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(56) Related Art
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ABSTRACT

A system and method provides a holding member for releasably positioning a rotating control head assembly in a subsea housing. The holding member engages an internal formation in the subsea housing to resist movement of the rotating control head assembly relative to the subsea housing. The rotating control head assembly is sealed with the subsea housing when the holding member engages the internal formation. An extendible portion of the holding member assembly extrudes an elastomer between an upper portion and a lower portion of the internal housing to seal the rotating control head assembly with the subsea housing. Pressure relief mechanisms release excess pressure in the subsea housing and a pressure compensation mechanism pressurize bearings in the bearing assembly at a predetermined pressure.

AUSTRALIA

Patents Act 1990

COMPLETE SPECIFICATION

STANDARD PATENT

Applicant(s):

WEATHERFORD/LAMB, INC.

Invention Title:

INTERNAL RISER ROTATING CONTROL HEAD

The following statement is a full description of this invention, including the best method of performing it known to me/us:

INTERNAL RISER ROTATING CONTROL HEAD

BACKGROUND OF THE INVENTION

1. Field of the Invention

[0001] The present invention relates to drilling subsea. In particular, the present invention relates to a holding member assembly for connection with a rotating control head.

2. Description of the Related Art

[0002] Marine risers extending from a wellhead fixed on the floor of an ocean have been used to circulate drilling fluid back to a structure or rig. The riser must be large enough in internal diameter to accommodate the largest bit and pipe that will be used in drilling a borehole into the floor of the ocean. Conventional risers now have internal diameters of $19^{1/2}$ inches, though other diameters can be used.

[0003] An example of a marine riser and some of the associated drilling components, such as shown in FIG. 1, is proposed in U.S. Pat. No. 4,626,135, assigned on its face to the Hydril Company, which is incorporated herein by reference for all purposes. Since the riser R is fixedly connected between a floating structure or rig S and the wellhead W, as proposed in the '135 Hydril patent, a conventional slip or telescopic joint SJ, comprising an outer barrel OB and an inner barrel IB with a pressure seal therebetween, is used to compensate for the relative vertical movement or heave between the floating rig and the fixed riser. A diverter D has been connected between the top inner barrel IB of the slip joint SJ and the floating structure or rig S to control gas accumulations in the marine riser R or low pressure formation gas from venting to the rig floor F. A ball joint BJ above the diverter D compensates for other relative movement (horizontal and rotational) or pitch and roll of the floating structure S and the fixed riser R.

[0004] The diverter D can use a rigid diverter line DL extending radially outwardly from the side of the diverter housing to communicate drilling fluid or mud from the riser R to a choke manifold CM, shale shaker SS or other drilling fluid receiving device. Above the diverter D is the rigid flowline RF, shown in FIG. 1, configured to communicate with the mud pit MP.

If the drilling fluid is open to atmospheric pressure at the bell-nipple in the rig floor F, the desired drilling fluid receiving device must be limited by an equal height or level on the structure S or, if desired, pumped by a pump to a higher level. While the shale shaker SS and mud pits MP are shown schematically in Figure 1, if a bell-nipple were at the rig floor F level and the mud return system was under minimal operating pressure, these fluid receiving devices may have to be located at a level below the rig floor F for proper operation. Since the choke manifold CM and separator MB are used when the well is circulated under pressure, they do not need to be below the bell nipple.

[0005] As also shown in Figure 1, a conventional flexible choke line CL has been configured to communicate with choke manifold CM. The drilling fluid then can flow from the choke manifold CM to a mud-gas buster or separator MB and a flare line (not shown). The drilling fluid can then be discharged to a shale shaker SS, and mud pits MP. In addition to a choke line CL and kill line KL, a booster line BL can be used.

[0006] In the past, when drilling in deepwater with a marine riser, the riser has not been pressurized by mechanical devices during normal operations. The only pressure induced by the rig operator and contained by the riser is that generated by the density of the drilling mud held in the riser (hydrostatic pressure). During some operations, gas can unintentionally enter the riser from the wellbore. If this happens, the gas will move up the riser and expand. As the gas expands, it will displace mud, and the riser will "unload". This unloading process can be quite violent and can pose a significant fire risk when gas reaches the surface of the floating structure via the bell-nipple at the rig floor F. As discussed above, the riser diverter D, as shown in Figure 1, is intended to convey this mud and gas away from the rig floor F when activated. However, diverters are not used during normal drilling operations and are generally only activated when indications of gas in the riser are observed. The '135 Hydril patent has proposed a gas handler annular blowout preventer GH, such as shown in Figure 1, to be installed in the riser R below the riser slip joint SJ. Like the conventional diverter D, the gas handler annular blowout preventer GH is activated only when needed, but instead of simply providing a safe flow path for mud and gas away from the rig floor F, the gas handler annular blowout provider GH can be used to hold limited pressure on the riser R and control the riser unloading process. An auxiliary choke line ACL is used to circulate mud from the riser R via the gas handler annular blowout preventer GH to a choke manifold CM on the rig.

[0007] Recently, the advantages of using underbalanced drilling, particularly in mature geological deepwater environments, have become known. Deepwater is considered to be between 3,000 to 7,500 feet deep and ultra deepwater is considered to be 7,500 to 10,000 feet deep. Rotating control heads, such as disclosed in U.S. Patent No. 5,662,181, have provided a dependable seal between a rotating pipe and the riser while drilling operations are being conducted. U.S. Patent No. 6,138,774, entitled "Method and Apparatus for Drilling a Borehole Into A Subsea Abnormal Pore Pressure Environment", proposes the use of a rotating control head for overbalanced drilling of a borehole through subsea geological formations. That is, the fluid pressure inside of the borehole is maintained equal to or greater than the pore pressure in the surrounding geological formations using a fluid that is of insufficient density to generate a borehole pressure greater than the surrounding geological formation's pore pressures without pressurization of the borehole fluid. U.S. Patent No. 6,263,982 proposes an underbalanced drilling concept of using a rotating control head to seal a marine riser while drilling in the floor of an ocean using a rotatable pipe from a floating structure. U.S. Patent Nos. 5,662,181; 6,138,774; and 6,263,982, which are assigned to the assignee of the present invention, are incorporated herein by reference for all purposes. Additionally, provisional application Serial No. 60/122,350, filed March 2, 1999, entitled "Concepts for the Application of Rotating Control Head Technology to Deepwater Drilling Operations" is incorporated herein by reference for all purposes.

[0008] It has also been known in the past to use a dual density mud system to control formations exposed in the open borehole. See Feasibility Study of a Dual Density Mud System For Deepwater Drilling Operations by Clovis A. Lopes and Adam T. Bourgoyne, Jr., © 1997 Offshore Technology Conference. As a high density mud is circulated from the ocean floor back to the rig, gas is proposed in this May of 1997 paper to be injected into the mud column at or near the ocean floor to lower the mud density. However, hydrostatic control of abnormal formation pressure is proposed to be maintained by a weighted mud system that is not gas-cut below the seafloor. Such a dual density mud system is proposed to reduce drilling costs by reducing the number of casing strings required to drill the well and by reducing the diameter requirements of the marine riser and subsea blowout preventers. This dual density mud system is similar to a mud nitrification system, where nitrogen is used to lower mud density, in that formation fluid is not necessarily produced during the drilling process.

[0009] U.S. Patent No. 4,813,495 proposes an alternative to the conventional drilling method and apparatus of Figure 1 by using a subsea rotating control head in conjunction with a subsea pump that returns the drilling fluid to a drilling vessel. Since the drilling fluid is returned to the drilling vessel, a fluid with additives may economically be used for continuous drilling operations. ('495 patent, col. 6, ln. 15 to col. 7, ln. 24) Therefore, the '495 patent moves the base line for measuring pressure gradient from the sea surface to the mudline of the sea floor ('495 patent, col. 1, lns. 31-34). This change in positioning of the base line removes the weight of the drilling fluid or hydrostatic pressure contained in a conventional riser from the formation. This objective is achieved by taking the fluid or mud returns at the mudline and pumping them to the surface rather than requiring the mud returns to be forced upward through the riser by the downward pressure of the mud column ('495 patent, col. 1, lns. 35-40).

[0010] U.S. Patent No. 4,836,289 proposes a method and apparatus for performing wire line operations in a well comprising a wire line lubricator assembly, which includes a centrally-bored tubular mandrel. A lower tubular extension is attached to the mandrel for extension into an annular blowout preventer. The annular blowout preventer is stated to remain open at all times during wire line operations, except for the testing of the lubricator assembly or upon encountering excessive well pressures. ('289 patent, col. 7, lns. 53-62) The lower end of the lower tubular extension is provided with an enlarged centralizing portion, the external diameter of which is greater than the external diameter of the lower tubular extension, but less than the internal diameter of the bore of the bell nipple flange member. The wireline operation system of the '289 patent does not teach, suggest or provide any motivation for use a rotating control head, much less teach, suggest, or provide any motivation for sealing an annular blowout preventer with the lower tubular extension while drilling.

[0011] In cases where reasonable amounts of gas and small amounts of oil and water are produced while drilling underbalanced for a small portion of the well, it would be desirable to use conventional rig equipment, as shown in Figure 1, in combination with a rotating control head, to control the pressure applied to the well while drilling. Therefore, a system and method for sealing with a subsea housing including, but not limited to, a blowout preventer while drilling in deepwater or ultra deepwater that would allow a quick rig-up and release using conventional pressure containment equipment would be desirable. In particular, a system that provides sealing of the riser at any predetermined location, or, alternatively, is capable of sealing the blowout preventer while rotating the pipe, where the seal could be relatively quickly installed, and quickly removed, would be desirable.

[0012] Conventional rotating control head assemblies have been sealed with a subsea housing using active sealing mechanisms in the subsea housing. Additionally, conventional rotating control head assemblies, such as proposed by U.S. Patent No. 6,230,824, assigned on its face to the Hydril Company, have used powered latching mechanisms in the subsea housing to position the rotating control head. A system and method that would eliminate the need for powered mechanisms in the subsea housing would be desirable because the subsea housing can remain bolted in place in the marine riser for many months, allowing moving parts in the subsea housing to corrode or be damaged.

[0013] Additionally, the use of a rotating control head assembly in a dual-density drilling operation can incur problems caused by excess pressure in either one of the two fluids. The ability to relieve excess pressure in either fluid would provide safety and environmental improvements. For example, if a return line to a subsea mud pump plugs while mud is being pumped into the borehole, an overpressure situation could cause a blowout of the borehole. Because dual-density drilling can involve varying pressure differentials, an adjustable overpressure relief technique has been desired.

[0014] Another problem with conventional drilling techniques is that moving of a rotating control head within the marine riser by tripping in hold (TIH) or pulling out of hole (POOH) can cause undesirable surging or swabbing effects, respectively, within the well. Further, in the case of problems within the well, a desirable mechanism should provide a "fail safe" feature to allow removal the rotating control head upon application of a predetermined force.

BRIEF SUMMARY OF THE INVENTION

[0014A] In accordance with the invention, there is provided a holding member assembly adapted for connection with a bearing assembly of a rotating control head, comprising: an internal housing, comprising: a holding member chamber; and a holding member positioned within the holding member chamber, the holding member movable between an extended position and a retracted position; and an extendible portion, concentrically interior to and slidably connectable to the internal housing.

[0014B] Preferred embodiments are suitable for use systems and methods for sealingly positioning a rotating control head in a subsea housing.

[0015] A system and method are disclosed for drilling in the floor of an ocean using a rotatable pipe. The system uses a rotating control head with a bearing assembly and a holding member for removably positioning the bearing assembly in a subsea housing. The bearing assembly is sealed with the subsea housing by a seal, providing a barrier between two different fluid densities. The holding member resists movement of the bearing assembly relative to the subsea housing. The bearing assembly can be connected with the subsea housing above or below the seal.

[0016] In one embodiment, the holding member rotationally engages and disengages a passive internal formation of the subsea housing. In another embodiment, the holding member engages the internal formation without regard to the rotational position of the holding member. The holding member is configured to release at predetermined force.

[0017] In one embodiment, a pressure relief assembly allows relieving excess pressure within the borehole. In a further embodiment, a pressure relief assembly allows relieving excess pressure within the subsea housing outside the holding member assembly above the seal.

[0018] In one embodiment, the internal formation is disposed between two spaced apart side openings in the subsea housing.

[0019] In one embodiment, a holding member assembly provides an internal housing concentric with an extendible portion. When the extendible portion extends, an upper portion of the internal housing moves toward a lower portion of the internal housing to extrude an elastomer disposed between the upper and lower portions to seal the holding member assembly with the subsea housing. The extendible portion is dogged to the upper portion or the lower portion of the internal housing depending on the position of the extendible portion.

[0020] In one embodiment, a running tool is used for moving the rotating control head assembly with the subsea housing and is also used to remotely engage the holding member with the subsea housing.

[0021] In one embodiment, a pressure compensation assembly pressurizes lubricants in the bearing assembly at a predetermined pressure amount in excess of the higher of the subsea housing pressure above the seal or below the seal.

BRIEF DESCRIPTION OF THE SEVERAL VIEWS OF THE DRAWINGS

[0022] A better understanding of the present invention can be obtained when the following detailed description of the disclosed embodiments is considered in conjunction with the following drawings, in which:

Figure 1 is an elevation view of a prior art floating rig mud return system, shown in broken view, with the lower portion illustrating the conventional subsea blowout preventer stack attached to a wellhead and the upper portion illustrating the conventional floating rig, where a riser having a conventional blowout preventer is connected to the floating rig;

Figure 2 is an elevation view of a blowout preventer in a sealed position to position an internal housing and bearing assembly of the present invention in the riser;

Figure 3 is a section view taken along line 3-3 of Figure 2;

Figure 4 is an enlarged elevation view of a blowout preventer stack positioned above a wellhead, similar to the lower portion of Figure 1, but with an internal housing and bearing assembly positioned in a blowout preventer communicating with the top of the blowout preventer stack and a rotatable pipe extending through the bearing assembly and internal housing of the present invention and into an open borehole;

Figure 5 is an elevation view of an embodiment of the internal housing;

Figure 6 is an elevation view of the embodiment of the step down internal housing of Figure 4;

Figure 7 is an enlarged section view of the bearing assembly of Figure 4 illustrating a typical lug on the outer member of the bearing assembly and a typical lug on the internal housing engaging a shoulder of the riser;

Figure 8 is an enlarged detail section view of the holding member of Figures 4 and 6;

Figure 9 is section view taken along line 9-9 of Figure 8;

Figure 10 is a reverse view of a portion of Figure 2;

Figure 11 is an elevation view of one embodiment of a system for positioning a rotating control head in a marine riser with a running tool attached to a holding member assembly;

Figure 12 is an elevation view of the embodiment of Figure 11, showing the running tool extending below the holding member assembly after latching an internal housing with a subsea housing;

Figure 13 is a section view taken along line 13-13 of Figure 11;

Figure 14 is an enlarged elevation view of a lower stripper rubber of the rotating control head in a "burping" position;

Figure 15 is an enlarged elevation view of a pressure relief assembly of the embodiment of Figure 11 in an open position;

Figure 16 is a section view taken along line 16-16 of Figure 15;

Figure 17 is an elevation view of the pressure relief assembly of Figure 15 in a closed position;

Figure 18 is an elevation view of another embodiment of the pressure relief assembly in the closed position;

Figure 19 is a detail elevation view of the subsea housing of Figures 11, 12, and 15-18 showing a passive latching formation of the subsea housing for engaging with the passive latching member of the internal housing;

Figure 20A is an elevation view of an upper section of another embodiment of a system for positioning a rotating control head in a marine riser showing a bi-directional pressure relief assembly in a closed position and an upper dog member in an engaged position;

Figure 20B is an elevation view of a lower section of the embodiment of Figure 20A, showing a running tool for positioning the rotating control head and showing the holding member of the internal housing and a latching profile in the subsea housing, with a lower dog member in a disengaged position;

Figure 21A is an elevation view of an upper section of the embodiment of Figure 20 showing a lower stripper rubber of the rotating control head spread by a spreader member of the running tool and showing the pressure relief assembly of Figure 20A in a first open position;

Figure 21B is an elevation view of a lower section of the embodiment of Figure 21A showing the holding member assembly in an engaged position;

Figure 22A is an elevation view of an upper section of the embodiment of Figures 20 and 21 with the bi-directional pressure relief assembly in a second open position, an elastomer member sealing the holding member assembly with the subsea housing, an extendible portion of the holding member assembly extended in a first position, and an upper dog member in a disengaged position;

Figure 22B is an elevation view of a lower section of the embodiment of Figure 22A, with the extendible portion of the holding member assembly engaged with the subsea housing;

Figure 23A is an elevation view of the upper section of the embodiment of Figures 20, 21 and 22 showing an upper portion of the bi-directional pressure relief assembly in a closed position and the running tool extended further downwardly;

Figure 23B is an elevation view of the lower section of the embodiment of Figure 23A with the lower dog member in an engaged position and the running tool disengaged from the extendible member of the internal housing for moving toward the borehole;

Figure 24 is an enlarged elevation view of the bi-directional pressure relief assembly taken along line 24-24 of Figure 21A;

Figure 25 is a section view taken along line 25-25 of Figure 23B;

Figure 26A is an elevation view of an upper section of a bearing assembly of a rotating control head according to one embodiment with an upper pressure compensation assembly;

Figure 26B is an elevation view of a lower section of the embodiment of Figure 26A with a lower pressure compensation assembly;

Figure 26C is a detail elevation view of one orientation of the upper pressure compensation assembly of Figure 26A;

Figure 26D is a detail view in a second orientation of the upper pressure compensation assembly of Figure 26A;

Figure 26E is a detail elevation view of one orientation of the lower pressure compensation assembly of Figure 26B;

Figure 26F is a detail view in a second orientation of the lower pressure compensation assembly of Figure 26B;

Figure 27 is a detail elevation view of a holding member of the embodiment of Figures 20B-26B;

Figure 28 is a detail elevation view of an exemplary dog member;

Figure 29A is an elevation view of an upper section of another embodiment, with the bearing assembly positioned below the holding member assembly;

Figure 29B is an elevation view of a lower section of the embodiment of Figure 29A;

Figure 30 is an elevation view of the upper section of the embodiment of Figures 29A-29B, with the holding member assembly engaged with the subsea housing;

Figure 31 is an elevation view of the upper section of the embodiment of Figures 29A-29B with the extendible member in a partially extended position;

Figure 32A is an elevation view of the upper section of the embodiment of Figures 29A-29B with the extendible member in a fully extended position;

Figure 32B is an elevation view of the lower section of the embodiment of Figures 29A-29B, with the running tool in a partially disengaged position;

Figure 33 is an elevation view of an embodiment of the lower section of Figure 29B with only one stripper rubber;

Figure 34 is an elevation view of the embodiment of Figure 33, with the running tool in a partially disengaged position; and

Figure 35 is an elevation view of an alternative embodiment of a bearing assembly.

DETAILED DESCRIPTION OF THE INVENTION

[0023] Turning to Figure 2, the riser or upper tubular R is shown positioned above a gas handler annular blowout preventer, generally designated as GH. While a "HYDRIL" GH 21-2000 gas handler BOP or a "HYDRIL" GL series annular blowout handler could be used, ram type blowout preventers, such as Cameron U BOP, Cameron UII BOP or a Cameron T blowout preventer, available from Cooper Cameron Corporation of Houston, Texas, could be used. Cooper Cameron Corporation also provides a Cameron DL annular BOP. The gas handler annular blowout preventer GH includes an upper head 10 and a lower body 12 with an outer body or first or subsea housing 14 therebetween. A piston 16 having a lower wall 16A moves relative to the first housing 14 between a sealed position, as shown in Figure 2, and an open position, where the piston moves downwardly until the end 16A' engages the shoulder 12A. In this open position, the annular packing unit or seal 18 is disengaged from the internal housing 20 of the present invention while the wall 16A blocks the gas handler discharge outlet 22. Preferably, the seal 18 has a height of 12 inches. While annular and ram type blowout preventers, with or without a gas handler discharge outlet, are disclosed, any seal to retractably seal about an internal housing to seal between a first housing and the internal housing is contemplated as covered by the present invention. The best type of retractable seal, with or without a gas handler outlet, will depend on the project and the equipment used in that project.

[0024] The internal housing 20 includes a continuous radially outwardly extending holding member 24 proximate to one end of the internal housing 20, as will be discussed below in detail. When the seal 18 is in the open position, it also provides clearance with the holding member 24. As best shown in Figures 8 and 9, the holding member 24 is preferably fluted with a plurality of bores or openings, like bore 24A, to reduce hydraulic surging and/or swabbing of the internal housing 20. The other end of the internal housing 20 preferably includes inwardly facing right-hand Acme threads 20A. As best shown in Figures 2, 3 and 10, the internal housing includes four equidistantly spaced lugs 26A, 26B, 26C and 26D.

[0025] As best shown in Figures 2 and 7, the bearing assembly, generally designated 28, is similar to the Weatherford-Williams Model 7875 rotating control head, now available from Weatherford International, Inc. of Houston, Texas. Alternatively, Weatherford-Williams Models 7000, 7100, IP-1000, 7800, 8000/9000 and 9200 rotating control heads, now available from Weatherford International, Inc., could be used. Preferably, a rotating control head with two spaced-apart seals is used to provide redundant sealing. The major components of the bearing assembly 28 are described in U.S. Patent No. 5,662,181, now owned by Weatherford/Lamb, Inc. The '181 patent is incorporated herein by reference for all purposes. Generally, the bearing assembly 28 includes a top rubber pot 30 that is sized to receive a top stripper rubber or inner member seal 32. Preferably, a bottom stripper rubber or inner member seal 34 is connected with the top seal 32 by the inner member 36 of the bearing assembly 28. The outer member 38 of the bearing assembly 28 is rotatably connected with the inner member 36, as best shown in Figure 7, as will be discussed below in detail.

[0026] The outer member 38 includes four equidistantly spaced lugs. A typical lug 40A is shown in Figures 2, 7, and 10, and lug 40C is shown in Figures 2 and 10. Lug 40B is shown in Figure 2. Lug 40D is shown in Figure 10. As best shown in Figure 7, the outer member 38 also includes outwardly-facing right-hand Acme threads 38A corresponding to the inwardly-facing right-hand Acme threads 20A of the internal housing 20 to provide a threaded connection between the bearing assembly 28 and the internal housing 20.

[0027] Three purposes are served by the two sets of lugs 40A, 40B, 40C and 40D on the bearing assembly 28 and lugs 26A, 26B, 26C and 26D on the internal housing 20. First, both sets of lugs serve as guide/wear shoes when lowering and retrieving the threadedly connected bearing assembly 28 and internal housing 20, both sets of lugs also serve as a tool backup for screwing the bearing assembly 28 and housing 20 on and off, lastly, as best shown in Figures 2 and 7, the lugs 26A, 26B, 26C and 26D on the internal housing 20 engage a shoulder R' on the upper tubular or riser R to block further downward movement of the internal housing 20, and, therefore, the bearing assembly 28, through the bore of the blowout preventer GH. The Model 7875 bearing assembly 28 preferably has an 8¾" internal diameter bore and will accept tool joints of up to 8½" to 8⅝", and has an outer diameter of 17" to mitigate surging problems in a 19½" internal diameter marine riser R. The internal diameter below the shoulder R' is preferably 18¾". The outer diameter of lugs 40A, 40B, 40C and 40D and lugs 26A, 26B, 26C and 26D are preferably sized at 19" to facilitate their function as guide/wear shoes when lowering and retrieving the bearing assembly 28 and the internal housing 20 in a 19½" internal diameter marine riser R.

[0028] Returning again to Figures 2 and 7, first, a rotatable pipe P can be received through the bearing assembly 28 so that both inner member seals 32 and 34 sealably engage the bearing assembly 28 with the rotatable pipe P. Secondly, the annulus A between the first housing 14 and the riser R and the internal housing 20 is sealed using seal 18 of the annular blowout preventer GH. These two sealings provide a desired barrier or seal in the riser R both when the pipe P is at rest and while rotating. In particular, as shown in Figure 2, seawater or a fluid of one density SW could be maintained above the seal 18 in the riser R, and mud M, pressurized or not, could be maintained below the seal 18.

[0029] Turning now to Figure 5, a cylindrical internal housing 20' could be used instead of the step-down internal housing 20 having a step down 20B to a reduced diameter 20C of 14", as best shown in Figures 2 and 6. Both of these internal housings 20 and 20' can be of different lengths and sizes to accommodate different blowout preventers selected or available for use. Preferably, the blowout preventer GH, as shown in Figure 2, could be positioned in a predetermined elevation between the wellhead W and the rig floor F. In particular, it is contemplated that an optimized elevation of the blowout preventer could be calculated, so that the separation of the mud M, pressurized or not, from seawater or gas-cut mud SW would provide a desired initial hydrostatic pressure in the open borehole, such as the borehole B, shown in Figure 4. This initial pressure could then be adjusted by pressurizing or gas-cutting the mud M.

[0030] Turning now to Figure 4, the blowout preventer stack, generally designated BOPS, is in fluid communication with the choke line CL and the kill line KL connected between the desired ram blowout preventers RBP in the blowout preventer stack BOPS, as is known by those skilled in the art. In the embodiment shown in Figure 4, two annular blowout preventers BP are positioned above the blowout preventer stack BOPS between a lower tubular or wellhead W and the upper tubular or riser R. Similar to the embodiment shown in Figure 2, the threadedly connected internal housing 20 and bearing assembly 28 are positioned inside the riser R by moving the annular seal 18 of the top annular blowout preventer BP to the sealed position. As shown in Figure 4, the annular blowout preventer BP does not include a gas handler discharge outlet 22, as shown in Figure 2. While an annular blowout preventer with a gas handler outlet could be used, fluids could be communicated without an outlet below the seal 18, to adjust the fluid pressure in the borehole B, by using either the choke line CL and/or the kill line KL.

[0031] Turning now to Figure 7, a detail view of the seals and bearings for the Model 7875 Weatherford-Williams rotating control head, now sold by Weatherford International, Inc., of Houston, Texas, is shown. The inner member or barrel 36 is rotatably connected to the outer member or barrel 38 and preferably includes 9000 series tapered radial bearings 42A and 42B positioned between a top packing box 44A and a bottom packing box 44B. Bearing load screws, similar to screws 46A and 46B, are used to fasten the top plate 48A and bottom plate 48B, respectively, to the outer barrel 38. Top packing box 44A includes packing seals 44A' and 44A" and bottom packing box 44B includes packing seals 44B' and 44B" positioned adjacent respective wear sleeves 50A and 50B. A top retainer plate 52A and a bottom retainer plate 52B are provided between the respective bearing 42A and 42B and packing box 44A and 44B. Also, two thrust bearings 54 are provided between the radial bearings 42A and 42B.

[0032] As can now be seen, the internal housing 20 and bearing assembly 28 of the present invention provide a barrier in a subsea housing 14 while drilling that allows a quick rig up and release using a conventional upper tubular or riser R. In particular, the barrier can be provided in the riser R while rotating pipe P, where the barrier can relatively quickly be installed or tripped relative to the riser R, so that the riser could be used with underbalanced drilling, a dual density system or any other drilling technique that could use pressure containment.

[0033] In particular, the threadedly assembled internal housing 20 and the bearing assembly 28 could be run down the riser R on a standard drill collar or stabilizer (not shown) until the lugs 26A, 26B, 26C and 26D of the assembled internal housing 20 and bearing assembly 28 are blocked from further movement upon engagement with the shoulder R' of riser R. The fixed preferably radially continuous holding member 24 at the lower end of the internal housing 20 would be sized relative to the blowout preventer so that the holding member 24 is positioned below the seal 18 of the blowout preventer. The annular or ram type blowout preventer, with or without a gas handler discharge outlet 22, would then be moved to the sealed position around the internal housing 20 so that a seal is provided in the annulus A between the internal housing 20 and the subsea housing 14 or riser R. As discussed above, in the sealed position the gas handler discharge outlet 22 would then be opened so that mud M below the seal 18 can be controlled while drilling with the rotatable pipe P sealed by the preferred internal seals 32 and 34 of the bearing assembly 28. As also discussed above, if a blowout preventer without a gas handler discharge outlet 22 were used, the choke line CL, kill line KL or both could be used to communicate fluid, with the desired pressure and density, below the seal 18 of the blowout preventer to control the mud pressure while drilling.

[0034] Because the present invention does not require any significant riser or blowout preventer modifications, normal rig operations would not have to be significantly interrupted to use the present invention. During normal drilling and tripping operations, the assembled internal housing 20 and bearing assembly 28 could remain installed and would only have to be pulled when large diameter drill string components were tripped in and out of the riser R. During short periods when the present invention had to be removed, for example, when picking up drill collars or a bit, the blowout preventer stack BOPS could be closed as a precaution with the diverter D and the gas handler blowout preventer GH as further backup in the event that gas entered the riser R.

[0035] As best shown in Figures 1, 2 and 4, if the gas handler discharge outlet 22 were connected to the rig S choke manifold CM, the mud returns could be routed through the existing rig choke manifold CM and gas handling system. The existing choke manifold CM or an auxiliary choke manifold (not shown) could be used to throttle mud returns and maintain the desired pressure in the riser below the seal 18 and, therefore, the borehole B.

[0036] As can now also be seen, the present invention along with a blowout preventer could be used to prevent a riser from venting mud or gas onto the rig floor F of the rig S. Therefore, the present invention, properly configured, provides a riser gas control function similar to a diverter D or gas handler blowout preventer GH, as shown in Figure 1, with the added advantage that the system could be activated and in use at all times – even while drilling.

[0037] Because of the deeper depths now being drilled offshore, some even in ultradeepwater, tremendous volumes of gas are required to reduce the density of a heavy mud column in a large diameter marine riser R. Instead of injecting gas into the riser R, as described in the Background of the Invention, a blowout preventer can be positioned in a predetermined location in the riser R to provide the desired initial column of mud, pressurized or not, for the open borehole B since the present invention now provides a barrier between the one fluid, such as seawater, above the seal 18 of the subsea housing 14, and mud

M, below the seal 18. Instead of injecting gas into the riser above the seal 18, gas is injected below the seal 18 via either the choke line CL or the kill line KL, so less gas is required to lower the density of the mud column in the other remaining line, used as a mud return line.

[0038] Turning now to Figure 11, an elevation view of one embodiment for positioning a rotating control head in a marine riser R is shown. As shown in Figure 11, the marine riser R is comprised of three sections, an upper tubular 1100, a subsea housing 1105, and a lower body 1110. The lower body 1110 can be an apparatus for attaching at a borehole, such as a wellhead W, or lower tubular similar to the upper tubular 1100, at the desire of the driller. The subsea housing 1105 is typically connected to the upper tubular by a plurality of equidistantly spaced bolts, of which exemplary bolts 1115A and 1115B are shown. In one embodiment, four bolts are used. Further, the upper tubular 1100 and the subsea housing 1105 are typically sealed with an O-ring 1125A of a suitable substance.

[0039] Likewise, the subsea housing 1105 is typically connected to the lower body 1110 using a plurality of equidistantly spaced bolts, of which exemplary bolts 1120A and 1120B are shown. In one embodiment, four bolts are used. Further, the subsea housing 1105 and the lower body 1110 are typically sealed with an O-ring 1125B of a suitable substance. However, the technique for connecting and sealing the subsea housing 1105 to the upper tubular 1100 and the lower body 1110 are not material to the disclosure and any suitable connection or sealing technique known to those of ordinary skill in the art can be used.

[0040] The subsea housing 1105 typically has at least one opening 1130A above the surface that the rotating control head assembly RCH is sealed to the subsea housing 1105, and at least one opening 1130B below the sealing surface. By sealing the rotating control head between the opening 1130A and the opening 1130B, circulation of fluid on one side of the sealing surface can be accomplished independent of circulation of fluid on the other side of the sealing surface which is advantageous in a dual-density drilling configuration. Although two spaced-apart openings in the subsea housing 1105 are shown in Figure 11, other openings and placement of openings can be used.

[0041] In a disclosed embodiment, the rotating control head assembly RCH is constructed from a bearing assembly 1140 and a holding member assembly 1150. The internal structure of the bearing assembly 1140 can be as shown in Figures 2, 7, and 10, although other bearing assembly 1140 configurations, including those discussed below in detail, can be used.

[0042] As shown in Figure 11, the bearing assembly 1140 has an interior passage for extending rotatable pipe P therethrough and uses two stripper rubbers 1145A and 1145B for sealingly engaging the rotatable pipe P. Stripper rubber seals as shown in Figure 11 are examples of passive seals, in that they are stretch-fit and cone shape vector forces augment a closing force of the seal around the rotatable pipe P. In addition to passive seals, active seals can be used. Active seals typically require a remote-to-the-tool source of hydraulic or other energy to open or close the seal. An active seal can be deactivated to reduce or eliminate sealing forces with the rotatable pipe P. Additionally, when deactivated, an active seal allows annulus fluid continuity up to the top of the rotating control head assembly RCH. One example of an active seal is an inflatable seal. The Shaffer Type 79 Rotating Blowout Preventer from Varco International, Inc., the RPM SYSTEM 3000™ from TechCorp Industries International Inc., and the Seal-Tech Rotating Blowout Preventer from Seal-Tech are three examples of rotating blowout preventers that use a hydraulically operated active seal. Co-pending U.S. Patent Application No. 09/911,295, filed July 23, 2001, entitled "Method and System for Return of Drilling Fluid from a Sealed Marine Riser to a Floating Drilling Rig While Drilling," and assigned to the assignee of this application, discloses active seals and is incorporated in its entirety herein by reference for all purposes. U.S. Patent Nos. 3,621,912, 5,022,472, 5,178,215, 5,224,557, 5,277,249, 5,279,365, and 6,450,262B1 also disclose active seals and are incorporated in their entirety herein by reference for all purposes.

[0043] Figure 35 is an elevation view of a bearing assembly 3500 with one embodiment of an active seal. The bearing assembly 3500 can be placed on the rotatable pipe, such as pipe P in Figure 11, on a rig floor. The lower passive seal 1145B holds the bearing assembly 3500 on the rotatable pipe while the bearing assembly 3500 is being lowered into the marine riser R. As the bearing assembly 3500 is lowered deeper into the water or TIH, the pressure in the accumulators 3510 and 3511 increase. Lubricant, such as oil, is transferred from the accumulators 3510 and 3511 through the bearings 3520, and through a communication port 3530 into an annular chamber 3540 behind the active seal 3550. As the pressure behind the active seal 3550 increases, the active seal 3550 moves radially onto the rotatable pipe creating a seal. As the rotatable pipe is pulled through the active seal 3550, tool joints will enter the active seal 3550 creating a piston pump effect, due to the increased volume of the tool joint. As a result, the lubricant behind the active seal 3550 in the annular chamber 3540 is forced back though the communication port 3530 into the bearings 3520 and finally into the accumulators 3510 and 3511. After use, the bearing assembly 3500 can be retrieved or POOH though the marine riser R. As the water depth decreases, the amount of pressure exerted by the accumulators 3510 and 3511 on the active seal 3550 decreases, until there is no pressure exerted by the active seal 3550 at the surface. In another embodiment, additional hydraulic connections can be used to provide increased pressure in the accumulators 3510 and 3511. It is also contemplated that a remote operated vehicle (ROV) could be used to activate and deactivate the active seal 3550.

[0044] Other types of active seals are also contemplated for use. A combination of active and passive seals can also be used.

[0045] The bearing assembly 1140 is connected to the holding member assembly 1150 in Figure 11 by threading section 1142 of the bearing assembly 1140 to section 1152 of the holding member assembly 1150, similar to the threading discussed above. However, any convenient technique for connecting the holding member assembly to the bearing member assembly known to those of ordinary skill in the art can be used.

[0046] As shown in Figure 11, a running tool 1190 is used for tripping the rotating control head assembly RCH into and out of the marine riser R. A bell-shaped lower portion 1155 of the holding member assembly 1150 is shaped to receive a bell-shaped portion 1195 of the running tool 1190. During insertion or extraction of the rotating control head assembly RCH, the running tool 1190 and the holding member assembly 1150 are latched together using a passive latching technique. A plurality of passive latching members are formed in the bell-shaped lower portion 1155 of the holding member assembly 1150. Two of these passive latching members are shown in Figure 11 as lugs 1199A and 1199B. In one embodiment, four passive latching members are used. However, any desired number of passive latching members can be used, spaced around the circumference of the holding member bell-shaped section 1155.

[0047] Corresponding to the passive latching members, the running tool 1190 bell-shaped portion 1195 uses a plurality of passive formations to engage with and latch with the passive latching members. Two such passive formations 1197A and 1197B are shown in Figure 11, latched with passive latching members 1199A and 1199B, respectively. In one embodiment, four such passive formations are used. Each of the passive formations is a generally J-shaped indentation in the bell-shaped portion 1195. A vertical portion 1198 of each of the passive formations mates with one of the passive latching members when the running tool 1190 is vertically inserted from beneath the holding member assembly 1150. Rotation of the holding member assembly 1150 may be required to properly align the passive latching members with the passive formations. Conventionally, the rotatable pipe P of a drill string is rotated clockwise for drilling. Upon full insertion of the running tool 1190 into the holding member assembly 1150, the running tool 1190 is rotated clockwise, to move the passive latching members into the horizontal section 1196 of the passive formations. The passive latching member 1199A is further secured in a vertical section 1192, which requires an additional vertical movement for engaging and disengaging the running tool 1190 with the bell-shaped portion 1155 of the holding member assembly 1150.

[0048] After latching, the running tool 1190 can be connected to the rotatable pipe P of the drill string (not shown) for insertion of the rotating control head assembly RCH into the marine riser R. Upon positioning of the holding member assembly 1150, as described below, the running tool 1190 can be rotated in a counterclockwise direction to disengage the running tool 1190, which can then be moved downwardly with the rotatable pipe P of the drill string, as is shown in Figure 12.

[0049] When the running tool 1190 has positioned the holding member assembly 1150, a drill operator will note that "weight on bit" has decreased significantly. The drill operator will also be aware of where the running tool 1190 is relative to the subsea housing by number of feet of drill pipe P in the drill string that has been lowered downhole. In this embodiment, the drill operator can rotate the running tool 1190 counterclockwise upon recognizing the running tool 1190 and rotating control head assembly RCH are latched in place, as discussed above, to disengage the running tool 1190 from the holding member assembly 1150, then continue downward movement of the running tool 1190.

[0050] Figure 12 shows the running tool 1190 extended below the holding member assembly 1150 when latched to the subsea housing 1105, as will be discussed below in detail. Additionally shown are passive latching members 1199C (in phantom) and 1199D. One skilled in the art will recognize that the number of passive latching members can vary.

[0051] Because the running tool 1190 has been extended downwardly in Figure 12, the stripper rubber 1145B is shown in a sealed position, sealing the bearing assembly 1140 to a section of rotatable pipe 1210, which is connected to the running tool 1190 at a connection point 1200, shown as a threaded connection in phantom. One skilled in the art will recognize other connection techniques can be used.

[0052] Figures 11, 12, 19, 20B, 21B, 22B, and 23B assume that the drilling procedure rotates the drill string in a clockwise direction. If the drilling procedure rotates the drill string in a counterclockwise direction, then the orientation of the J-shaped passive formations 1197 can be reversed.

[0053] Additionally, as best shown in Figures 16 and 19, a passive latching technique allows latching the holding member assembly 1150 to the subsea housing 1105. A plurality of passive holding members of the holding member assembly 1150 engage with a plurality of passive internal formations of the subsea housing 1105, not visible in detail in Figure 11. Two such passive holding members 1160A and 1160B are shown in Figure 11. In one embodiment, as shown in Figure 16 four such passive holding members 1160A, 1160B, 1160C, and 1160D and passive internal formations are used.

[0054] Figure 19 is a detail elevation view of a portion of an inner surface of the subsea housing 1105 showing a typical passive internal formation 1900 providing a profile, in the form of a J-shaped indentation in a reduced diameter section 1930 of the subsea housing 1105. Identical passive internal formations are equidistantly spaced around the inner surface of the holding member assembly 1150. Each of the passive holding members of the holding member assembly 1150 engages a vertical section 1910 of the passive internal formation 1900, possibly requiring rotation to properly align with the vertical section 1910. A curved upper end 1940 of the vertical section 1910 allows easier alignment of the passive holding members with the passive internal formation 1900. Upon reaching the bottom of the vertical section 1910, rotation of the running tool 1190 rotates the holding member assembly 1150, causing each of the passive holding members to enter a horizontal section 1920 of the passive internal formation 1900, latching the holding member assembly 1150 to the subsea housing 1105. When extraction of the rotating control head assembly RCH is desired, rotation of the running tool 1190 will cause the passive holding members to align with the vertical section 1910, allowing upward movement and disengagement of the holding member assembly 1150 from the subsea housing 1105. A seal 1950, typically in the form of an O-ring, positioned in an interior groove 1951 of the housing 1105 seals the passive holding members 1160A, 1160B, 1160C, and 1160 D of the holding member assembly 1150 with the subsea housing 1105.

[0055] A pressure relief mechanism attached to the passive holding members 1160A, 1160B, 1160C, and 1160D allows release of borehole pressure if the borehole pressure exceeds the fluid pressure in the upper tubular 1100 by a predetermined pressure. A plurality of bores or openings, two of which are shown in Figure 11 as 1165A and 1165B are normally closed by a spring-loaded valve 1170. In one embodiment, a bottom plate 1170 is biased against the bores by a coil spring 1180, secured in place by an upper member 1175. The spring 1180 is calibrated to allow the bottom plate 1170 to open the bores 1165 at the predetermined pressure. The bores also provide for alleviation of surging during insertion of the rotating control head assembly RCH.

[0056] Swabbing during removal of the rotating control head assembly can be alleviated by using a plurality of spreader members on the outer surface of the running tool 1190, two of which are shown in Figure 11 as spreader members 1185A and 1185A. These spreader members spread the stripper rubbers 1145A and 1145B. Also, the stripper rubbers can "burp" during removal of the rotating control head assembly, as described in more detail with respect to Figures 13 and 14.

[0057] Turning to Figure 13, spreader members 1185C and 1185D, not visible in Figure 11, are shown.

[0058] Also shown in Figure 13, guide members 1300A, 1300B, 1300C, and 1300D are attached to an outer surface of the bearing assembly 1140, for centrally positioning the bearing assembly 1140 away from an inner surface 1320 of the upper tubular 1100. Guide members 1300A and 1300C are shown in elevation view in Figure 14. As described above, the spreader members 1185 spread the stripper rubbers, allowing fluid passage through openings 1310A, 1310B, 1310C, and 1310D, which reduces surging and swabbing during insertion and removal of the rotating control head assembly RCH.

[0059] Turning to Figure 14, an elevation view shows "burping" of the stripper rubber 1145A, allowing additional fluid communication for reducing swabbing. A fluid passage 1400 allows fluid communication through the bearing assembly 1140. When sufficient fluid pressure builds, the stripper rubber 1145A, whether or not already spread by the spreader members 1185A and 1185B, can spread to "burp" fluid past the stripper rubber 1145A, reducing fluid pressure. A similar "burping" can occur with stripper rubber 1145B.

[0060] Turning now to Figures 15, a detail elevation view of a pressure relief assembly, according to the embodiment of Figure 11, is shown in an open position.

[0061] As shown in Figure 15, a latching/pressure relief section 1550 is threadedly connected at location 1520 to a threaded section 1510 of the bell-shaped lower portion 1155 of the holding member assembly. Likewise, the latching/pressure relief section 1550 is threadedly connected at location 1540 to an upper portion 1560 of the holding member assembly 1150 at a threaded section 1530. Other attachment techniques can be used. The section 1550 can also be integrally formed with either or both of sections 1560 and 1155 as desired.

[0062] The bottom plate 1170 in Figure 15 is shown opened for pressure relief away from the openings 1165A and 1165B, compressing the coil spring 1180 against annular upper member 1175. This allows fluid communication upwards from the borehole B to the upper tubular side of the subsea housing 1105, as shown by the arrows. Once the borehole pressure is reduced so the borehole pressure no longer exceeds the fluid pressure by the predetermined amount calibrated by the coil spring 1180, the spring 1180 will urge the annular bottom plate 1170 against the openings, closing the pressure relief assembly, as shown below in Figure 17. Bottom plate 1170 is typically an annular plate concentrically and movably mounted on the latching/pressure relief section 1550. As noted above, the openings and the bottom plate 1170 also assist in reducing surging effects during insertion of the rotating control head assembly RCH.

[0063] Figure 16 shows all the openings 1165A, 1165B, 1165C, 1165D, 1165E, 1165F, 1165G, 1165H, 1165I, 1165J, 1165K, and 1165L are visible in this section view, showing that the openings are equidistantly spaced around member 1600 into which are formed the passive holding members 1160A, 1160B, 1160C, and 1160D. Additionally, vertical sections 1910A, 1910B, 1910C, and 1910D of passive internal formations 1900 are shown equidistantly spaced around the subsea housing 1105 to receive the passive holding members. One skilled in the art will recognize that the number of openings 1165A-1165L is exemplary and illustrative and other numbers of openings could be used.

[0064] Turning to Figure 17, a detail elevation view of the latching/pressure relief section 1550 of Figure 15 is shown, with the bottom plate 1170 closing the openings 1165A to 1165L.

[0065] An alternative threaded section 1710 of the latching/pressure relief section 1550 is shown for threadedly connecting the upper member 1175 to the latching/pressure relief section 1550, allowing adjustable positioning of the upper member 1175. This adjustable positioning of threaded member 1175 allows adjustment of the pressure relief pressure. A setscrew 1700 can also be used to fix the position of the upper member 1175.

[0066] Figure 18 shows another alternative embodiment of the latching/pressure relief section 1550, identical to that shown in Figure 17, except that a different coil spring 1800 and a different upper member 1810 are shown. Spring 1800 can be a spring of a different tension than the spring 1180 of Figure 11, allowing pressure relief at a different borehole pressure. Upper member 1810 attaches to section 1550 in a non-threaded manner, such as a snap ring, but otherwise functions identically to upper member 1175 of Figure 17.

[0067] One skilled in the art will recognize that other techniques for attaching the upper member 1175 can be used. Further the springs 1180 of Figures 17 and 18 are exemplary and illustrative only and other types and configurations of springs 1180 can be used, allowing configuration of the pressure relief to a desired pressure.

[0068] Turning to Figures 20A and 20B, an elevation view of an another embodiment is shown, with Figure 20A showing an upper section of the embodiment and Figure 20B showing a lower section of the embodiment for clarity of the drawings.

[0069] In this embodiment, a subsea housing 2000 is bolted to an upper tubular 1100 and a lower body 1110 similar to the connection of the subsea housing 1105 in Figure 11. However, in the embodiment of Figures 20A and 20B, a different technique for latching and sealing a holding member assembly 2026 is shown. The holding member assembly 2026 is connected to a bearing assembly similarly to how the holding member assembly 1150 is connected to the bearing assembly 1140 in Figure 11, although the connection technique is not visible in Figures 20A-20B. A running tool 1190 is used for insertion and removal of the rotating control head assembly RCH, as in Figure 11. The passive latching formations, with passive formation 2018A most visible in Figure 20B, allow the passive latching member 1199A to be further secured in a vertical section 1192, which requires an additional vertical movement for engaging and disengaging the running tool 1190 with the bell-shaped portion 1155 of the holding member assembly, generally designated 2026.

[0070] As best shown in Figure 20A, the holding member assembly 2026 is comprised of an internal housing 2028, with an upper portion 2045, a lower portion 2050, and an elastomer 2055; and an extendible portion 2080.

[0071] The upper portion 2045 is connected to the bearing assembly 1140. The lower portion 2050 and the upper portion 2045 are pulled together by the extension of the extendible portion 2080, compressing the elastomer 2055 and causing the elastomer 2055 to extrude radially outwardly, sealing the holding member assembly 2026 to a sealing surface 2000', as best shown in Figure 22A, the subsea housing 2000. Upon retracting the extendible portion 2080, the upper portion 2045 and the lower portion 2050 decompress the elastomer 2055 to release the seal with the sealing surface 2000' of the subsea housing 2000.

[0072] A bi-directional pressure relief assembly or mechanism is incorporated into the upper portion 2045. A plurality of passages are equidistantly spaced around the circumference of the upper portion 2045. Figure 20A shows two of these passages, identified as 2005A and 2005B. Four such passages are typically used; however, any desired member of passages can be used.

[0073] An outer annular slidable member 2010 moves vertically in an annular recess 2035. A plurality of passages in the slidable member 2010 of an equal number to the number of upper portion passages allow fluid communication between the interior of the holding member assembly 2026 and the subsea riser when the upper portion passages communicate with the slidable member passages. Upper portion passages 2005A-2005B and slidable member passages 2015A-2015B are shown in Figure 20A.

[0074] Similarly, opposite direction pressure relief is obtained via a plurality of passages through the upper portion 2045 and a plurality of passages through an interior slidable annular member 2025. Four such corresponding passages are typically used; however, any desired number of passages can be used. Upper portion passages 2020A-2020B and slidable member passages 2030A-2030B are shown in Figure 20A. When vertical movement of member 2025 communicates the passages, fluid communication allows equalization of pressure similar to that allowed by vertical movement of member 2010 when pressure inside the holding member assembly 2026 exceeds pressure in the upper tubular 1100. Figure 20A is shown with all of the passages in a closed position. Operation of the bi-directional pressure relief assembly is described below.

[0075] Turning to Figure 20B, latching of the holding member assembly 2026 is performed by a plurality of holding members, spaced equidistantly around the circumference of the lower portion 2050 of the internal housing 2028 of the holding member assembly 2026. Two exemplary passive holding members 2090A and 2090B are shown in Figure 20B. As best shown in Figure 25, preferably, four equidistant spaced holding members 2090A, 2090B, 2090C, and 2090D are used, but any desired number can be used. When the holding members are engaged with the subsea housing, as described below, movement of the rotating control head assembly RCH to the subsea housing 2000 is resisted.

[0076] Returning to Figure 20B, a passive internal formation 2002, providing a profile, is annularly formed in an inner surface of the subsea housing 2000. As best shown in Figure 25, the shape of the passive internal formation 2002 is complementary to that of the holding members 2090A to 2090D, allowing solid latching when fully aligned when urged outwardly by surface 2085 of the extendible portion 2080 of the holding member assembly 2026. However, because an annular passive internal formation 2002 is used, rotation of the holding member assembly 2026 is not required before engagement of the holding members 2090A to 2090D with the passive latching formation 2002.

[0077] Each of the holding members 2090A to 2090D, are a generally rhomboid shaped structure, shown in detail elevation view in Figure 27. An inner portion 2700 of the exemplary member 2090 is a rhomboid with an upper edge 2720, slanted upwardly in an outward direction as shown. Exerting force in a downhole direction by the surface 2085 of extendible portion 2080 on the upper edge 2700 will urge the members 2090A to 2090D outwardly, to latch with the passive latching formation 2002. An outer portion 2710 attached to the inner portion 2700 is generally a rhomboid, with a plurality of rhomboidal extensions or protuberances 2730A, 2730B and 2730C, each of which has an upper edge 2740A, 2740B, and 2740C which slopes downwardly and outwardly. The upper edge 2740A generally extends across the upper edge of the outer portion 2710. In addition to corresponding to the shape of the passive internal formation 2002, the slope of the edges 2740A, 2740B and 2740C urge the passive holding member inwardly when the passive holding member 2090 is pulled or pushed upwardly against the matching surfaces of the passive internal formation 2002.

[0078] Reviewing Figures 20B, 21B, and 25 during insertion of the rotating control head assembly RCH, the holding members 2090A, 2090B, 2090C, and 2090D are recessed into a corresponding number of recesses 2095A, 2095B, 2095C, and 2095D in the lower portion 2050, with the extensions 2730A, 2730B, 2730C and 2730D serving as guide members to centrally position the holding member assembly 2026 in the upper tubular 1100.

[0079] Turning to Figure 20A, an upper dog member recess 2032 is annularly formed around the circumference of the extendible portion 2080, and on initial insertion is mated with a plurality of upper dog members that are mounted in recesses of the upper portion 2045. Dog members 2070A and 2070B and their corresponding recesses 2075A and 2075B are shown in Figure 20A. In one embodiment, four dog members and corresponding recesses are used; however, other numbers of dog members and recesses can be used. Because an annular upper dog member recess 2032 is used, rotation of the holding member assembly 2026 is not required before engagement of the upper dog members with the upper dog member recess 2032. When engaged, the upper dog members allow the extendible portion 2080 to stay in alignment with the upper portion 2045 and carry the rotating control head assembly RCH until the holding members 2090A, 2090B, 2090C, and 2090D engage the passive latching formation 2002.

[0080] Turning to Figure 20B, a similar plurality of lower dog members, recessed in an equal number of recesses are configured in the lower portion 2050, and an annular lower dog recess 2012 is formed in extendible portion 2080. The lower dog members are in a disengaged position in Figure 20B. Lower dog members 2008A-2008B and recesses 2014A-2014B are shown in Figure 20B. Four lower dog members are typically used; however, any convenient number of lower dog members can be used.

[0081] Although the upper dog members and lower dog members are shown in Figures 20A and 20B as disposed in the upper portion 2045 and lower portion 2050, respectively, while upper dog recesses 2032 and lower dog recesses 2014 are shown in Figures 20A and 20B as disposed in the extendible portion 2080, the upper dog members and the lower dog members can be disposed in extendible member 2080 with upper dog recesses and lower dog recesses disposed in upper portion 2045 and lower portion 2050, respectively.

[0082] Figure 28 is a detail elevation view of an exemplary dog member and dog member recess. Each dog member is positioned in a recess 2810 with a spring-loaded dog assembly 2800. The spring-loaded dog assembly 2800 is comprised of an upper spring 2820A and a lower spring 2820B, attached to an upper urging block 2830A and a lower urging block 2830B, respectively. The urging blocks are shaped so that pressure from the springs on the urging blocks urges a central block 2840 outwardly (relative to the recess 2810). The central block 2840 is generally a trapezoid, with a plurality of trapezoidal extensions 2850A and

2850B for mating with corresponding dog recesses 2860A and 2860B. One skilled in the art will recognize that the number of extensions and recesses shown in Figure 28, corresponding to the lower and upper dog members and the lower and upper dog recesses, are exemplary and illustrative only, and other numbers of extensions and recesses can be used.

[0083] Extensions and recesses are trapezoidal shaped to allow bidirectional disengagement through vector forces, when the dog member 2800 is urged upwardly or downwardly relative to the recesses, retracting into the recess 2810 when disengaged, without fracturing the central block 2840 or any of the extensions 2850A or 2850B, which would leave unwanted debris in the borehole B upon fracturing. The springs 2820A and 2820B can be chosen to configure any desired amount of force necessary to cause retraction. In one embodiment, the springs 2820 are configured for a 100 kips force.

[0084] Returning to Figure 20A, the upper dog members are engaged in recesses 2032, while the lower dog members are disengaged with recesses 2012.

[0085] Turning to Figure 20B, an end portion 2004 with a threaded section 2024 can be threaded into a threaded section 2022 of the lower portion 2050 to allow access to the recess or chamber of the dog member.

[0086] Turning now to Figures 21A-21B, the embodiment of Figures 20A-20B is shown with the holding members 2090A, 2090B, 2090C, and 2090D engaged with the passive internal formation 2002, latching the holding member assembly 2026 to the subsea housing 2000. Downward pressure at location 2085 of the extendible portion 2080 has urged the holding members 2090A, 2090B, 2090C, and 2090D outwardly when aligned with the recesses of the passive internal formation 2002.

[0087] As shown in Figure 21A, one portion of the bi-directional pressure relief assembly is in an open position, with passages 2030A, 2020A, 2030B, and 2020B communicating when sliding member 2025 moves downwardly into annular area 2040 (see Figure 20A) to allow fluid communication between the inside of the holding member assembly 2026 and the annulus 1100′ (see Figure 21A) of the upper tubular 1100.

[0088] Turning to Figure 22A, one portion of the pressure relief assembly is in an open position, with passages 2005A, 2015A, 2005B, and 2015B communicating when sliding member 2010 moves upwardly in recess 2035.

[0089] The extendible portion 2080 is extended into an intermediate position in Figures 22A and 22B. The dog members 2070A and 2070B have disengaged from dog recesses 2032, allowing movement of the extendible portion 2080 relative to the upper portion 2045. A shoulder 2060 on the extendible portion 2080 is landed on a landing shoulder 2065 of the upper portion 2045, so that extension of the extendible portion 2080 downwardly pulls the upper portion 2045 toward the lower portion 2050, which is fixed in place by the holding members 2090A, 2090B, 2090C, and 2090D engaging with the passive internal formation 2002 of the subsea housing 2000. This compresses the elastomer 2055, causing it to extrude radially outwardly, sealing the holding member assembly 2026 with the sealing surface 2000′ of the subsea housing 2000.

[0090] As shown in Figure 22B, at this intermediate position the lower dog members 2008A and 2008B are also disengaged from the lower dog recesses 2012.

[0091] Turning now to Figures 23A and 23B, the extendible portion 2080 is in the lower or fully extended position. As in Figure 22A, the upper dog members 2070A and 2070B are disengaged from the upper dog recesses 2032, while shoulder 2060 is landed on shoulder 2065, causing the elastomer 2055 to be fully compressed, extruding outwardly to seal the holding member assembly 2026 with the sealing surface 2000′ subsea housing 2000. Further, in Figure 23B, the lower dog members 2008A and 2008B are engaged with the lower dog recesses 2012, blocking the extendible portion 2080 in the lower or fully-extended position.

[0092] This blocking of the extendible portion 2080 allows disengaging the running tool 1190, as shown in Figure 23B, without the extendible portion 2080 retracting upwardly, which would decompress the elastomer 2055 and unseal the holding member assembly 2026 from the subsea housing 2000.

[0093] As stated above, to disengage the holding member assembly 2026, an operator will recognize a decreased "weight on bit" when the running tool is ready to be disengaged. As shown best in Figure 22B and 23B, an operator momentarily reverses the rotation of the drill string, while pulling the running tool 1190 slightly upwards, to release the passive latching members 1199 from the position 1192 of the J-shaped passive formations 1199. The running tool 1190 can then be lowered, causing the passive latching members 1199 to exit through the vertical section 1198 of each formation 1197, as shown in Figure 23B. The running tool 1190 can then be lowered and normal rotation resumed, allowing the running tool to move downward through the lower body 1110 toward the borehole.

[0094] Turning now to Figure 24, a detail elevation view of the pressure relief assembly of Figures 20A, 21A, 22A, and 23A is shown, with the lower slidable member 2025 in a lower position, communicating the passages 2020 and 2030 for fluid communication while the upper slidable member 2010 is in a lower position, which ensures the passages 2015 and 2005 are not communicating, preventing fluid communication. Additionally, Figure 24 shows a plurality of seals for sealing the upper slidable member 2010 to the upper portion 2045 of the holding member assembly 2026. Shown are seals 2400A, 2400B, and 2400C, typically O-rings of a suitable material. Also shown are seals for sealing the lower slidable member 2025 to the upper portion 2045, with exemplary seals 2410A, 2410B, and 2410C, typically O-rings of a similar material as used in seals 2400A, 2400B and 2400C. Other numbers, positions, arrangements, and types of seals can be used. A coil spring 2420 biases the upper slidable member 2010 in a downward or closed position. Similarly, a coil spring 2430 biases the lower sliding member 2025 in an upward or closed position. When fluid pressure in the interior of the holding member assembly exceeds the fluid pressure in the subsea riser R by a predetermined amount, fluid will pass through the passage 2005, forcing the upper sliding member 2010 upwardly against the spring 2420, until the passages 2005 align with the passages 2015, allowing fluid communication and pressure relief. Likewise, when fluid pressure in the subsea riser R exceeds the fluid pressure in the holding member assembly by a predetermined amount, fluid will pass through the passage 2020, forcing the lower sliding member 2025 downwardly against the spring 2430, until the passages 2030 align with the passages 2020, allowing fluid communication and pressure relief. One skilled in the art will recognize that the springs 2420 and 2430 can be configured for any pressure release desired. In one embodiment, springs 2420 and 2430 are configured for a 100PSI excess pressure release. One skilled in the art will also recognize that the spring 2420 can be configured for a different excess pressure release amount than the spring 2430.

[0095] Springs 2420 and 2430 bias slidable members 2010 and 2025, respectively, toward a closed position. When fluid pressure interior to the holding member assembly 2026 exceeds fluid pressure exterior to the holding member assembly 2026 by a predetermined amount, fluid will pass through the passages 2005, forcing the slidable member 2010 upward against the biasing spring 2420 until the passages 2015 are aligned with the passages 2005, allowing fluid communication between the interior of the holding member 2026 and the exterior of the holding member 2026. Once the excess pressure has been relieved, the slidable member 2010 will return to the closed position because of the spring 2420.

[0096] Similarly, the sliding member 2025 will be forced downwardly by excess fluid pressure exterior to the holding member assembly 2026, flowing through the passages 2020 until passages 2020 are aligned with the passages 2030. Once the excess pressure has been relieved, the slidable member 2025 will be urged upward to the closed position by the spring 2430.

[0097] As discussed above, Figure 25 is a section view along line 25-25 of Figure 23B, showing holding members 2090A, 2090B, 2090C and 2090D engaged with passive internal formation 2002. Figure 25 shows that there are gaps 2500A, 2500B, 2500C, and 2500D between the exterior of the lower portion 2050 of the holding member assembly 2026 and the interior of subsea housing 2000, allowing fluid communication past the holding members, to reduce or eliminate surging and swabbing during insertion and removal of the rotating control head assembly RCH.

[0098] Figures 26A and 26B are a detail elevation view of pressure compensation mechanisms 2600 and 2660 of the bearing assembly 1140 of the embodiments of Figures 11-25B. Pressure compensation mechanisms 2600 and 2660 allow for maintaining a desired lubricant pressure in the bearing assembly 1140 at a higher level than the fluid pressure within the subsea housing above or below the seal. Figures 26C and 26D are detailed elevation views of two orientations of the pressure compensation mechanisms 2600. Figures

26E and 26F are detailed elevation views of lower pressure compensation mechanisms 2660, again in two orientations.

[0099] A chamber 2615 is filled with oil or other hydraulic fluid. A barrier 2610, such as a piston, separates the oil from the sea water in the subsea riser. Pressure is exerted on the barrier 2610 by the sea water, causing the barrier 2610 to compress the oil in the chamber 2615. Further, a spring 2605, extending from block 2635, adds additional pressure on the barrier 2610, allowing calibration of the pressure at a predetermined level. Communication bores 2645 and 2697 allow fluid communication between the bearing chamber – for example, referenced by 2650A, 2650B in Figure 26D and Figure 26F, respectively - and the chambers 2615, 2695 pressurizing the bearing assembly 1140.

[00100] A corresponding spring 2665 in the lower pressure compensation mechanisms 2660 operates on a lower barrier 2690, such as a lower piston, augmenting downhole pressure. The springs 2605 and 2665 are typically configured to provide a pressure 50 PSI above the surrounding sea water pressure. By using an upper and lower pressure compensation mechanism, the bearing pressure can be adjusted to ensure the bearing pressure is greater than the downhole pressure exerted on the lower barrier 2690.

[00101] In the upper mechanism 2600a, shown in Figure 26C, a nipple 2625 and pipe 2620 are used for providing oil to the chamber 2615. Access to the nipple 2625 is through an opening 2630 in the bearing assembly 1140. In one embodiment, the upper and lower pressure compensation mechanisms 2600 and 2660 provide 50 psi additional pressure over the maximum of the seawater pressure in the subsea housing and the borehole pressure.

[00102] Figures 26E and 26F show the lower pressure compensation mechanism 2660 in elevation view. Passages 2675 through block 2680 allow downhole fluid to enter the chamber 2670 to urge the barrier 2690 upward, which is further urged upward by the spring 2665 as described above. Each of the barriers 2690 and 2610 are sealed using seals 2685 and 2640. The upper and lower pressure compensation mechanisms 2600 and 2660 together ensure that the bearing pressure will always be at least as high as the higher of the sea water pressure being exerted on the upper pressure compensation mechanism 2600 and the downhole pressure being exerted on the lower pressure compensation mechanism 2660, plus the additional pressure caused by the springs 2605 and 2665. One advantage of the disclosed pressure compensation technique is that exterior hydraulic connections are not needed to adjust for changes in either the sea water pressure or the borehole pressure.

[00103] Figures 20A-23B illustrate an embodiment in which the bearing assembly 1140 is mounted above the holding member assembly 2026. In contrast, Figures 29A-34 illustrate an alternate embodiment, in which the bearing assembly 1140 is mounted below the holding member assembly 2026. Such a configuration may be advantageous because it provides less area for borehole cuttings to collect around the passive latching mechanism of the holding member assembly 2026 and reduces equipment in the riser above the seal of the holding member assembly 2026. In either configuration, sealing the holding member assembly between the openings 1130a and 1130b allows independent fluid circulation both above and below the seal.

[00104] As shown in Figures 29A, 30, 31, and 32A, the operation of the holding member assembly 2026 is identical in either the over slung or under slung configurations, latching the holding members 2090a-2090d into passive internal formation 2002, sealing the holding member assembly 2026 to the subsea housing 2000 by extruding elastomer 2055 while extending extendible portion 2080, and alternatively dogging the extendible member 2080 to upper or lower sections 2045 and 2050.

[00105] Unlike the overslung configuration of Figures 20A-23B, however, the running tool 1190 in the underslung configuration of Figures 29A, 30, 31, and 32A latches to a latching section 2920 attached to the bottom of the bearing assembly 1140. The latching section 2920 uses the same latching technique described above with regard to the bell-shaped lower portion 1155 in Figure 11, but as shown in Figures 29B, 32B, and 33-34, is a generally cylindrical section. Figures 29B and 33 show the running tool 1190 latched to the latching section 2920, while Figures 32B and 34 show the running tool 1190 extending downwardly after unlatching. Note that as shown in Figures 29B, 32B, 33, and 34, the running tool 1190 does not include the spreader members 1185 shown previously in Figures 11, 20A, 21A, 22A, and 23A. However, one skilled in the art will recognize that the running tool 1190 can include the spreader members 1185 in an underslung configuration as shown in Figures 29B, 32B, 33, and 34.

[00106] Figures 29B, 32B, and 33-34 illustrate that the bearing assembly 1140 can be implemented using a unidirectional pressure relief mechanism 2910, which comprises the lower pressure relief mechanism of the bi-directional pressure relief mechanism shown in Figures 20A, 21A, 22A, 23A and 24, allowing pressure relief from excess downhole pressure, but using the ability of stripper rubbers 1145 to "burp" to allow relief from excess interior pressure.

[00107] Figures 33 and 34 illustrate a bearing assembly 3300 otherwise identical to bearing assembly 1140, that uses only a single lower stripper rubber 1145b, in contrast to the dual stripper rubber configuration of bearing assembly 1140 as shown in Figures 20A-23B. The use of two stripper rubbers 1145 is preferred to provide redundant sealing of the bearing assembly 3300 with the rotatable pipe of the drill string.

[00108] In the claims which follow and in the preceding description of the invention, except where the context requires otherwise due to express language or necessary implication, the word "comprise" or variations such as "comprises" or "comprising" is used in an inclusive sense, i.e. to specify the presence of the stated features but not to preclude the presence or addition of further features in various embodiments of the invention.

[00109] It is to be understood that, if any prior art publication is referred to herein, such reference does not constitute an admission that the publication forms a part of the common general knowledge in the art, in Australia or any other country.

[00110] The foregoing disclosure and description of the invention are illustrative and explanatory thereof, and various changes in the details of the illustrated apparatus and construction and method of operation may be made without departing from the spirit of the invention.

THE CLAIMS DEFINING THE INVENTION ARE AS FOLLOWS:

1. A holding member assembly adapted for connection with a bearing assembly of a rotating control head, comprising: an internal housing, comprising: a holding member chamber; and a holding member positioned within the holding member chamber, the holding member movable between an extended position and a retracted position; and an extendible portion, concentrically interior to and slidably connectable to the internal housing.

2. The holding member assembly of claim 1, the internal housing further comprising: an upper portion; a lower portion; and an elastomer positioned between the upper portion and the lower portion.

3. The holding member assembly of claim 2, wherein the holding member chamber is defined by the lower portion.

4. The assembly of claim 2, wherein the elastomer is extrudable radially outwardly when compressed between the upper portion and the lower portion.

5. The holding member assembly of claim 4, wherein extension of the extendible portion causes the internal housing upper portion to move toward the internal housing lower portion, thereby extruding the elastomer.

6. The holding member assembly of claim 2, wherein the upper portion has a shoulder; and the extendible portion has a shoulder, the upper portion shoulder engaging with the extendible portion shoulder to move the upper portion toward the lower portion.

7. The holding member assembly of claim 1, further comprising a dog member; and a dog recess, wherein the dog member engages with the dog recess when the extendible portion is in an unextended position, and wherein the dog member disengages from the dog recess when the extendible portion is in an extended position.

8. The holding member assembly of claim 7, further comprising: a second dog member; and a second dog recess; wherein the second dog member engages with the second dog recess when the extendible portion is in an extended position.

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9. The holding member assembly of claim 1 or 8, wherein the extendible portion can rotate relative to the upper portion and the lower portion.

10. The holding member assembly of claim 8, wherein the second dog member can interengage with the extendible portion without rotation of the extendible portion.

11. The holding member assembly of claim 7, wherein the dog member can interengage with the extendible portion without rotation of the extendible portion.

12. The holding member assembly of claim 1, wherein an outer surface of the extendible portion blocks the holding member radially outward when the extendible portion is in an extended position.

13. The holding member assembly of claim 1, wherein the holding member is configured to retract at a predetermined force on the holding member assembly.

14. The holding member assembly of claim 1, further comprising: means for latching a running tool with the holding member assembly.

15. The holding member assembly of claim 1, the internal housing further comprising: a plurality of holding members spaced around a circumference of the internal housing.

16. The holding member assembly of claim 2, wherein the extendible portion blocks the elastomer when the extendible portion is in the extended position.

17. The holding member assembly of claim 1, further comprising a rotating control head connected to the internal housing.

18. The holding member assembly of claim 7, wherein the dog member is configured to disengage with the dog recess when a predetermined downward force is exerted on the extendible portion.

19. The holding member assembly of claim 8, wherein the second dog member is configured to disengage when a predetermined upward force is exerted on the extendible portion.

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20. A holding member assembly substantially as herein described with reference to the accompanying drawings.

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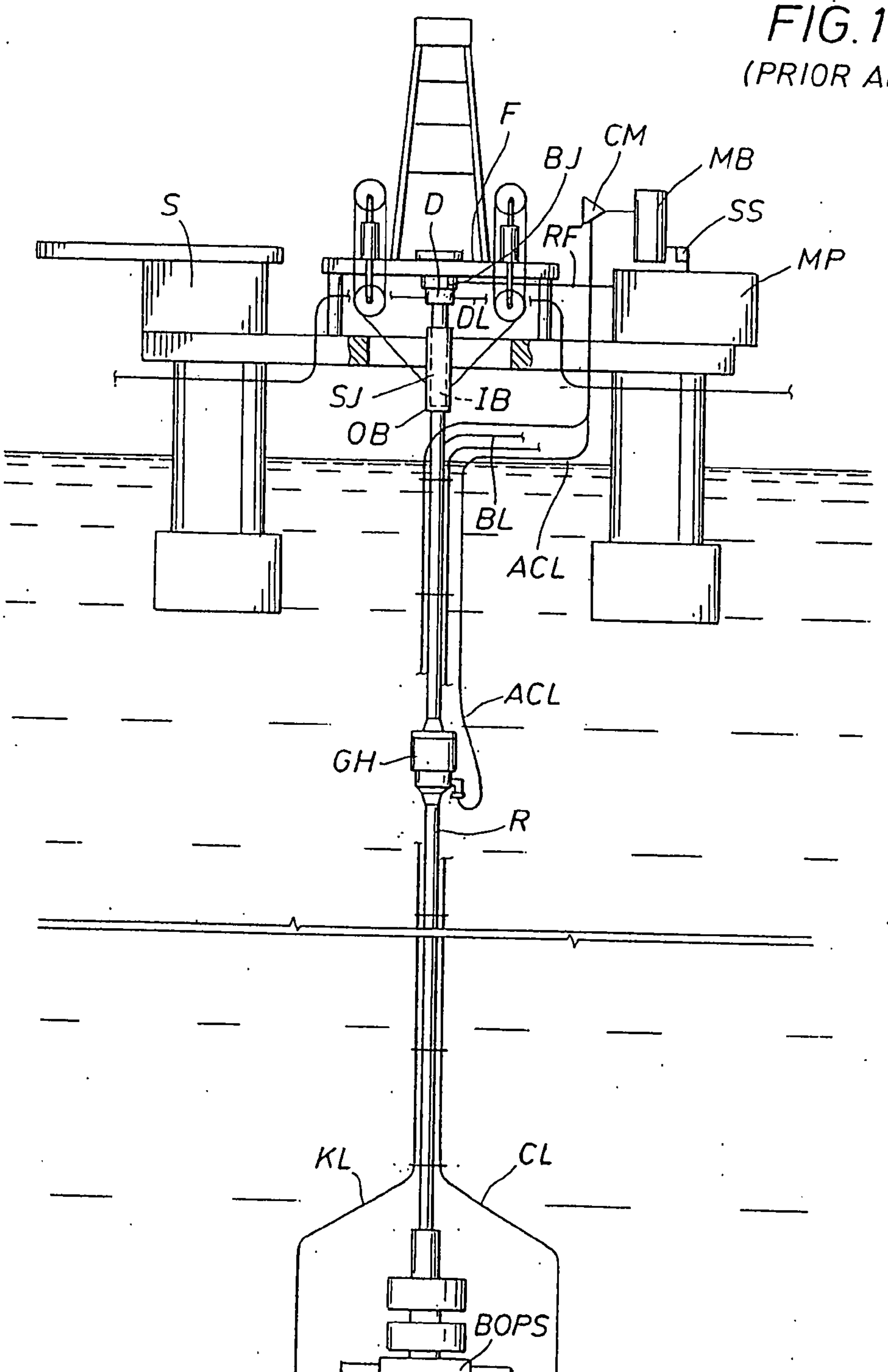
FIG. 1
(PRIOR ART)



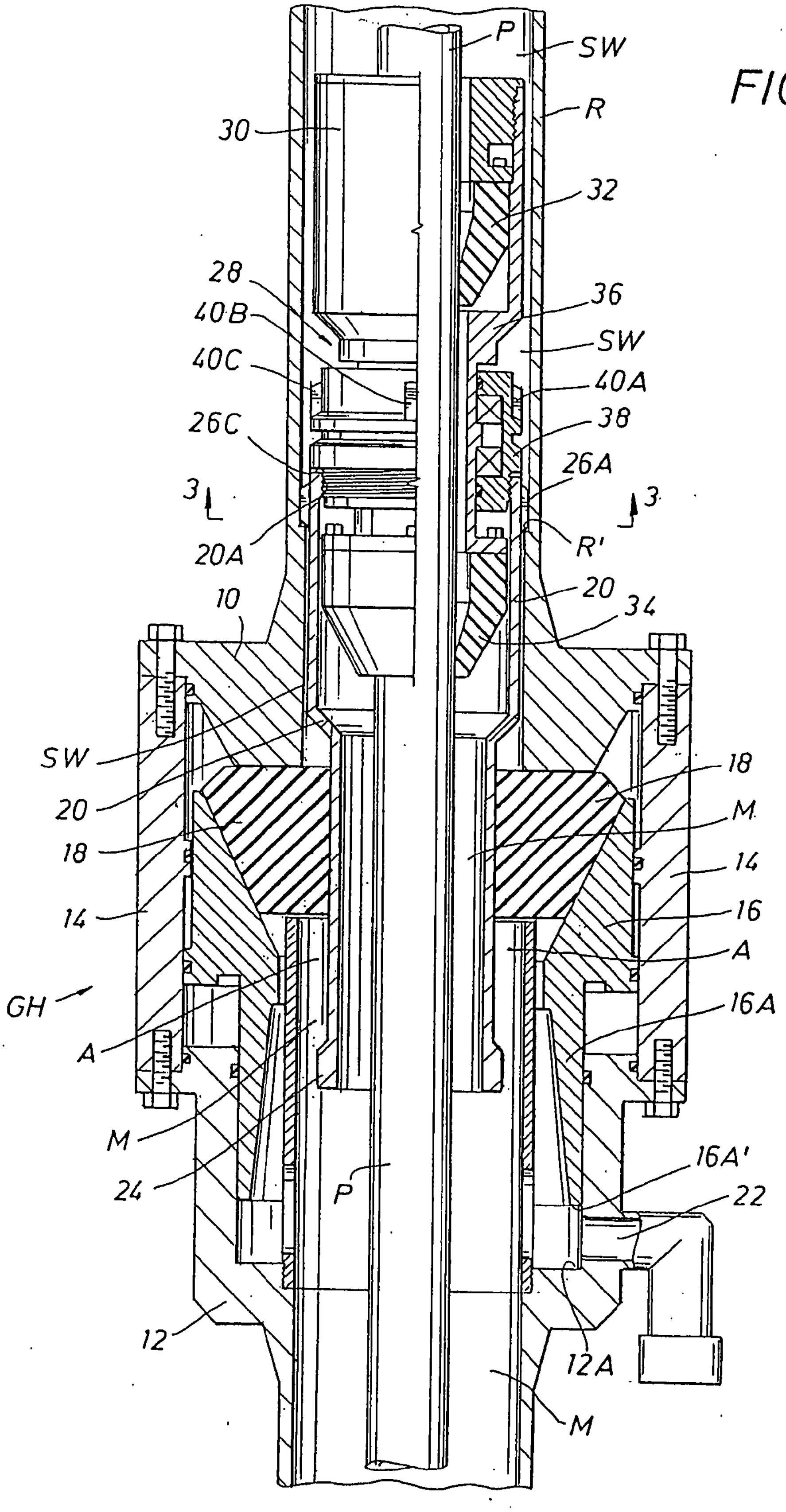

P
SW
R
30
32
28
40B
36
SW
40C
40A
26C
38
26A
3
3
20A
R'
20
10
34
SW
20
18
18
M
14
14
16
A
GH
16A
A
M
16A'
24
22
P
12
12A
M

FIG. 2

FIG. 3

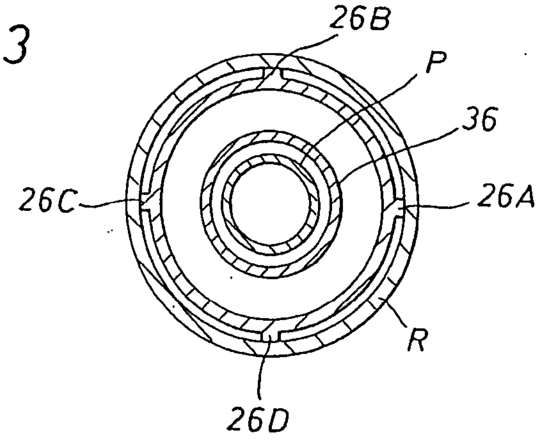


FIG. 5

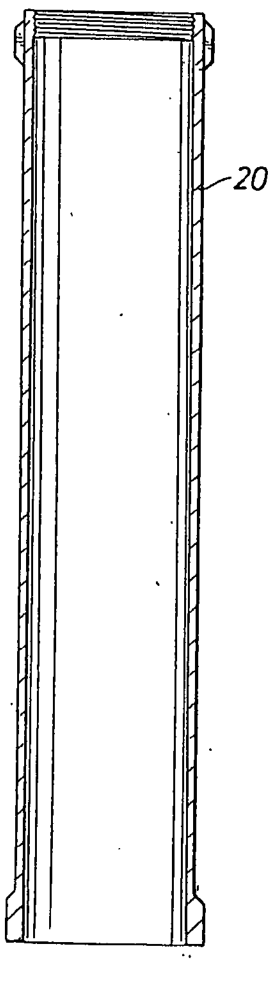
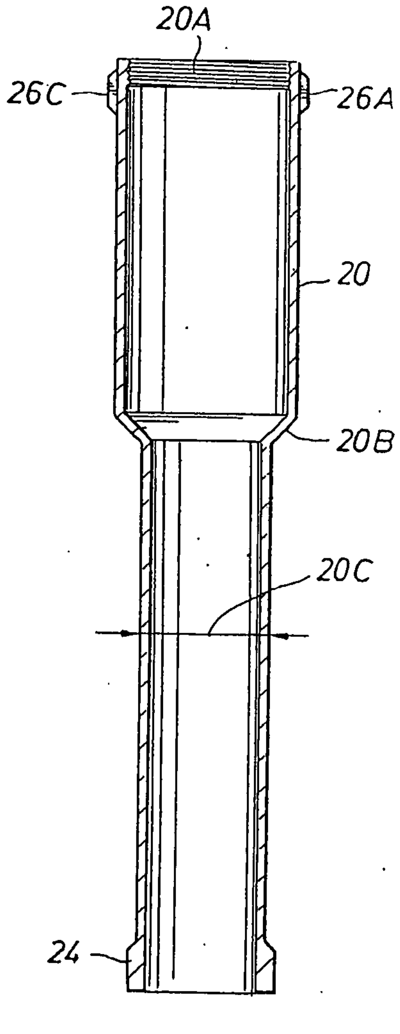


FIG. 6



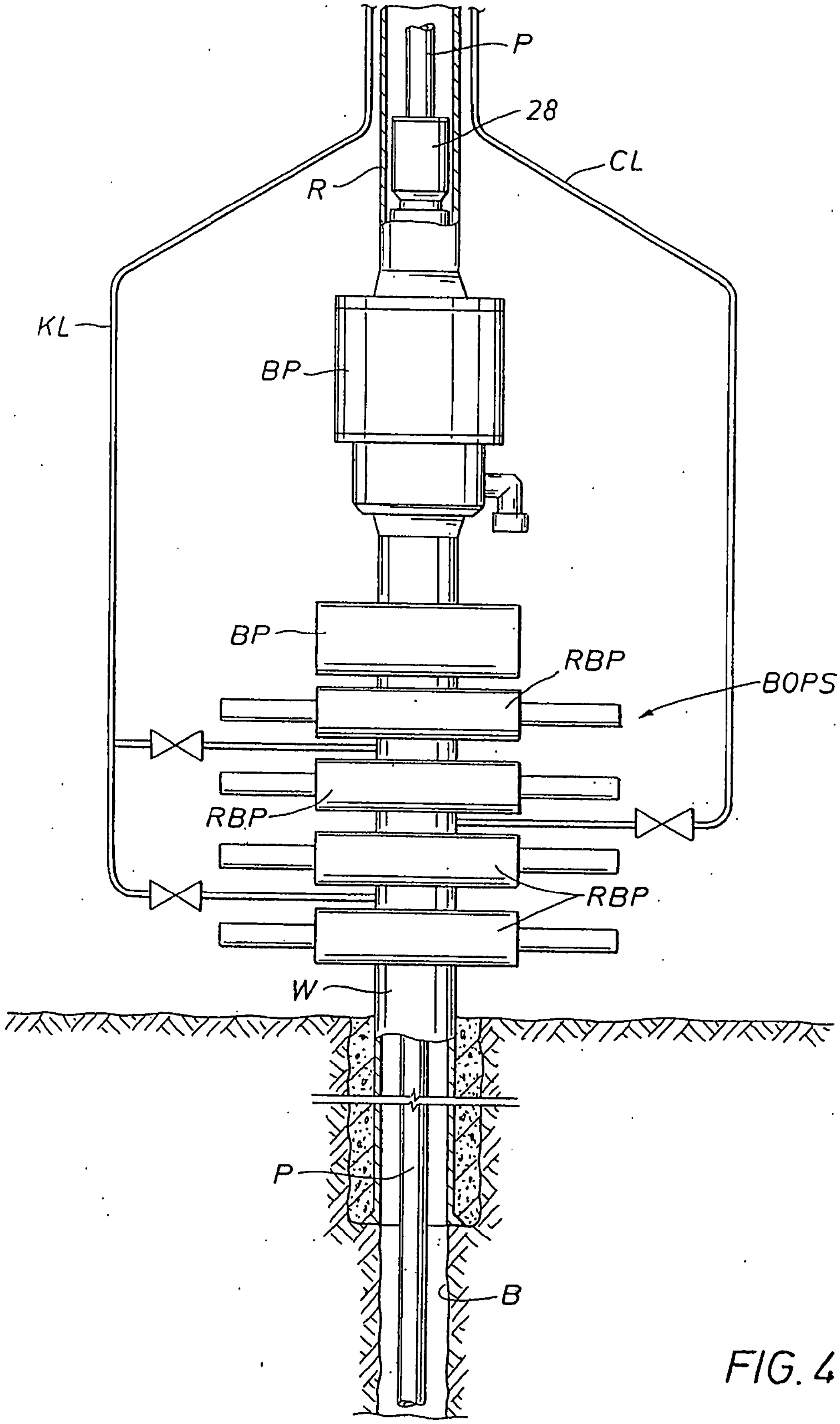


FIG. 4

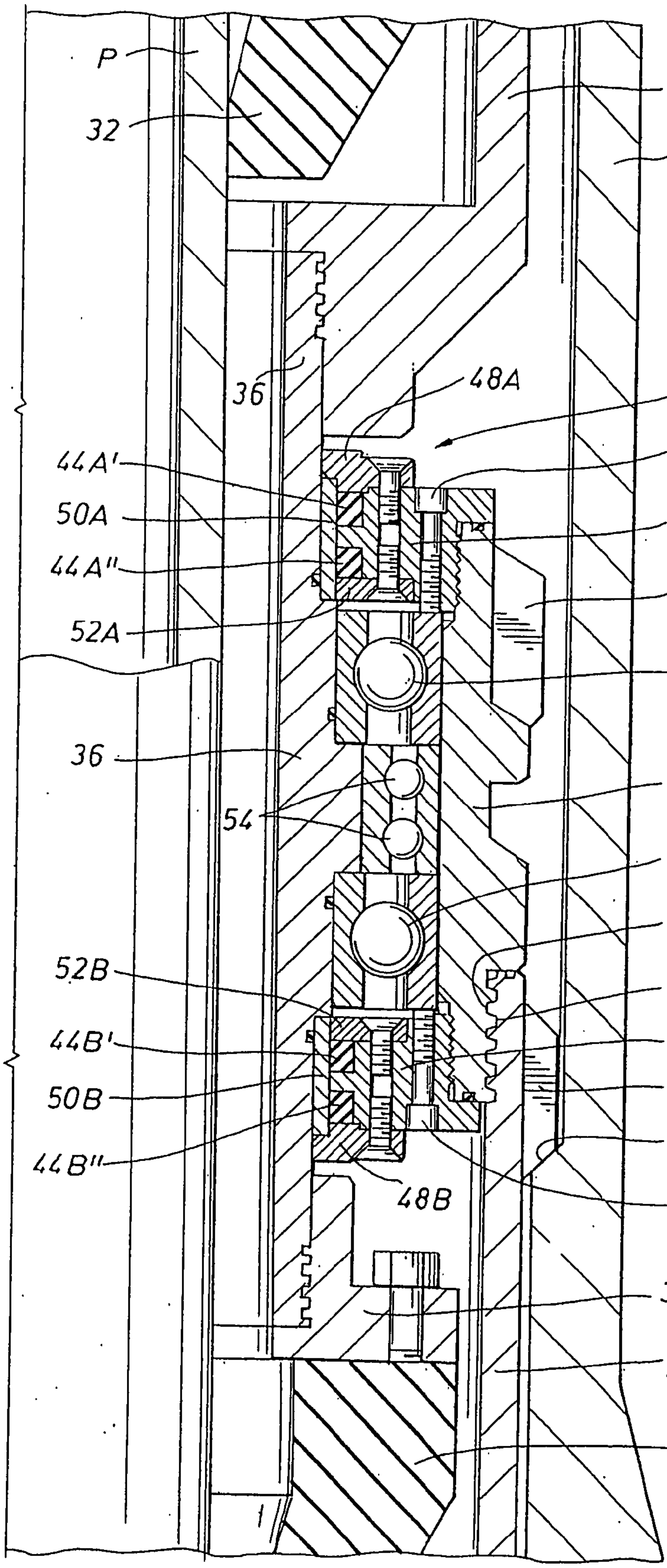
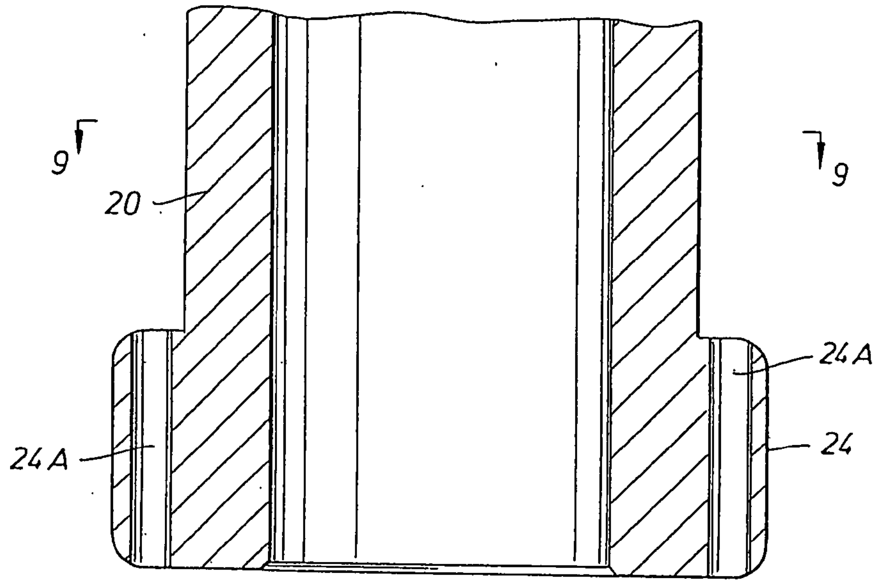

P
32
30
R
36
48A
28
44A'
46A
50A
44A
44A''
40A
52A
42A
36
38
54
42B
20A
52B
38A
44B'
44B
50B
26A
44B''
R'
48B
46B
36
20
34

FIG. 7

FIG. 8



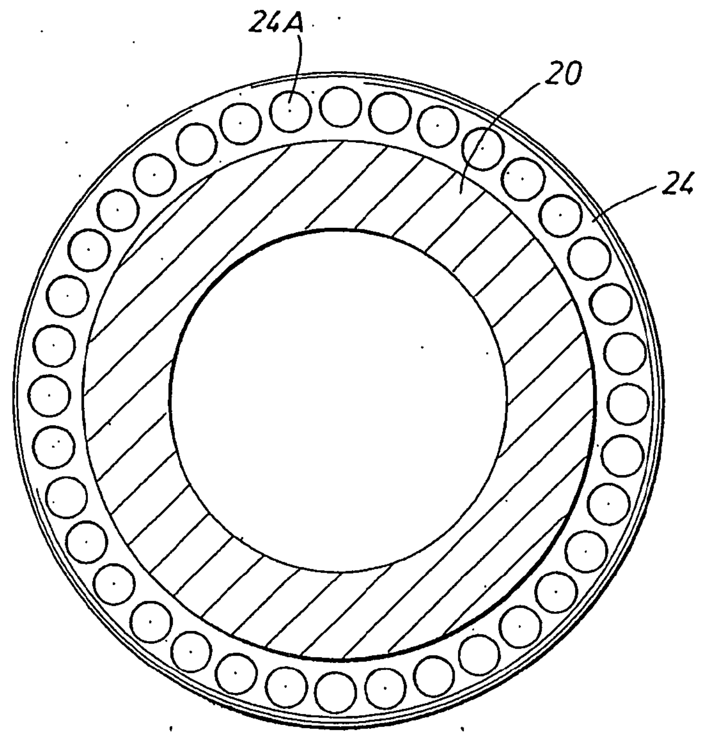


FIG. 9

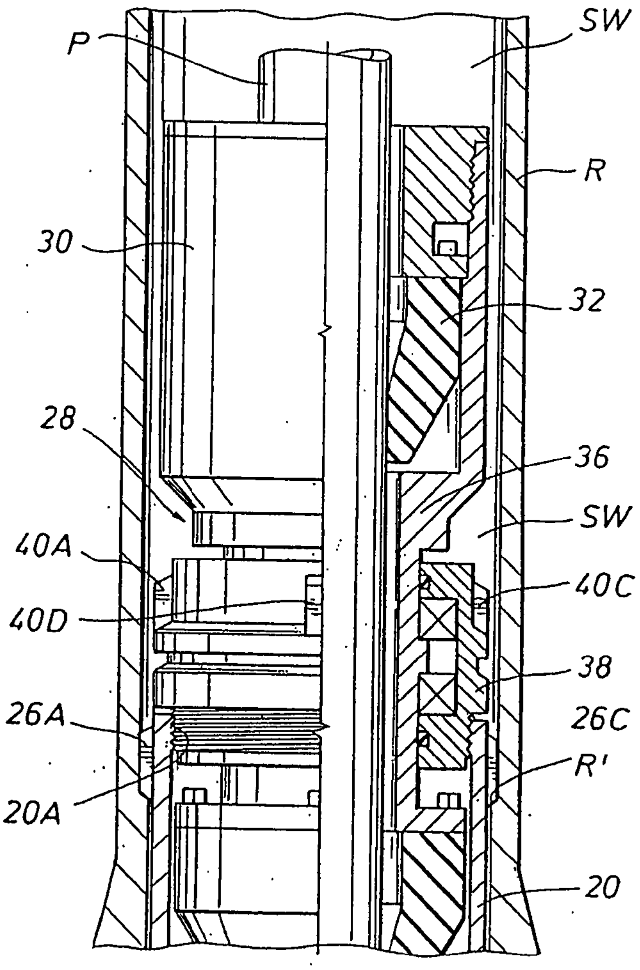


FIG. 10

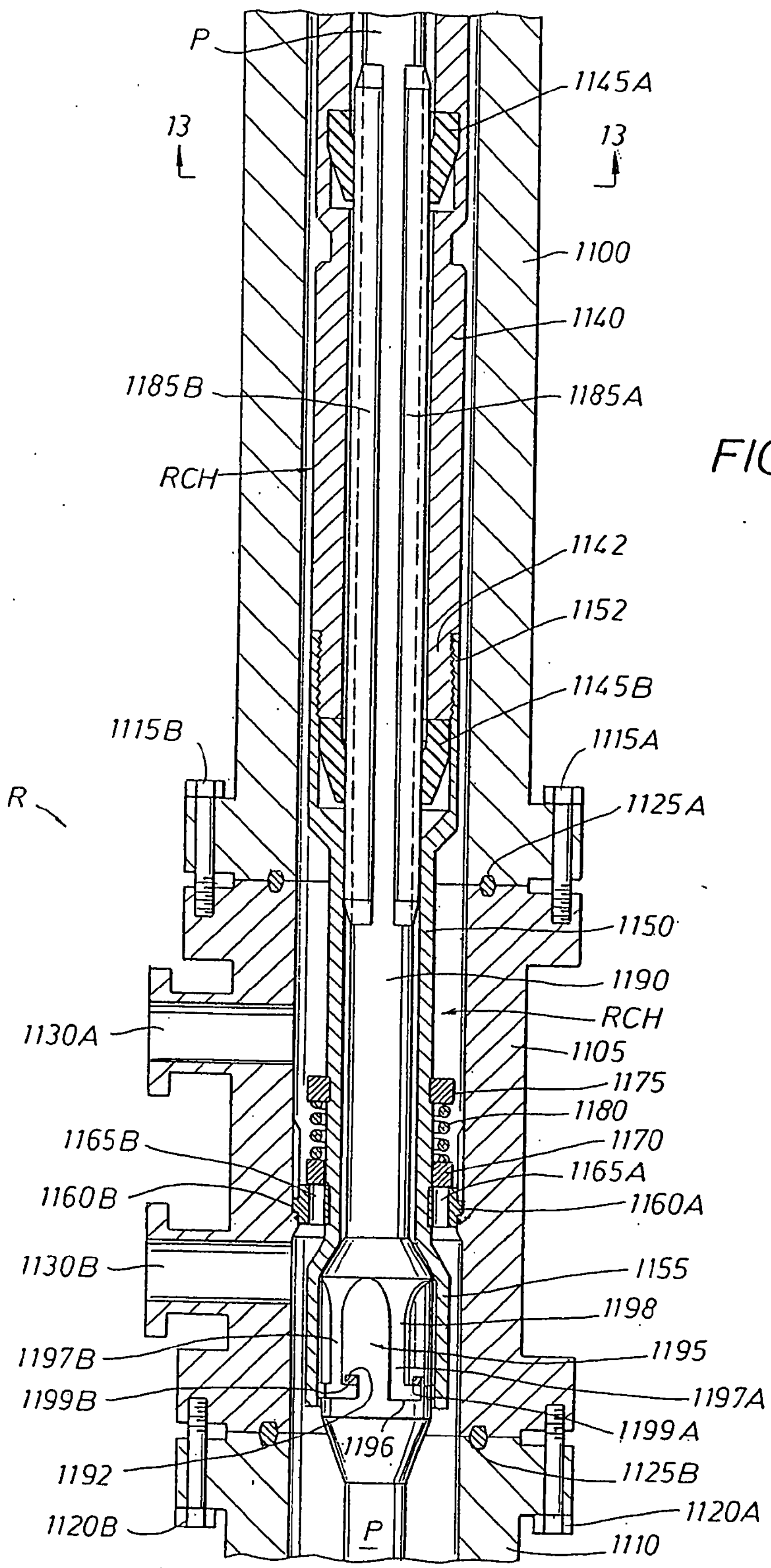

P
1145A
13
13
1100
1140
1185B
1185A
RCH
1142
1152
1145B
1115B
1115A
R
1125A
1150
1190
RCH
1130A
1105
1175
1180
1170
1165B
1165A
1160B
1160A
1130B
1155
1198
1195
1197B
1197A
1199B
1199A
1196
1192
1125B
1120B
1120A
P
1110

FIG.11

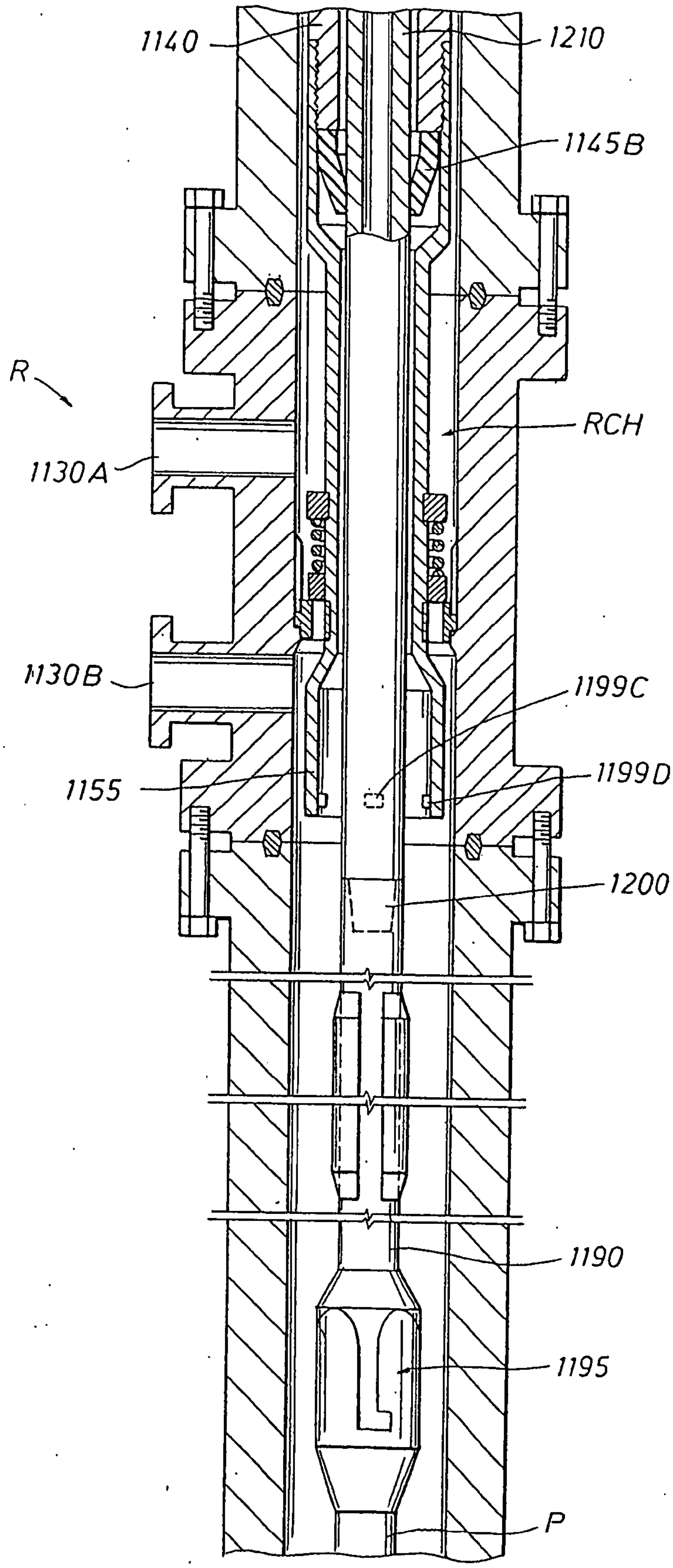

1140
1210
1145B
R
RCH
1130A
1130B
1199C
1155
1199D
1200
1190
1195
P

FIG.12

FIG.13

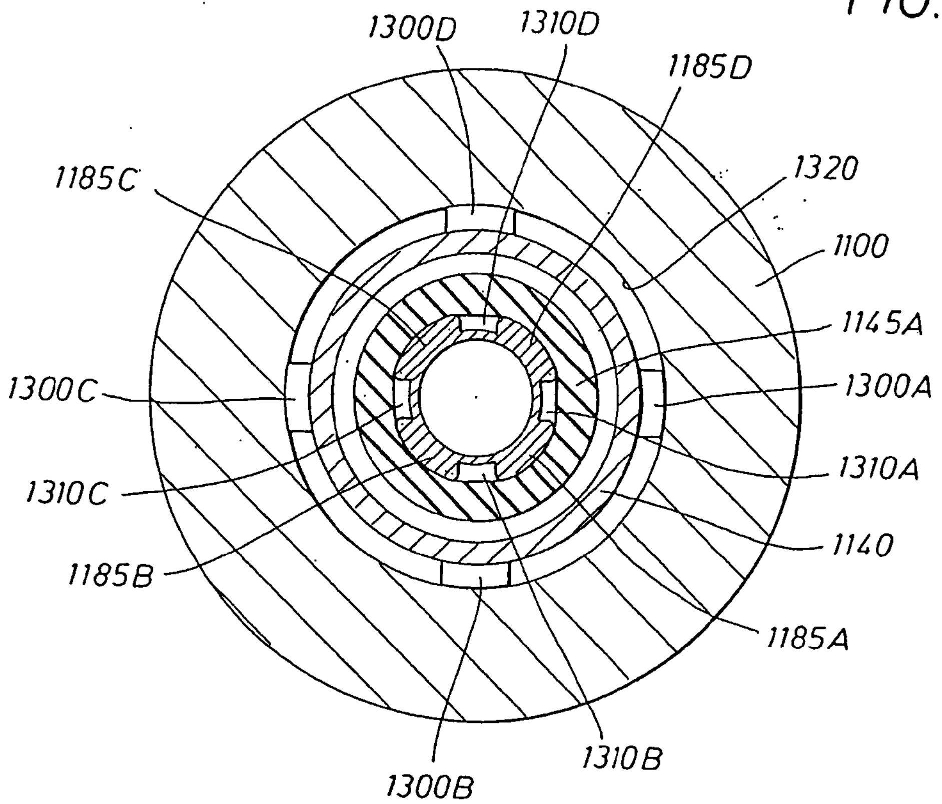

1300D
1310D
1185D
1185C
1320
1100
1145A
1300C
1300A
1310A
1310C
1140
1185B
1185A
1310B
1300B

FIG.14

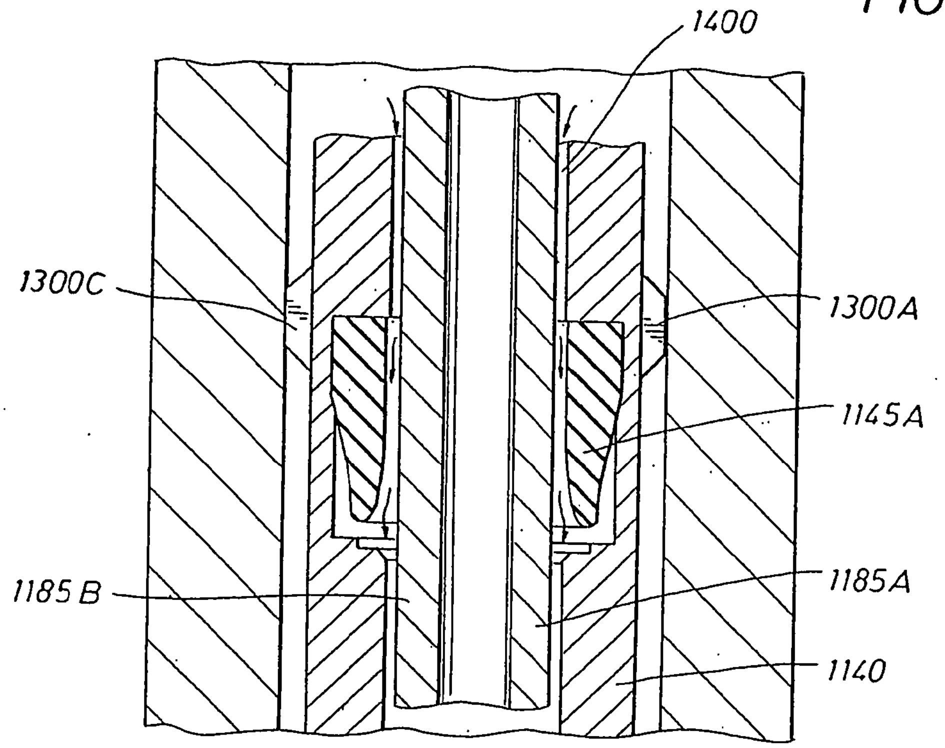

1400
1300C
1300A
1145A
1185B
1185A
1140

FIG. 15

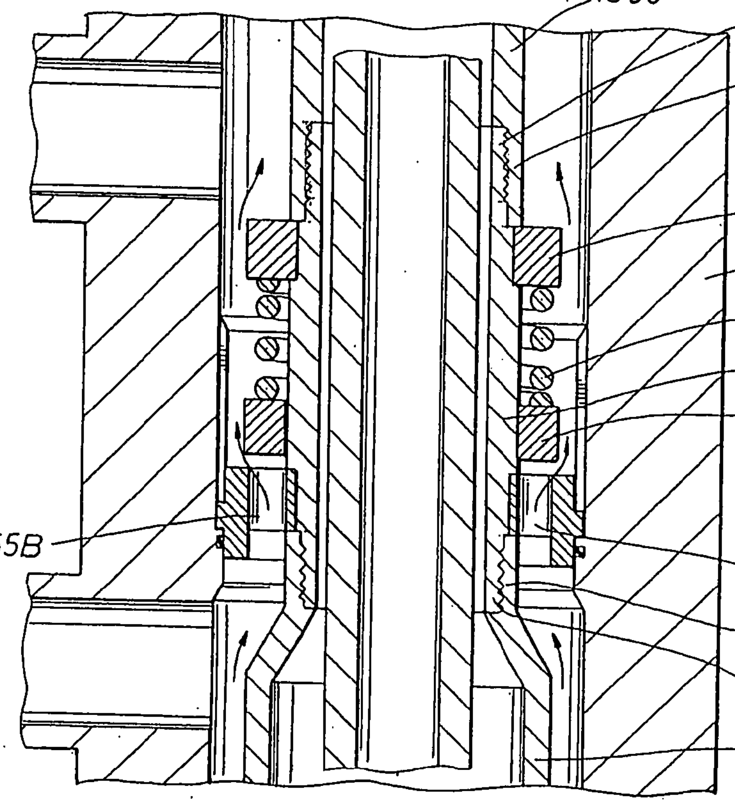
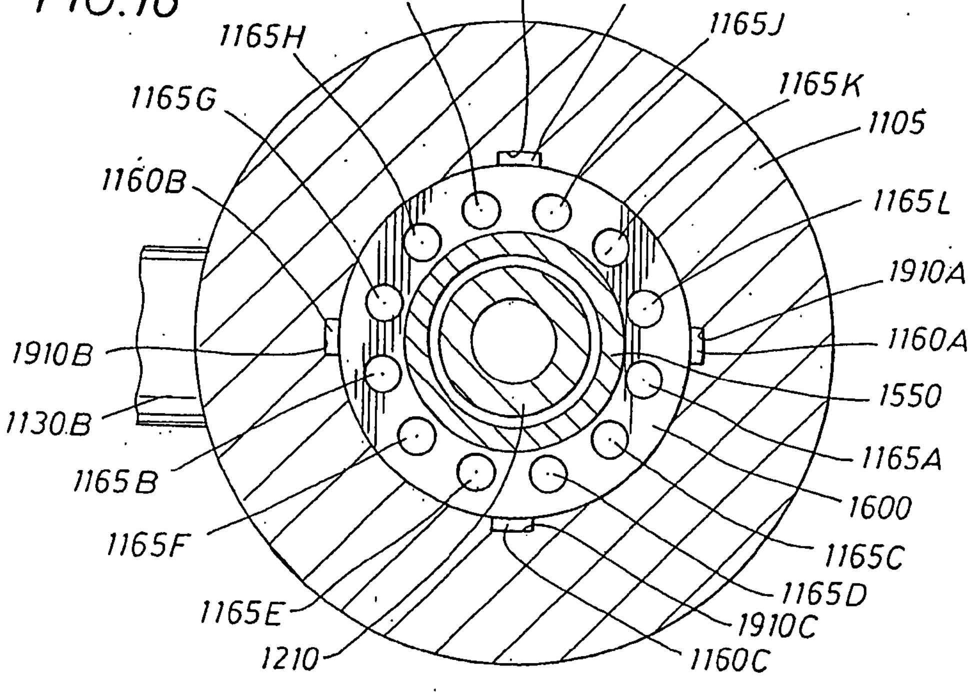

1560
1540
1530
1175
1105
1180
1550
1170
16
1165B
16
1165A
1510
1520
1155

FIG. 16


1165I
1910D
1160D
1165J
1165H
1165K
1165G
1105
1160B
1165L
1910A
1160A
1910B
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1165E
1910C
1210
1160C

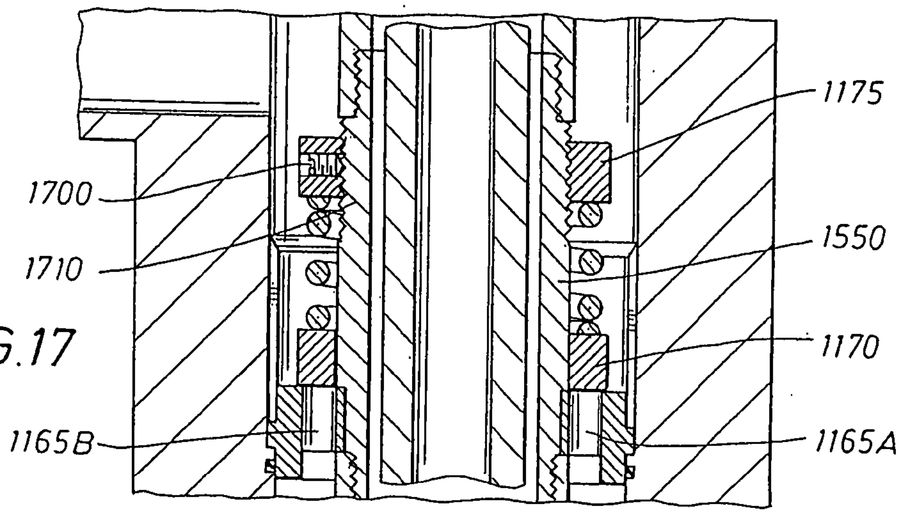


FIG.17

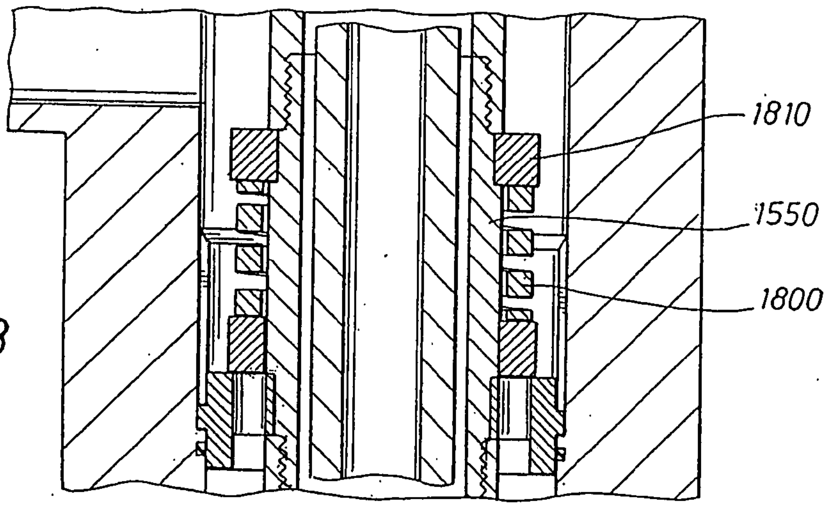


FIG.18

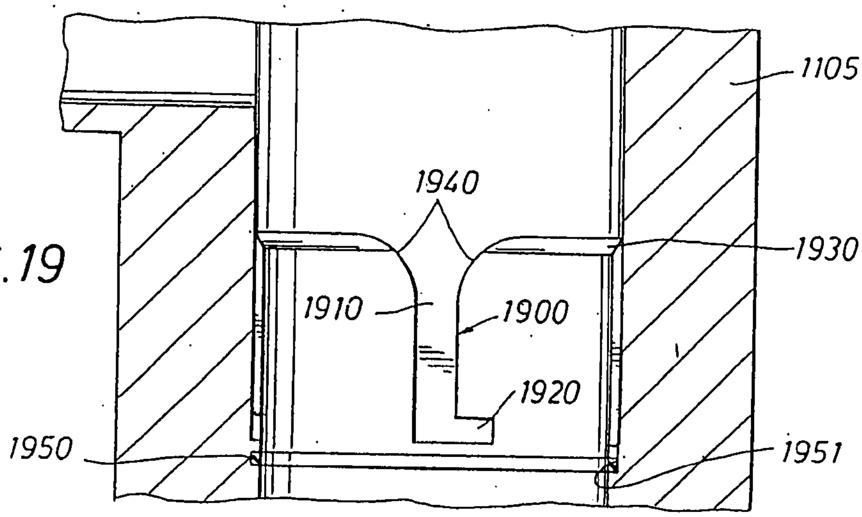


FIG.19

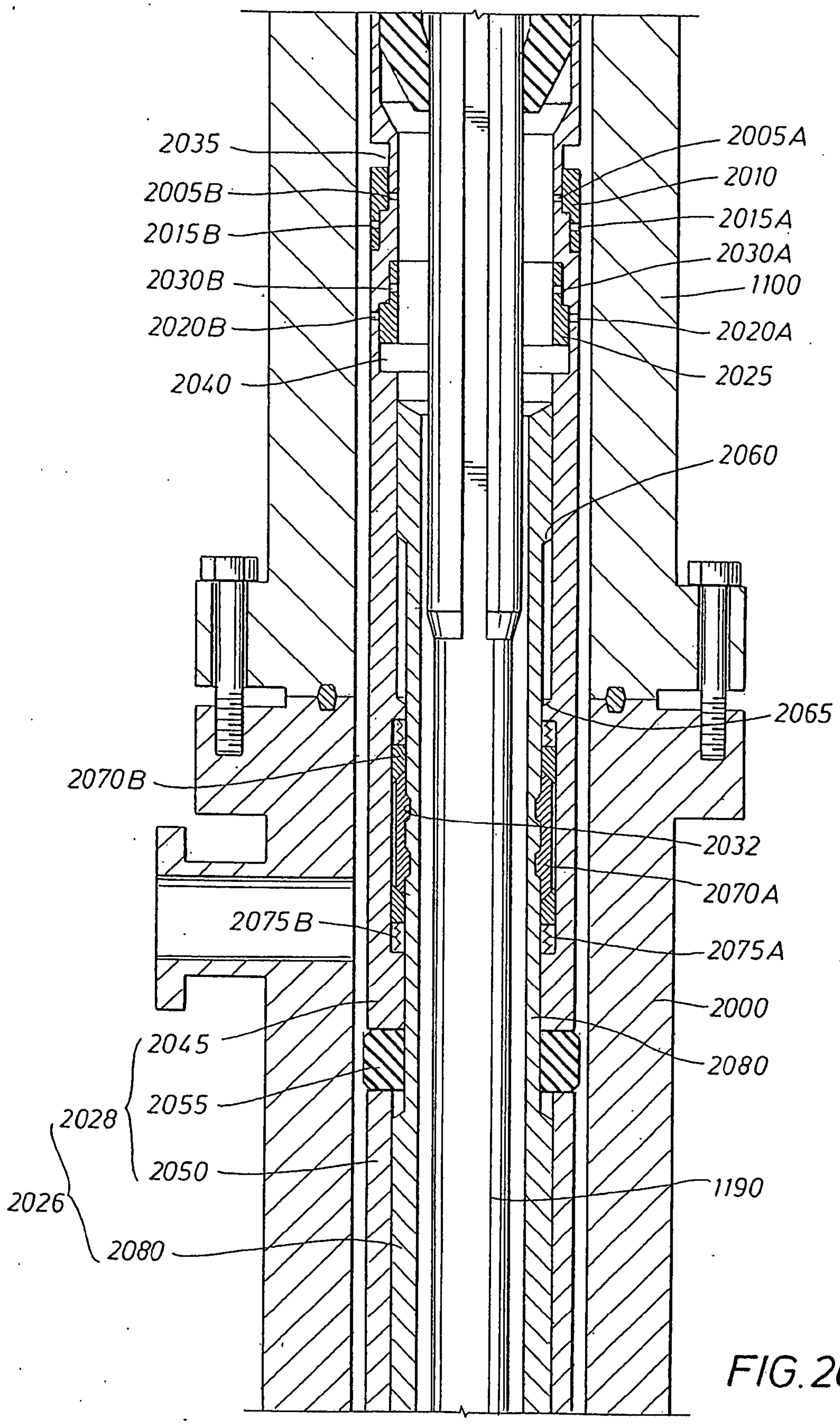
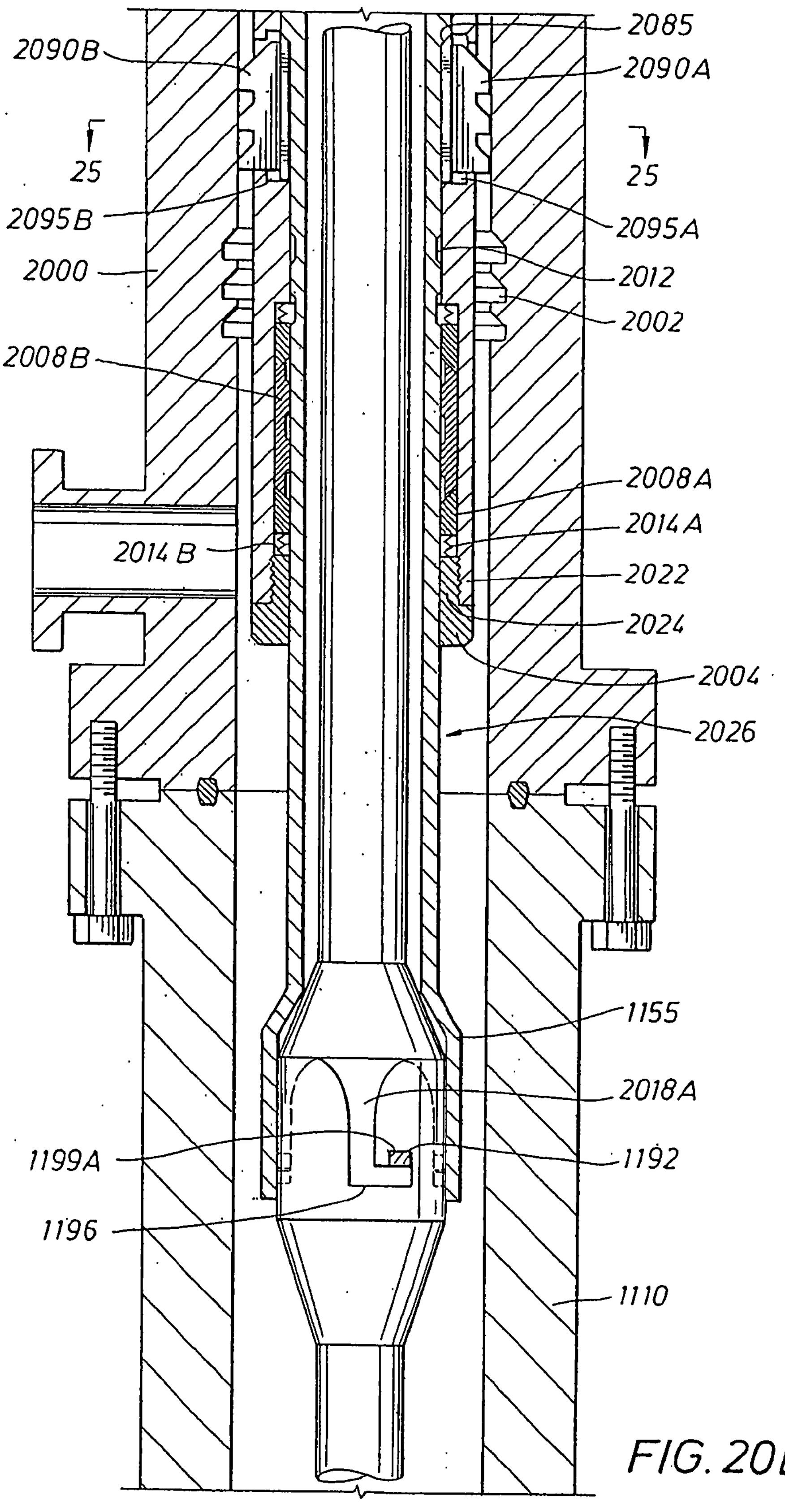

2035
2005B
2015B
2030B
2020B
2040
2005A
2010
2015A
2030A
1100
2020A
2025
2060
2065
2070B
2032
2070A
2075B
2075A
2000
2045
2080
2055
2028
2050
1190
2026
2080

FIG. 20A



2085
2090B
2090A
25
25
2095B
2095A
2000
2012
2002
2008B
2008A
2014A
2014 B
2022
2024
2004
2026
1155
2018A
1199A
1192
1196
1110

FIG. 20B

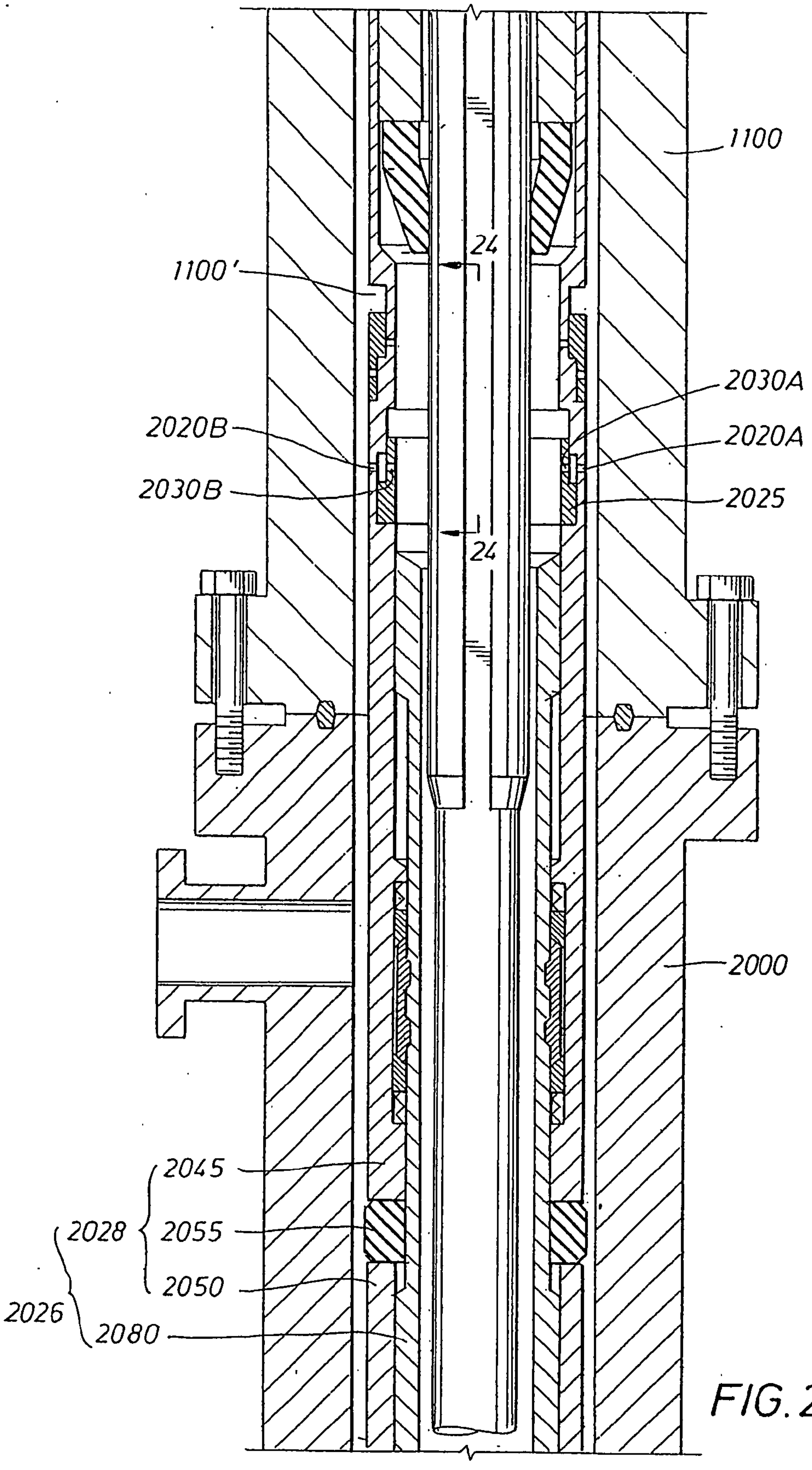

1100
1100'
24
2030A
2020B
2020A
2030B
2025
24
2000
2045
2028
2055
2050
2026
2080

FIG. 21A

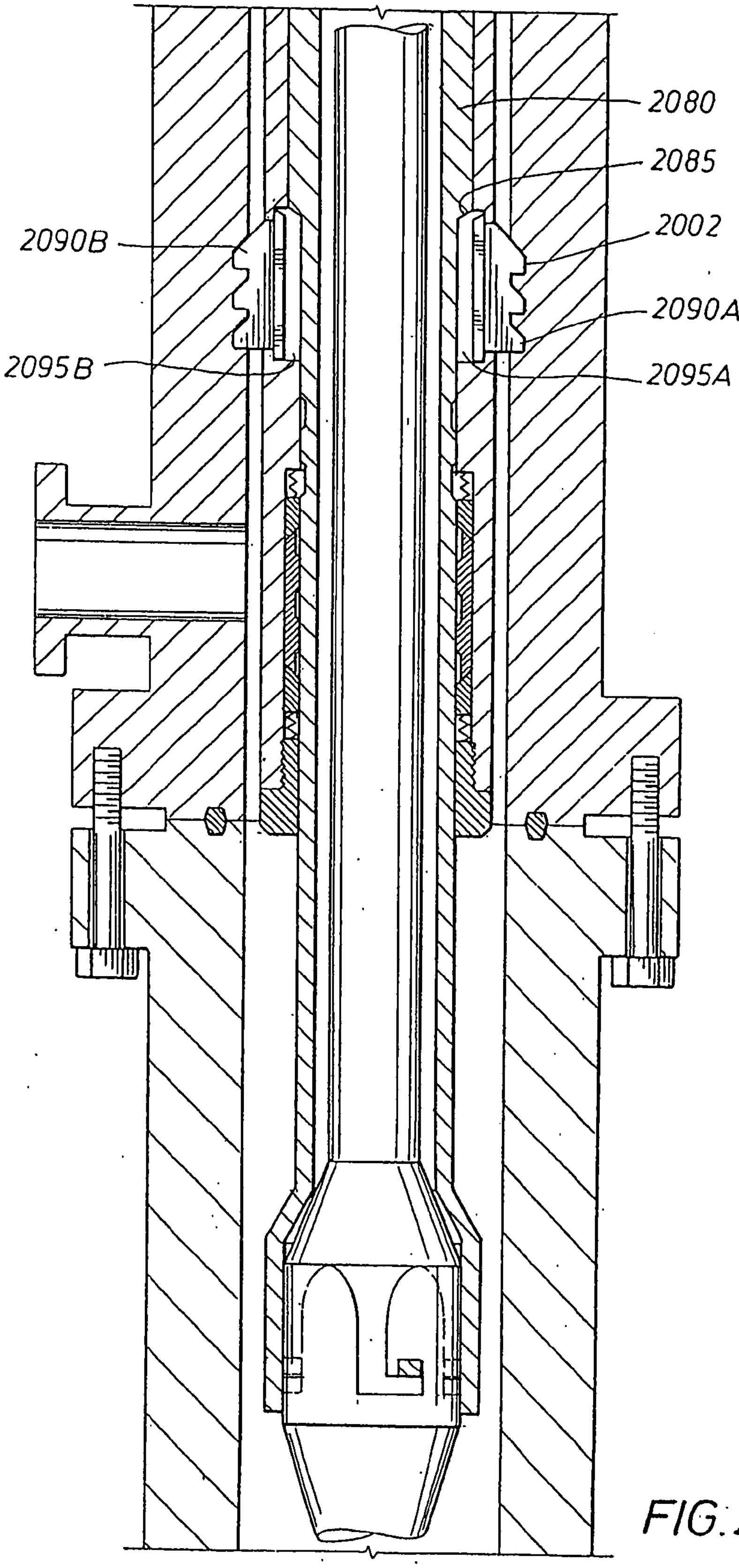


FIG. 21B

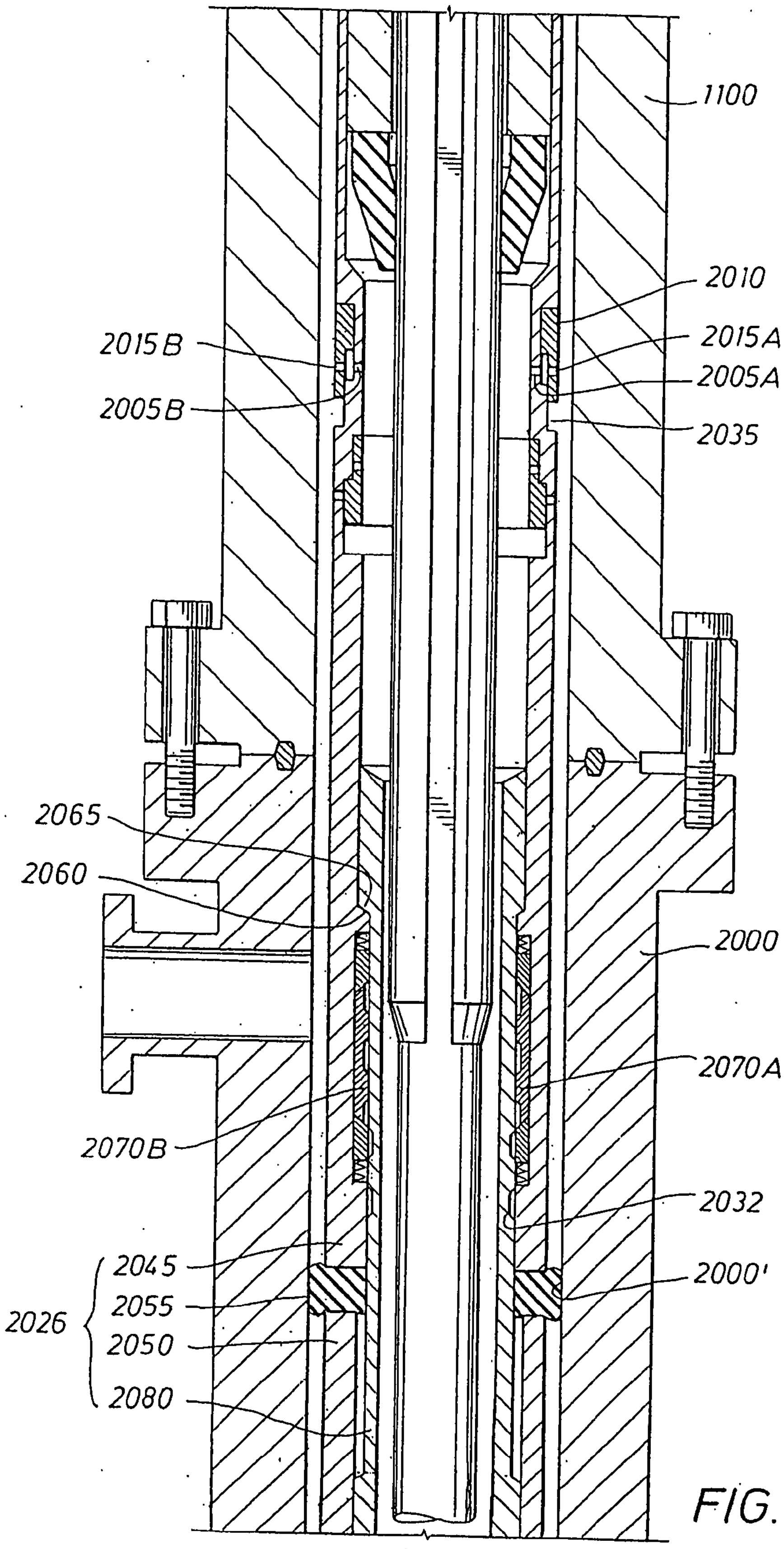

1100
2010
2015B
2015A
2005A
2005B
2035
2065
2060
2000
2070A
2070B
2032
2045
2000'
2026
2055
2050
2080

FIG. 22A

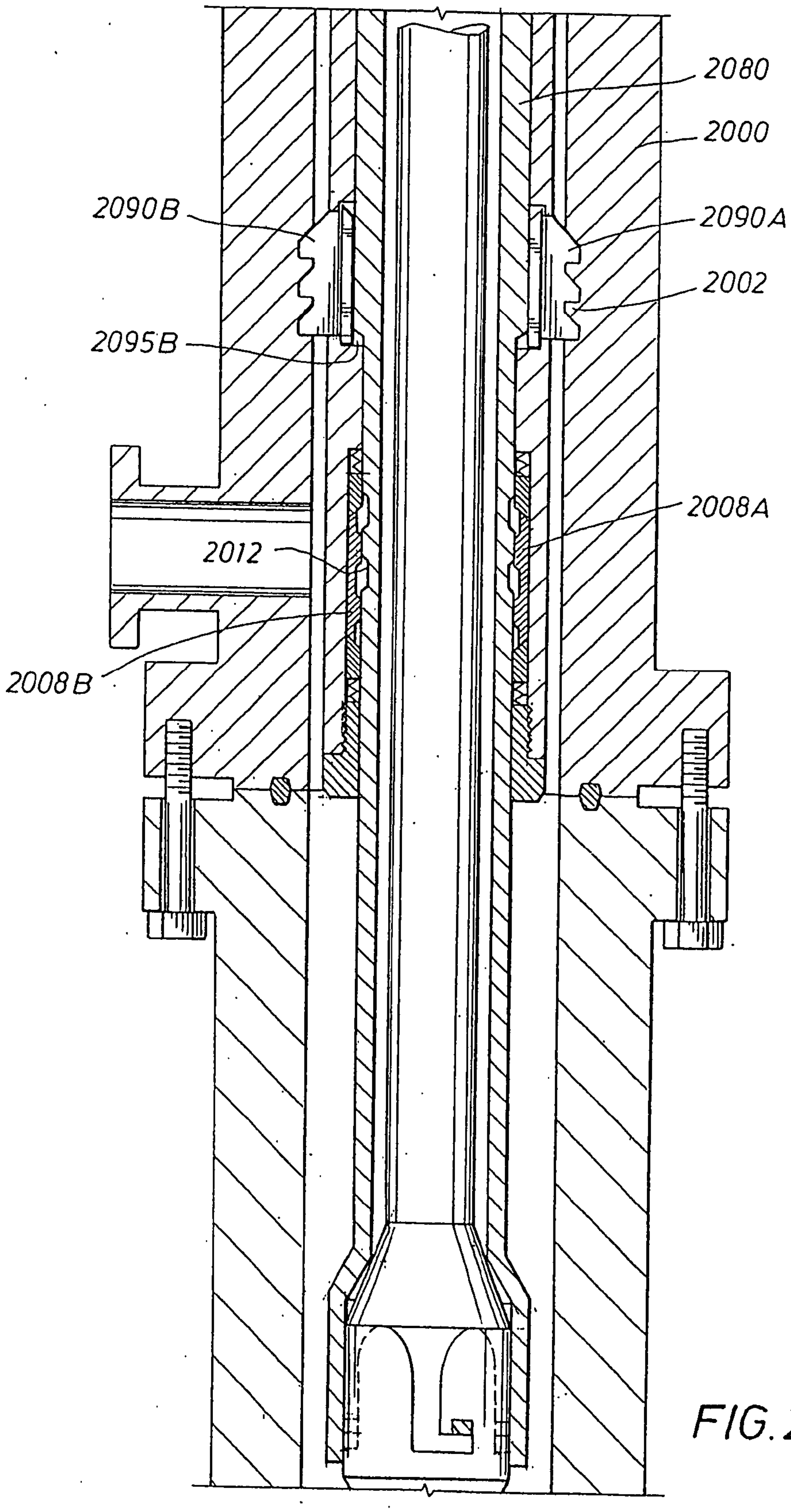
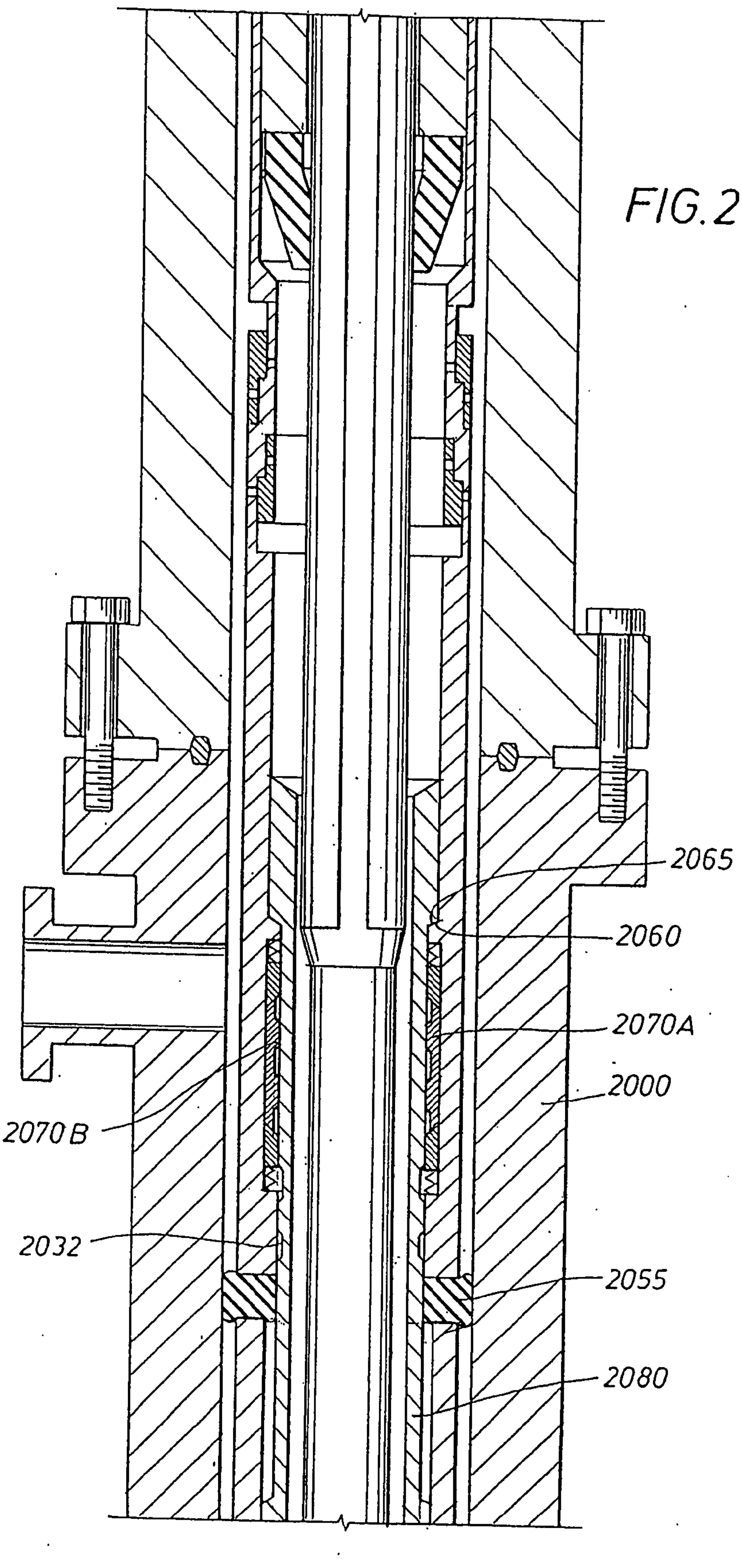


FIG. 22B

FIG.23A



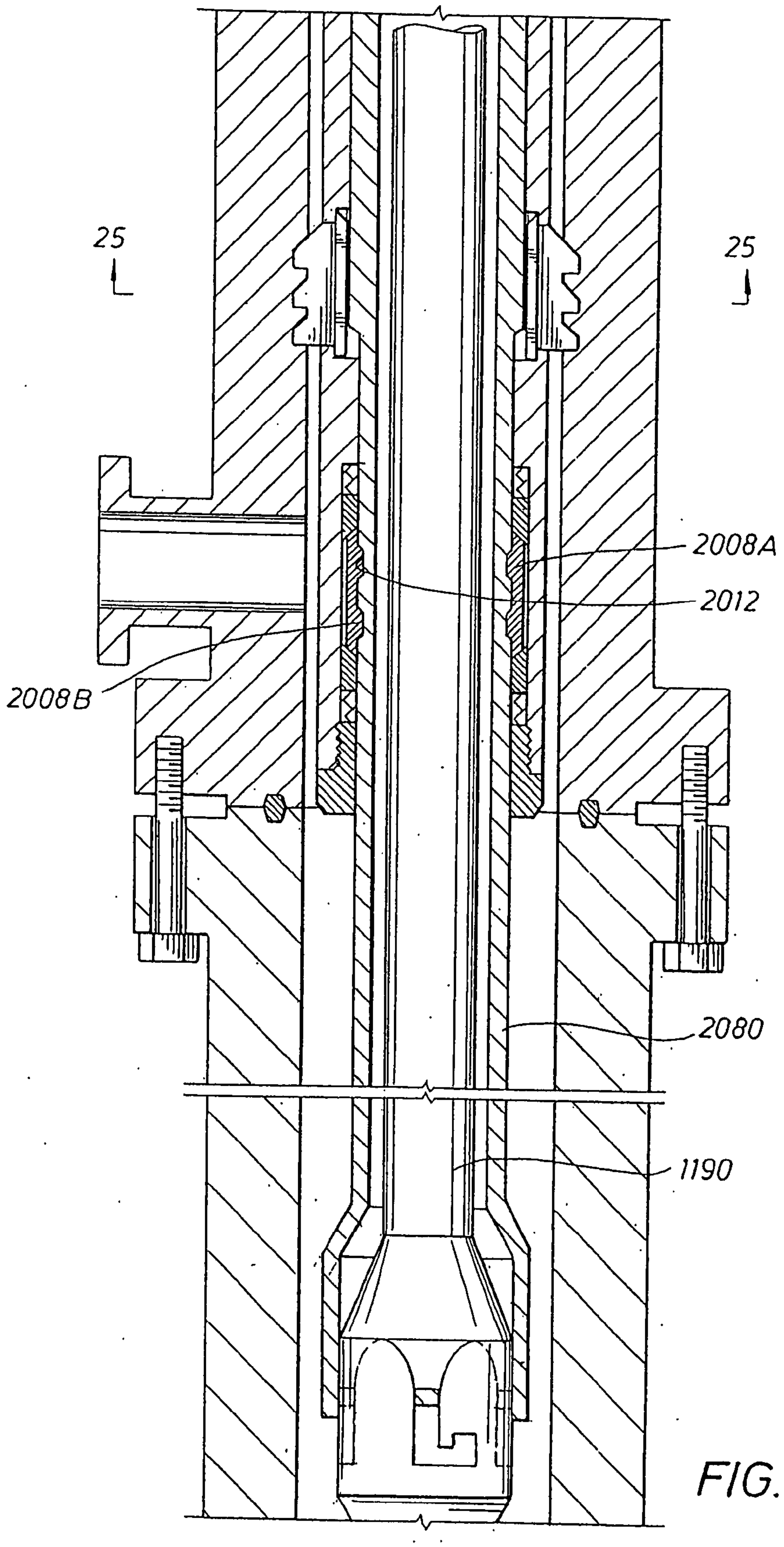
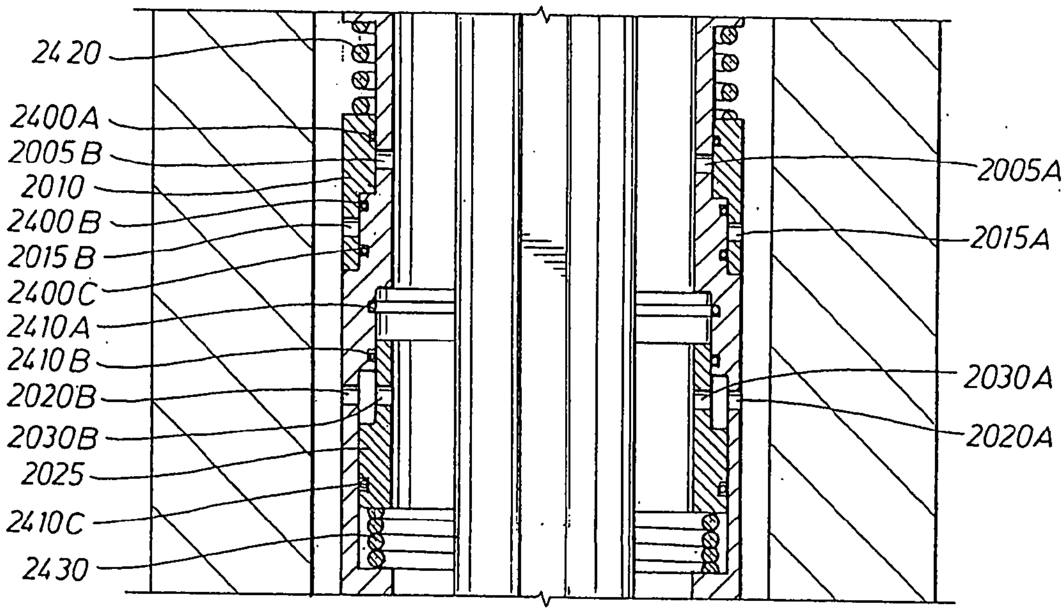


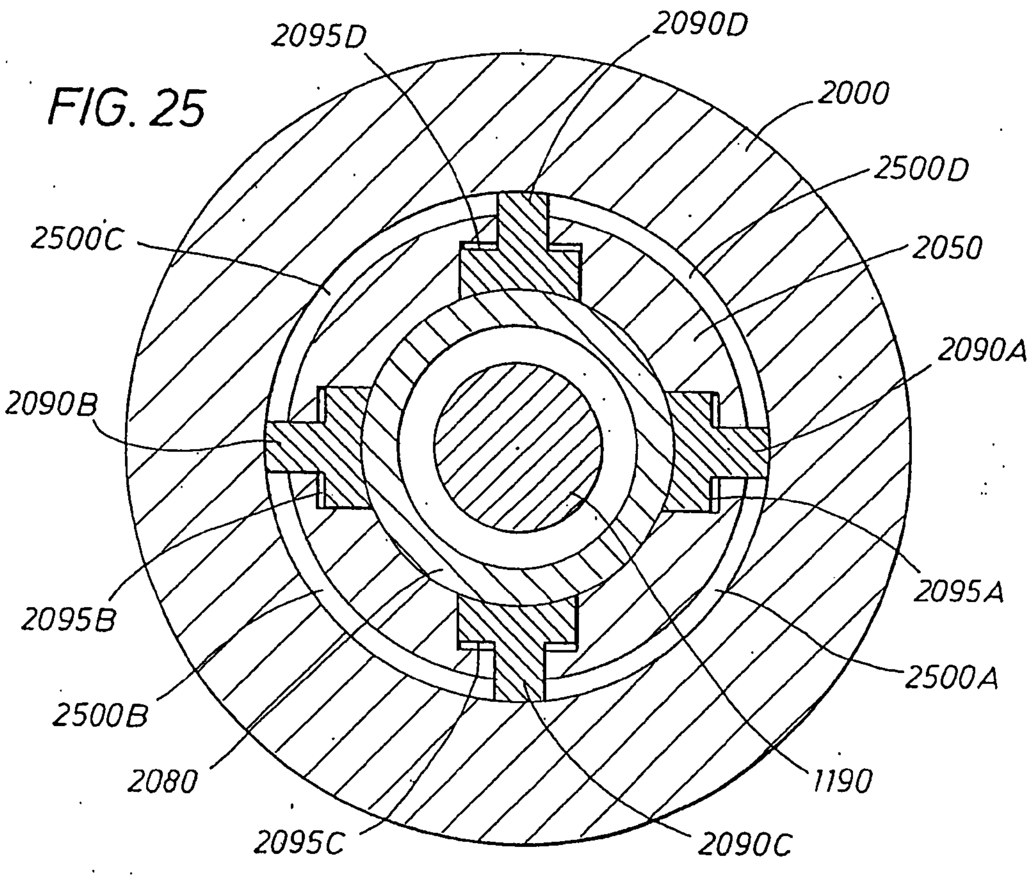
FIG.23B

FIG. 24



2420
2400A
2005B
2010
2400B
2015B
2400C
2410A
2410B
2020B
2030B
2025
2410C
2430
2005A
2015A
2030A
2020A

FIG. 25



2095D
2090D
2000
2500D
2500C
2050
2090A
2090B
2095A
2095B
2500A
2500B
2080
1190
2095C
2090C

FIG. 26A

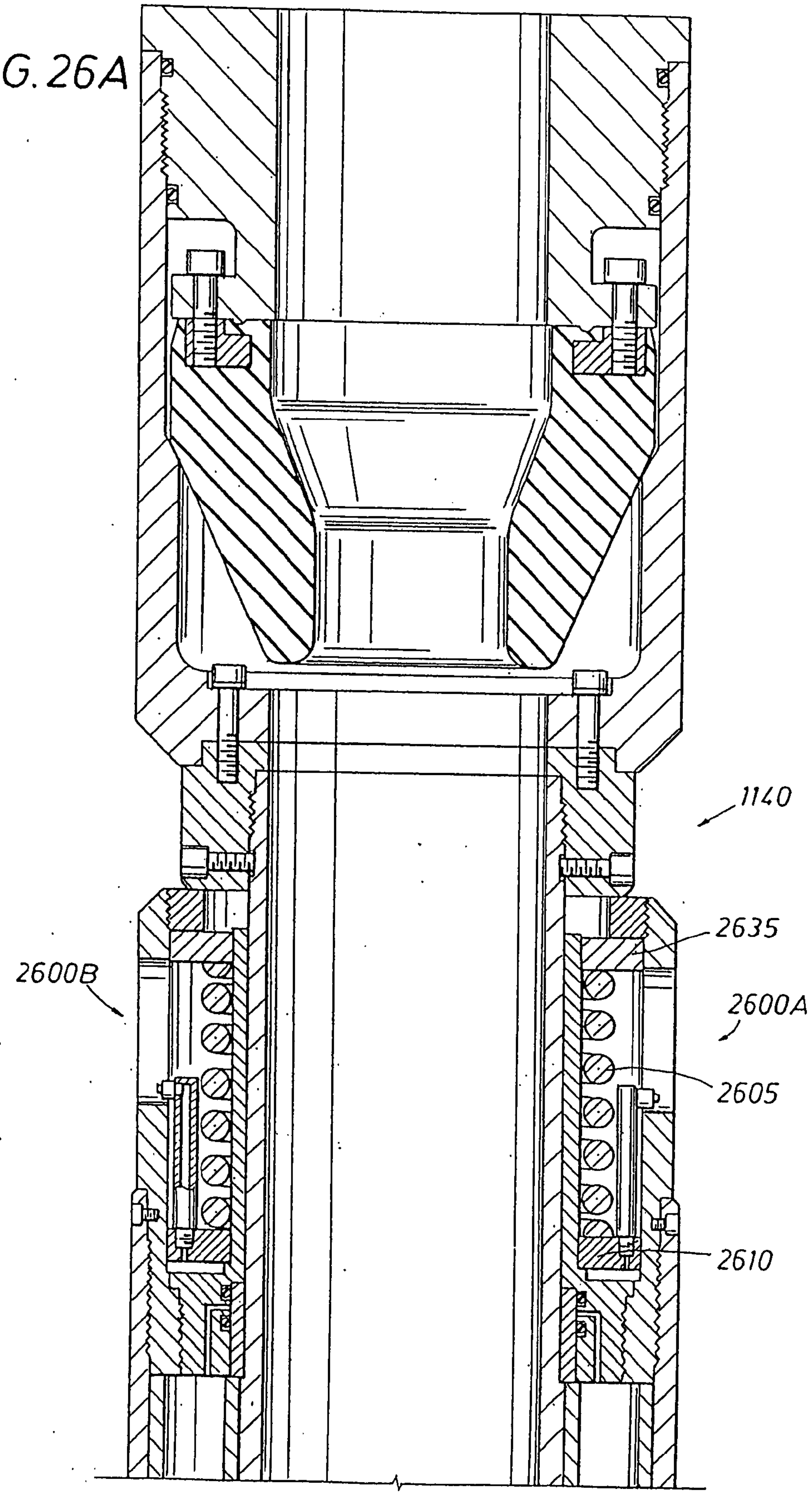


FIG. 26B

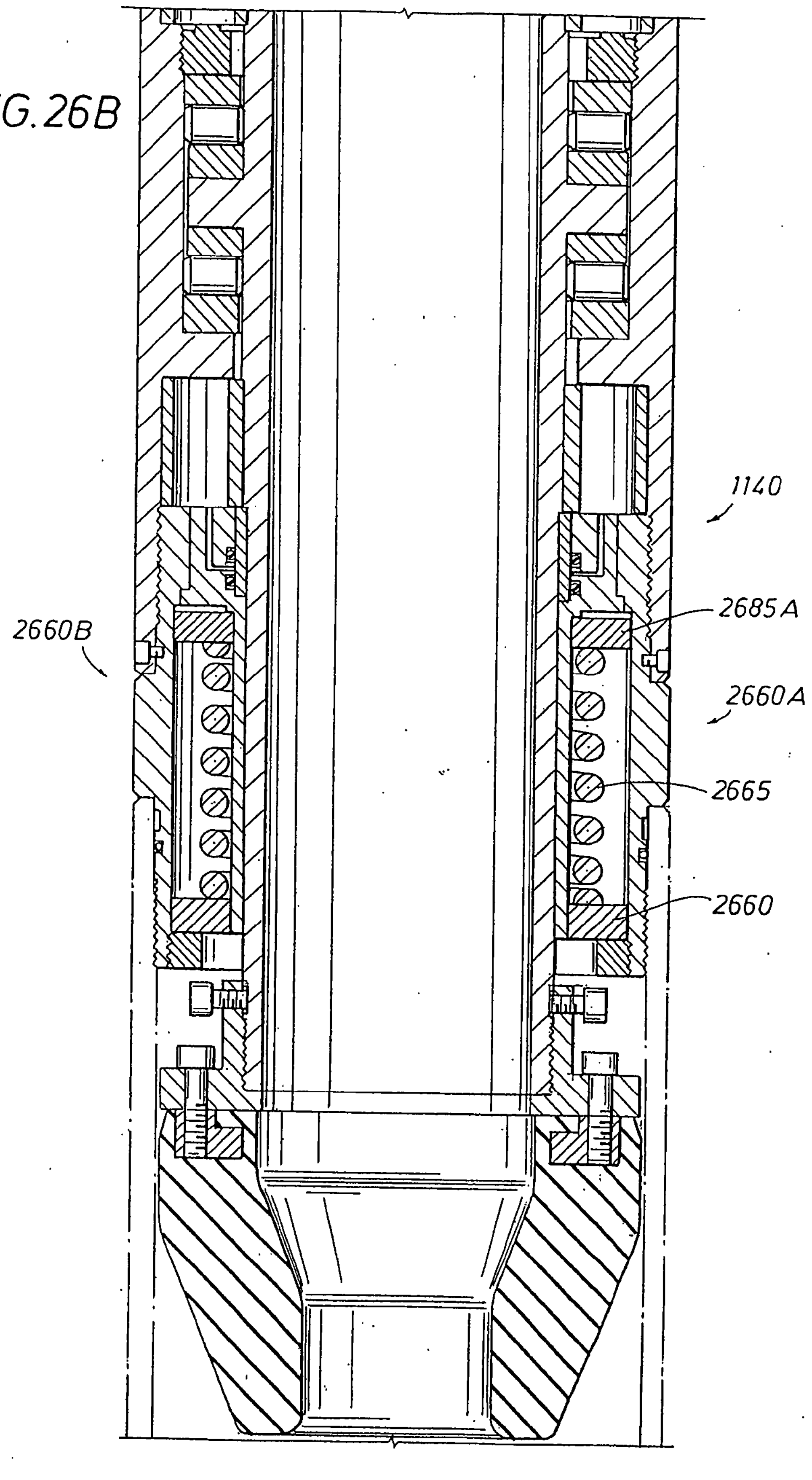


FIG. 26C

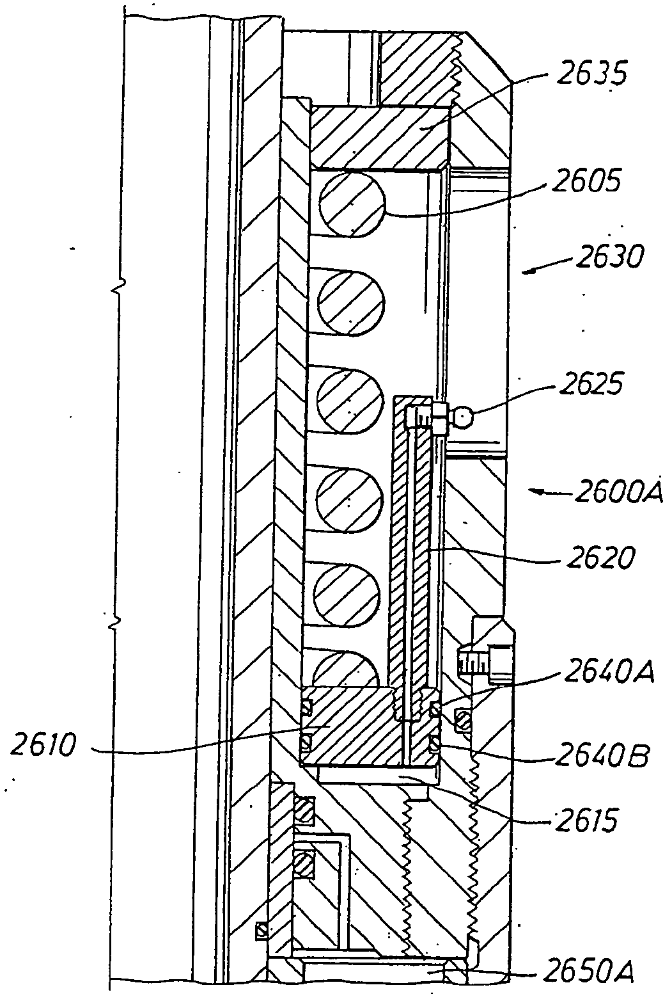


FIG. 26D

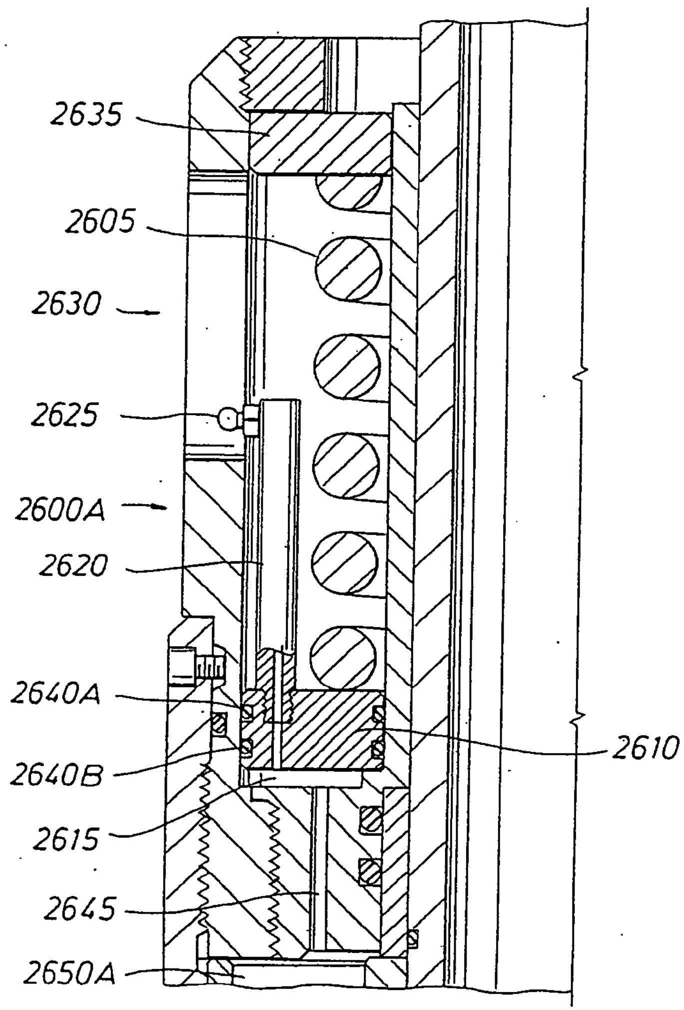


FIG. 26E

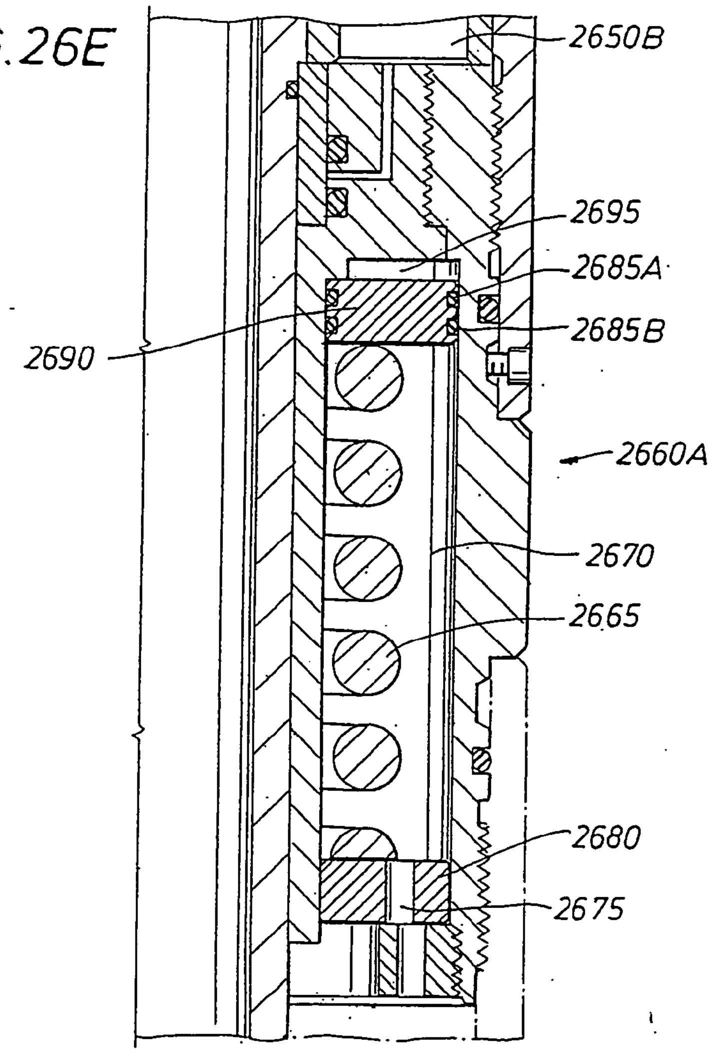
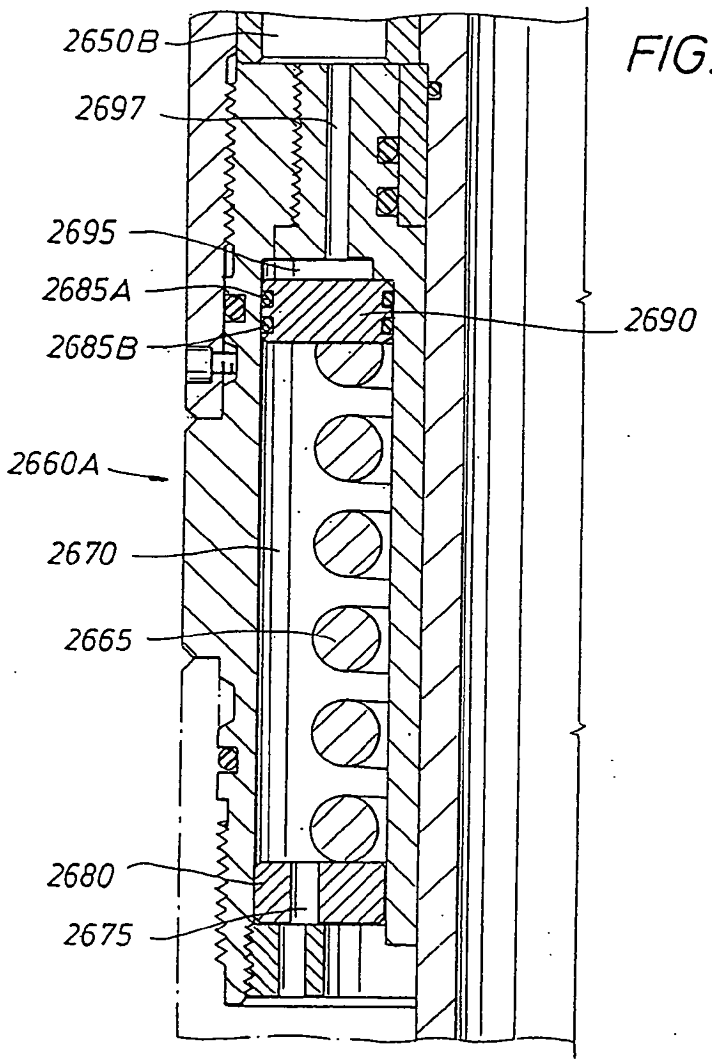


FIG. 26F



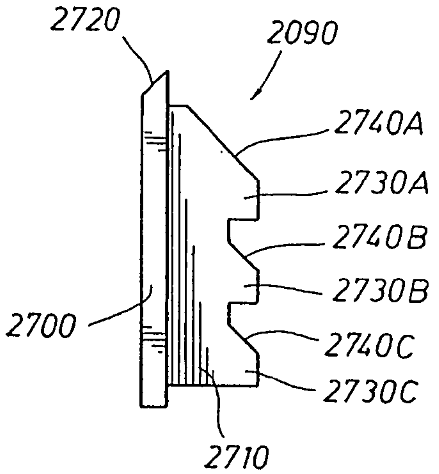

2720
2090
2740A
2730A
2740B
2730B
2700
2740C
2730C
2710

FIG. 27

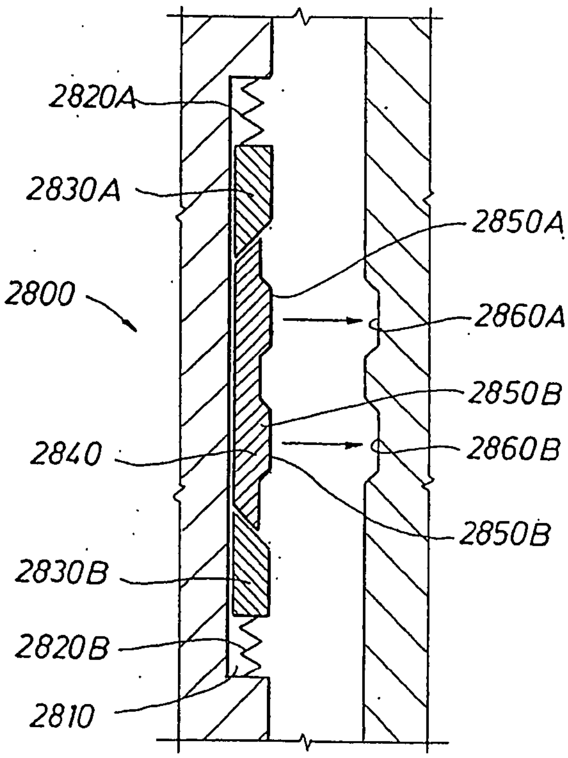

2820A
2830A
2850A
2800
2860A
2850B
2840
2860B
2850B
2830B
2820B
2810

FIG. 28

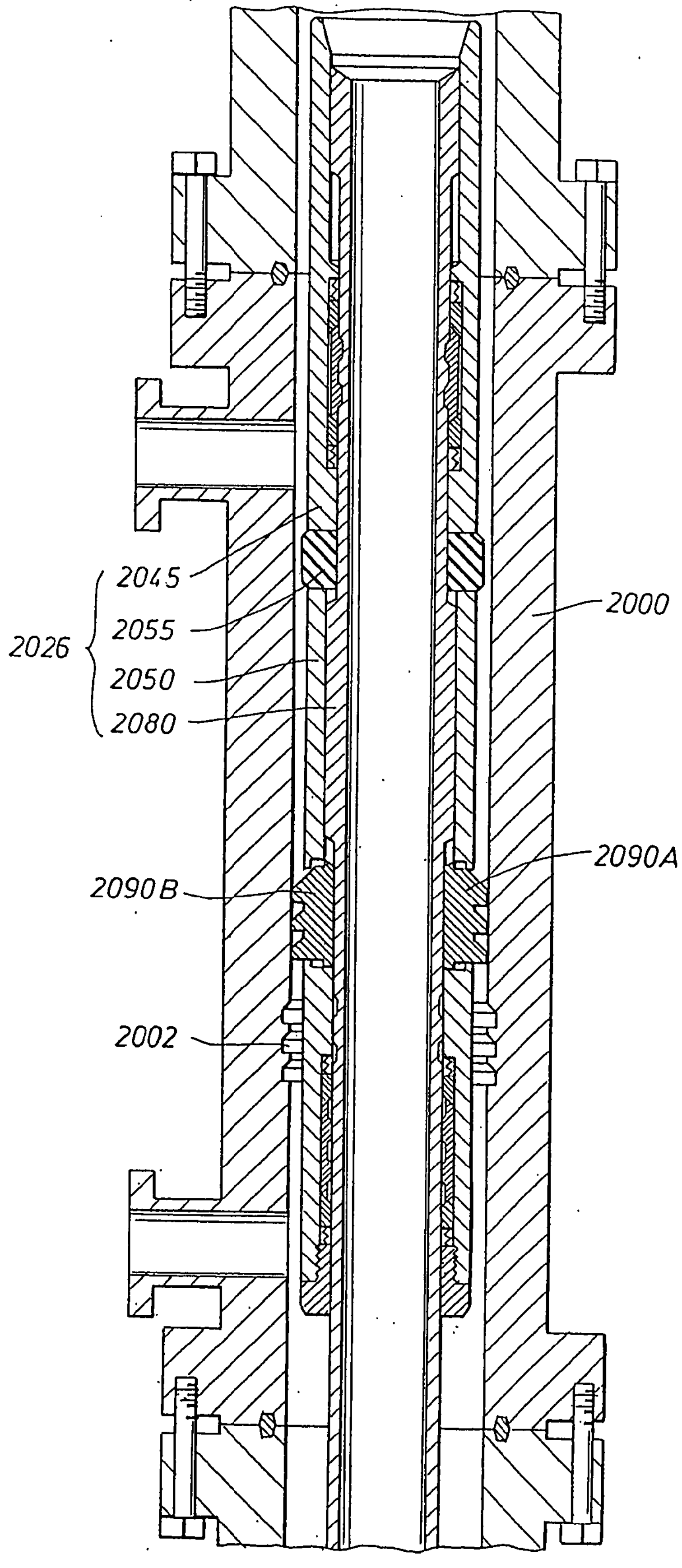


FIG. 29A

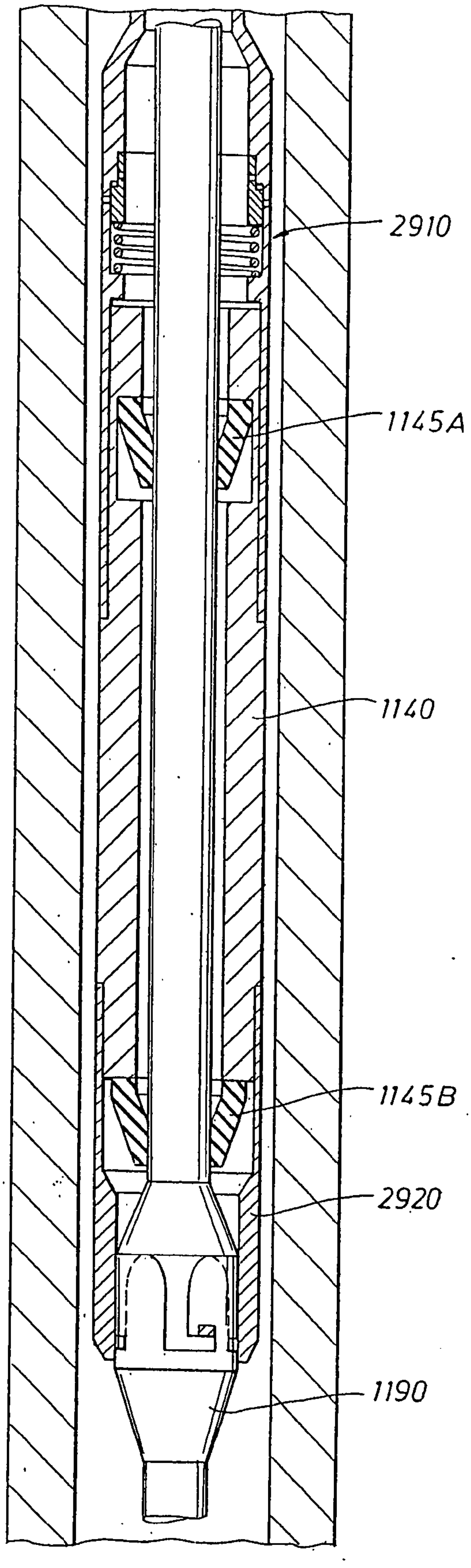


FIG. 29B

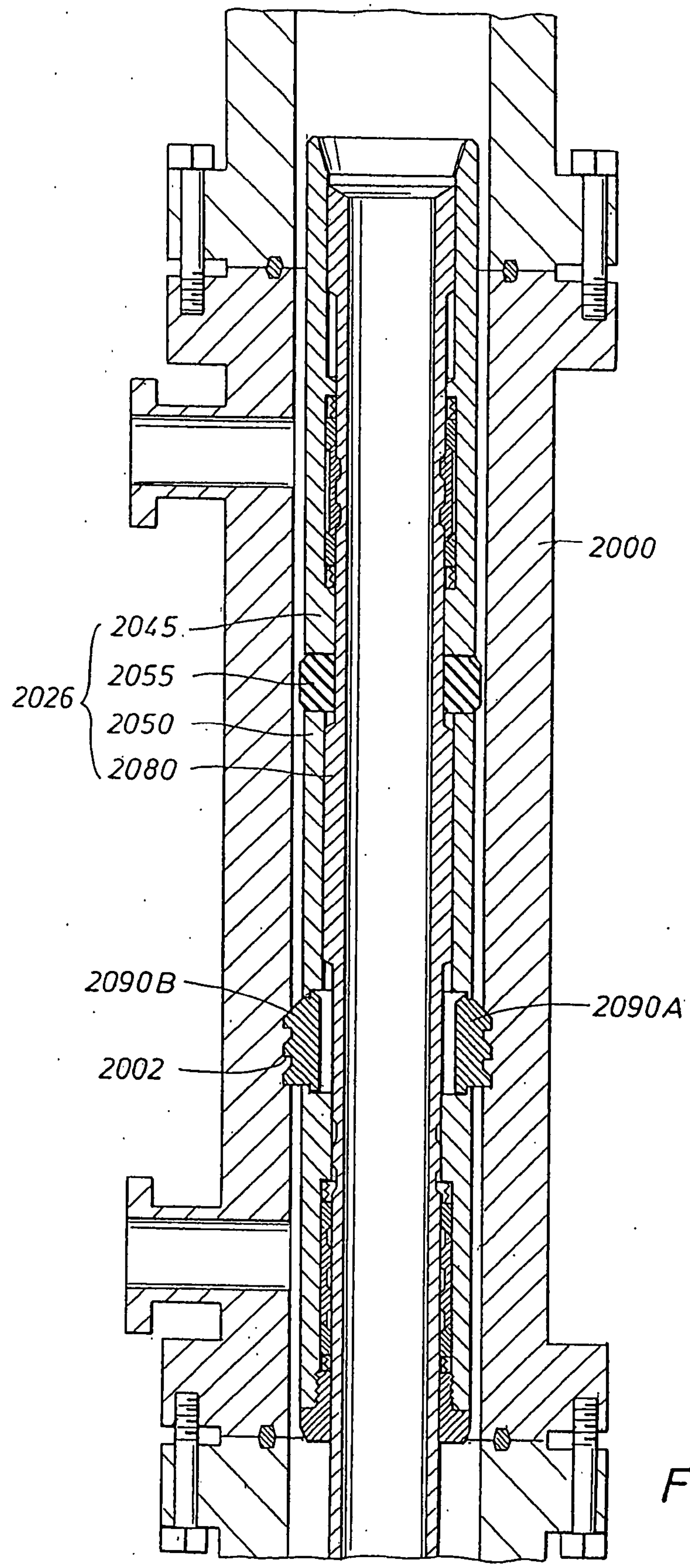


FIG. 30

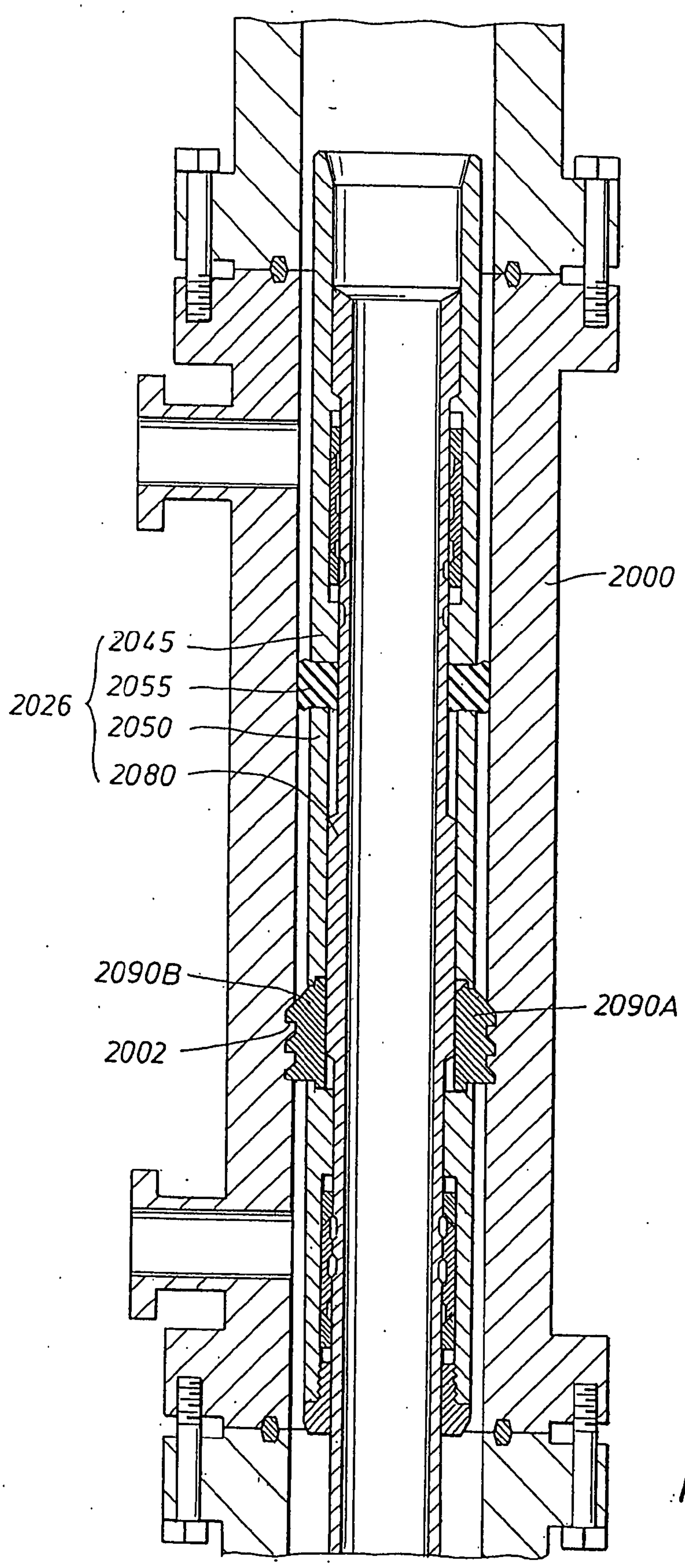


FIG. 31

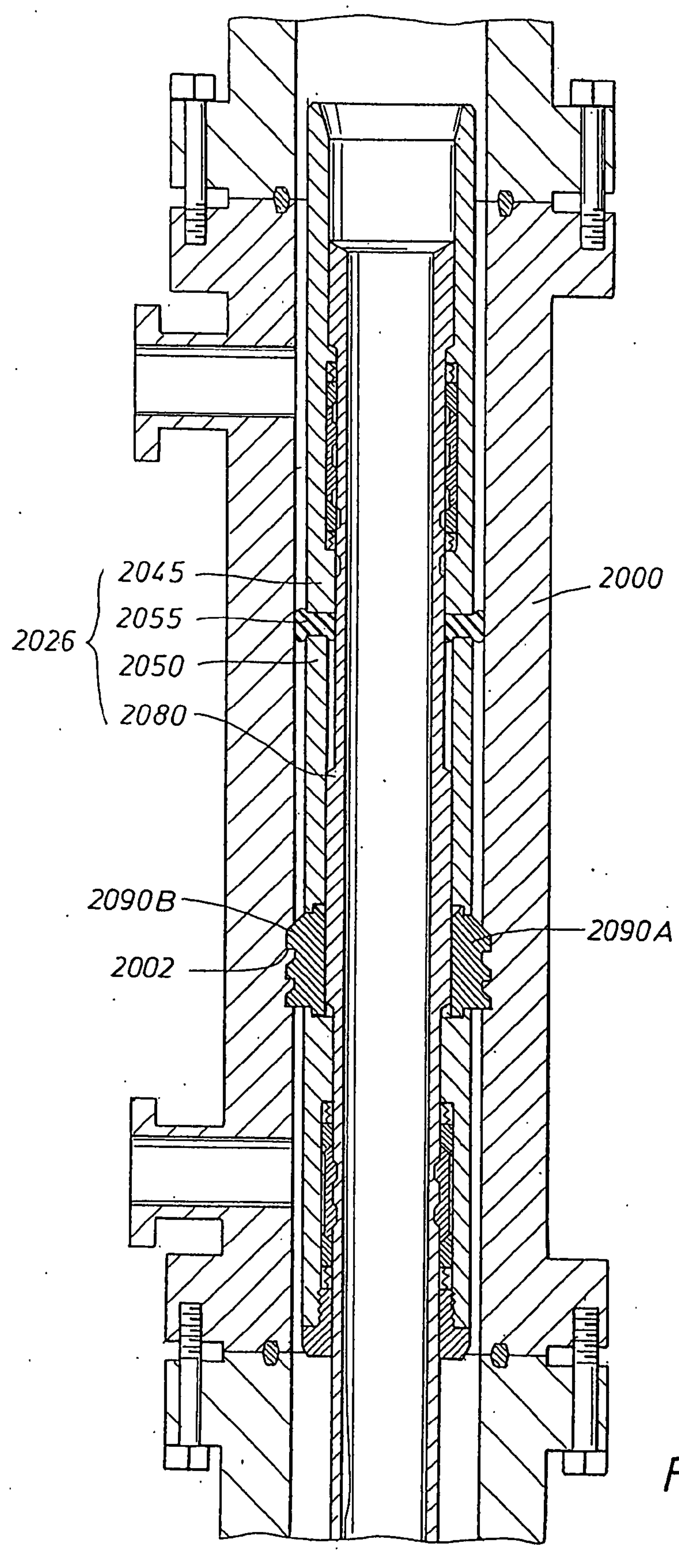


FIG. 32A

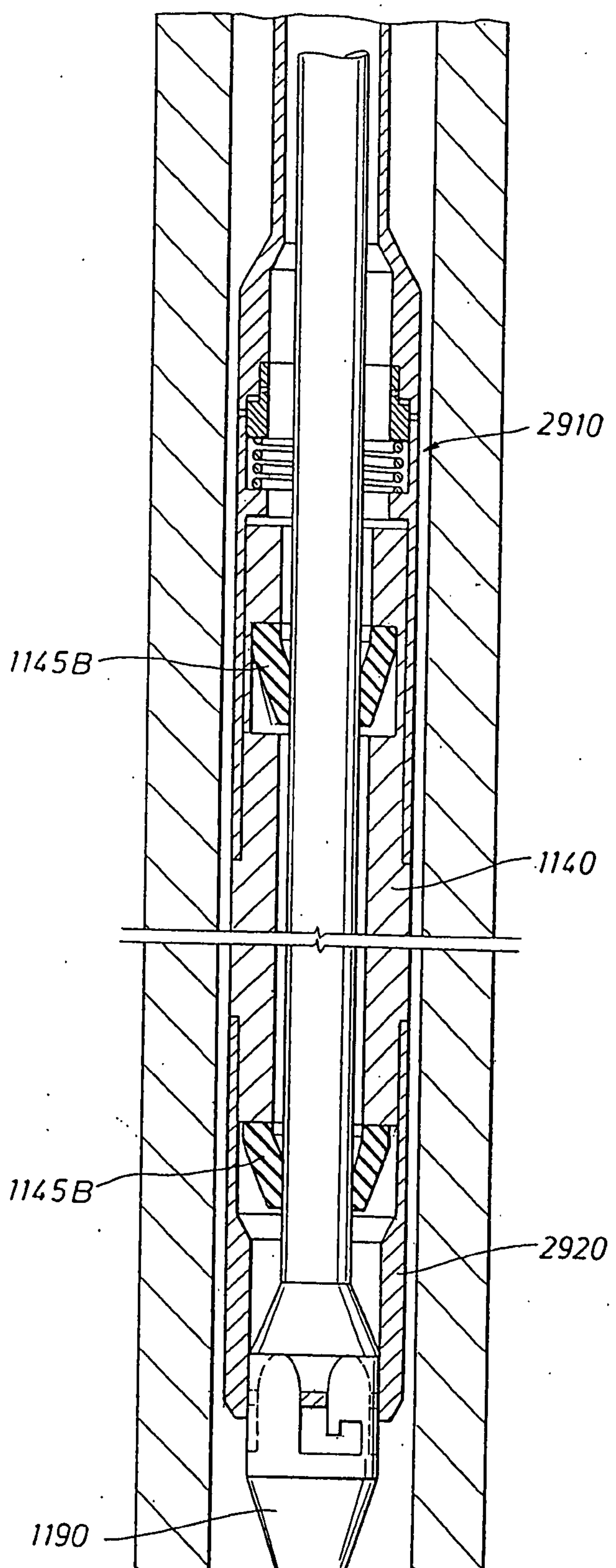


FIG. 32B

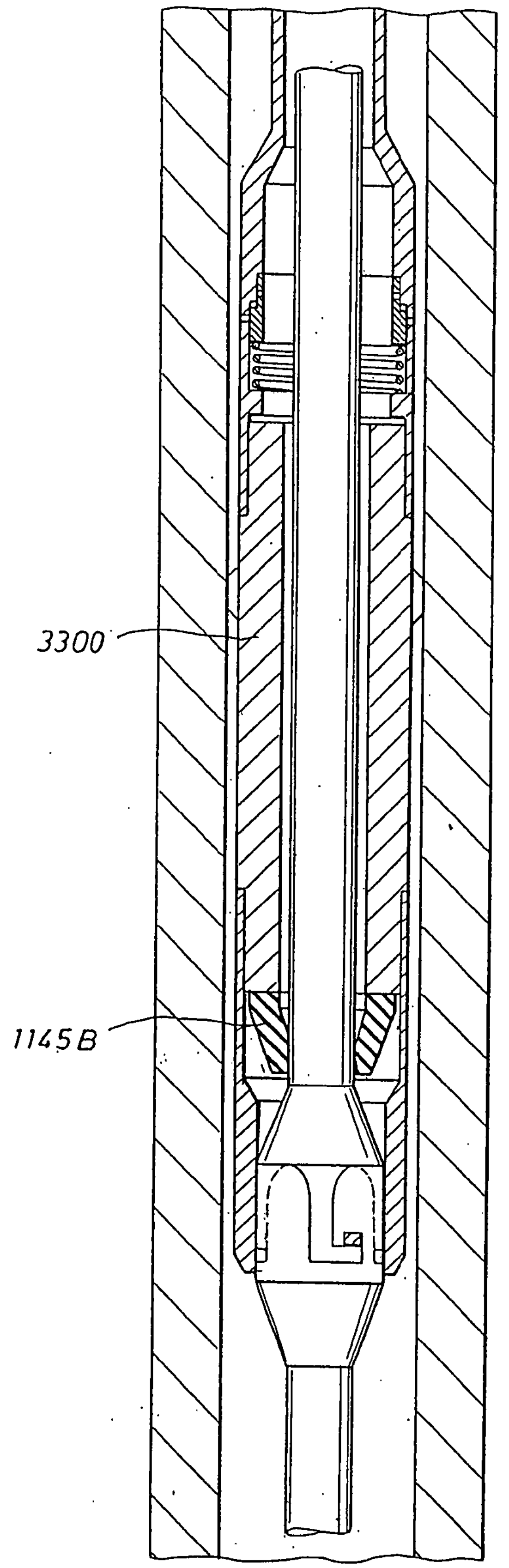


FIG.33

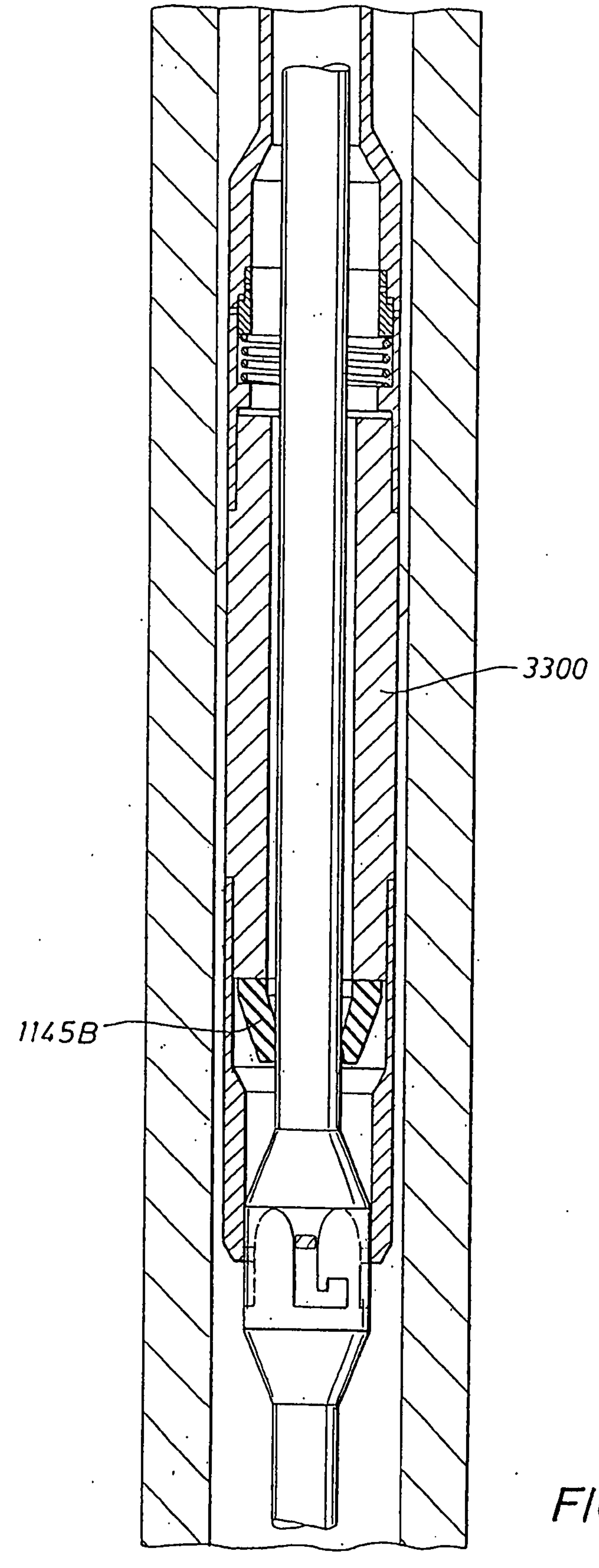


FIG.34

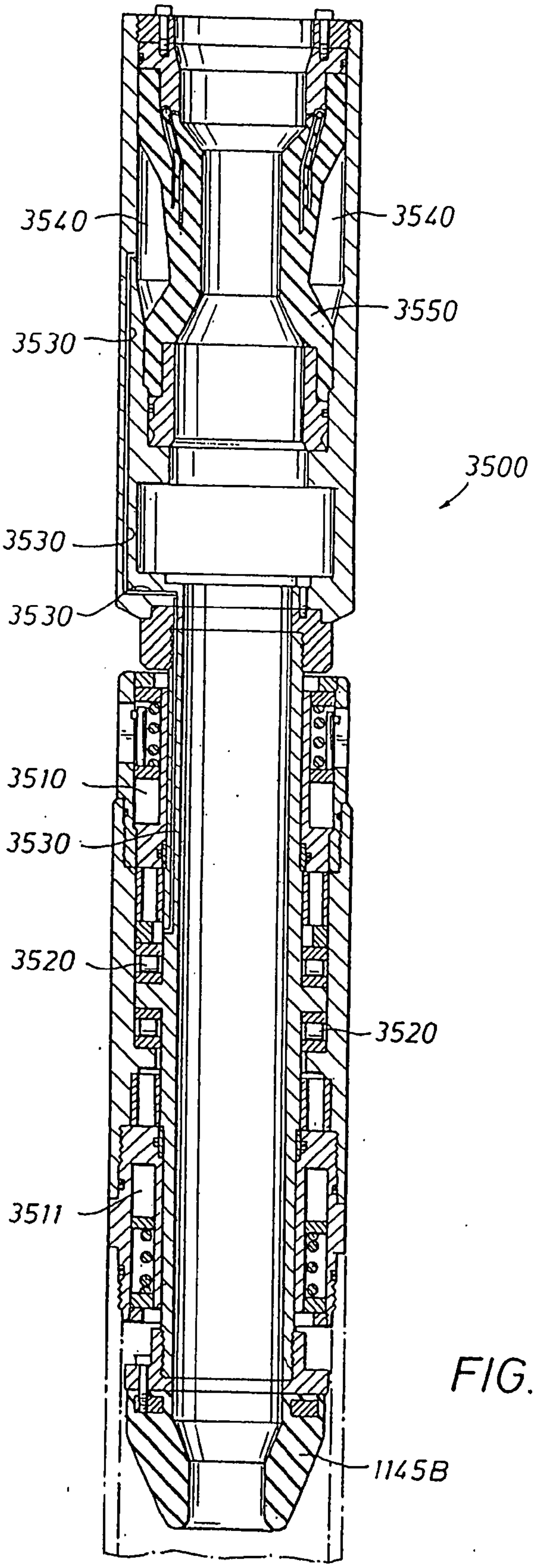

3540
3540
3550
3530
3500
3530
3530
3510
3530
3520
3520
3511
1145B

FIG.35