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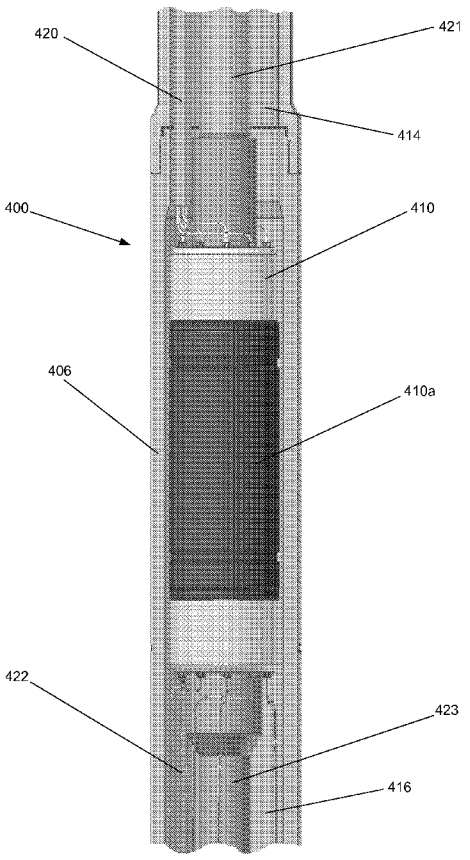
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[Continued on next page]

(54) Title: SYSTEMS AND METHODS FOR USING AN UMBILICAL



(57) Abstract: A subsea well system comprising a vessel located in a body of water; a blowout preventer connected to said vessel, the blowout preventer defining a top of the system; a riser comprising a first end connected to said blowout preventer at the top of the system, and a second end connected to a wellhead of a wellbore at the bottom of the system; a seal located within the riser below the blowout preventer and above the wellhead; and an umbilical within the riser connected to the vessel at a first end, and connected to the seal at a second end.

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SYSTEMS AND METHODS FOR USING AN UMBILICAL

Field of the Invention

The present invention is directed to using an umbilical in conjunction with a Surface Blow Out Preventer Stack.

Background of the Invention

Exploration and production of hydrocarbons from subsea reservoirs is an expensive and time-consuming process. The drilling and production processes used to obtain hydrocarbon products from subsea wells often require allocation of expensive assets, such as floating drilling and production facilities located offshore. There are a number of problems associated with deepwater offshore drilling and production that are not found in shallow water or land operations.

Primary among these is the marine environment. Unlike the surface environment, much of the deepwater offshore drilling control equipment is located on the seabed and is not subject to direct control and monitoring--one simply cannot see the equipment without the use of vision equipped remotely operated vehicles (ROVs).

Offshore operations may use location of a floating drilling unit and/or production unit in waters located generally above the reservoir of interest. The depth of the water may range from several hundred meters to depths of several kilometers. A drilling riser comprised of generally cylindrical elements may be provided for and extends from a wellhead located at the seabed up to the drilling platform located above the surface of the water. The riser operates to protect the drill string during operations and acts as an artificial annulus.

The risers may be formed from metal tubular goods/joints linked together. Buoyancy elements, also called floats, may be affixed to the external surface of the drilling riser along its length in order to establish essentially neutral buoyancy.

As with land drilling operations, subsea drilling operations usually provide a means for shutting down the well in emergency situations. Generally, a series of blowout preventers (BOPs) referred to as a BOP stack, are used to control well flow in such instances. The BOP stack typically consists of multiple BOPs connected to each other and to the wellhead, and may include shear ram or annular BOPs. In land

operations, the BOP stack is typically just below the rotary table and may be easily monitored and operated in response to a significant well event. However, in conventional subsea drilling systems the BOP stack is located on the seafloor and requires various umbilical and control lines in order to monitor conditions and operate the BOP stack. It will be appreciated that similar to the drill string and drilling riser, the umbilical and control lines must traverse the distance between the offshore platform and the subsea wellhead.

Metaocean conditions, such as winter storms, hurricanes and typhoons add yet another element of complexity to offshore drilling operations. During such events, drilling and/or production operations are typically suspended and the crew is evacuated. In the case of fixed offshore platforms or compliant tower platforms, the riser is often left in place as it is supported by a conductor system that extends from near surface to near sea bed. Floating offshore platforms present different problems in that there are no conductors to support the riser system, which depends instead, on a combination of flotation cells and topside tensioners for support. Should a metaocean condition occur, the crew is similarly evacuated, leaving the riser system subject to current stresses, as well as wind and wave stresses placed on the floating platform. To prevent damage from occurring, the riser system is often disconnected from the sea floor BOP stack and tripped, together with the control lines, to the platform surface. After the condition abates, the riser system, as well as the umbilicals and control lines are then reconnected to the sea floor BOP stack and a series of time-consuming safety tests are performed before drilling can resume.

It will be appreciated that the time required to disconnect and subsequently reconnect the riser system results in significant loss of rig time, particularly in the case of offshore platforms. Reconnection typically includes running the riser and associated umbilicals down to the seafloor BOP stack, and these are typically reconnected utilizing ROVs. The reconnection process can take many hours, followed by days of testing.

Also, using conventional subsea BOP equipment, critical rig time is required to run, set and retrieve the subsea BOP and its accessories. There is correlation between the depth of the water and the time involved. There is also an associated

risk of down time simply due to the complexity of the equipment. In addition to the down time associated with conventional subsea BOP equipment, conventional subsea BOPs require use of a large-diameter riser, which in turn requires more storage space on the deck of the platform prior to installation of said riser. The large-diameter risers also require high riser-tensioning capacity and/or additional buoyancy elements.

Surface BOP stack (SBOP) technology overcomes some of the problems described for subsea BOPS. The SBOP is placed on or slightly below the deck of an offshore drilling platform. The riser connecting the wellhead to the surface BOP may be a high pressure riser, capable of withstanding formation pressure from the well.

Unfortunately, problems may also be associated with the use of a Surface BOP stack. During completions or other operations it may be desired to control a tool or other device downhole with the use of an umbilical. Some umbilicals would be crushed if used within a high pressure environment below a SBOP stack.

U.S. Pat. No. 6,672,390 discloses systems and methods for time and labor-efficient construction and production of subsea wells. The systems generally comprise a surface blowout preventer stack, a high pressure riser, and a drill thru Xmas tree. The systems may further comprise a subsea shut off and disconnect device. U.S. Pat. No. 6,672,390 is herein incorporated by reference in its entirety.

Thus, there is a need in the art for systems and methods for time efficient drilling and completion of wells in marine environments, which do not suffer from the disadvantages of the prior art systems and methods.

There is another need for systems and methods using a SBOP stack, that will allow the use of an umbilical.

Summary of the Invention

In one aspect the invention provides a subsea well system comprising a vessel located in a body of water; a blowout preventer connected to said vessel, the blowout preventer defining a top of the system; a riser comprising a first end connected to said blowout preventer at the top of the system, and a second end connected to a wellhead of a wellbore at the bottom of the system; a seal located within the riser

below the blowout preventer and above the wellhead; and an umbilical within the riser connected to the vessel at a first end, and connected to the seal at a second end.

In another aspect the invention provides a method comprising installing a riser from a vessel at the top of a body of water, to a wellhead at the bottom of the body of water; installing a blowout preventer adjacent the top of the body of water; lowering a seal within the riser to a point below the blowout preventer, and above the wellhead; connecting an umbilical between the vessel and the seal; and activating the seal to define a first pressure region within the riser above the seal, and a second pressure region within the riser below the seal.

Advantages of the invention may include one or more of the following:

An improved umbilical and method of use in conjunction with a surface blow out preventer.

An improved surface blow out preventer and method of use.

An improved umbilical and method of use to control a tool in a riser.

An improved seal and method of use in a riser.

An improved seal inflation system and use.

Brief Description of the Drawings

Figure 1 is an illustration of an offshore drilling system.

Figure 2 is an illustration of an offshore drilling system.

Figure 3 is an illustration of an offshore drilling system.

Figure 4 is an illustration of a sealing mechanism within a tubular.

Detailed Description of the Drawings

In one embodiment, there is disclosed a subsea well system comprising a vessel located in a body of water; a blowout preventer connected to said vessel, the blowout preventer defining a top of the system; a riser comprising a first end connected to said blowout preventer at the top of the system, and a second end connected to a wellhead of a wellbore at the bottom of the system; a seal located within the riser below the blowout preventer and above the wellhead; and an umbilical within the riser connected to the vessel at a first end, and connected to the seal at a second end. In some embodiments, the system also includes a subsea shut off and disconnect device positioned below the seal and above the wellhead. In some

embodiments, the wellhead is connected to a casing lining an interior of said wellbore. In some embodiments, said blowout preventer is positioned above sea level and controlled from above sea level. In some embodiments, the system also includes a drill-thru Christmas tree positioned at the wellhead. In some embodiments, said riser is utilized in drilling though the wellbore into a formation and in producing a product from said formation. In some embodiments, said seal separates a low pressure region within the riser above the seal and below the blowout preventer, and a high pressure region within the riser below the seal and above the wellhead. In some embodiments, the system also includes a tool within the high pressure region. In some embodiments, said tool is controlled by the umbilical. In some embodiments, said seal comprises expandable elements movable from a first small diameter position and a second large diameter position, wherein said seal occludes said riser when the seal is in the second large diameter position.

In one embodiment, there is disclosed a method comprising installing a riser from a vessel at the top of a body of water, to a wellhead at the bottom of the body of water; installing a blowout preventer adjacent the top of the body of water; lowering a seal within the riser to a point below the blowout preventer, and above the wellhead; connecting an umbilical between the vessel and the seal; and activating the seal to define a first pressure region within the riser above the seal, and a second pressure region within the riser below the seal. In some embodiments, the method also includes controlling well blowout with a subsea shut off and disconnect device. In some embodiments, the method also includes pressurizing the second pressure region to a high pressure. In some embodiments, the method also includes pressurizing the first pressure region to a low pressure. In some embodiments, the method also includes lowering a tubing hanger running tool into the second pressure region. In some embodiments, the method also includes lowering a tubing hanger running tool into the second pressure region and testing a seal of the tubing hanger running tool with a high pressure in the second pressure region. In some embodiments, the method also includes inflating the seal with a control line connected to the vessel.

Referring first to Figure 1, in one embodiment, there is illustrated system 100. System 100 includes vessel 102 floating in water 104. Vessel 102 is connected to riser 106 which also connects to wellhead 113 at mudline 105. A surface blow-out preventor (BOP) 108 is provided on vessel 102. A seal 110 is provided within riser 106 to create first pressure region 114 and second pressure region 116. A pressure differential can be maintained between first pressure region 114 and second pressure region 116 by seal 110. For example, second pressure region 116 may be maintained at a higher pressure than first pressure region 114. Subsea shutoff and disconnect 112 is provided adjacent wellhead 113 on riser 106. Well 118 is below mudline 105 and connected to wellhead 113.

Referring now to Figure 2, in some embodiments, system 200 is illustrated. System 200 includes vessel 202 floating in water 204. Riser 206 is connected to vessel 202 and wellhead 213 at mudline 205. Blow-out preventor 208 is connected to vessel 202 and riser 206. Tubing 221, for example a drill string or production tubing, is within riser 206. Umbilical 220 is connected to seal 210 within riser 206. Seal 210 may be activated with inflation line 223 to separate first pressure region 214 from second pressure region 216. Control line 222 is provided to connect seal 210 with tubing hanger running tool 224. Subsea shutoff and disconnect 212 is adjacent to wellhead 213 and is adapted to shut off riser 206. Well 218 is beneath mudline 205 and connects to wellhead 213.

In some embodiments, seal 210 may be activated so that first pressure region 214 may be a relatively low pressure region, and second pressure region 216 may be a relatively high pressure region, so that umbilical 220 is isolated from second pressure region 216 and not crushed by the high pressure. For example, second pressure region 216 may be a relatively high pressure region in order to test the seals of tubing hanger running tool 224 with a high pressure. In some embodiments, seal 210 may be activated by pressure within umbilical 220. In some embodiments, seal 210 may be retained in a small diameter configuration within a sleeve (not shown), and released to a large diameter configuration by removing the sleeve. In some embodiments, sleeve may be inflated and/or deflated with inflation line 223.

Referring now to Figure 3, in some embodiments, system 300 is provided. System 300 includes riser 306 connecting vessel 302 with wellhead 313. Blow-out preventor 308 is provided above water 304 in order to shutoff riser 306. Blow-out preventor includes pipe rams 308a, shear rams 308b, annular bag 308c, kill line 308d, and choke line 308e. Umbilical 320 is within riser 306, and is feed off a spool 320a on vessel 302 and teminates at seal 310. Tubular 321 connects to valve 321a on vessel 302 and teminates at seal 310. In operation, pressure may be provide within tubular 321 through valve 321a in order to operate seal 310, which may be expanded to occlude the annulus of riser 306, to create first pressure region 314, and second pressure region 316. Beneath seal 310 is subsea shutoff 312, which may include shear rams. Control lines 322 connect seal 310 with tubing hanger running tool 324. Tubing hanger running tool 324 is connected to tubing hanger 325, within wellhead 313. Wellhead 313 rests adjacent mudline 305, and is the upper end of well 318. Well 318 may include a safety valve, an FBIV valve, and/or other elements as are known in the art.

In operation, valve 321a may be opened to provide a high pressure into tubular 321 which activates seal 310, to create a low pressure region 314, which is separated from high pressure region 316 by seal 310. Low pressure region 314 is maintained at a level so that umbilical 320 would not be crushed by the high pressures. High pressure region 316 is provided at a suitable level so that seals on tubing hanger running tool 324 and/or tubing hanger 325 may be tested, and so that control lines 322 are not crushed. In some embodiments, control lines 322 are able to withstand a higher external pressure than umbilical 320.

In some embodiments, control lines 322, subsea shutoff 312, tubing hanger running tool 324, tubing hanger 325, wellhead 313, and/or well 318 are designed to be able to withstand the pressure of high pressure region 316.

Referring now to Figure 4, in some embodiments, system 400 is illustrated. System 400 includes seal 410 which is placed in tubular 406. Seal 410 includes expandable elements 410a. Connected to seal 410 from the top are umbilical 420 and tubular 421. Connected to seal 410 at the bottom are control lines 422 and tubular 423. In some embodiments, a pressure may be placed within tubular 421

which acts to expand expandable elements 410a and occlude the annulus of tubular 406, creating first pressure region 414 and second pressure region 416, so that pressure differential may be maintained between first pressure region 414 and second pressure region 416. In some embodiments, a movable sleeve (not shown) may be used to maintain seal 410 in a small diameter configuration. In some embodiments, a separate control line (not shown) may be used to inflate and/or deflate seal 410.

In some embodiments, first pressure region 414 is a relatively low pressure region so that umbilical 420 is not crushed by high pressure. In some embodiments, second pressure region 416 is a relatively high pressure region in order to provide pressure testing of elements in second pressure region 416. Control lines 422 and tubular 423 may be designed to withstand the relatively high pressure.

In some embodiments, a suitable liner hanger running tool is disclosed in U.S. patent number 6,739,398, which is herein incorporated by reference in its entirety.

In some embodiments, suitable blow-out preventors, subsea shutoff and disconnect devices, risers, wells, and vessels are disclosed in U.S. patent number 6,672,390, which is herein incorporated by reference in its entirety.

In some embodiments, suitable slick joints and packers are disclosed in U.S. patent number 6,302,208, which is herein incorporated by reference in its entirety.

In some embodiments, suitable blow-out preventors are disclosed in U.S. patent number 6,059,042, which is herein incorporated by reference in its entirety.

In some embodiments, suitable risers and/or surface blow-out preventors are disclosed in U.S. patent number 5,533,574, which is herein incorporated by reference in its entirety.

In some embodiments, a suitable wellhead is disclosed in U.S. patent number 4,616,707, which is herein incorporated by reference in its entirety.

In some embodiments, a suitable packer is disclosed in U.S. patent number 4,548,265, which is herein incorporated by reference in its entirety.

In some embodiments, a suitable packer and/or a suitable slick joint are disclosed in U.S. patent number 4,307,781, which is herein incorporated by reference in its entirety.

In some embodiments, a suitable packer is disclosed in the U.S. patent number 3,256,437, which is herein incorporated by reference in its entirety.

In some embodiments, suitable linger hangers, inflatable packers, blow-out preventors, and subsea shutoff devices, and wellheads are commercially available from Baker Oil Tools of Houston, Texas; Schlumberger of Houston, Texas; and Halliburton Company of Houston, Texas.

C L A I M S

1. A subsea well system comprising:

a vessel located in a body of water;

a blowout preventer connected to said vessel, the blowout preventer defining a top of the system;

a riser comprising a first end connected to said blowout preventer at the top of the system, and a second end connected to a wellhead of a wellbore at the bottom of the system;

a seal located within the riser below the blowout preventer and above the wellhead; and

an umbilical within the riser connected to the vessel at a first end, and connected to the seal at a second end.

2. The system of claim 1 further comprising:

a subsea shut off and disconnect device positioned below the seal and above the wellhead.

3. The system of one or more of claims 1-2, wherein the wellhead is connected to a casing lining an interior of said wellbore.

4. The system of one or more of claims 1-3, wherein said blowout preventer is positioned above sea level and controlled from above sea level.

5. The system of one or more of claims 1-4, further comprising a drill-thru Christmas tree positioned at the wellhead.

6. The system of one or more of claims 1-5, wherein said riser is utilized in drilling though the wellbore into a formation and in producing a product from said formation.

7. The system of one or more of claims 1-6, wherein said seal separates a low pressure region within the riser above the seal and below the blowout preventer, and a high pressure region within the riser below the seal and above the wellhead.

8. The system of claim 7, further comprising a tool within the high pressure region.

9. The system of one or more of claims 7-8, wherein said tool is controlled by the umbilical.

10. The system of one or more of claims 1-9, wherein said seal comprises expandable elements movable from a first small diameter position and a second large diameter position, wherein said seal occludes said riser when the seal is in the second large diameter position.

11. A method comprising:
installing a riser from a vessel at the top of a body of water, to a wellhead at the bottom of the body of water;
installing a blowout preventer adjacent the top of the body of water;
lowering a seal within the riser to a point below the blowout preventer, and above the wellhead;
connecting an umbilical between the vessel and the seal; and
activating the seal to define a first pressure region within the riser above the seal, and a second pressure region within the riser below the seal.

12. The method of claim 11, further comprising controlling well blowout with a subsea shut off and disconnect device.

13. The method of one or more of claims 11-12, further comprising pressurizing the second pressure region to a high pressure.

14. The method of one or more of claims 11-13, further comprising pressurizing the first pressure region to a low pressure.

15. The method of one or more of claims 11-14, further comprising lowering a tubing hanger running tool into the second pressure region.

16. The method of one or more of claims 11-15, further comprising lowering a tubing hanger running tool into the second pressure region and testing a seal of the tubing hanger running tool with a high pressure in the second pressure region.

17. The method of one or more of claims 11-16, further comprising inflating the seal with a control line connected to the vessel.

Figure 1

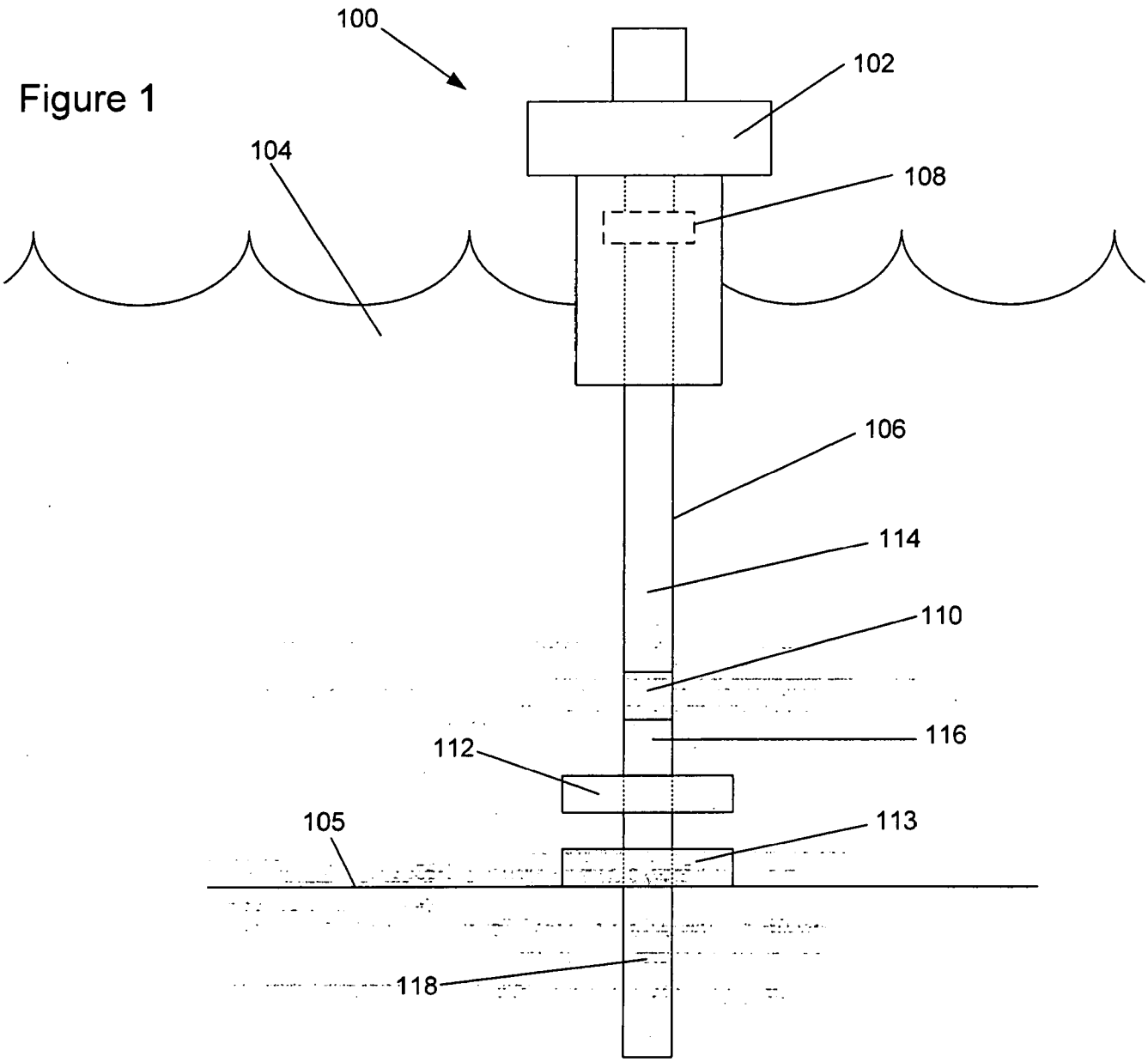


Figure 2

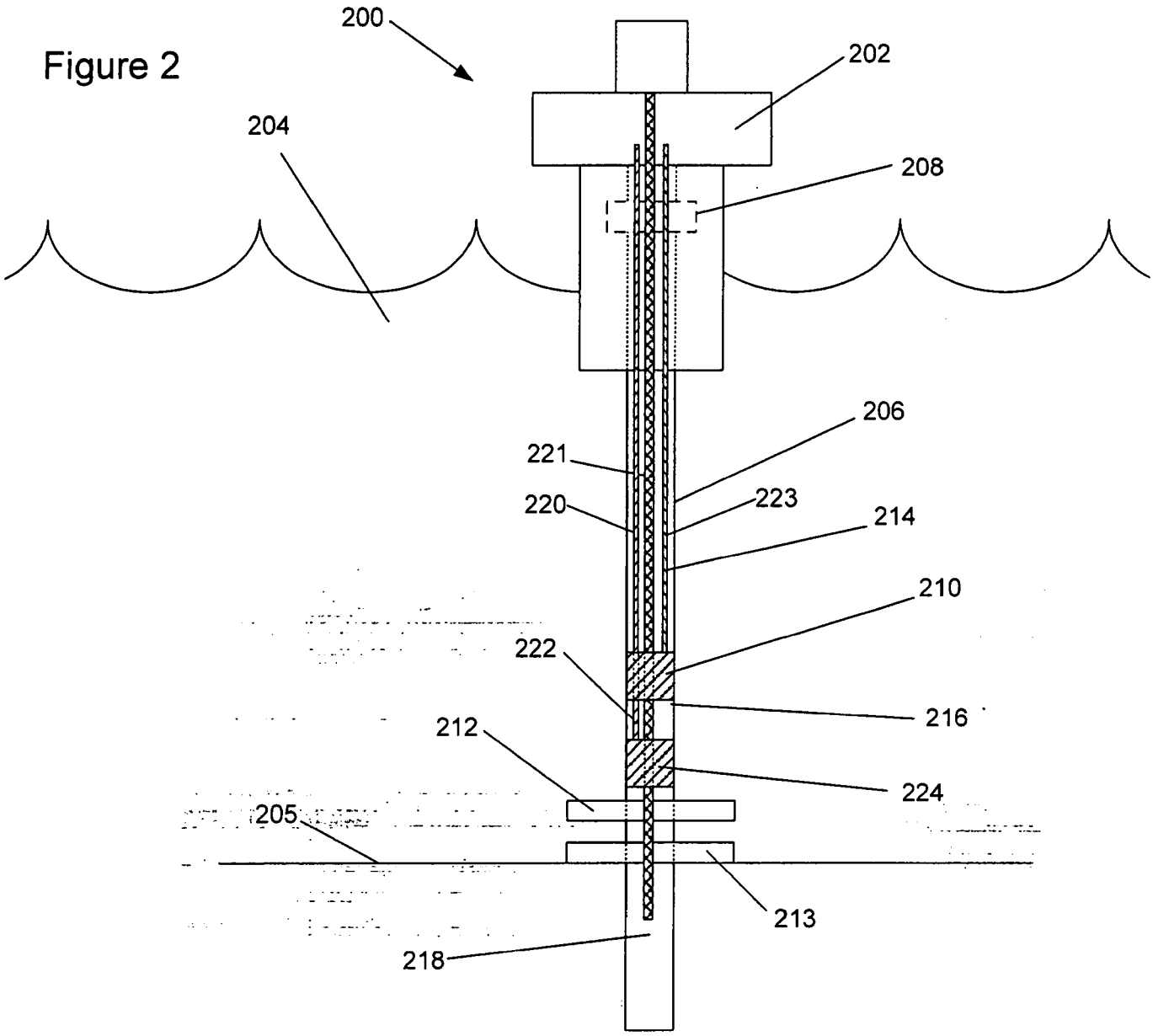

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Figure 3

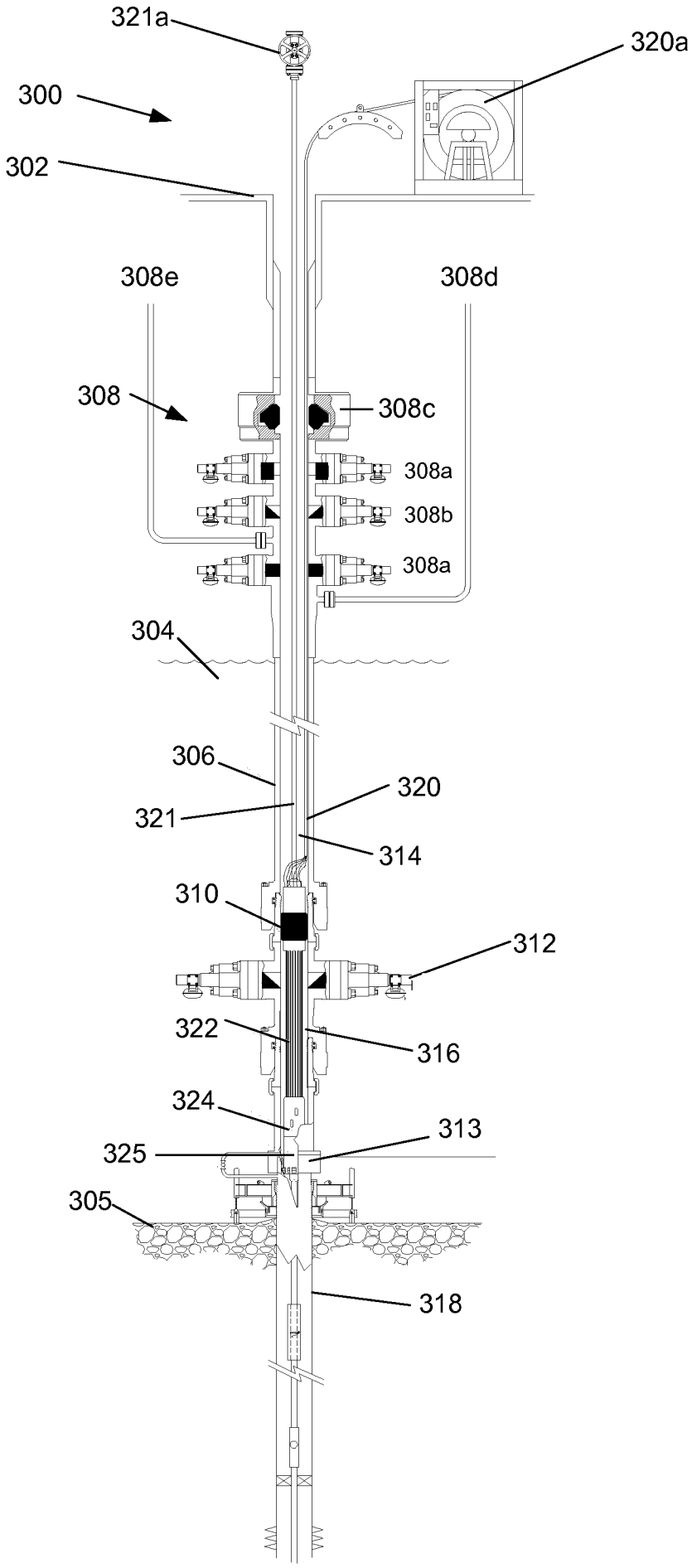

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Figure 4

