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(52) UK CL (Edition W):
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TXTUS2, TXTUS3, TXTEP1, TXTGB1,
TXTWO1

(54) Abstract Title: **Internal riser rotating control head**

(57) A system for forming a subsea borehole is provided, whereby the borehole is formed by utilising a rotatable pipe P, and a fluid. The system comprises a subsea housing 14 that is positioned above the borehole. A bearing assembly 28 is mounted with the housing, the bearing assembly featuring an inner 36 and outer 38 member, with the inner member rotatable relative to the outer member, and with a passage within it allowing the rotatable pipe to extend through the bearing assembly. A seal is also provided to seal the bearing with the rotatable pipe. Finally, a holding member 24 is employed to locate the entire bearing assembly within the subsea housing. Numerous other embodiments are disclosed, some utilising a feature whereby the fluid pressure in the system can be increased to control borehole pressure.

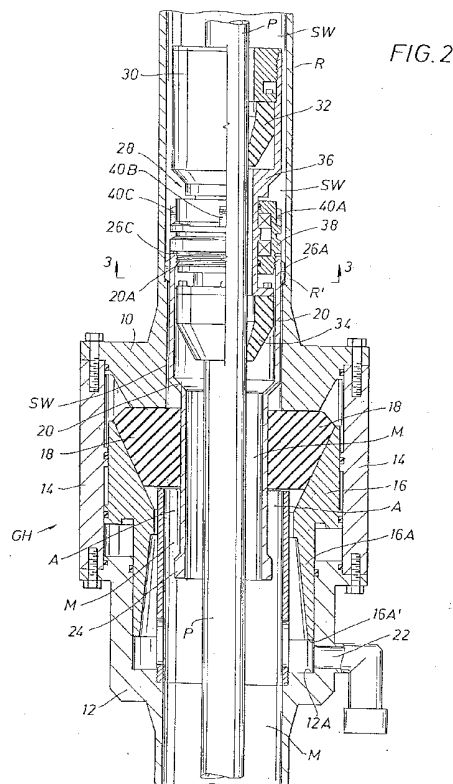


FIG. 1
(PRIOR ART)

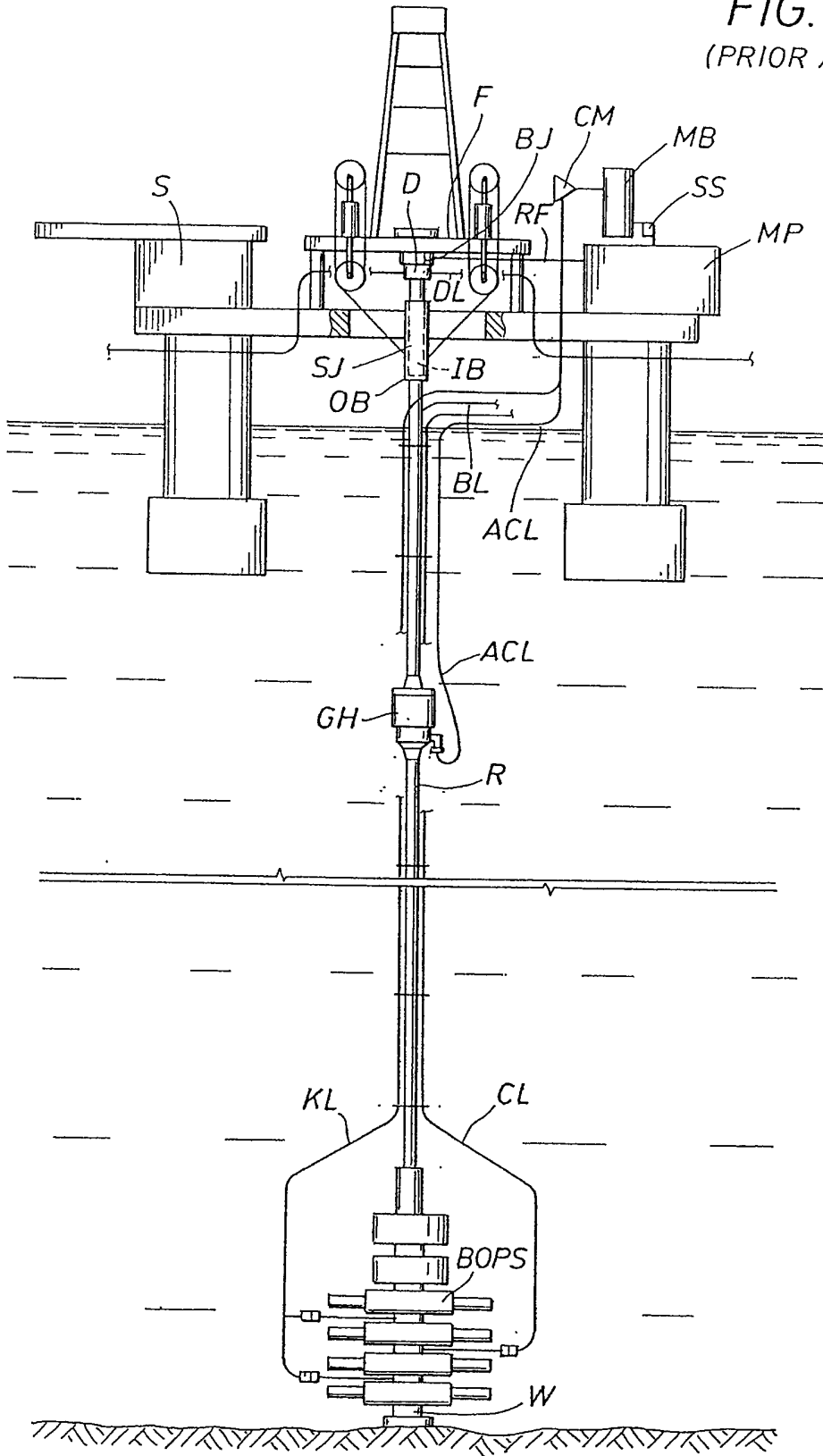


FIG. 2

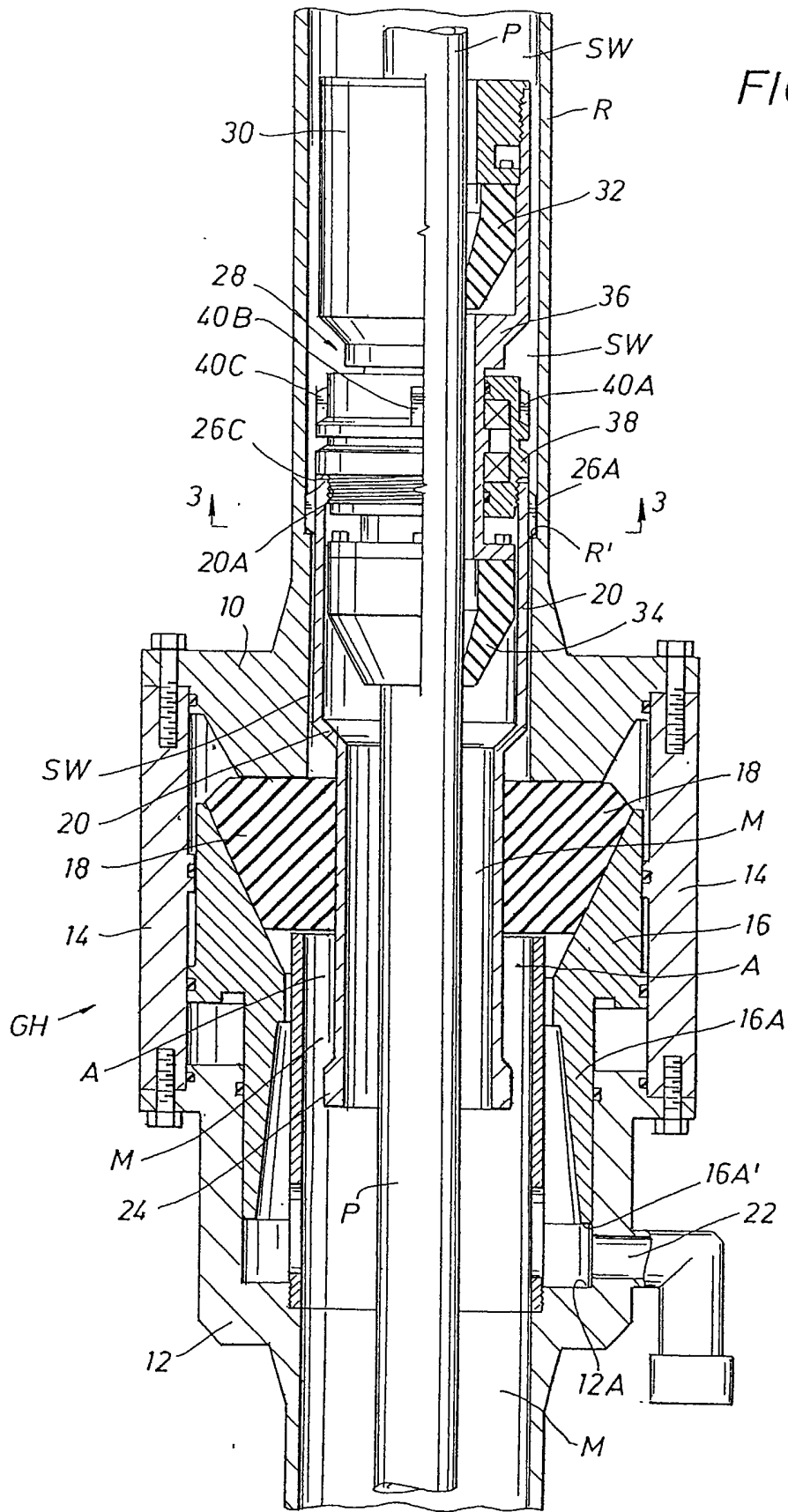


FIG. 3

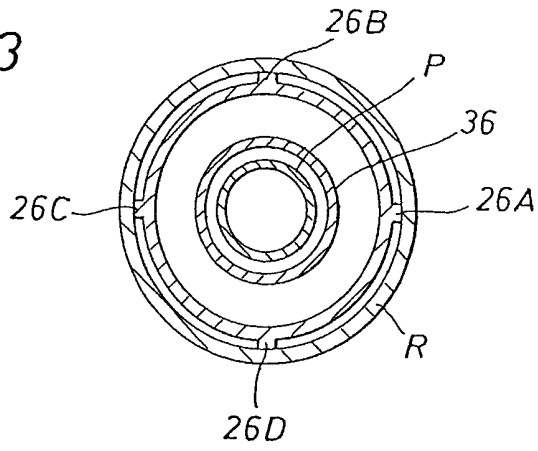


FIG. 5

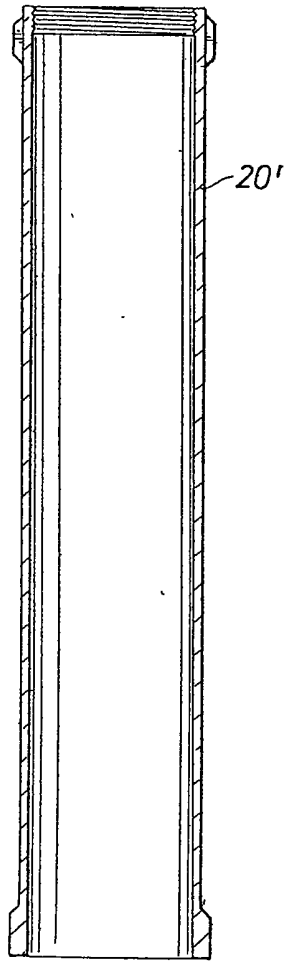
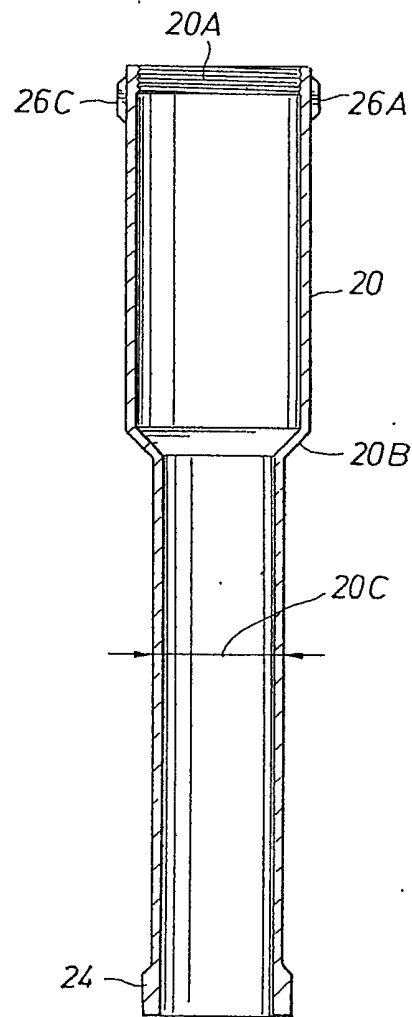


FIG. 6



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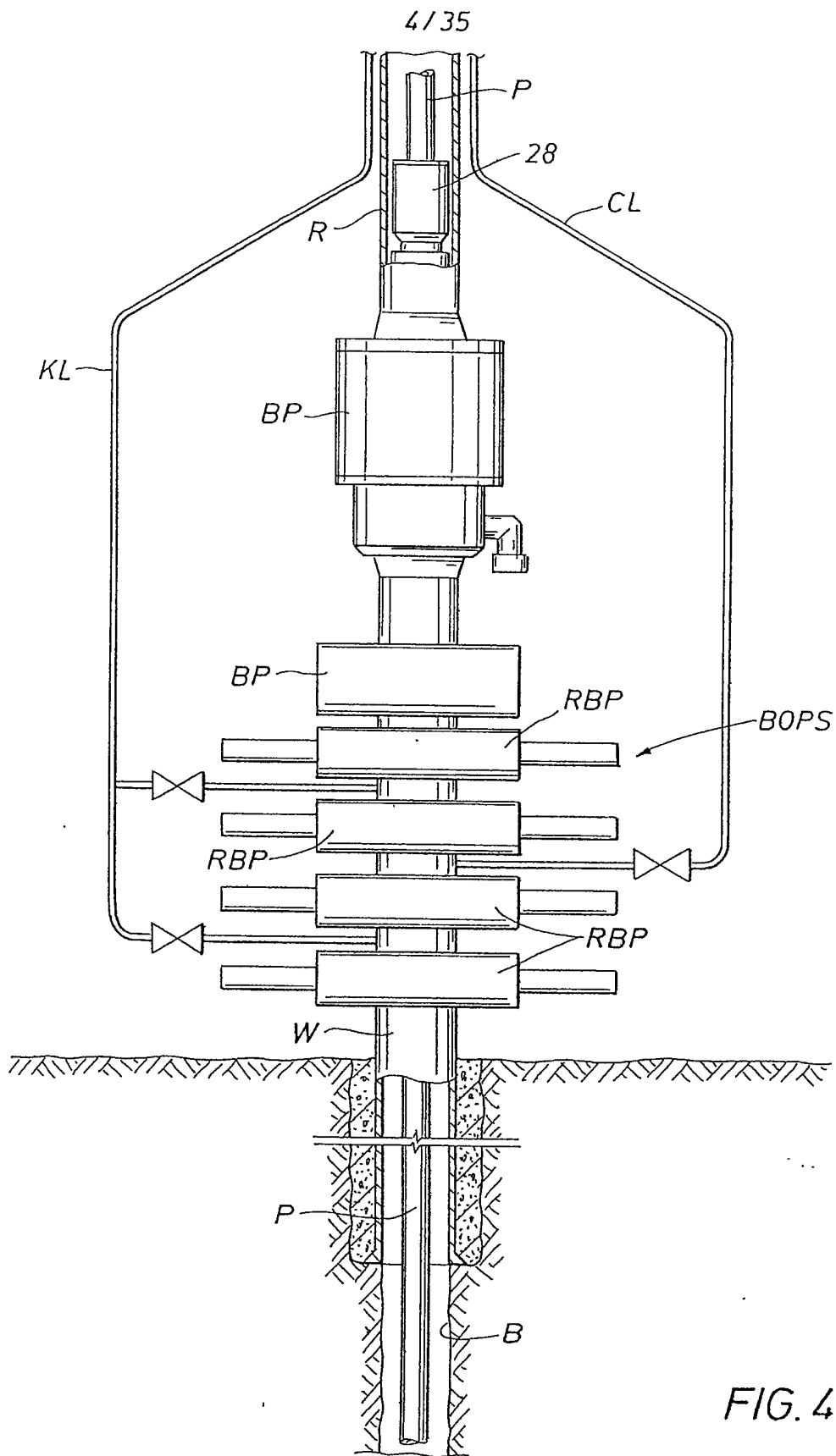


FIG. 4

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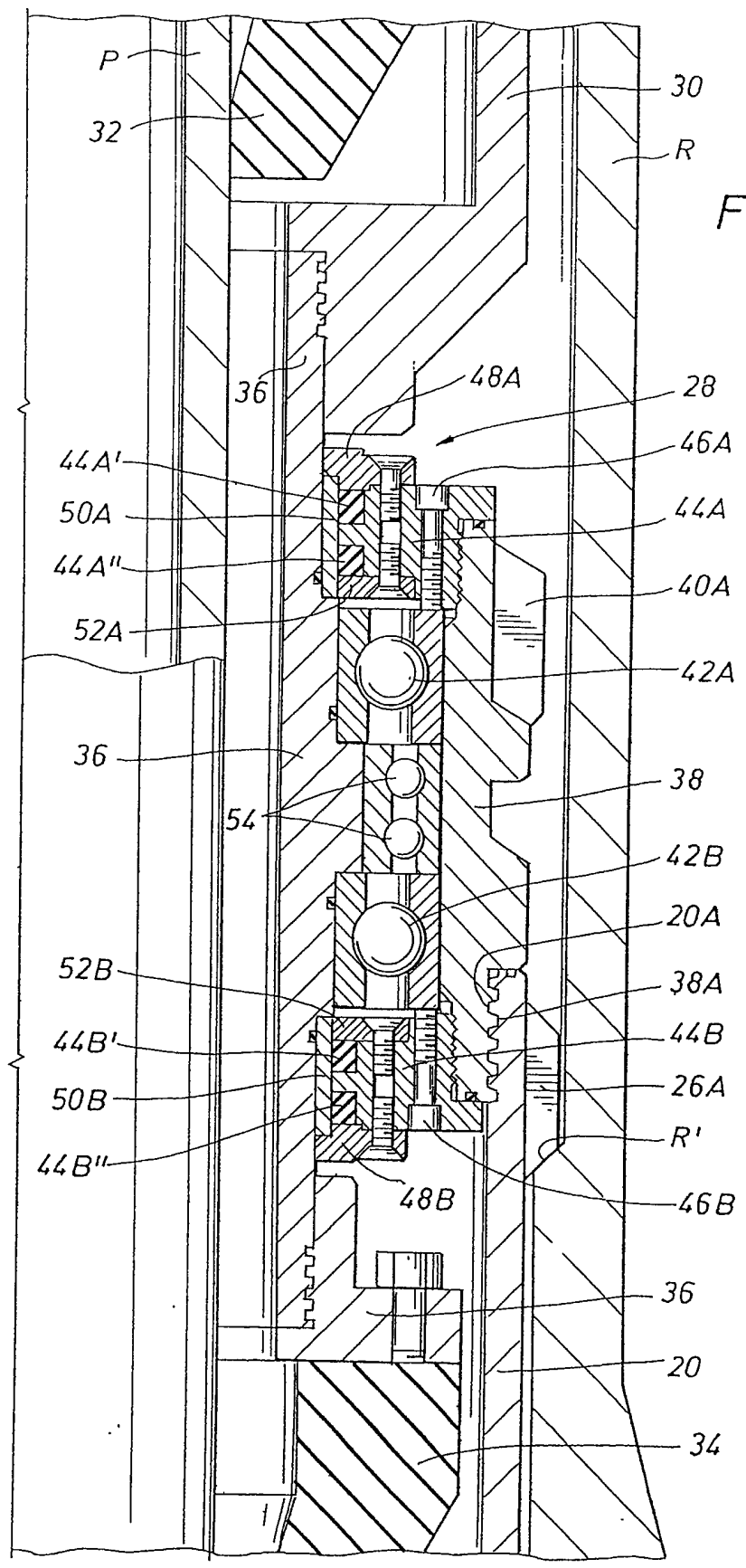


FIG. 7

FIG. 8

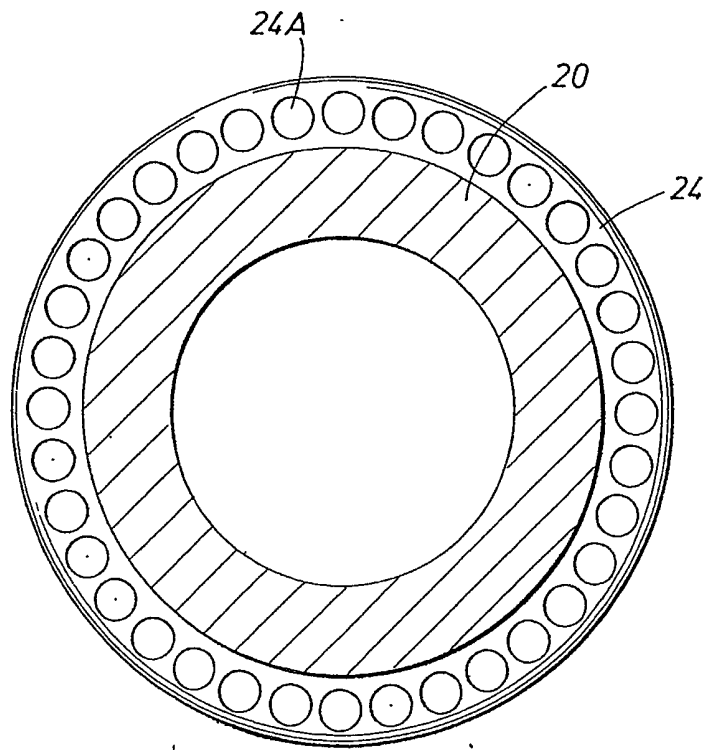
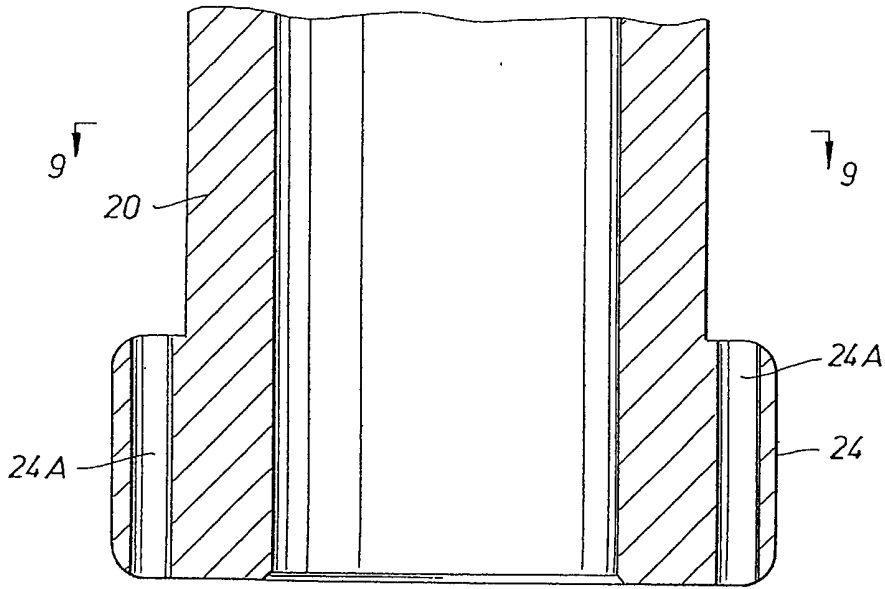


FIG. 9

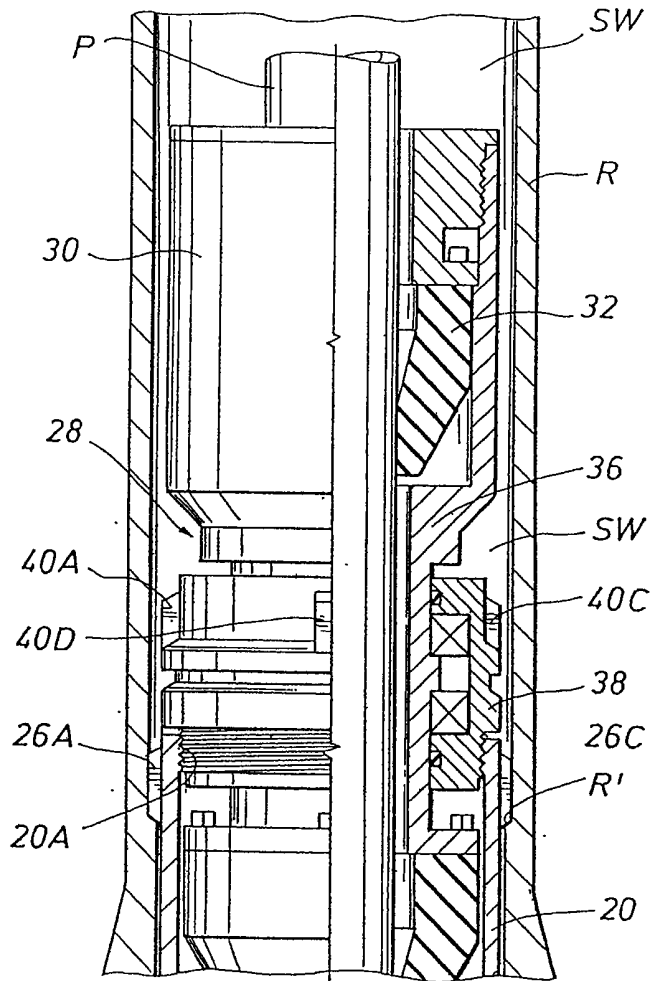


FIG. 10

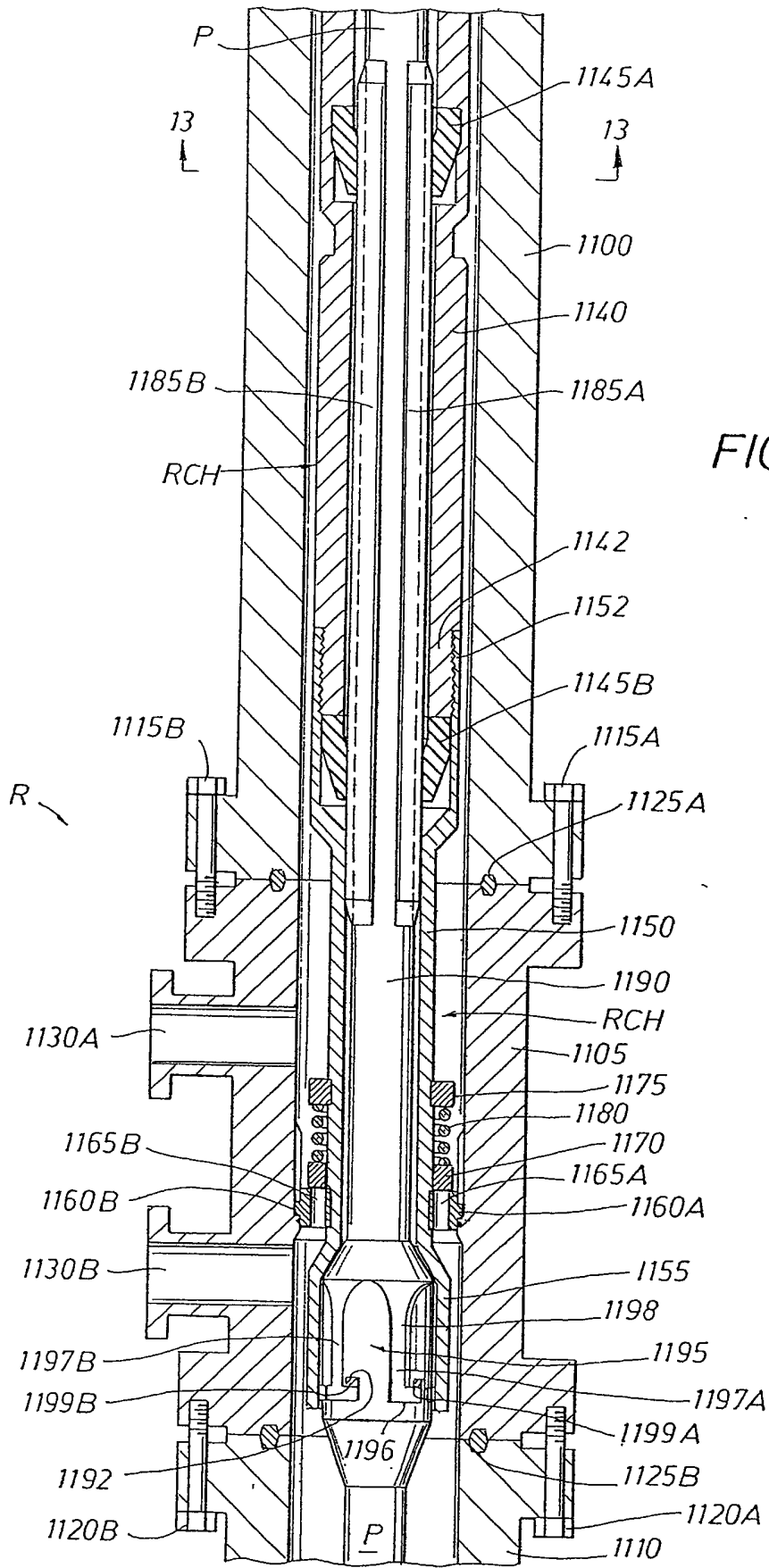


FIG. 11

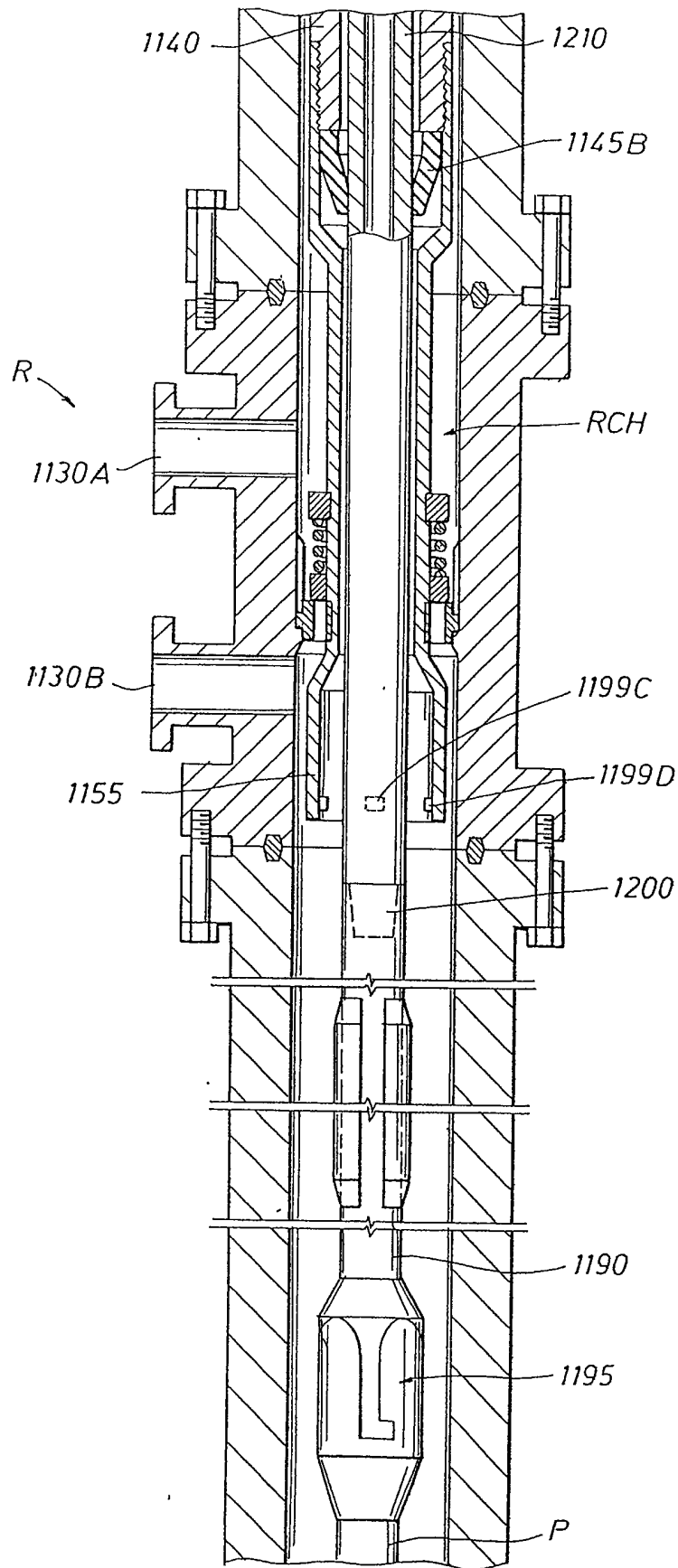


FIG. 12

FIG.13

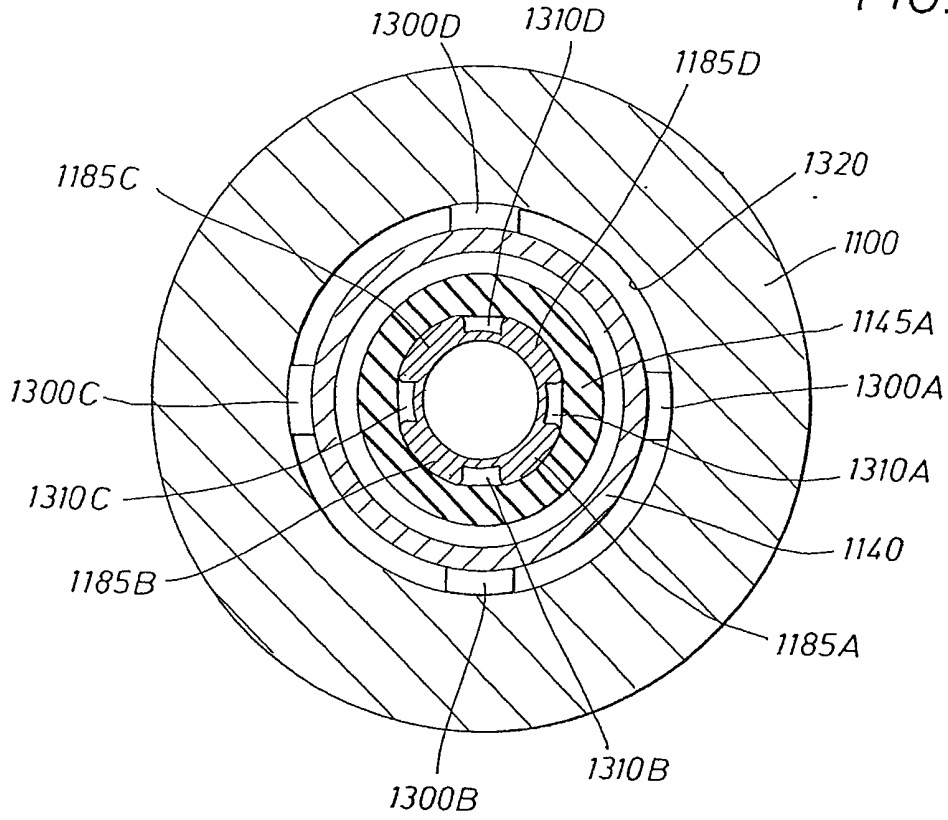


FIG.14

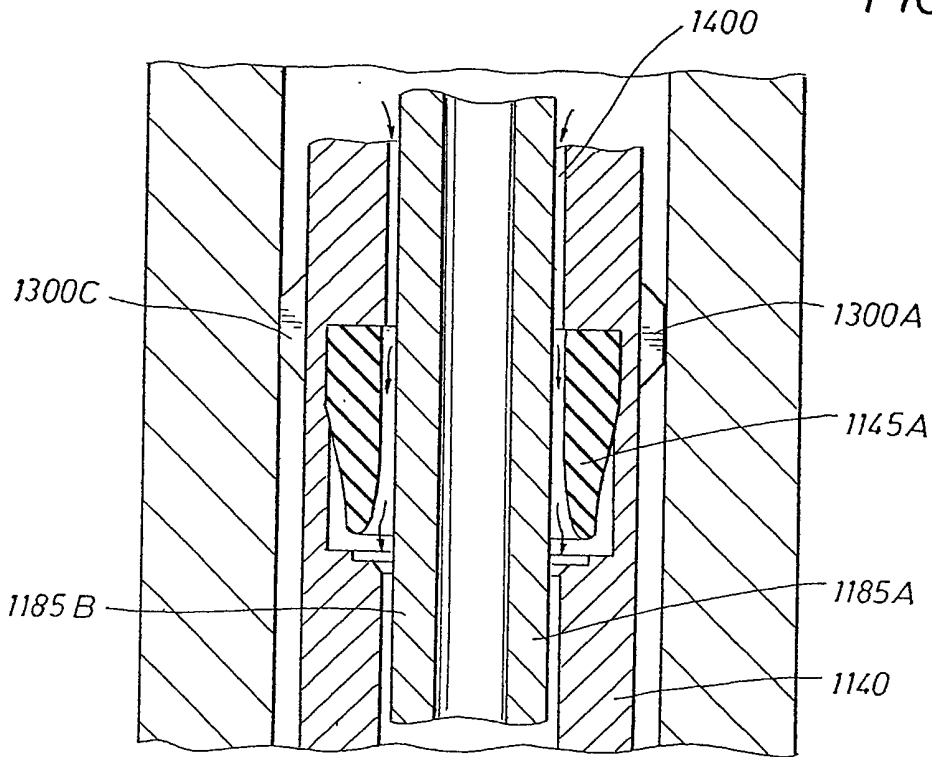


FIG. 15

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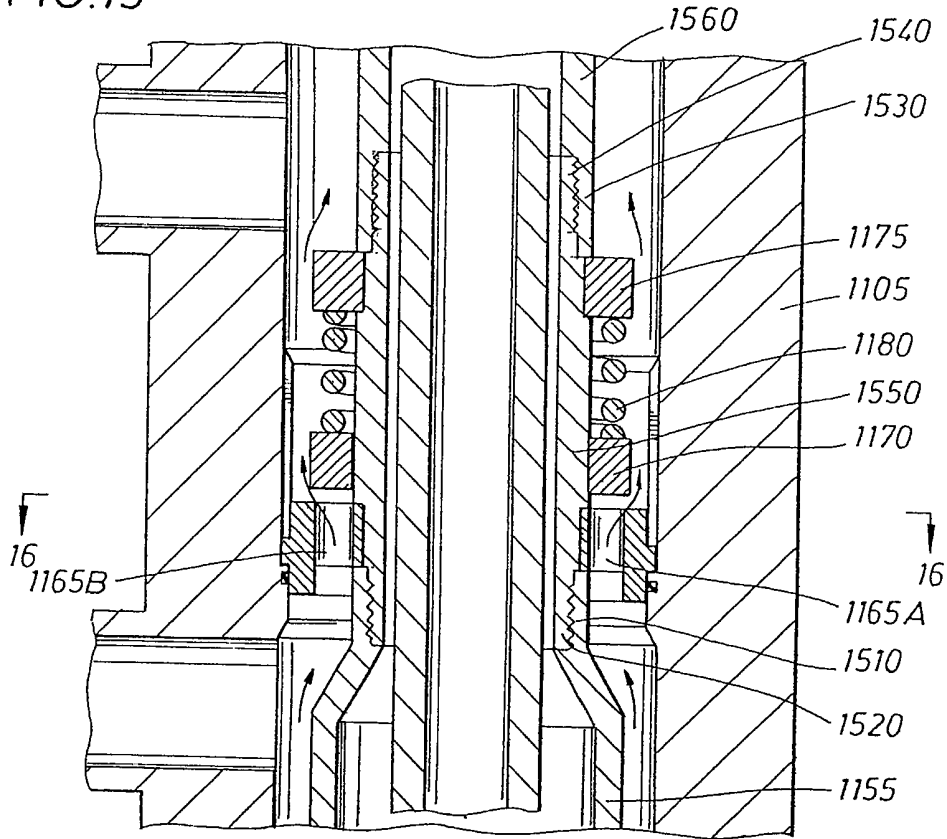
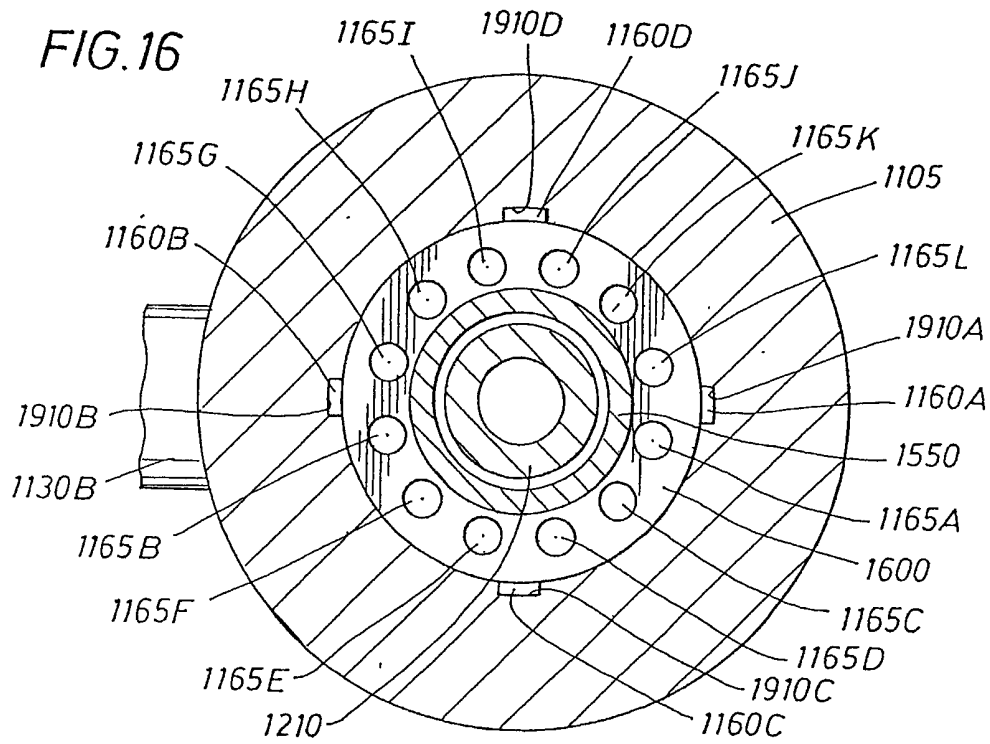
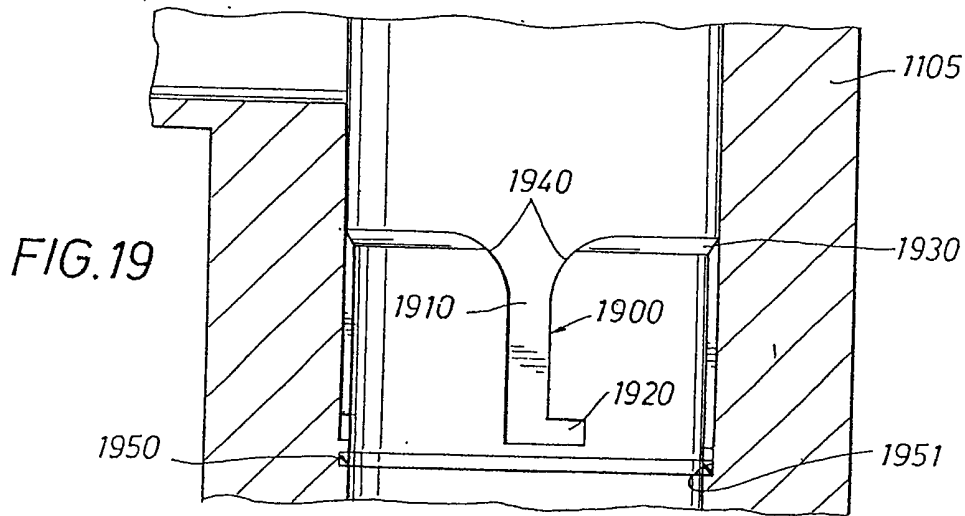
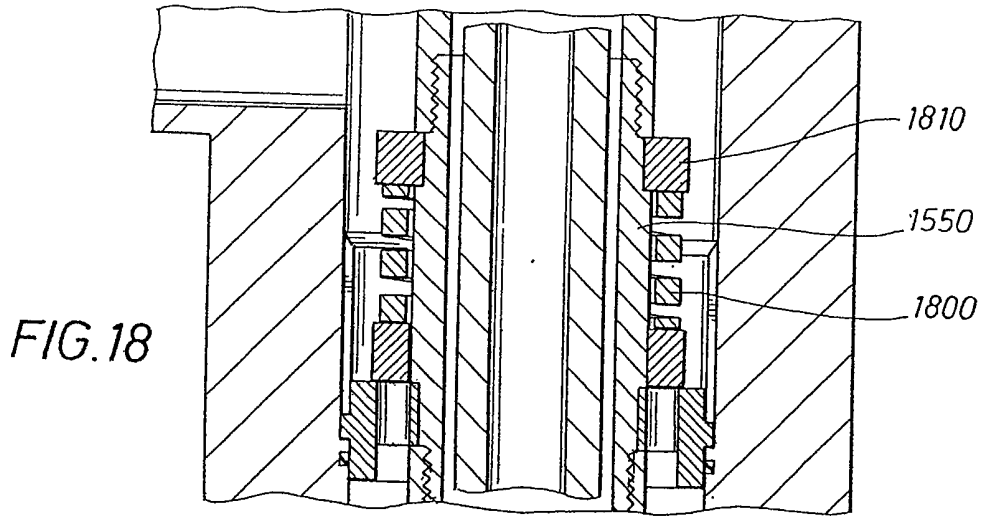
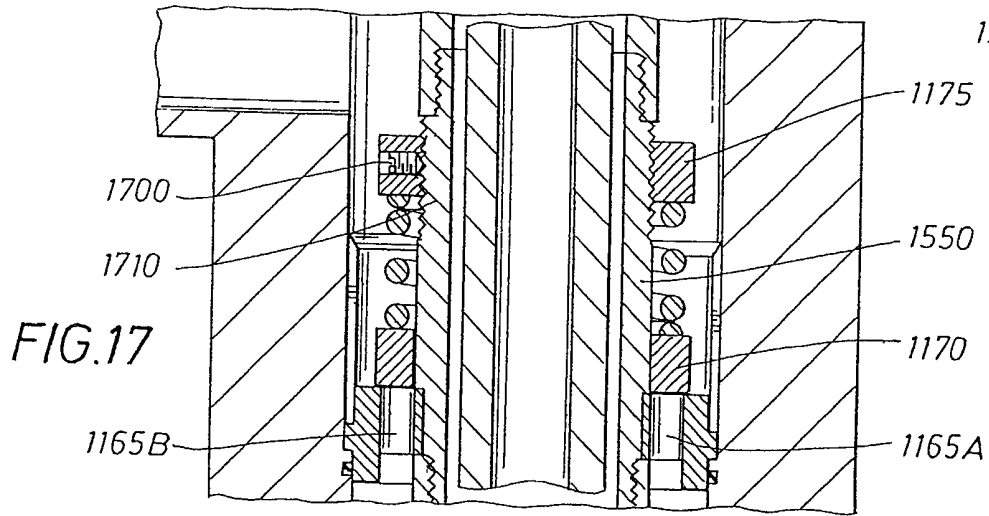


FIG. 16





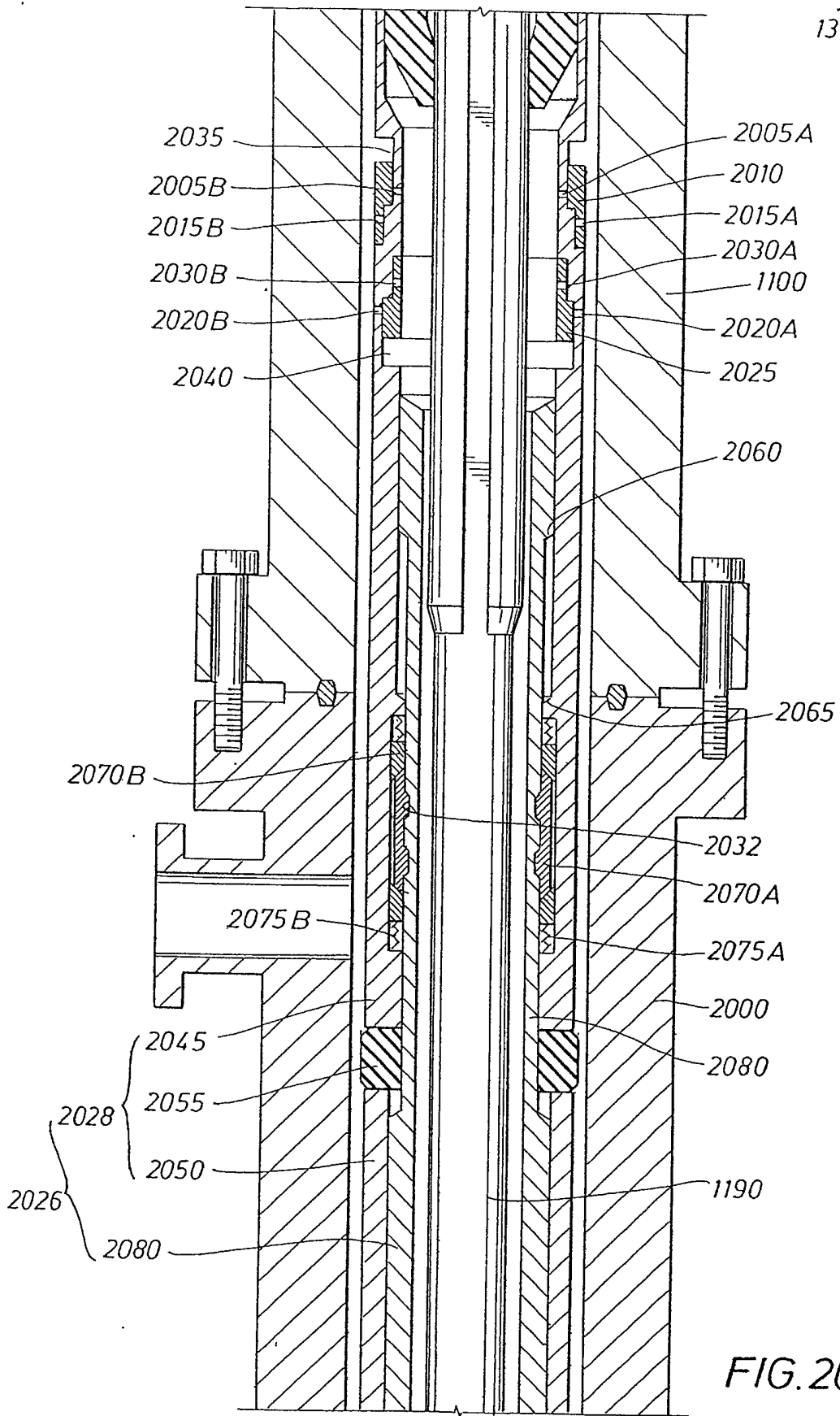


FIG. 20A

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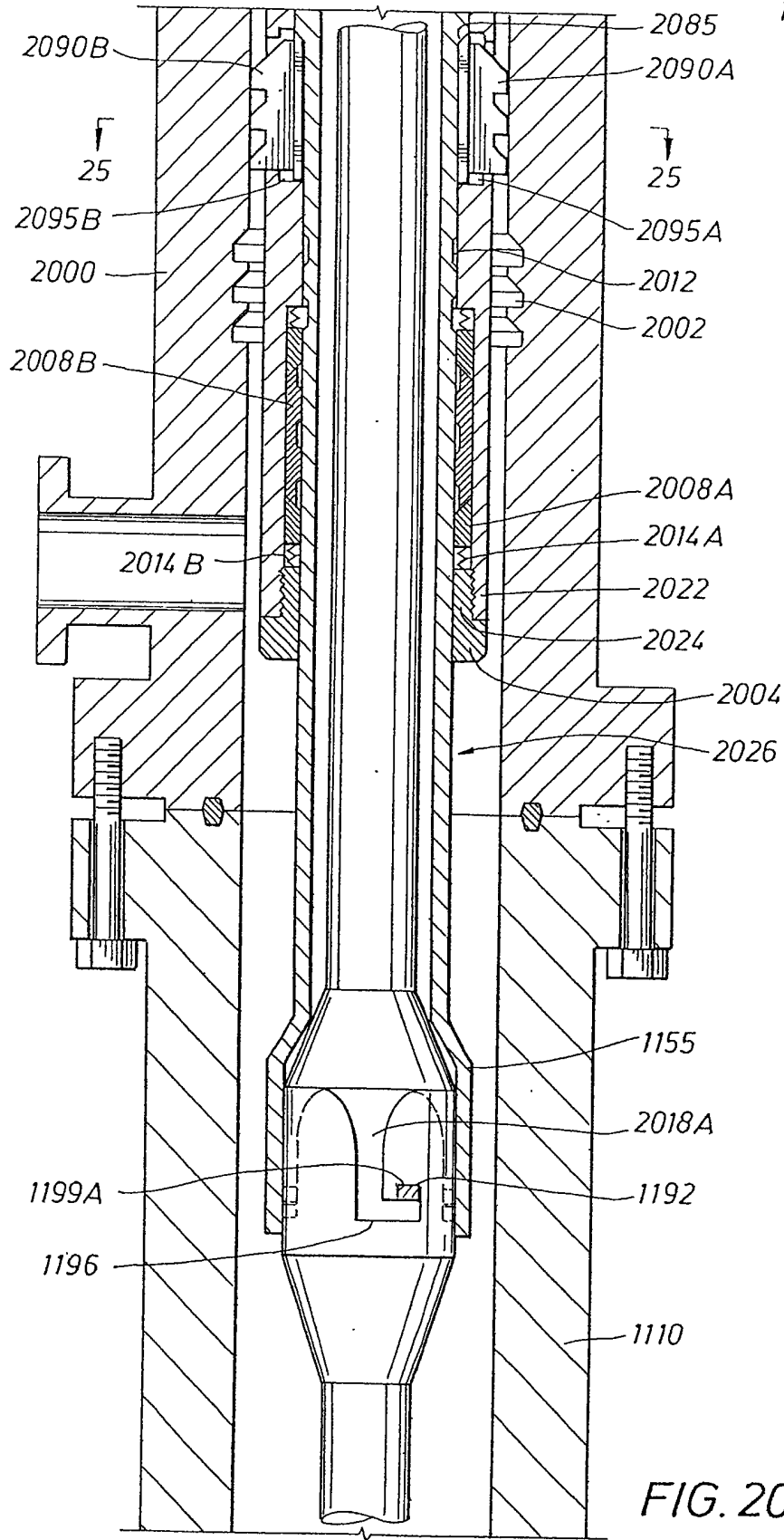


FIG. 20B

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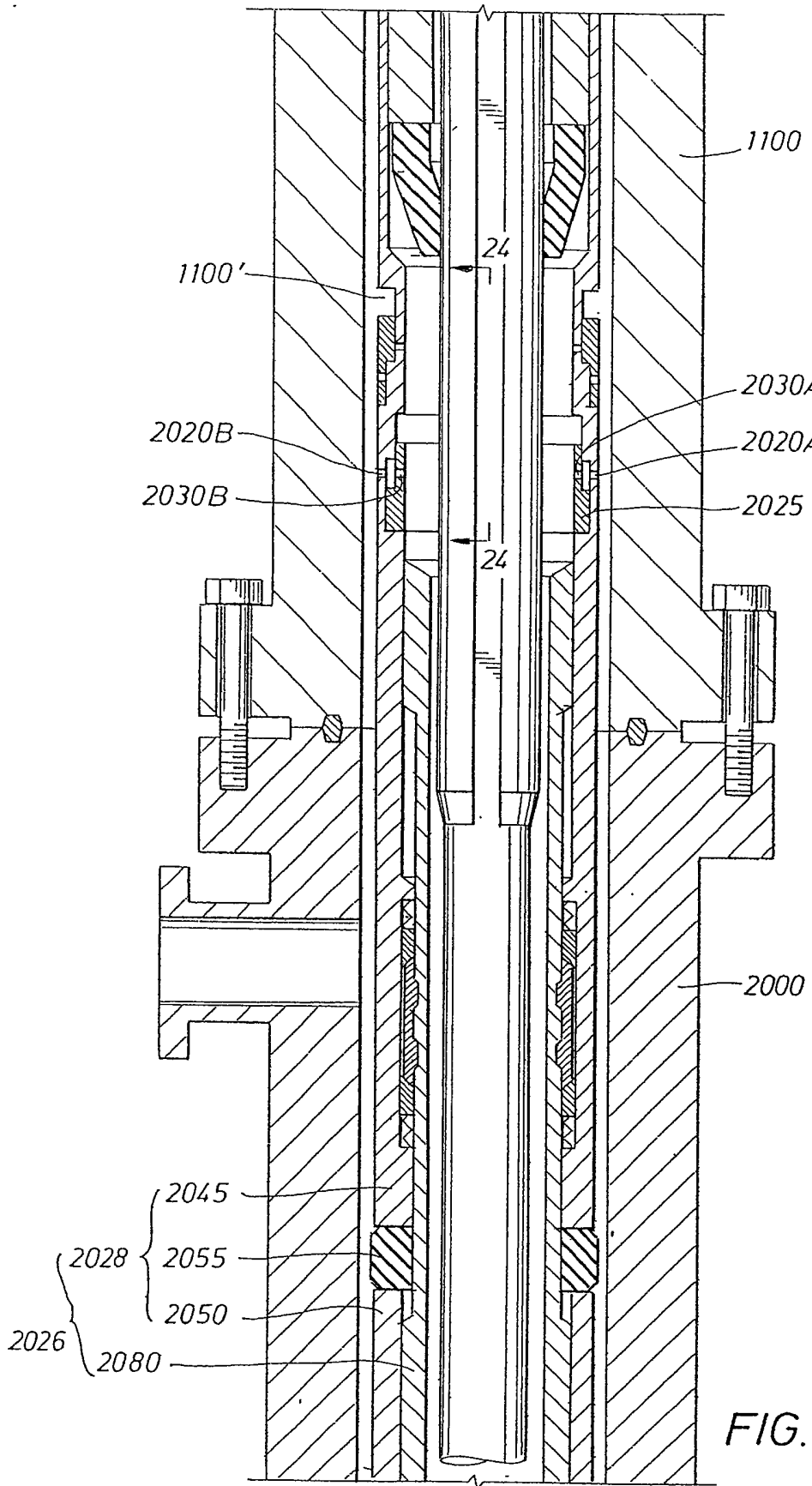


FIG. 21A

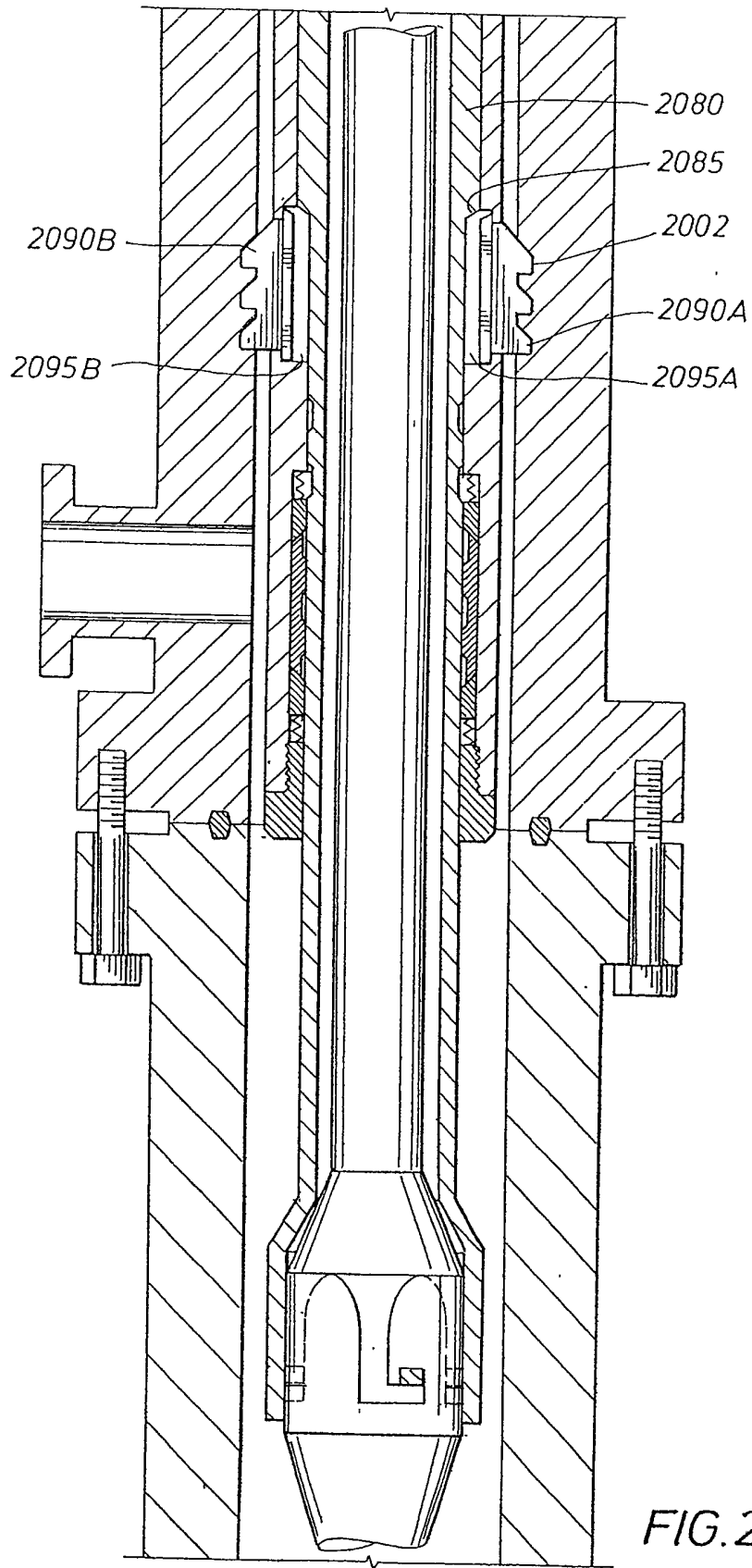


FIG. 21B

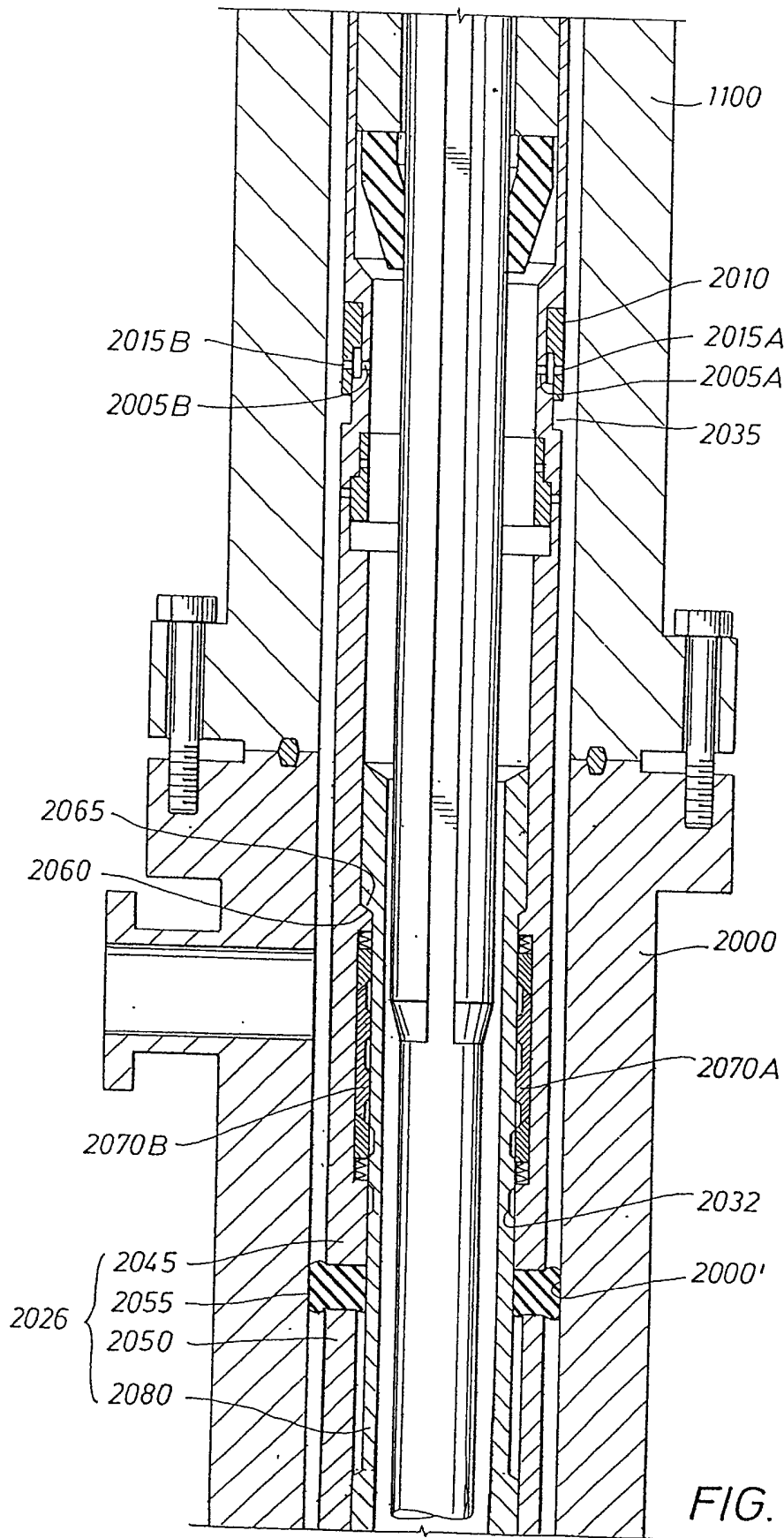


FIG. 22A

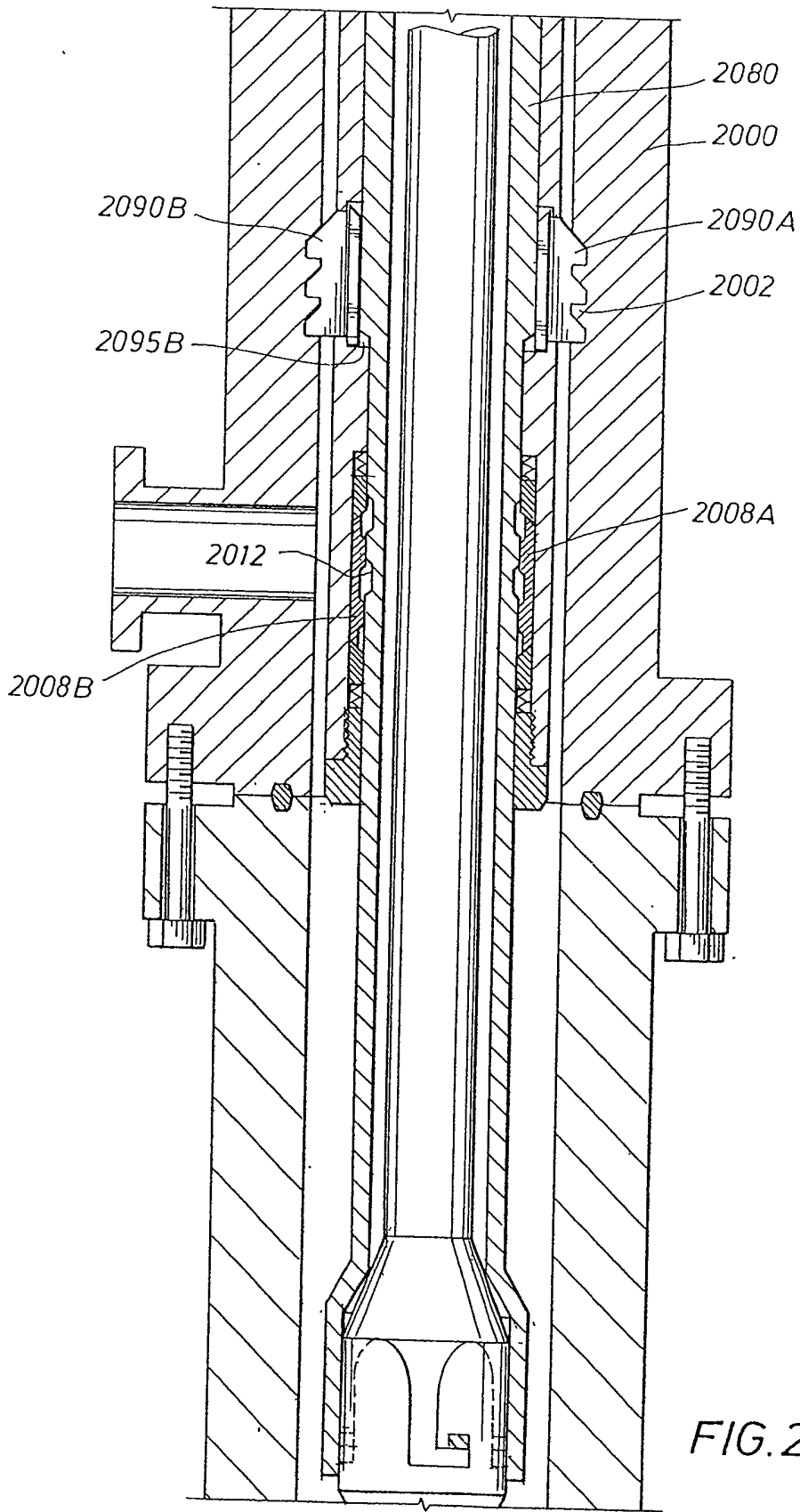
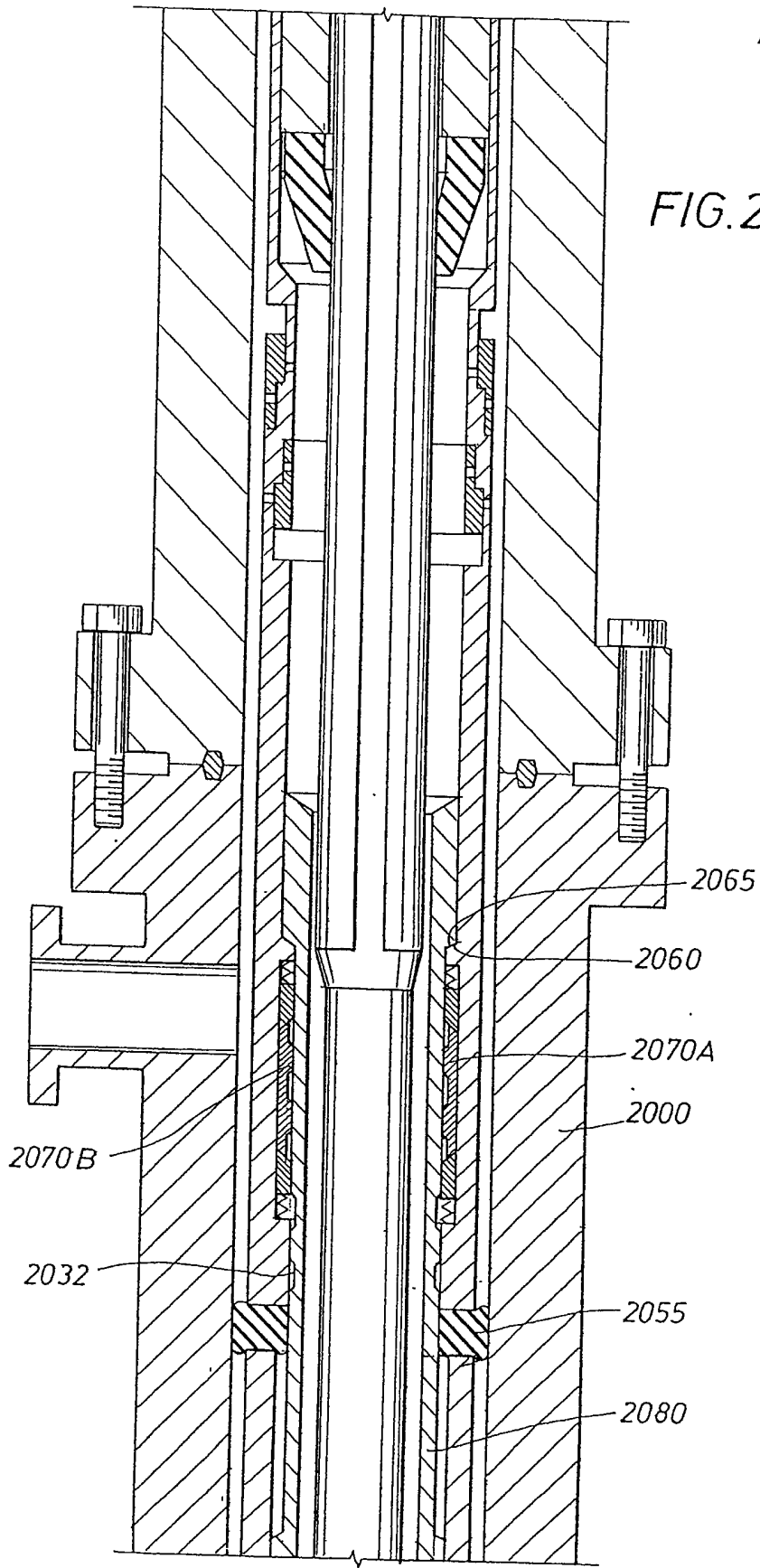


FIG. 22B

FIG. 23A



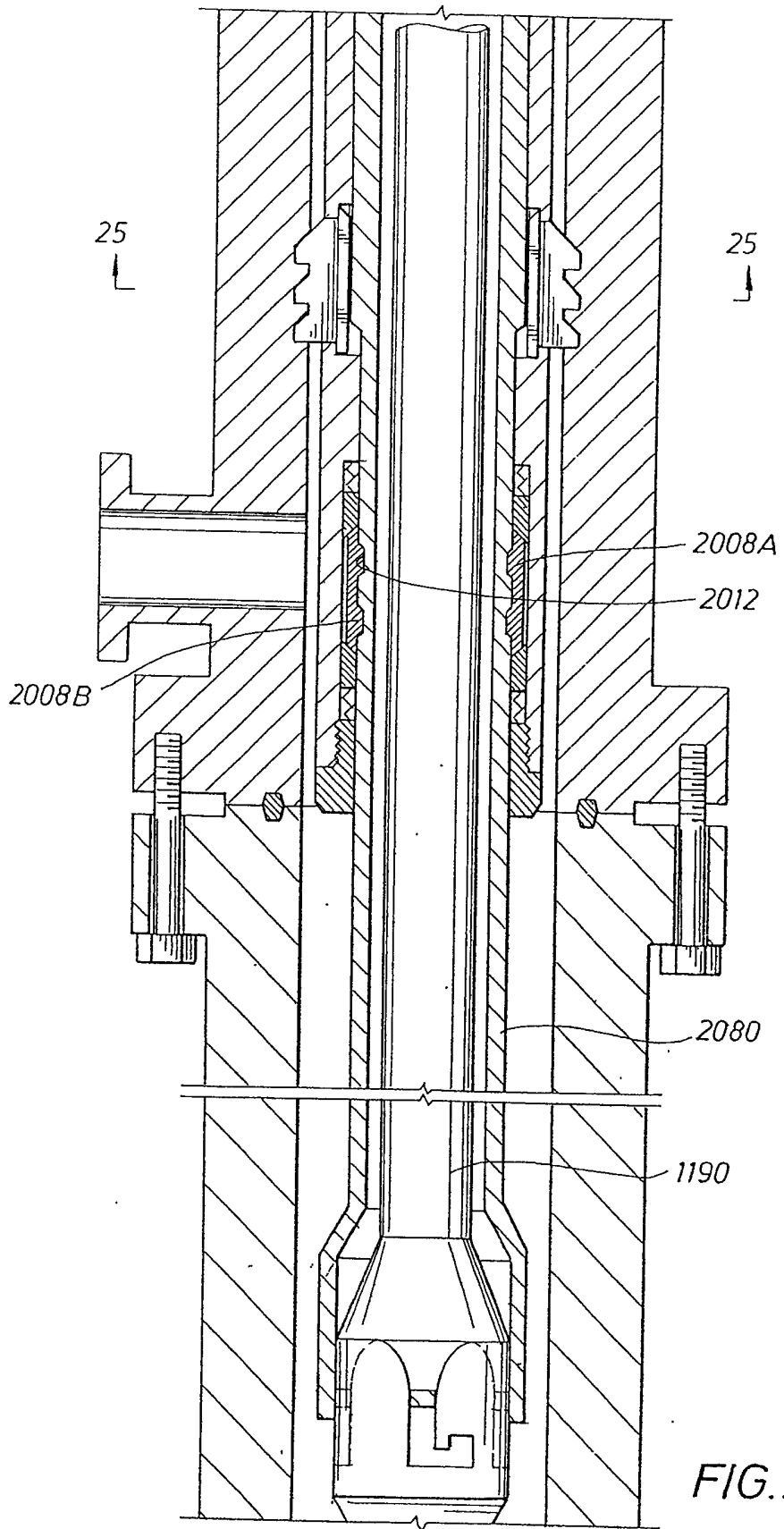


FIG. 24

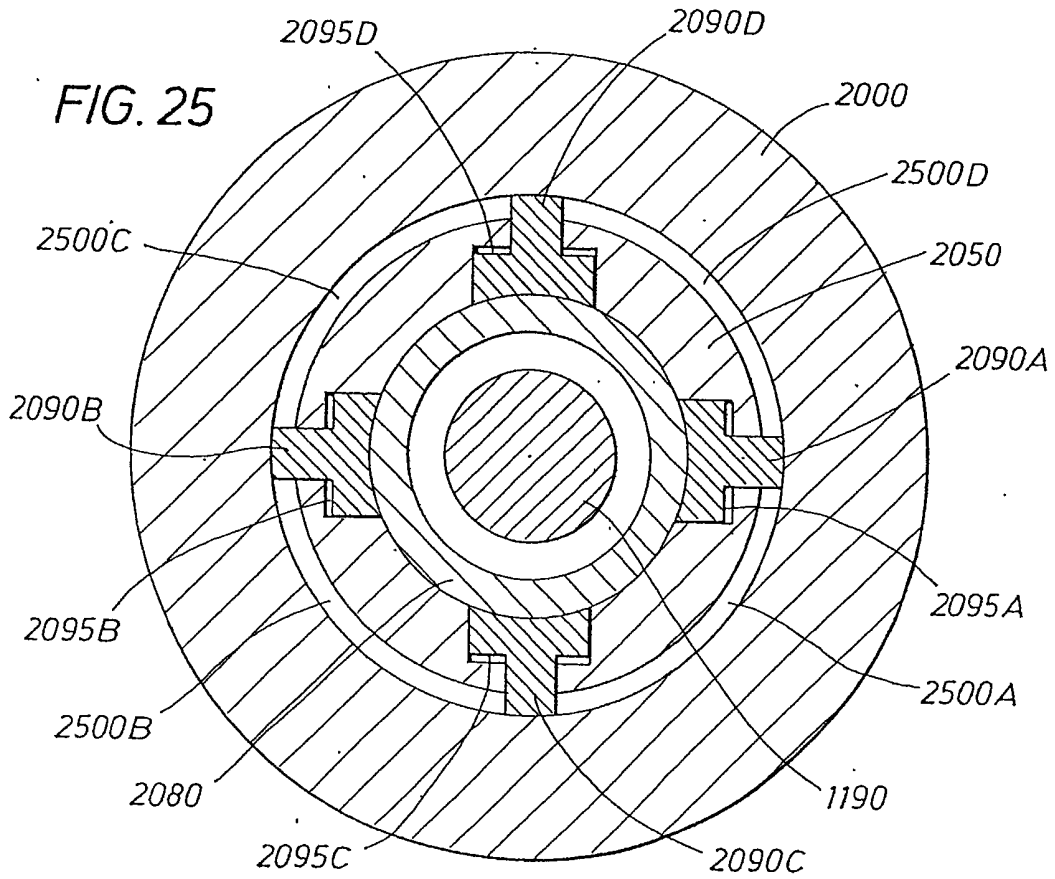
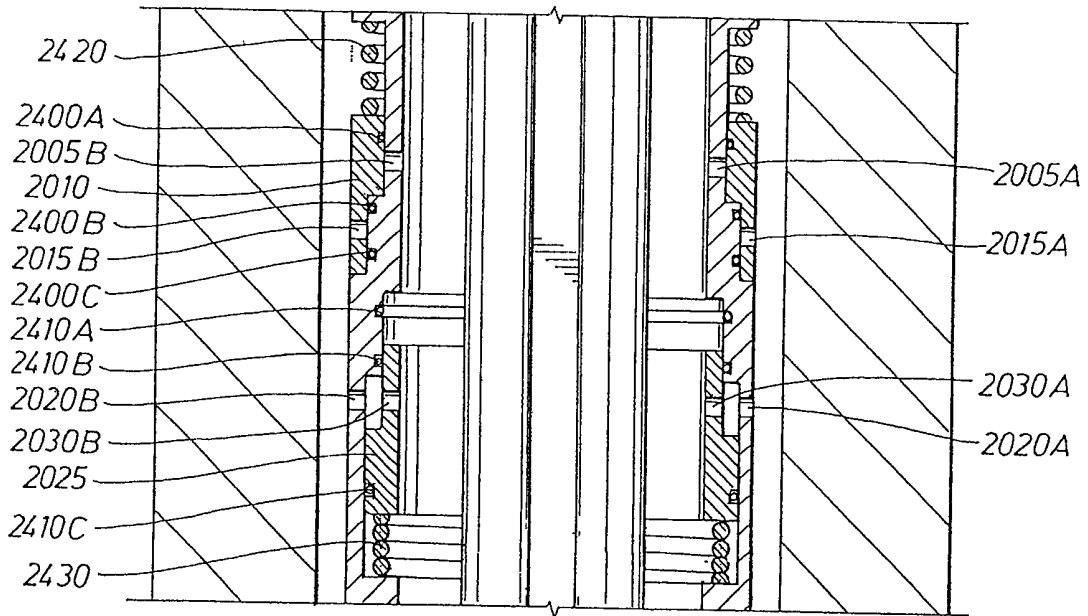


FIG. 26A

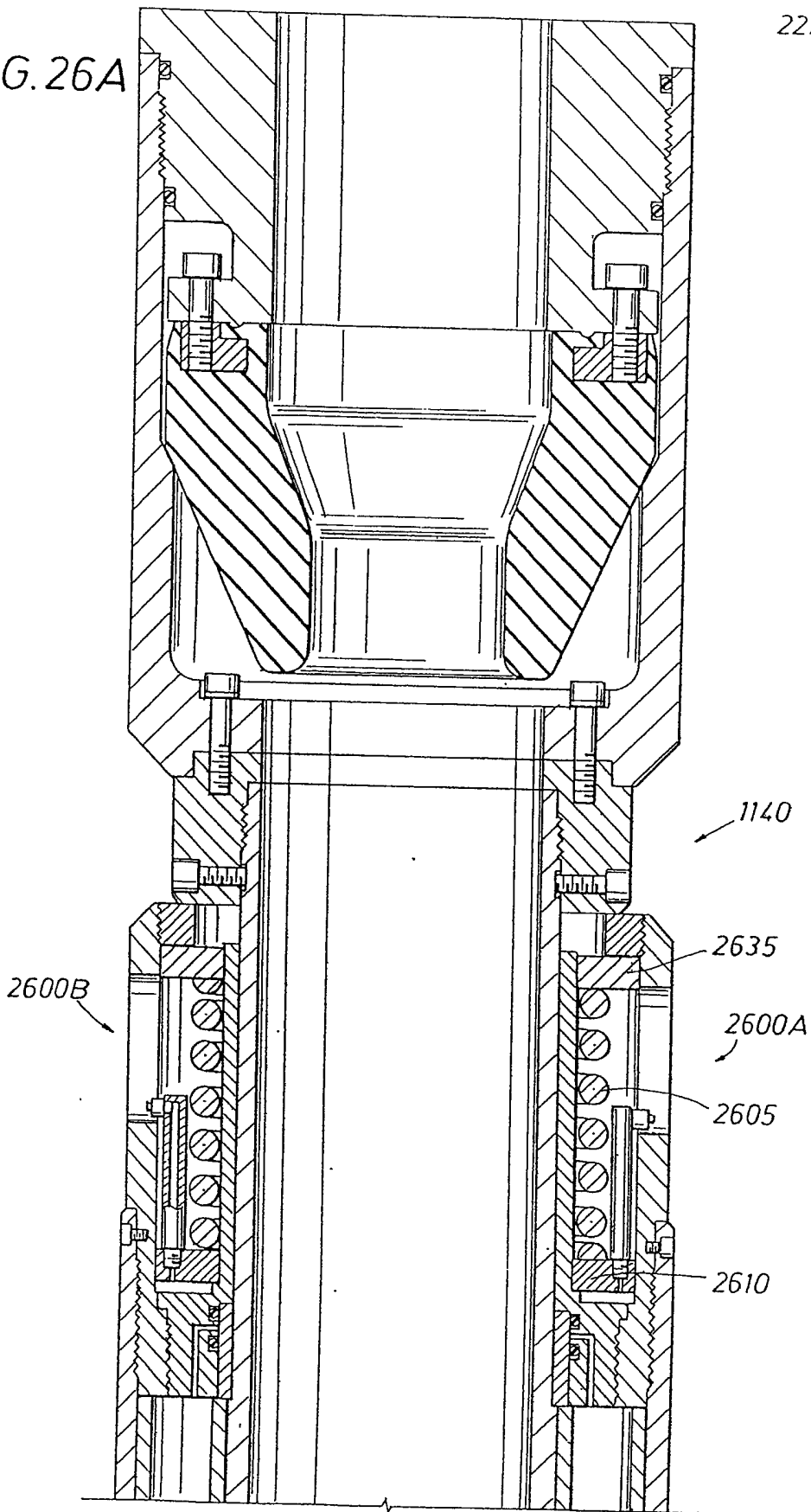


FIG. 26B

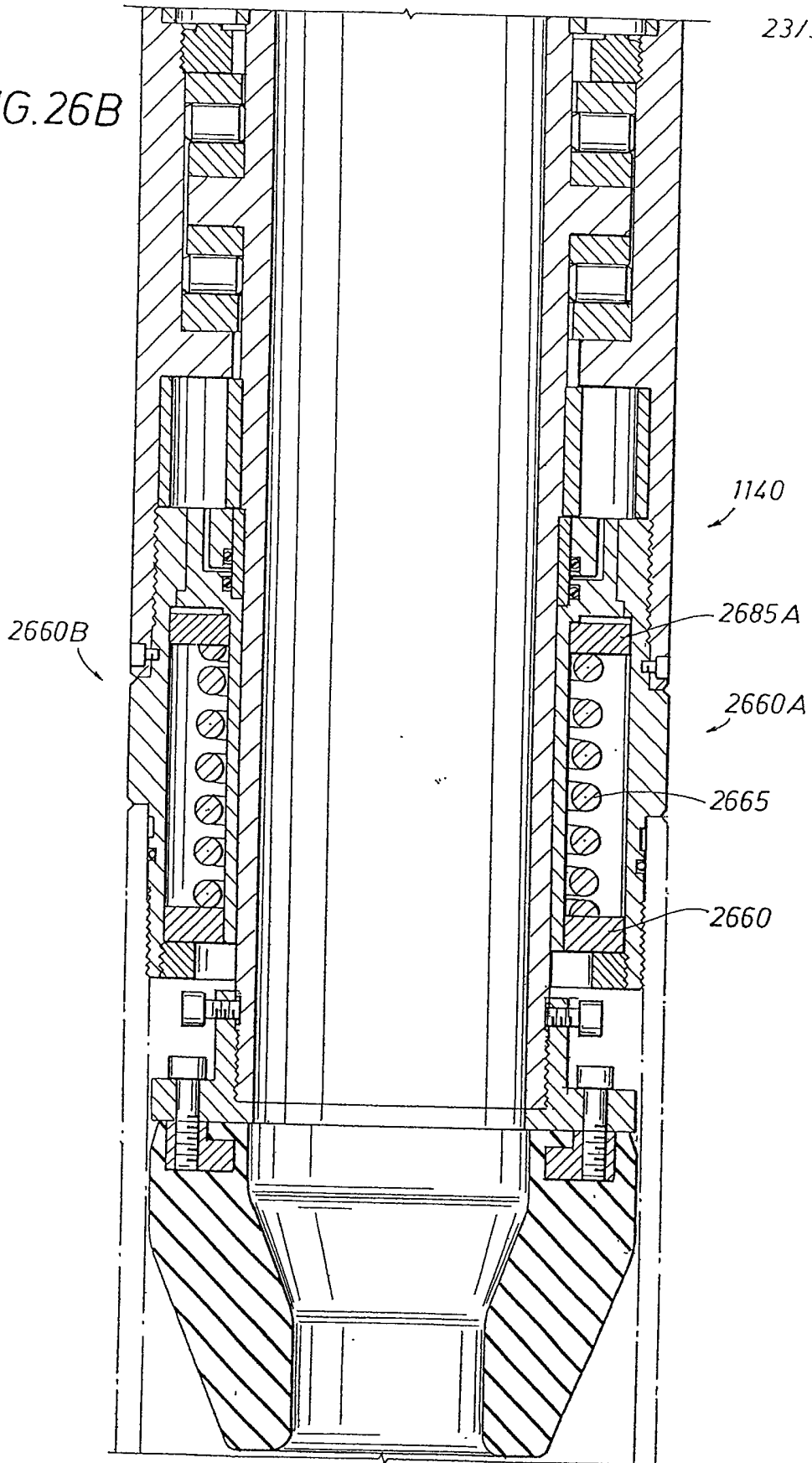


FIG. 26D

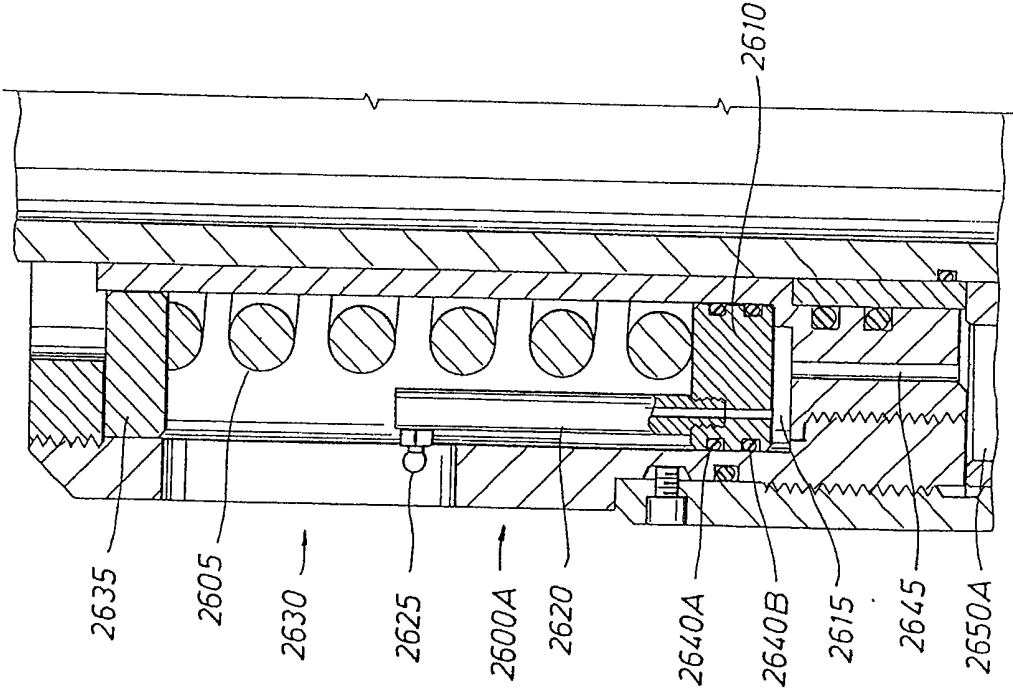
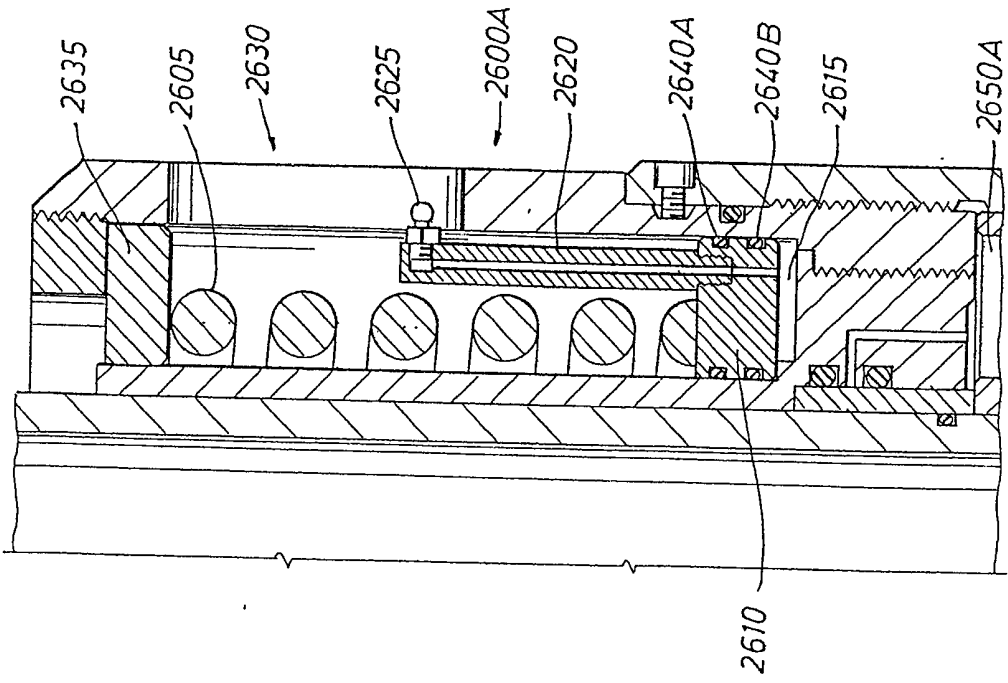


FIG. 26C



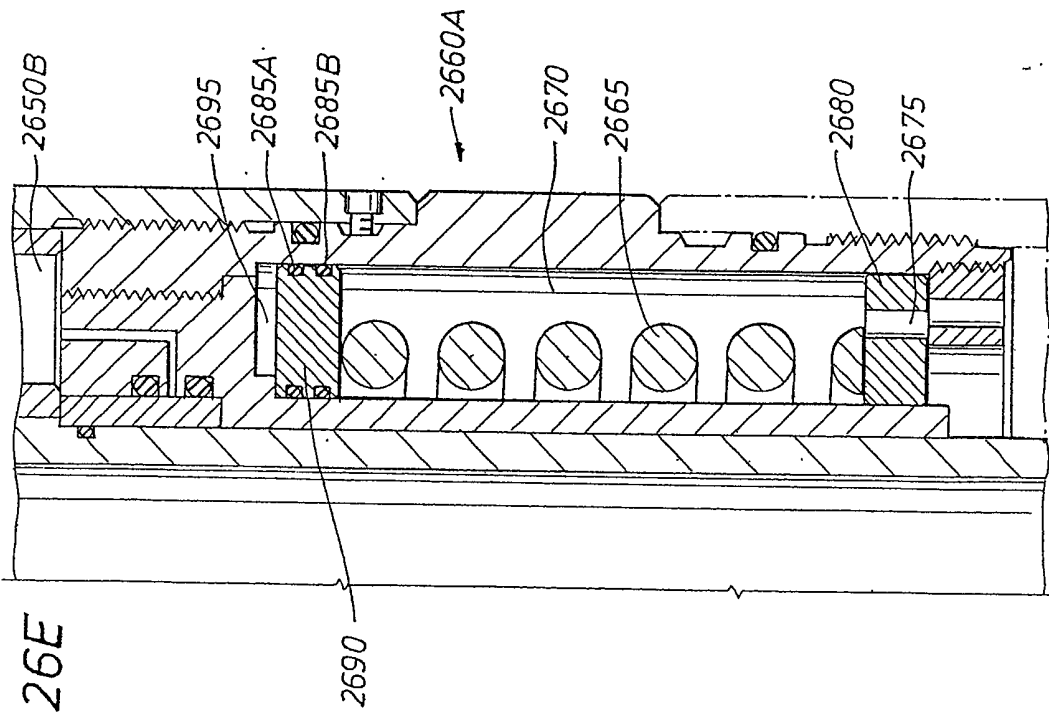
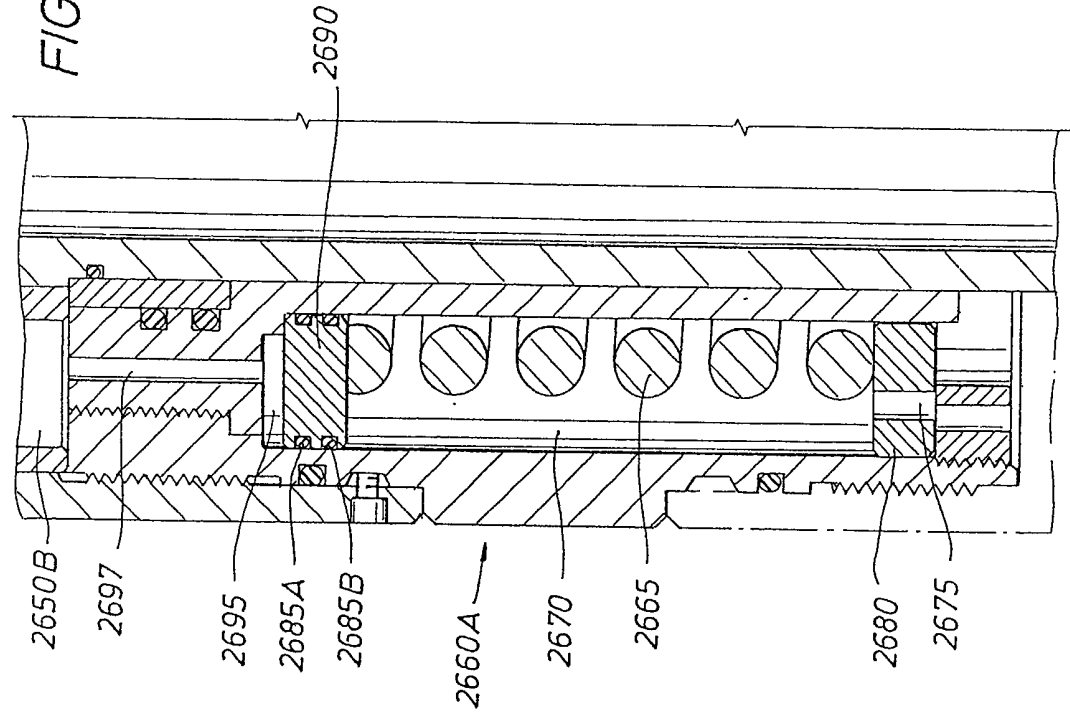


FIG. 26E

FIG. 26F

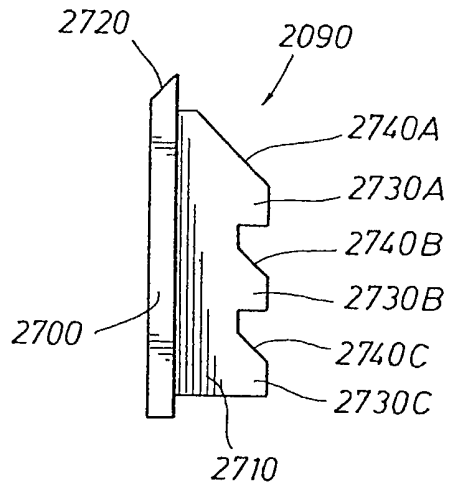


FIG. 27

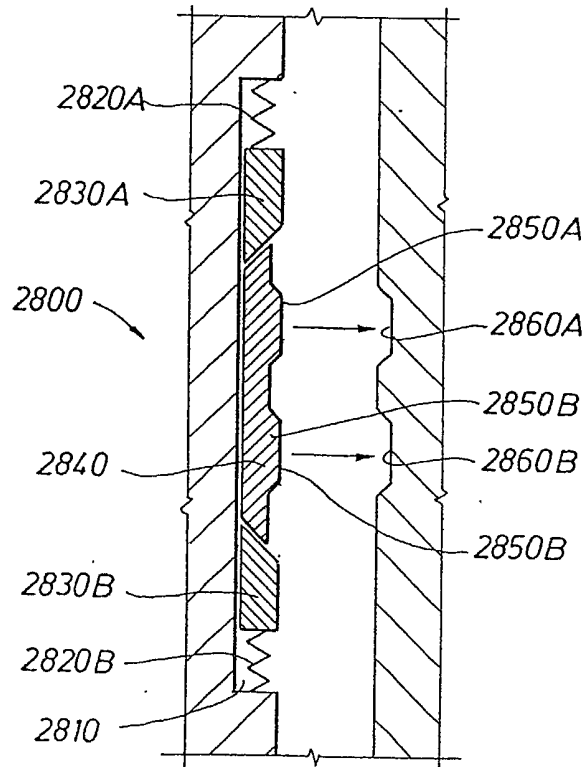


FIG. 28

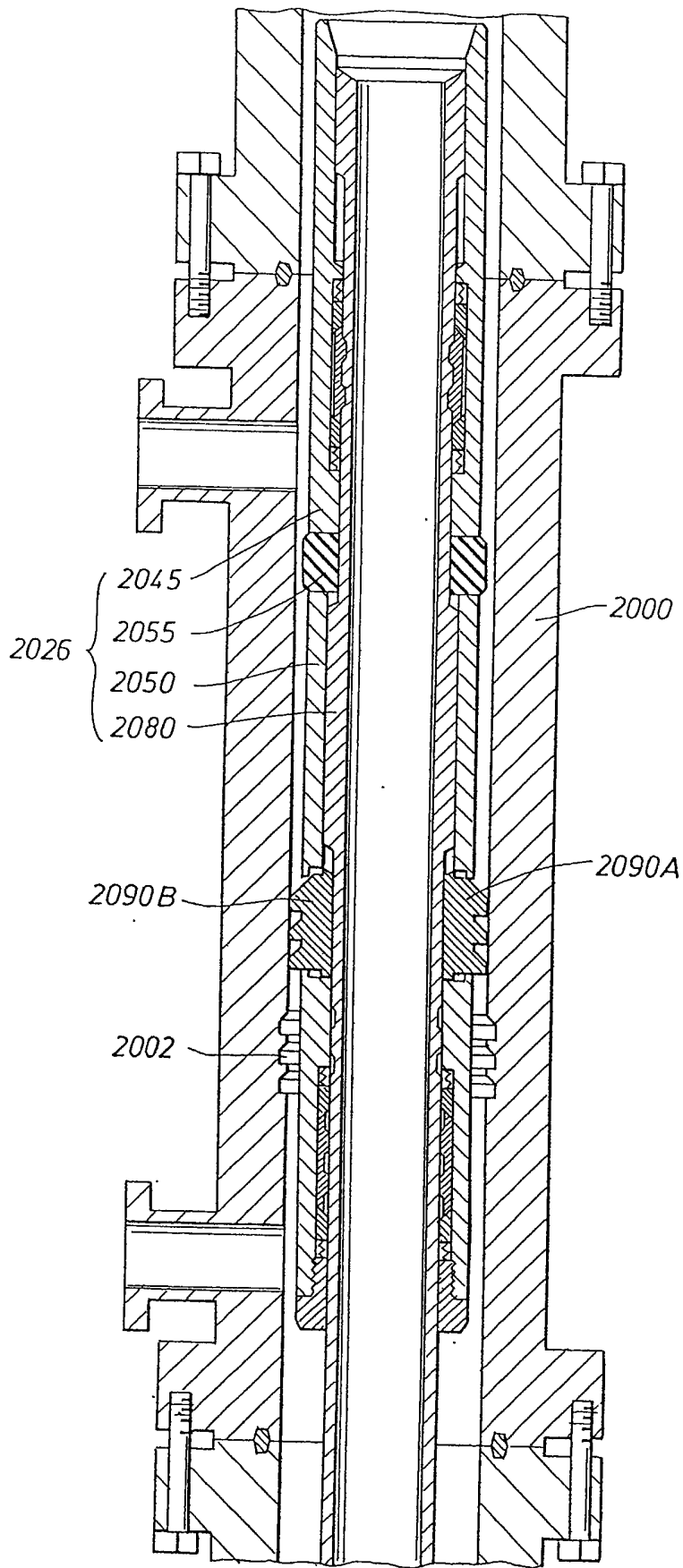


FIG. 29A

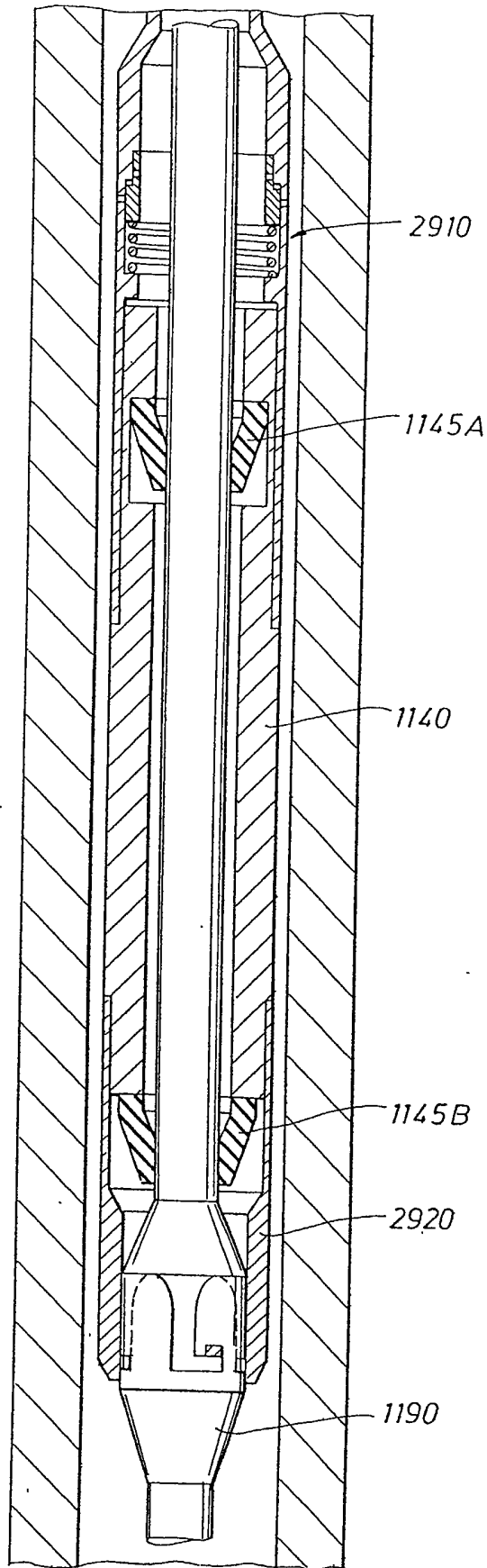


FIG. 29B

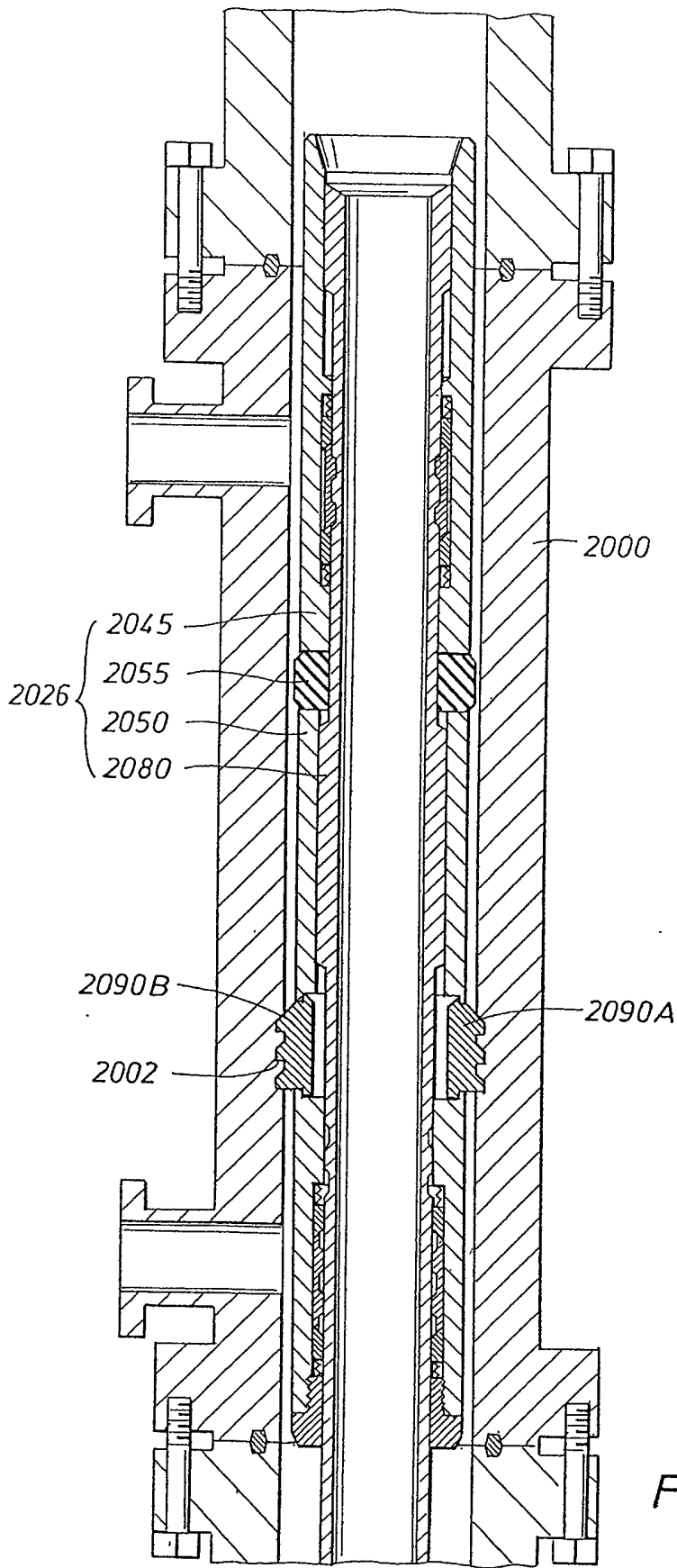


FIG. 30

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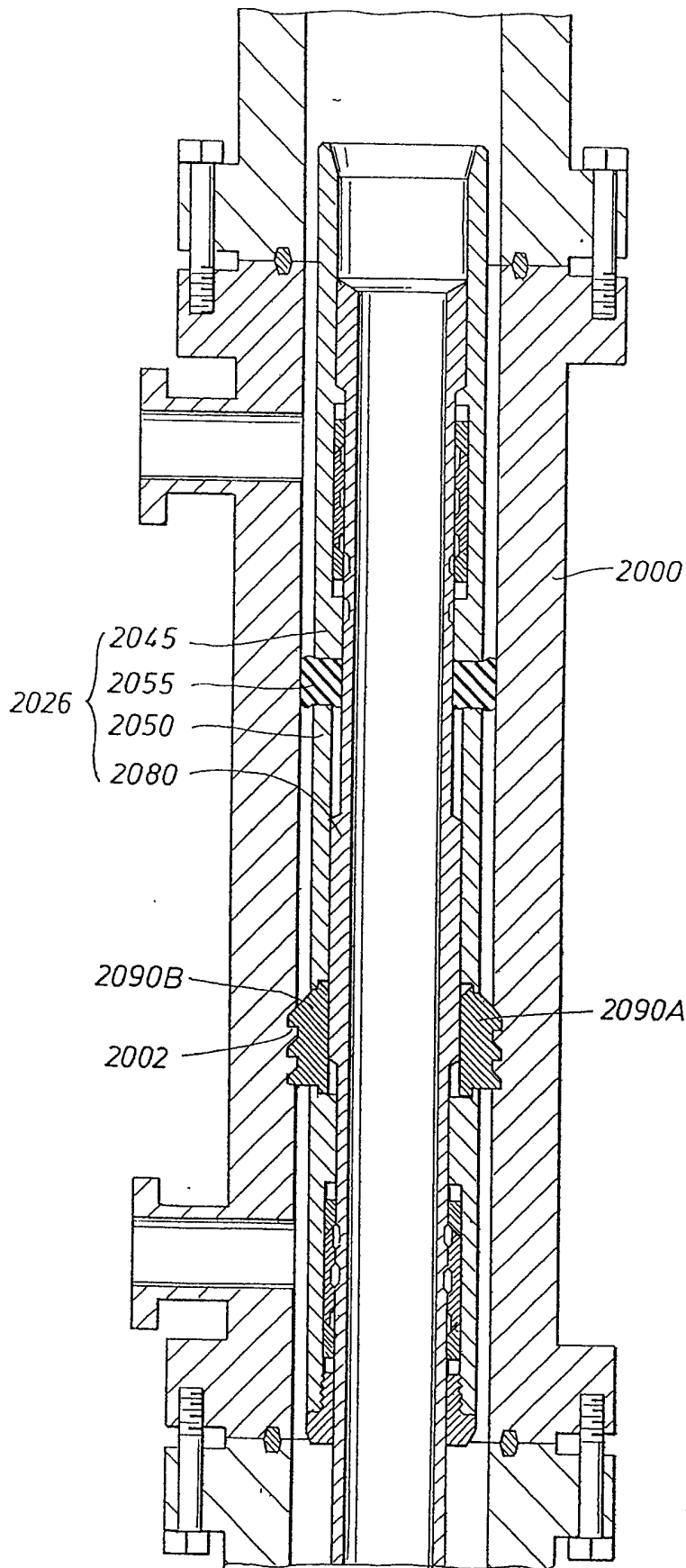


FIG. 31

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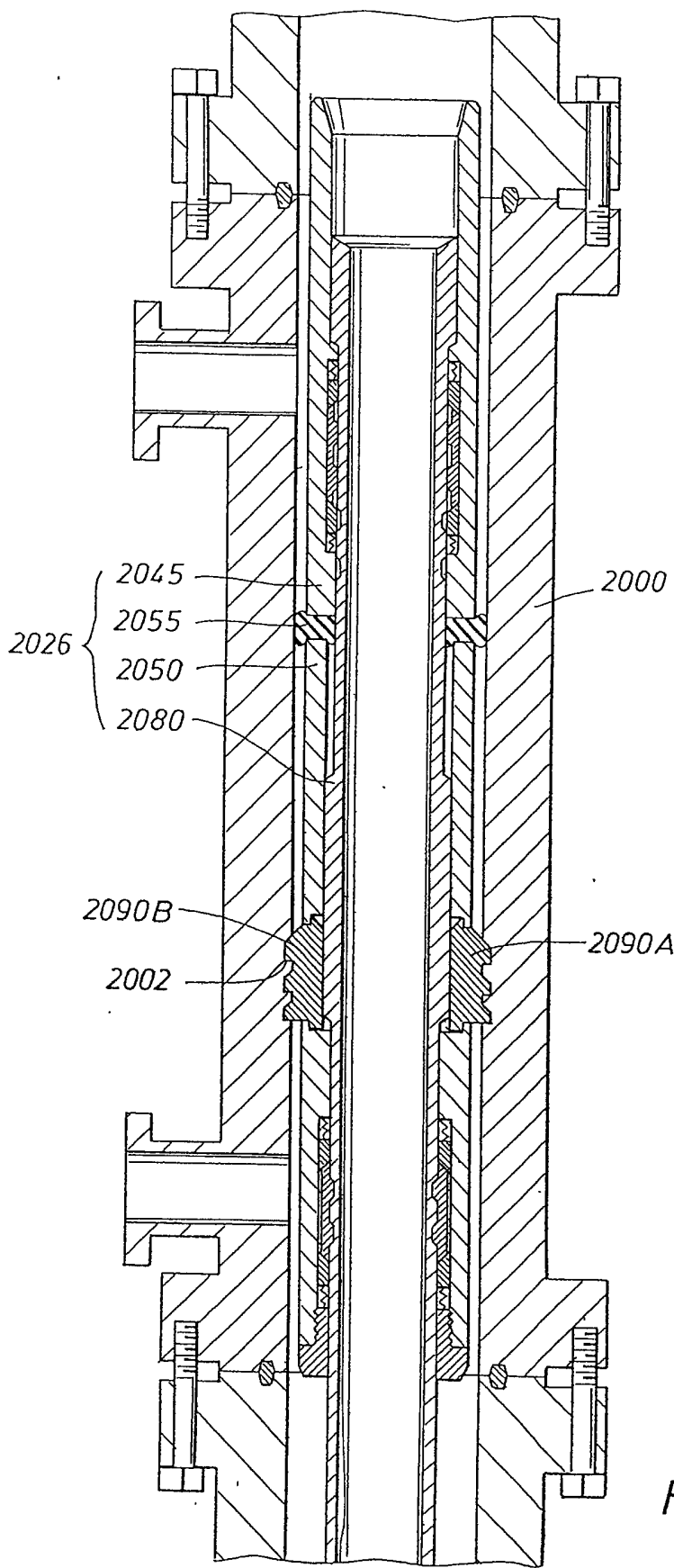


FIG. 32A

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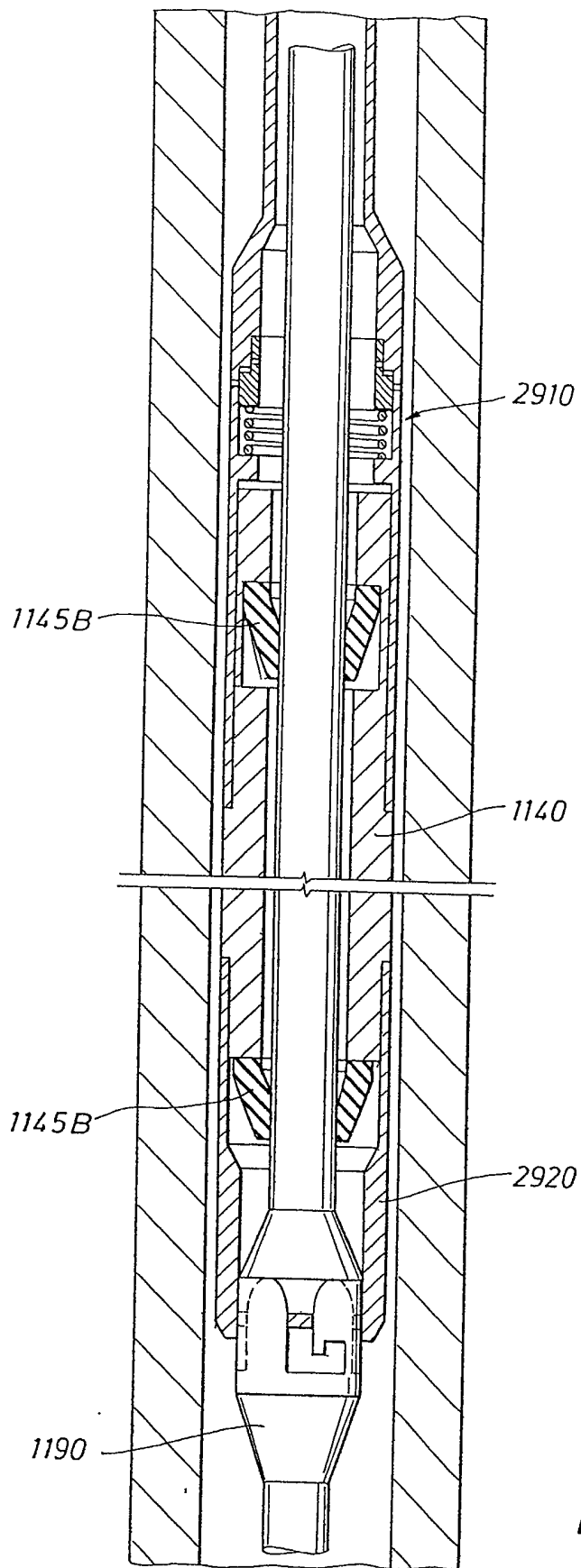


FIG. 32B

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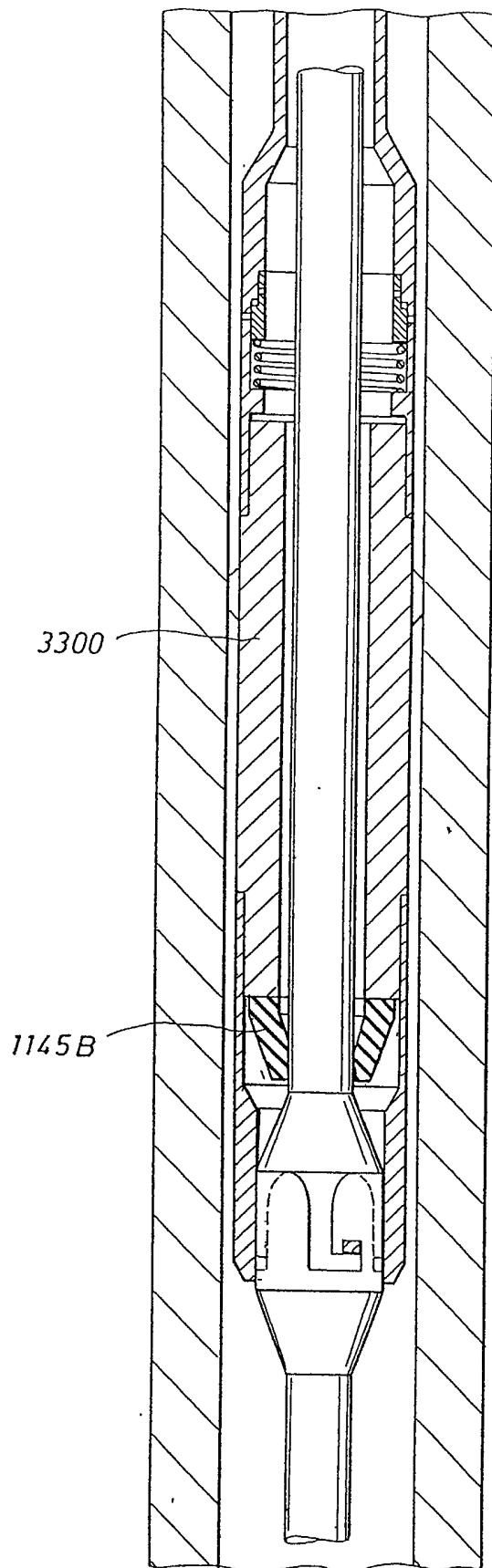


FIG.33

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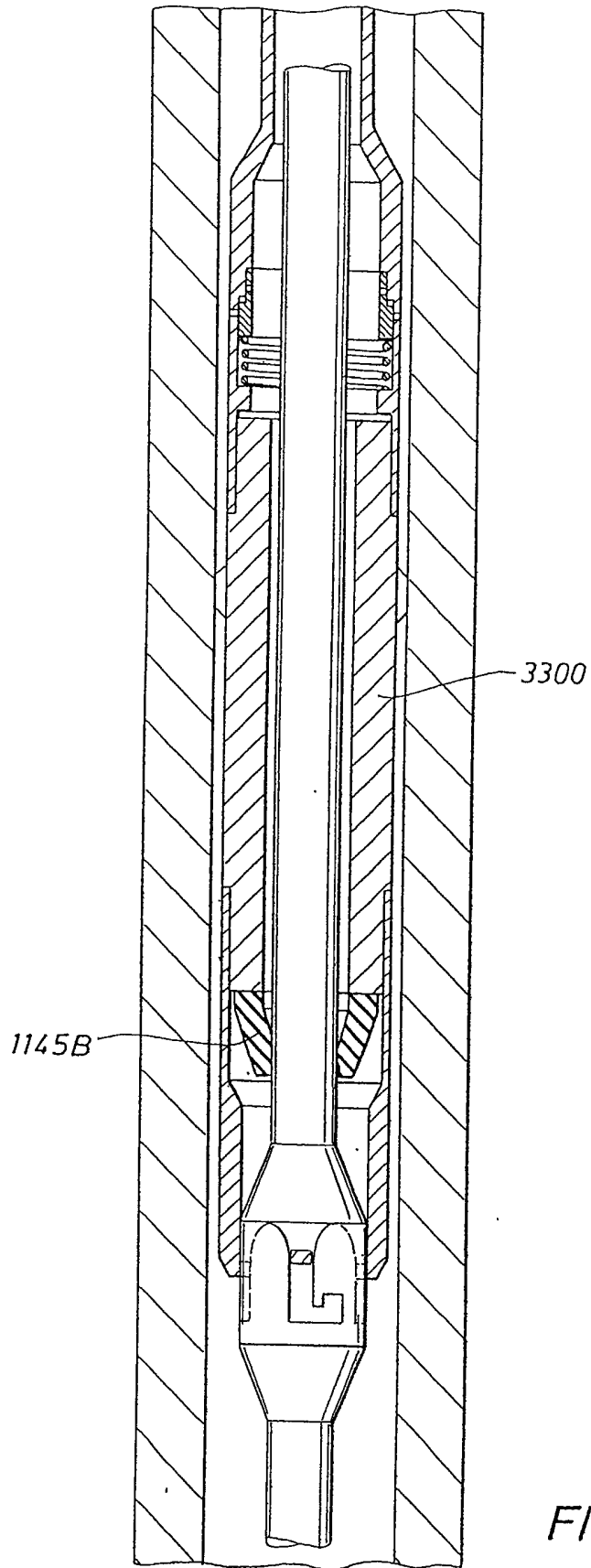


FIG.34

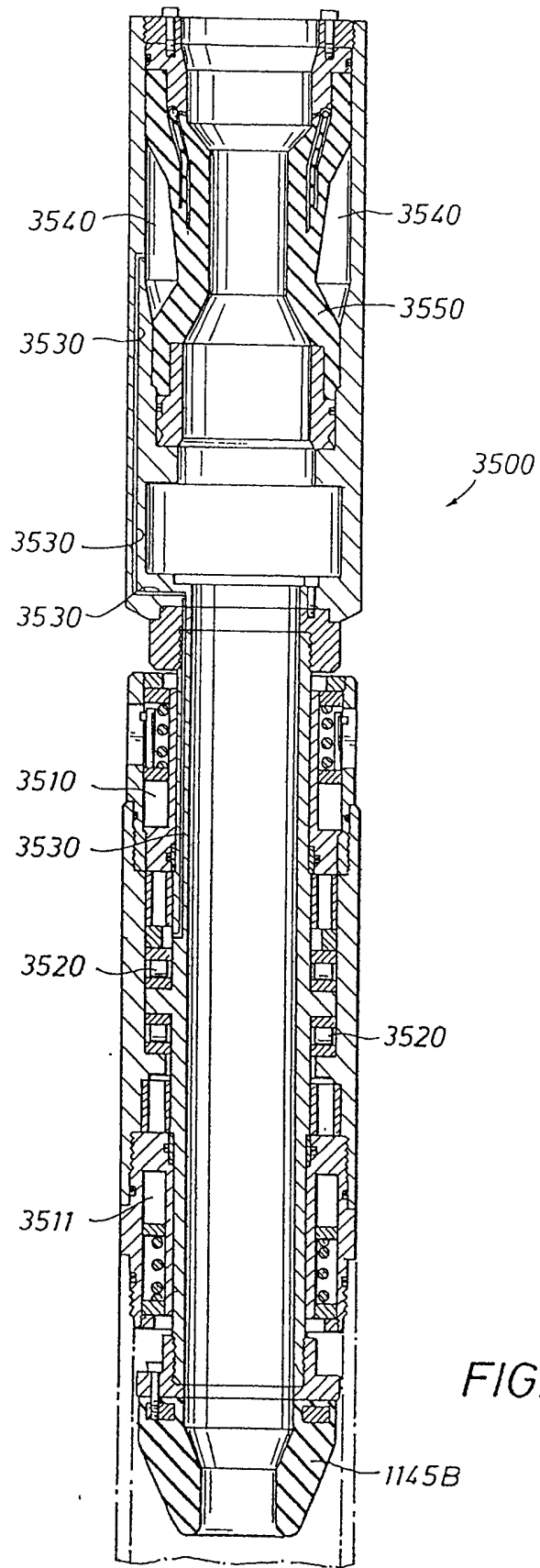


FIG.35

INTERNAL RISER ROTATING CONTROL HEAD

[0001] Some non-SI units are used in this specification. Their conversion factors are:

1psi = 6.892kPa

1foot = 30.48cm

1inch (sometimes abbreviated as 1") = 2.54cm

[0002] This application claims priority from a continuation-in-part of U.S. Application Serial No. 09/516,368, entitled "Internal Riser Rotating Control Head," filed March 1, 2000, which issued as U.S. Patent No. 6,470,975 on October 29, 2002, and which claims the benefit of and priority to U.S. Provisional Application Serial No. 60/122,530, filed March 2, 1999, entitled "Concepts for the Application of Rotating Control Head Technology to Deepwater Drilling Operations," which are hereby incorporated by reference in their entirety for all purposes.

[0003] The present invention relates to drilling subsea. In particular, the present invention relates to a system and method for sealingly positioning a rotating control head in a subsea housing.

[0004] 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 ½ inches, though other diameters can be used.

[0005] An example of a marine riser and some of the associated drilling components, such as shown in Figure 1, is proposed in U.S. Patent 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.

[0006] 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 Figure 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.

[0007] 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.

[0008] 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.

[0009] 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.

[0010] 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.

[0011] 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).

[0012] 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.

[0013] 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.

[0014] 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.

[0015] 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.

[0016] 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.

[0017] Aspects of the invention are set out in the independent claims.

[0018] 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.

[0019] 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.

[0020] 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.

[0021] In one embodiment, the internal formation is disposed between two spaced apart side openings in the subsea housing.

[0022] 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.

[0023] 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.

[0024] 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.

[0025] Some preferred embodiments of the invention will now be described by way of example only and with reference to the accompanying 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.

[0026] 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.

[0027] 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.

[0028] 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.

[0029] 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.

[0030] 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 8^{3/4}" 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.

[0031] 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.

[0032] 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.

[0033] 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.

[0034] 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.

[0035] 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.

[0036] 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.

[0037] 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.

[0038] 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.

[0039] 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.

[0040] 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.

[0041] 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.

[0042] 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.

[0043] 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.

[0044] 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.

[0045] 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.

[0046] 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 TII, 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 through 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 through 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.

[0047] Other types of active seals are also contemplated for use. A combination of active and passive seals can also be used.

[0048] 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.

[0049] 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.

[0050] 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.

[0051] 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.

[0052] 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.

[0053] 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.

[0054] 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.

[0055] 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.

[0056] 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.

[0057] 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.

[0058] 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.

[0059] 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.

[0060] Turning to Figure 13, spreader members 1185C and 1185D, not visible in Figure 11, are shown.

[0061] 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.

[0062] 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.

[0063] 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.

[0064] 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.

[0065] 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.

[0066] 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.

[0067] 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.

[0068] 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.

[0069] 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.

[0070] 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.

[0071] 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.

[0072] 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.

[0073] 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.

[0074] 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.

[0075] 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.

[0076] 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.

[0077] 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.

[0078] 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.

[0079] 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.

[0080] 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.

[0081] 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.

[0082] 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.

[0083] 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.

[0084] 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.

[0085] 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.

[0086] 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.

[0087] Returning to Figure 20A, the upper dog members are engaged in recesses 2032, while the lower dog members are disengaged with recesses 2012.

[0088] 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.

[0089] 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.

[0090] 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.

[0091] 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.

[0092] 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.

[0093] 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.

[0094] 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.

[0095] 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.

[0096] 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.

[0097] 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.

[0098] 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.

[0099] 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.

[00100] 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.

[00101] 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.

[00102] 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.

[00103] 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.

[00104] 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.

[00105] 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.

[00106] 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.

[00107] 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.

[00108] 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.

[00109] 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.

[00110] 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.

[00111] Although the invention has been described in terms of preferred embodiments as set forth above, it should be understood that these embodiments are illustrative only and that the claims are not limited to those embodiments. Those skilled in the art will be able to make modifications and alternatives in view of the disclosure which are contemplated as

falling within the scope of the appended claims. Each feature disclosed or illustrated in the present specification may be incorporated in the invention, whether alone or in any appropriate combination with any other feature disclosed or illustrated herein.

CLAIMS

1. A system adapted for forming a borehole using a rotatable pipe and a fluid, the system comprising:
 - a subsea housing disposed above the borehole;
 - a bearing assembly having an inner member and an outer member and being positioned with the subsea housing, the inner member rotatable relative to the outer member and having a passage through which the rotatable pipe may extend;
 - a bearing assembly seal to sealably engage the rotatable pipe with the bearing assembly; and
 - a holding member for positioning the bearing assembly with the subsea housing.

2. The system of claim 1, further comprising:
 - a holding member assembly including the holding member, and
 - a first seal disposed between the holding member assembly and the subsea housing.

3. The system of claim 2, wherein the first seal includes an annular seal.

4. The system of claim 2, further comprising:
 - a stack positioned from an ocean floor,
 - wherein the subsea housing is positioned above and in fluid communication with the stack.

5. The system of claim 2, wherein the first seal is movable between a sealed position and an unsealed position.

6. The system of claim 2, wherein the subsea housing is sealed with the bearing assembly by the first seal.

7. The system of claim 2, wherein the bearing assembly is removably positioned with the holding member assembly.

8. The system of claim 2, wherein the holding member is movable relative to the holding member assembly.

9. The system of claim 8, wherein the first seal is movable between a sealed position and an unsealed position,
whereby the subsea housing is sealed with the bearing assembly when the first seal is in the sealed position.

10. The system of claim 8,
whereby the holding member blocks movement of the bearing assembly relative to the subsea housing.

11. A system adapted for forming a borehole having a borehole fluid pressure, the system using a rotatable pipe and a fluid having a pressure, the system comprising:

a subsea housing disposed above the borehole;

an upper tubular disposed above the subsea housing;

a bearing assembly having an inner member and an outer member and being removably positioned with the subsea housing, the inner member rotatable relative to the outer member and having a passage through which the rotatable pipe may extend;

a bearing assembly seal to sealably engage the rotatable pipe;

a holding member for removably positioning the bearing assembly with the subsea housing; and

a first seal, the bearing assembly sealed with the subsea housing by the first seal,

whereby the pressure of the fluid can be increased proximate the first seal for controlling the borehole fluid pressure.

12. The system of claim 11, wherein the subsea housing has a passive latching formation.

13. The system of claim 11, wherein the bearing assembly is removably positioned with the holding member.

14. The system of claim 13, wherein the holding member has a shoulder.

15. The system of claim 13, wherein the first seal is removably positioned with the subsea housing.

16. The system of claim 15, wherein the first seal is movable between a sealed position and an unsealed position,

whereby the subsea housing is sealed by the first seal when the first seal is in the sealed position, and

whereby the holding member is removable from the subsea housing when the first seal is in the unsealed position.

17. A system adapted for forming a borehole in a floor of an ocean, the borehole having a borehole fluid pressure, the system using a fluid having a pressure, the system comprising:

a lower tubular adapted to be fixed relative to the floor of the ocean;

a subsea housing disposed above the lower tubular;

an upper tubular disposed above the subsea housing;

a bearing assembly having an inner member and an outer member and being removably positioned with the subsea housing, the inner member rotatable relative to the outer member and having a passage;

a bearing assembly seal disposed with the inner member;

an internal housing having a holding member, the internal housing communicating with the bearing assembly, the holding member extending from the internal housing for positioning with the subsea housing; and

a first seal movable between a sealed position and an unsealed position,

whereby the internal housing seals with the subsea housing when the first seal is in the sealed position, and

whereby the pressure of the fluid below the first seal can be increased for controlling the borehole fluid pressure.

18. A method for controlling the pressure of a fluid in a borehole while sealing a rotatable pipe, comprising the steps of:

positioning a subsea housing above the borehole;

holding a bearing assembly within the subsea housing;
sealing the bearing assembly with the rotatable pipe; and
sealing the subsea housing with the bearing assembly to control the pressure of the fluid in the borehole,
wherein the bearing assembly has an inner member and an outer member,
wherein the inner member is rotatable relative to the outer member, and
wherein the inner member has a passage through which the rotatable pipe may extend.

19. The method of claim 18, further comprising the step of:
rotating the rotatable pipe while increasing the pressure of the fluid in the borehole.

20. The method of claim 18, further comprising the step of:
sealing the bearing assembly with an internal housing sized to be received within an upper tubular.

21. The method of claim 20, further comprising the steps of:
sealing the subsea housing with the internal housing.

22. The method of claim 21, further comprising the step of:
moving a first seal from a retracted position to an extended sealed position for sealing the subsea housing with the internal housing.

23. A rotating control head system, comprising:
a first tubular;
an outer member removably positionable relative to the first tubular;
an inner member disposed within the outer member, the inner member having a passage running therethrough and adapted to receive and sealingly engage a rotatable pipe;

bearings disposed between the outer member and the inner member to rotate the inner member relative to the outer member when the inner member is sealingly engaged with the rotatable pipe;

a subsea housing connectable to the first tubular; and

a holding member for positioning the outer member with the subsea housing.

24. The rotating control head system of claim 23,
wherein the holding member is movable between a retracted position and an engaged position.

25. The rotating control head system of claim 23, further comprising a first seal,

wherein the first seal moves between an unsealed position and a sealed position, the outer member sealed with the subsea housing by the first seal when the first seal is in the sealed position; and

wherein the holding member limits movement of the outer member when the first seal is in the sealed position.

26. The rotating control head system of claim 25, further comprising a second tubular,

wherein the second tubular contains a second fluid having a second fluid pressure,

wherein the first tubular contains a first fluid having a first fluid pressure, and

wherein when the first seal is in the sealed position, the second fluid pressure can differ from the first fluid pressure.

27. The rotating control head system of claim 23, the holding member comprising:

a plurality of angled shoulders.

28. The rotating control head system of claim 24, wherein the holding member engages the subsea housing when the holding member is in the engaged position.

29. The rotating control head system of claim 28, further comprising a running tool,

wherein the holding member is moved from the retracted position to the engaged position with the subsea housing by moving the running tool.

30. The rotating control head system of claim 29, wherein the running tool can retrieve the outer member when the holding member is in the retracted position.

31. A method of forming a borehole, comprising the steps of:
positioning a housing above the borehole;
moving a rotating control head relative to the housing;
extending a rotatable pipe through the rotating control head and into the borehole;
positioning the rotating control head relative to the housing;
sealing the rotating control head with the housing;
sealing an inner member of the rotating control head with the rotatable pipe, the inner member rotating with the rotatable pipe relative to an outer member,
providing a first fluid within the borehole, the first fluid having a first fluid pressure;
providing a second fluid within the subsea housing, the second fluid having a second fluid pressure different from the first fluid pressure.

32. The method of claim 31, further comprising the step of:
limiting movement of the rotating control head when the rotating control head is sealed with the housing.

33. The method of claim 31, wherein the rotating control head is positioned above the housing.

34. The method of claim 31, wherein the rotating control head is positioned below the housing.

35. The method of claim 31, wherein the housing is a subsea housing and the method further comprising the step of:

forming the borehole while the inner member is sealed with the rotatable pipe and the subsea housing is sealed with the outer member.

36. A system adapted for forming a borehole using a rotatable pipe and a fluid, the system comprising:

a first housing having a bore running therethrough;

a bearing assembly disposed relative to the bore, the bearing assembly comprising an inner member and an outer member for rotatably supporting the inner member, the inner member being adapted to slidingly receive and sealingly engage the rotatable pipe wherein rotation of the rotatable pipe rotates the inner member;

a holding member for positioning the bearing assembly relative to the first housing; and

a seal having an elastomer element for sealingly engaging the bearing assembly with the first housing.

37. An internal riser rotating control head, comprising:

a housing having a bore running therethrough;

a bearing assembly disposed relative to the bore, the bearing assembly comprising an inner member and an outer member for rotatably supporting the inner member, the inner member being adapted to slidingly receive and sealingly engage the rotatable pipe, wherein rotation of the rotatable pipe rotates the inner member, the inner member having thereon a sealing element;

a holding member for positioning the bearing assembly relative to the housing;
and

a seal for securing the bearing assembly to the housing.

38. A system for positioning a rotating control head, comprising:

a subsea housing comprising:

an internal formation; and

a bearing assembly having a passage therethrough for receiving a rotatable pipe;

a holding member assembly connectable to the bearing assembly and the subsea housing, the holding member assembly comprising:

an internal housing coupled to the bearing assembly; and

a holding member coupled to the internal housing, the holding member engaging the internal formation, and the holding member sealing the holding member assembly with the subsea housing.

39. The system of claim 38, the bearing assembly further comprising:

a plurality of guide members on the bearing assembly.

40. The system of claim 38, the holding member comprising:
a latching portion; and
a plurality of openings.

41. The system of claim 40, the holding member assembly further comprising:

a pressure relief member for releasing pressure.

42. The system of claim 41, the pressure relief member comprising:
a valve engaging the plurality of openings in the holding member.

43. The system of claim 38, further comprising:
a running tool for moving the rotating control head assembly into the subsea housing, comprising:

a plurality of passive formations for engaging with the holding member assembly.

44. The system of claim 43,
wherein the running tool is rotated in a first direction for drilling, and
wherein the running tool is rotated in a second direction, rotationally opposite to the first direction, to disengage the running tool from the holding member assembly.

45. The system of claim 38, wherein the holding member is releasably positioned with the subsea housing.

46. The system of claim 38, the subsea housing further comprising:
a landing shoulder for blocking movement of the holding member assembly.

47. The system of claim 46, wherein the holding member assembly latches with the subsea housing when the holding member assembly engages the landing shoulder and is rotated.

48. The system of claim 47, further comprising:
a running tool for moving the rotating control head assembly into the subsea housing,
wherein the running tool rotates in a first direction during drilling, and
wherein the holding member assembly disengages with the subsea housing when the running tool is rotated in a second direction rotationally opposite to the first direction.

49. The system of claim 38, wherein the holding member assembly is threadedly connected to the bearing assembly.

50. The system of claim 38, the subsea housing having axially aligned openings, the subsea housing further comprising:
a first side opening; and
a second side opening spaced apart from the first side opening.

51. The system of claim 50, wherein the subsea housing internal formation is between the first side opening and the second side opening.

52. The system of claim 50, wherein the holding member seals the holding member assembly with the subsea housing between the first side opening and the second side opening.

53. A housing adapted for use subsea, comprising:
a tubular section having axially aligned openings, the tubular section further comprising:
a first side opening;
a second side opening spaced apart from the first side opening; and
an internal formation formed between the first side opening and second side opening.

54. The subsea housing of claim 53, further comprising a holding member, wherein the holding member seals the rotating control head assembly with the subsea housing.

55. The subsea housing of claim 53, further comprising:
an annular groove, and an annular seal positioned in the annular groove.
56. The subsea housing of claim 53, the internal formation comprising:
a landing shoulder for blocking movement.
57. The subsea housing of claim 53, further comprising a holding member,
wherein the holding member engages with the landing shoulder.
58. The subsea housing of claim 57, wherein the holding member
rotationally engages with the internal formation.
59. The subsea housing of claim 58, wherein the holding member
rotationally disengages with the internal formation.
60. The subsea housing of claim 57, wherein the holding member is
configured to disengage with the internal formation at a predetermined upward
pressure.
61. The subsea housing of claim 57, the internal formation comprising:
a passive annular formation adapted to interengage with the holding member
independent of rotation of the holding member.
62. The subsea housing of claim 53, the internal formation comprising:
a plurality of annular recesses.
63. The subsea housing of claim 62, wherein the plurality of recesses are
identical.
64. A rotating control head system, comprising:
a bearing assembly having a passage therethrough sized to receive a rotatable
pipe; and
a holding member assembly connected to the bearing assembly, comprising:
an internal housing, comprising:
a holding member recess; and

a holding member positioned in the holding member recess, the holding member movable between a retracted position in the recess and an extended position.

65. The system of claim 64, wherein the holding member assembly is threadedly connected to the bearing assembly.

66. The system of claim 64, further comprising a subsea housing, wherein the holding member assembly is releasably positionable with the subsea housing.

67. The system of claim 66, the subsea housing further comprising:
a first side opening; and
a second side opening spaced apart from the first side opening,
wherein an internal formation is disposed between the first side opening and the second side opening for receiving the holding member.

68. The system of claim 67, wherein the bearing assembly is disposed below the internal formation.

69. The system of claim 67, wherein the bearing assembly is disposed above the internal formation.

70. The system of claim 64, further comprising a subsea housing, wherein the bearing assembly is connected with the holding member assembly so that the bearing assembly is connected with the subsea housing.

71. The system of claim 64, the internal housing further comprising:
an upper annular portion;
a lower annular portion; and
an elastomer positioned between the upper portion and the lower portion.

72. The system of claim 71, wherein the holding member recess is defined by the lower portion.

73. The system of 71, further comprising:
an extendible portion concentrically interior to and slidably connectable to the internal housing upper portion and the internal housing lower portion.

74. The system of claim 73,
wherein extension of the extendible portion moves the upper portion toward the lower portion while the holding member moves to the extended position, thereby extruding the elastomer.

75. The system of claim 74,
the upper portion having a shoulder;
the extendible portion having a shoulder, the extendible portion shoulder engaging with the upper portion shoulder to move the internal housing upper portion toward the internal housing lower portion.

76. The system of claim 73,
a plurality of upper dog members; and
a plurality of upper dog recesses,
wherein the plurality of upper dog members releasably engage with the plurality of upper dog recesses.

77. The system of claim 76, wherein the plurality of upper dog members and the plurality of upper dog recesses interengage the extendible portion with the internal housing upper portion.

78. The system of claim 76, wherein the plurality of upper dog members and the plurality of upper dog recesses release the extendible portion from the upper portion at a predetermined force.

79. The system of claim 73,
a plurality of lower dog members and a plurality of lower dog recesses,
wherein the plurality of lower dog members releasably engage with the plurality of lower dog recesses.

80. The system of claim 79, wherein the plurality of lower dog members and the plurality of lower dog recesses interengage the extendible portion with the internal housing lower portion.

81. The system of claim 80, the lower portion further comprising:
an end portion, connected to the lower portion, forming a lower chamber for positioning the plurality of lower dog members between the lower portion and the extendible portion.

82. The system of claim 80, wherein the plurality of lower dog recesses are formed on the extendible portion.

83. The system of claim 73, wherein an outer surface of the extendible portion blocks the holding member radially outward.

84. The system of claim 73, the extendible portion further comprising:
a running tool bell landing portion.

85. The system of claim 66, wherein the holding member disengages from the subsea housing at a predetermined upward pressure on the holding member assembly.

86. The system of claim 66, further comprising:
a running tool for positioning the bearing assembly with the subsea housing,
and;
the running tool having a latching member for latching with the holding member assembly.

87. The system of claim 86, wherein the rotatable pipe is rotated in a first direction, and
wherein the running tool disengages from the holding member assembly when the rotatable pipe is rotated in a direction rotationally opposite to the first direction.

88. The system of claim 64, further comprising a running tool, wherein the holding member assembly further comprising:

a running tool bell landing portion; and
the running tool comprising:
a bell portion engageable with the running tool bell landing portion.

89. The system of claim 64, the bearing assembly further comprising:
a bearing assembly seal sealably engaging the rotatable pipe in the passage.

90. The system of claim 64, the bearing assembly further comprising:
a plurality of bearings; and
a pressure compensation mechanism adapted to automatically provide fluid
pressure to the plurality of bearings, comprising:

an upper chamber in fluid communication with the plurality of
bearings;

a lower chamber in fluid communication with the plurality of bearings;

an upper spring-loaded piston forming one wall of the upper chamber;

and

a lower spring-loaded piston forming one wall of the lower chamber.

91. The system of claim 90, the pressure compensation mechanism further
comprising:

an upper chamber fill pipe communicating with the upper spring-loaded
piston.

92. The system of claim 64, the bearing assembly comprising:
a pressure relief mechanism.

93. The system of claim 92, the pressure relief mechanism comprising:
a first pressure relief mechanism having an open position and a closed
position, the first pressure relief mechanism changing to the open position when a first
fluid pressure inside the holding member assembly exceeds a second fluid pressure
outside the holding member assembly.

94. The system of claim 93, the first pressure relief mechanism further
comprising:

a slidable member having a passage therethrough for allowing fluid flow through the passage when in the open position, the open position aligning the slidable member passage with a passage through the holding member assembly; and
a spring adapted to urge the slidable member to the closed position.

95. The system of claim 94, the pressure relief mechanism comprising:
a second annular slidable member moving between a closed position and an open position, the second slidable member sliding to the open position when a first fluid pressure outside the holding member assembly exceeds a second fluid pressure inside the slidable member assembly.

96. The system of claim 95, wherein the slidable member having a passage therethrough for allowing fluid flow through the passage when in the open position;
and
a spring adapted to urge the slidable member to the closed position.

97. A method of controlling pressure in an internal housing positioned in a subsea tubular, comprising the steps of:
positioning the subsea tubular above a borehole;
positioning a holding member assembly with the subsea tubular; and
sealing the holding member assembly with the subsea tubular.

98. The method of claim 97, the step of positioning the holding member assembly, comprising the step of:
reducing surging by allowing fluid passage through the holding member assembly while positioning the holding member assembly.

99. The method of claim 97, further comprising the step of:
opening a pressure relief valve of the holding member assembly when a borehole pressure exceeds the fluid pressure within the subsea tubular by a predetermined pressure.

100. The method of claim 97, further comprising the step of releasably positioning a rotating control head assembly, comprising the step of:

engaging a holding member assembly with the rotating control head with an internal formation on the subsea tubular.

101. The method of claim 100, the step of engaging, comprising the step of: rotating the holding member assembly into the internal formation in a first rotational direction.

102. The method of claim 101, the further comprising the step of: rotating the holding member assembly in a second rotational direction to unlatch the holding member assembly from the internal formation, the second rotational direction rotationally opposite to the first rotational direction.

103. A method of positioning a rotating control head with a subsea housing, comprising the steps of:

connecting a holding member assembly to the rotating control head;
forming an internal formation in the subsea housing;
retracting a holding member into an internal housing of the holding member assembly;
positioning the rotating control head with the subsea housing; and
engaging the holding member assembly with the subsea housing by radially extending the holding member outwardly into the internal formation.

104. The method of claim 103, the step of connecting a holding member assembly, comprising the step of:

threading the holding member assembly with the rotating control head.

105. The method of claim 103, further comprising the steps of:
positioning an elastomer between an upper portion of the internal housing and a lower portion of the internal housing;

extending an extendible portion of the holding member assembly; and
extruding the elastomer radially outwardly, sealing the holding member assembly with the subsea housing while extending the extendible portion.

106. The method of claim 105, the step of extruding comprising the step of:

compressing the elastomer between the upper portion and the lower portion, comprising the step of:

urging the upper portion toward the lower portion with the extendible portion.

107. The method of claim 105, further comprising the step of:
dogging the lower portion of the internal housing with the extendible portion when the extendible portion is in an extended position.

108. The method of claim 107, further comprising the steps of:
retracting the extendible portion;
undogging the lower portion of the internal housing from the extendible portion upon retracting;
decompressing the elastomer to unseal the holding member assembly from the subsea housing; and
dogging the upper portion of the internal housing to the extendible portion.

109. The method of claim 107, further comprising the step of:
blocking the holding member radially outwardly with the extendible portion when the extendible member is in an extended position.

110. The method of claim 107, further comprising the step of:
retracting the extendible portion;
unblocking the holding member; and
disengaging the holding member from the internal formation.

111. The method of claim 103, further comprising the steps of:
disengaging the holding member when applying a predetermined force to the holding member.

112. The method of claim 103, further comprising the step of:
configuring a pressure relief assembly with the holding member assembly.

113. The method of claim 112, the step of configuring comprising:

providing fluid communication via a first passage through the internal housing;

opening the first passage if fluid pressure exceeds a borehole pressure by a first predetermined pressure.

114. The method of claim 113, the step of configuring comprising:

providing fluid communication via a second passage through the outer portion of the internal housing;

opening the second passage if borehole pressure exceeds fluid pressure by a predetermined amount.

115. A system for use in a rotating control head assembly having a bearing, the system comprising:

a pressure compensation mechanism adapted to automatically provide fluid pressure to the bearing, comprising:

a first chamber in fluid communication with the bearing;

a second chamber in fluid communication with the bearing;

a first biased barrier forming one wall of the first chamber and adapted to compress a fluid within the first chamber; and

a second biased barrier forming one wall of the second chamber and adapted to compress the fluid within the second chamber.

116. The system of claim 115, the pressure compensation mechanism further comprising:

a first chamber fill pipe communicating with the first biased barrier,

wherein a first end of the first chamber fill pipe is accessible through an opening in the side of the rotating control head assembly.

117. A system for positioning a rotating control head assembly within a subsea housing, the system comprising:

means for providing a bearing fluid pressure; and

means for increasing the bearing fluid pressure by a predetermined amount above the higher of the subsea housing fluid pressure or the borehole pressure.

118. A subsea housing system, comprising:
a holding member connected to a rotating control head assembly, and
an annular formation on the subsea housing for interengaging with the holding member without regard to a rotational position of the holding member.

119. The system of claim 118, the annular formation comprising:
a plurality of recesses configured to cooperatively interengage with a plurality of protuberances of the holding member.

120. The system of claim 119, wherein the plurality of recesses are identical.

121. The system of claim 119, wherein the plurality of recesses are configured to allow the holding member assembly to disengage from the internal formation at a predetermined force.

122. A holding member assembly adapted for connection with a bearing assembly of a rotating control head, comprising:
an internal housing, comprising:
a holding member recess; and
a holding member positioned with the holding member recess, the holding member movable between an extended position and a retracted position.

123. The holding member assembly of claim 122, further comprising:
a threaded section for threadedly connecting the holding member assembly to the bearing assembly.

124. The holding member assembly of claim 122, the internal housing comprising:
an upper portion;
a lower portion; and
an extrudable elastomer positioned between the upper portion and the lower portion.

125. The holding member assembly of claim 124, wherein the holding member recess is defined by the lower portion.

126. The holding member assembly of claim 124, further comprising:
an extendible portion concentrically interior to and slidably connectable to the internal housing upper portion and the internal housing lower portion.

127. The holding member assembly of claim 126,
wherein extension of the extendible portion causes the internal housing upper portion to move toward the internal housing lower portion, thereby extruding the elastomer.

128. The holding member assembly of claim 126, wherein
the upper portion having a shoulder;
the extendible portion having a shoulder, the upper portion shoulder engaging with the extendible portion shoulder to move the upper portion toward the lower portion

129. The holding member assembly of claim 126, 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.

130. The holding member assembly of claim 129,
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.

131. The holding member assembly of claim 130, the lower portion further comprising:

an end portion, connected to the lower portion, forming a chamber for the second dog member.

132. The holding member assembly of claim 126, wherein an outer surface of the extendible portion blocks the holding member radially outward when the extendible portion is in an extended position.

133. The holding member assembly of claim 122, wherein the holding member is configured to retract at a predetermined force on the housing member assembly.

134. The holding member assembly of claim 122, further comprising:
means for latching a running tool with the holding member assembly.

135. A housing adapted for use subsea, comprising:
a riser having axially aligned openings, the riser further comprising:
an internal formation formed on an internal surface of the riser to provide a profile.

136. The subsea housing of claim 135, further comprising:
a first side opening in the riser,
a second side opening in the riser spaced apart from the first side opening; and
the internal formation formed between the first side opening and the second side opening.

137. The subsea housing of claim 135, further comprising:
an annular groove; and
an annular seal positioned in the annular groove.

138. The subsea housing of claim 135, the internal formation comprising:
a landing shoulder.

139. The subsea housing of claim 138, further comprising:
a holding member,
wherein the holding member engages with the landing shoulder.

140. The subsea housing of claim 139, wherein the holding member rotationally engages with the internal formation.

141. The subsea housing of claim 140, wherein the holding member rotationally disengages with the internal formation.

142. The subsea housing of claim 139, wherein the holding member is configured to disengage with the internal formation at a predetermined upward pressure.

143. The subsea housing of claim 139, the internal formation comprising:
a passive annular formation adapted to interengage with the holding member independent of rotation of the holding member.

144. The subsea housing of claim 135, the internal formation comprising:
a plurality of annular recesses.

145. A rotating control head system, comprising:
a bearing assembly having a passage therethrough sized to receive a rotatable pipe; and
a holding member assembly connected to the bearing assembly, comprising:
an internal housing, comprising:
a holding member.

146. The system of claim 145, wherein the holding member assembly is threadedly connected to the bearing assembly.

147. The system of claim 145, further comprising a subsea housing,
wherein the holding member assembly is releasably positionable with the subsea housing.

148. The system of claim 147, the subsea housing further comprising:
a first side opening; and
a second side opening spaced apart from the first side opening,

wherein an internal formation is disposed between the first side opening and the second side opening for receiving the holding member.

149. The system of claim 148, wherein the bearing assembly is disposed below the internal formation.

150. The system of claim 148, wherein the bearing assembly is disposed above the internal formation.

151. The system of claim 145, further comprising a subsea housing, wherein the bearing assembly is connected with the holding member assembly so that the bearing assembly is connected with the subsea housing.

152. The system of claim 147, wherein the holding member disengages from the subsea housing at a predetermined upward pressure on the holding member assembly.

153. The system of claim 147, further comprising:
a running tool for positioning the bearing assembly with the subsea housing,
and;
the running tool having a latching member for latching with the holding member assembly.

154. The system of claim 153, wherein the rotatable pipe is rotated in a first direction, and
wherein the running tool disengages from the holding member assembly when the rotatable pipe is rotated in a direction rotationally opposite to the first direction.

155. The system of claim 145, further comprising a running tool, wherein the holding member assembly further comprising:
a running tool bell landing portion; and
the running tool comprising:
a bell portion engageable with the running tool bell landing portion.

156. The system of claim 145, the bearing assembly further comprising:

a bearing assembly seal sealably engaging the rotatable pipe in the passage.

157. The system of claim 145, the bearing assembly further comprising:
a bearing; and

a pressure compensation mechanism adapted to automatically provide fluid pressure to the bearing, comprising:

- a first chamber in fluid communication with the bearing;
- a second chamber in fluid communication with the bearing;
- a first piston forming one wall of the first chamber; and
- a second piston forming one wall of the second chamber.

158. The system of claim 145, the bearing assembly comprising:
a pressure relief mechanism.

159. The system of claim 158, the pressure relief mechanism comprising:

a first pressure relief mechanism having an open position and a closed position, the first pressure relief mechanism changing to the open position when a first fluid pressure inside the holding member assembly exceeds a second fluid pressure outside the holding member assembly.

160. A system, method, control head, housing or assembly, substantially as any one herein described with reference to, or as illustrated in, Figures 2 to 35 of the accompanying drawings.



INVESTOR IN PEOPLE

Application No: GB 0324939.8
Claims searched: 1

Examiner: Robert Lynch
Date of search: 21 January 2004

Patents Act 1977 : Search Report under Section 17

Documents considered to be relevant:

Category	Relevant to claims	Identity of document and passage or figure of particular relevance
X	1 at least	WO 00/52299 A1 (Weatherford/Lamb Inc.) See figures and claims, noting housing 14 and bearing assembly 28.
X	1 at least	US 6138774 A (Weatherford Holding U.S. Inc.) See figures and claims 1 - 3, noting bearing assembly 60 located in subsea apparatus above a borehole.

Categories:

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application

Field of Search:

Search of GB, EP, WO & US patent documents classified in the following areas of the UKC^W:

E1F

Worldwide search of patent documents classified in the following areas of the IPC[?]:

E21B

The following online and other databases have been used in the preparation of this search report:

Online: EPODOC, WPI, PAJ, OPTICS.TXTUS0, TXTUS1, TXTUS2, TXTUS3, TXTEP1, TXTGB1, TXTWO1