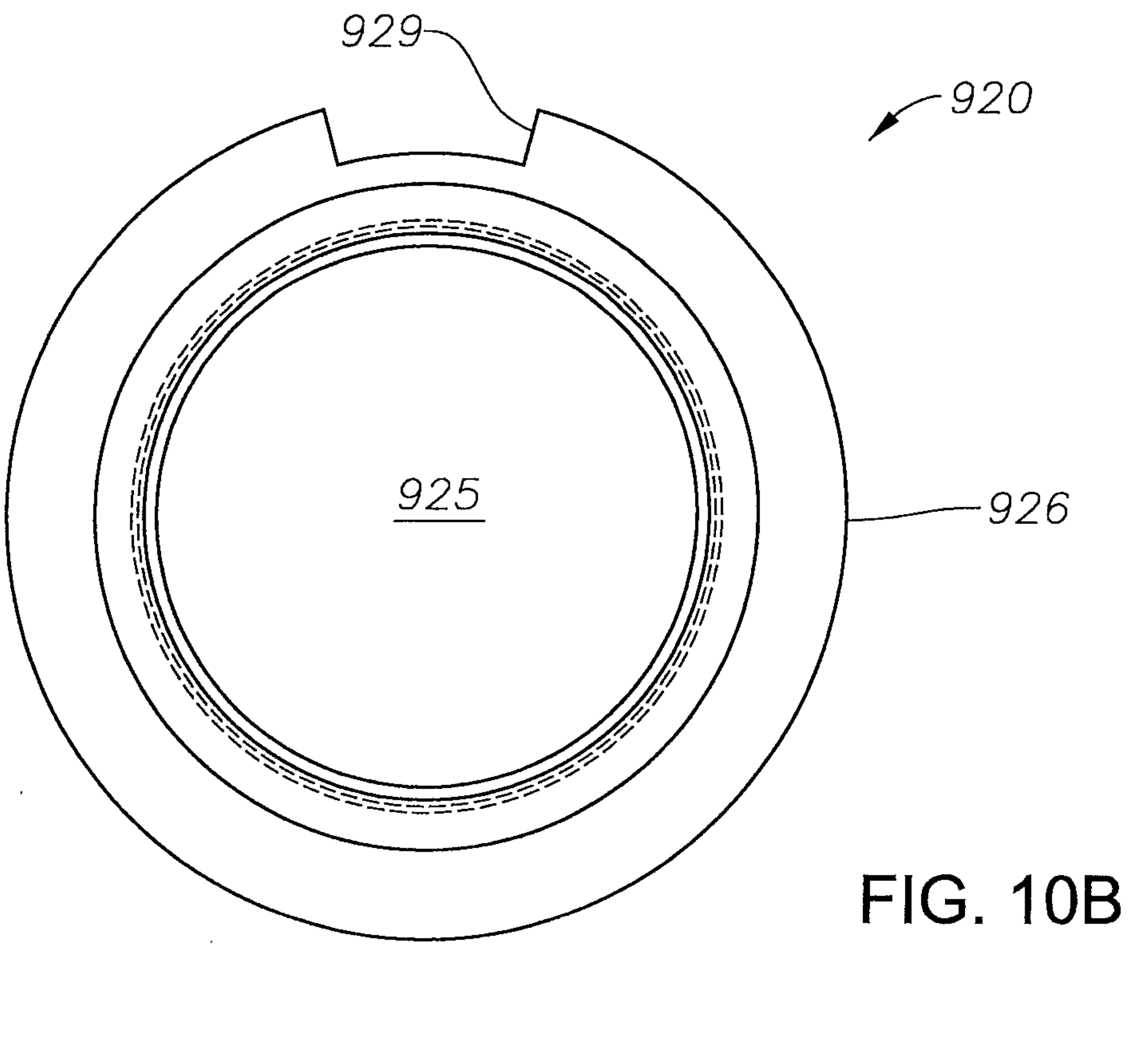


FIG. 10B

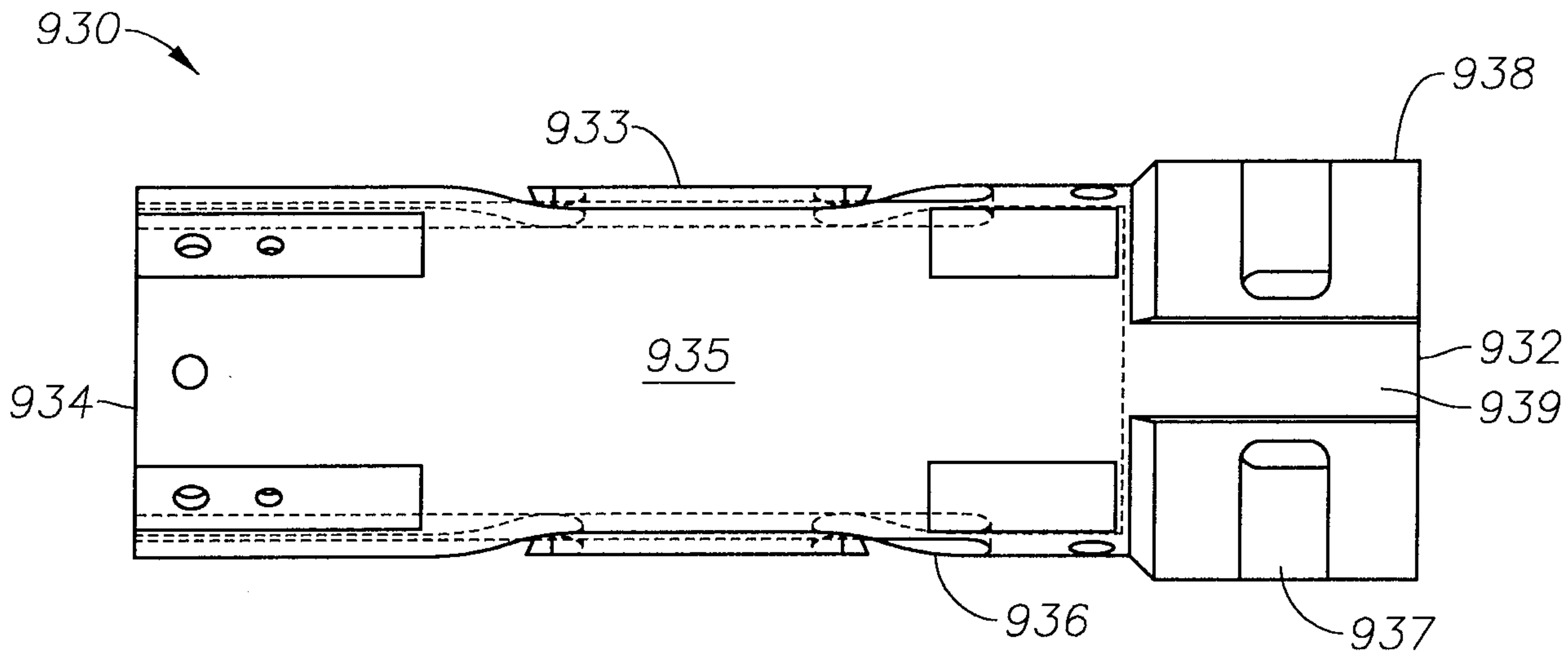


FIG. 11A

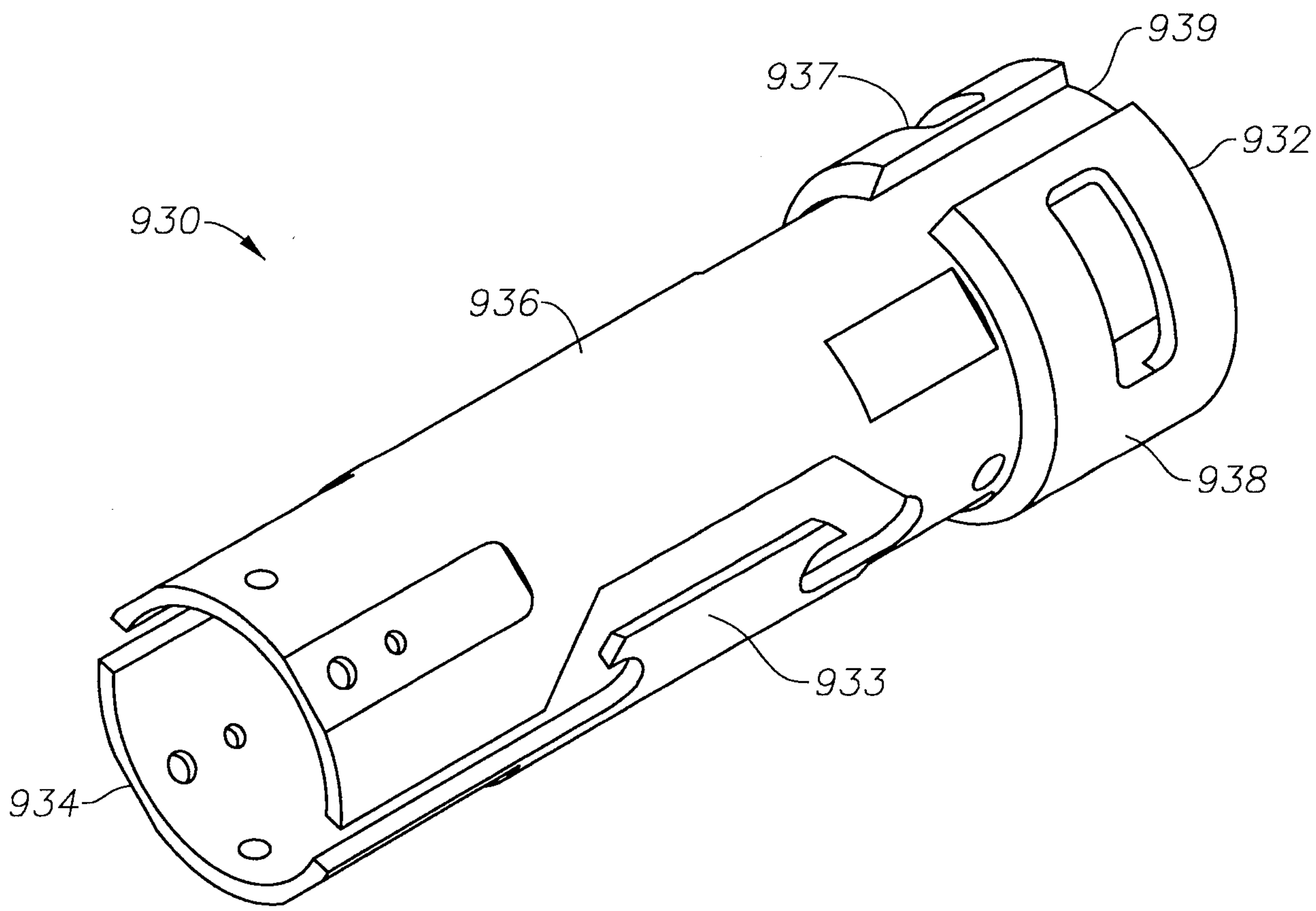


FIG. 11B

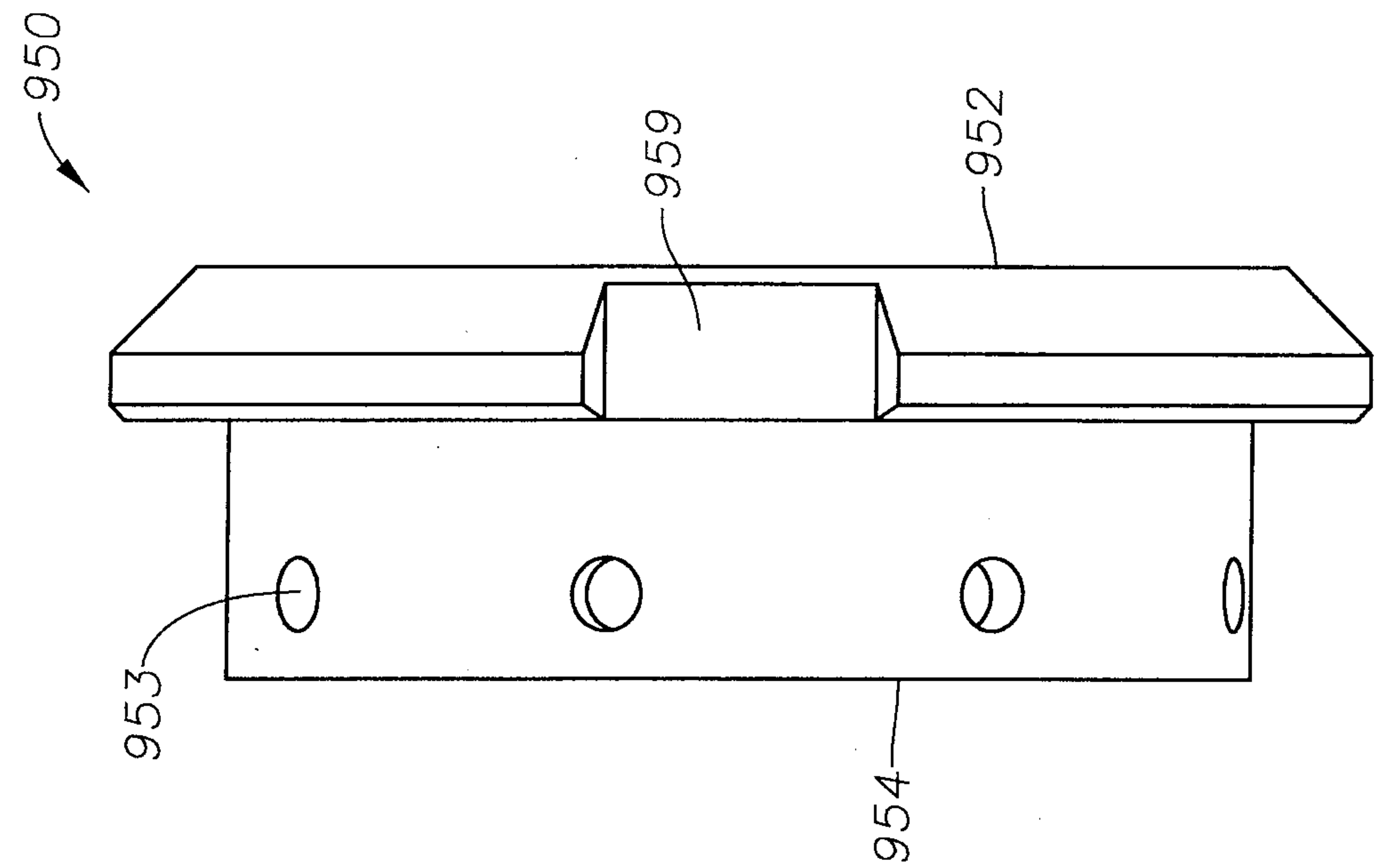


FIG. 12B

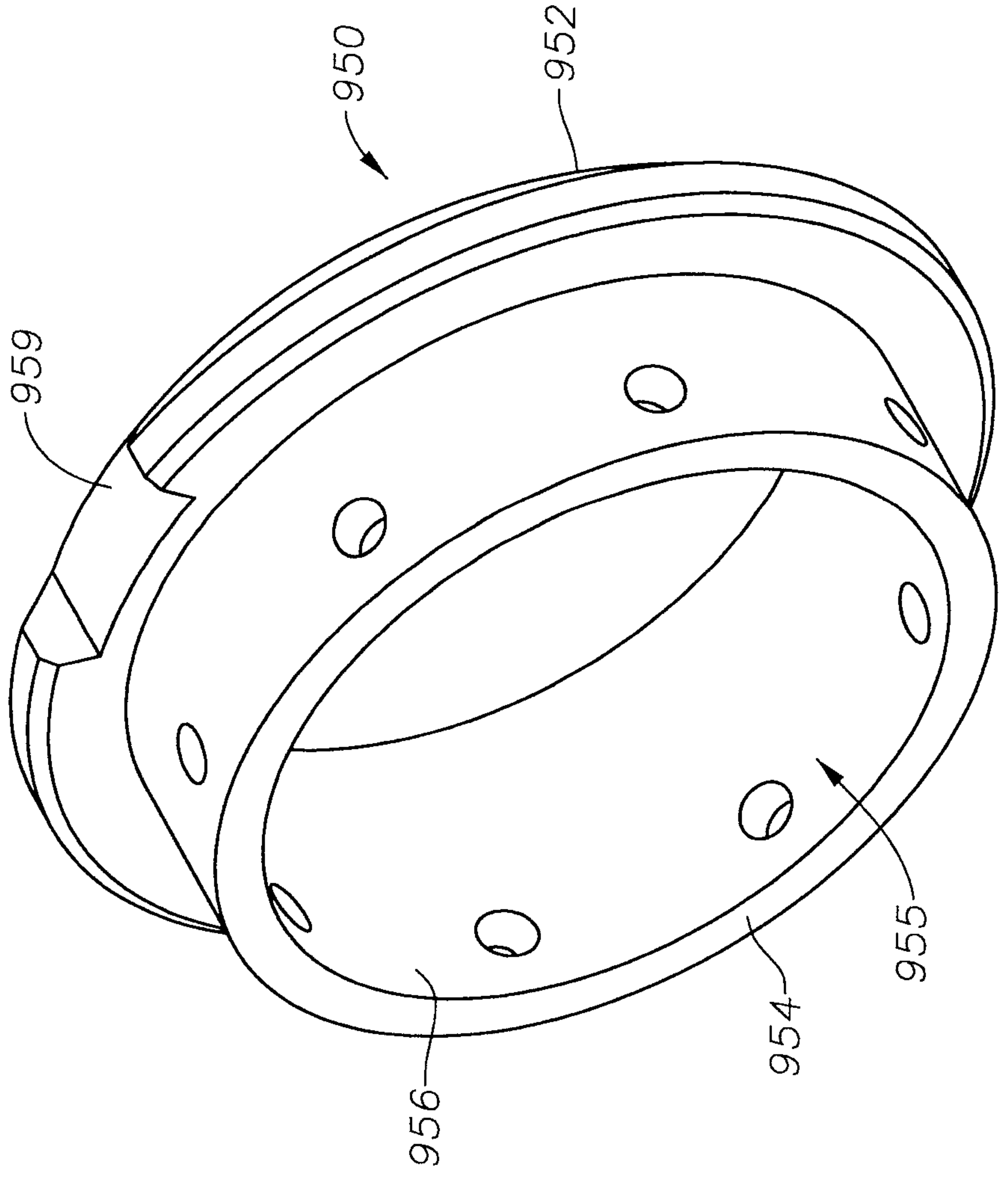


FIG. 12A

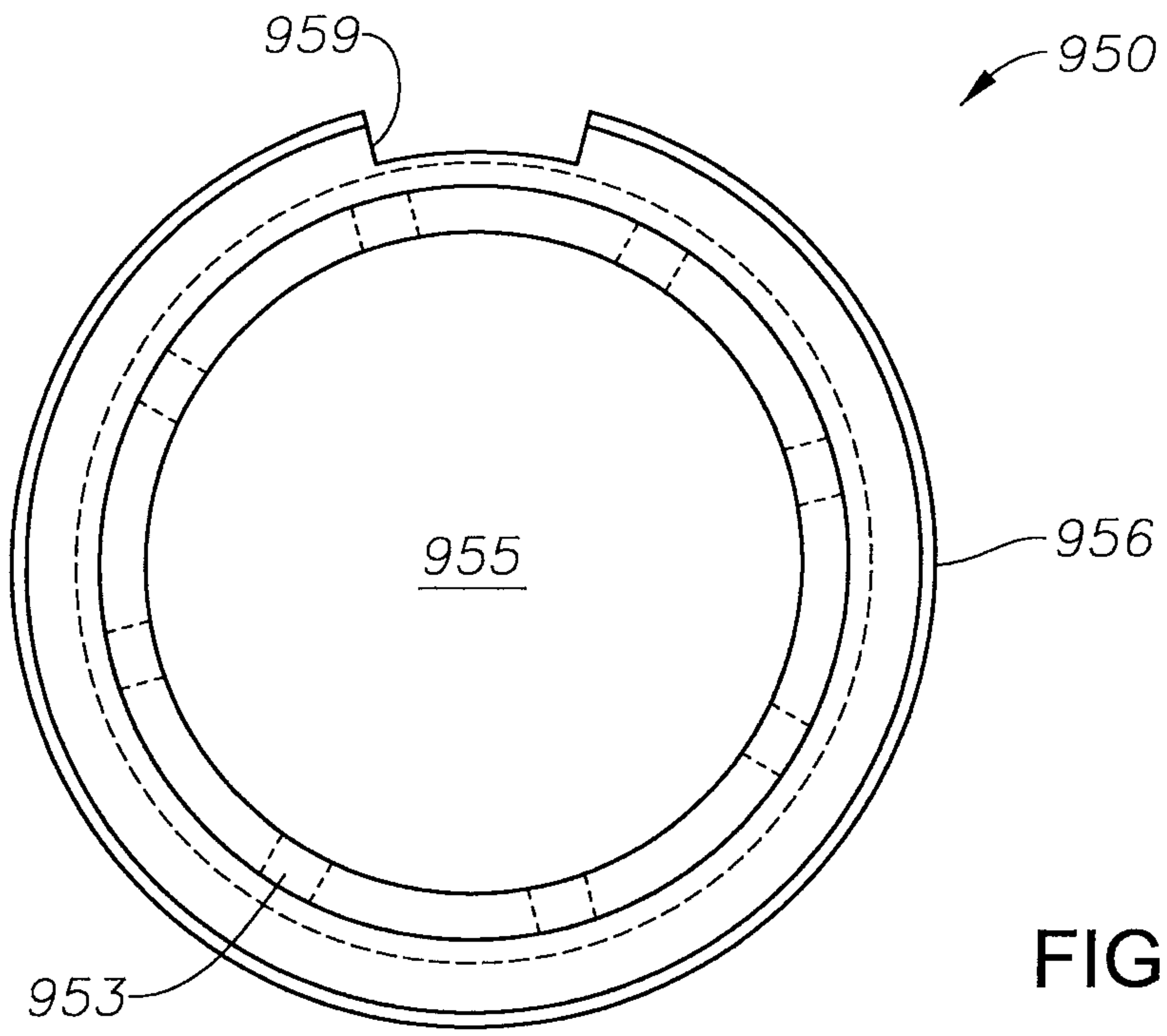


FIG. 12C

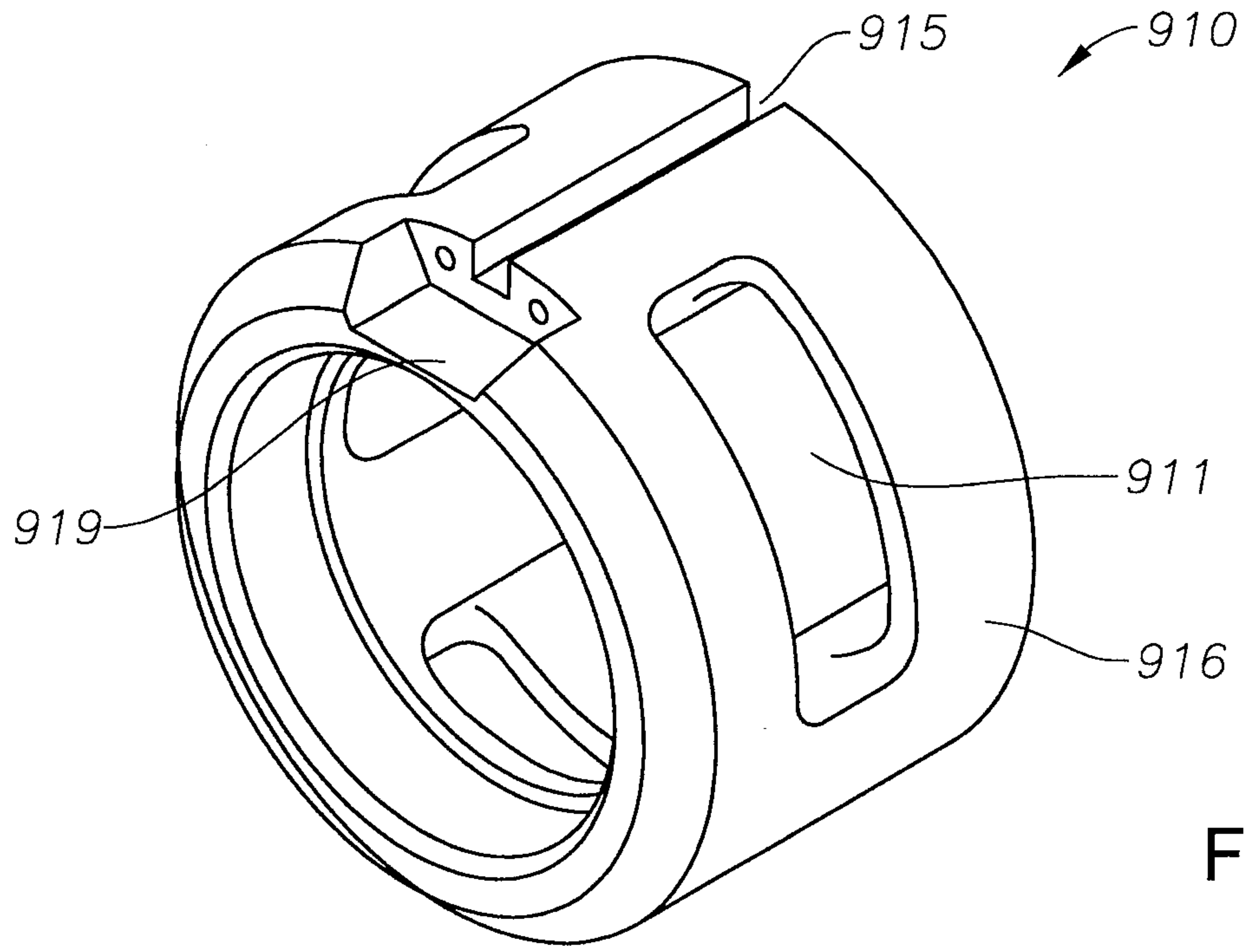
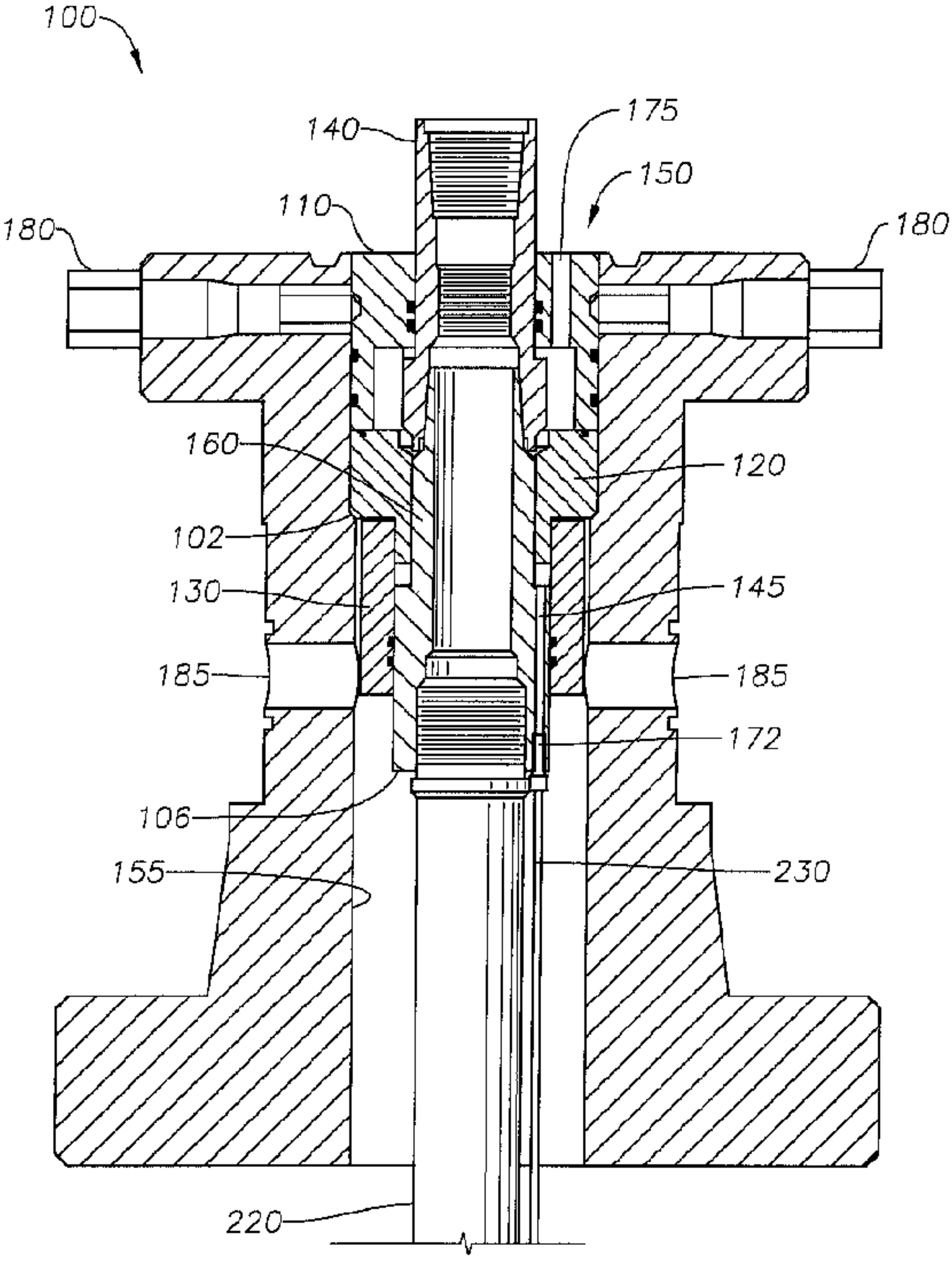


FIG. 13


100
140
175
150
110
180
180
160
120
102
130
145
185
185
172
106
155
230
220