



(51) International Patent Classification:
E21B 29/12 (2006.01)

(21) International Application Number:

PCT/US2012/023518

(22) International Filing Date:

1 February 2012 (01.02.2012)

(25) Filing Language:

English

(26) Publication Language:

English

(30) Priority Data:

13/018,871 1 February 2011 (01.02.2011) US

(71) Applicant (for all designated States except US): **WILD WELL CONTROL, INC.** [US/US]; Drilling Technology Center, 2202 Oil Center Court, Houston, Texas 77073 (US).

(72) Inventors; and

(75) Inventors/Applicants (for US only): **HOFFMAN, Corey Eugene** [US/US]; 7411 County Road 204, Plantersville,

Texas 77363 (US). **CARGOL, Patrick Michael Jr.** [US/US]; 246 Bristol Bend Circle, The Woodlands, Texas 77382 (US).

(74) Agents: **PATTERSON, William B.** et al.; Patterson & Sheridan, LLP, 3040 Post Oak Blvd., Suite 1500, Houston, Texas 77056 (US).

(81) Designated States (unless otherwise indicated, for every kind of national protection available): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH,

[Continued on next page]

(54) Title: COILED TUBING MODULE FOR RISERLESS SUBSEA WELL INTERVENTION SYSTEM

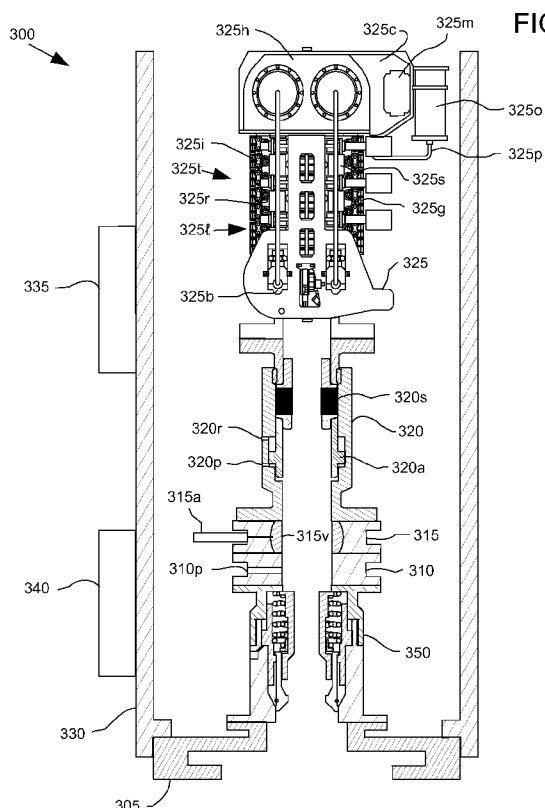


FIG. 2C

(57) Abstract: A method for riserless intervention of a subsea well includes connecting an intervention assembly to a bottom hole assembly (BHA). The BHA is connected to coiled tubing. The method further includes lowering the intervention assembly to a blowout preventer (BOP) fastened to a subsea production tree using an injector of a support vessel engaged with the coiled tubing; fastening the intervention assembly to the BOP; slacking the coiled tubing using the vessel injector; engaging a stripper of the intervention assembly with the coiled tubing; and driving the BHA through the tree and into a wellbore using a subsea injector of the intervention assembly while synchronizing both injectors to maintain the slack in the coiled tubing.



GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:

— *without international search report and to be republished upon receipt of that report (Rule 48.2(g))*

COILED TUBING MODULE FOR RISERLESS SUBSEA WELL INTERVENTION SYSTEM

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of United States patent application serial
5 number 13/018,871, filed February 1, 2011, which is herein incorporated by
reference.

BACKGROUND OF THE INVENTION

Field of the Invention

[0002] Embodiments of the present invention generally relate to a coiled tubing
10 module for a riserless subsea well intervention system.

Description of the Related Art

[0003] Subsea crude oil and/or natural gas wells frequently require workover to
maintain adequate production. Workover operations may include perforating, gravel
packing, production stimulation and repair of a downhole completion or production
15 tubing. During the workover, specialized tools are lowered into the well by means of a
wireline and winch. This wireline winch is typically positioned on the surface and the
workover tool is lowered into the well through a lubricator and blowout preventer
(BOP). Workover operations on subsea wells require specialized intervention
equipment to pass through the water column and to gain access to the well. The
20 system of valves on the wellhead is commonly referred to as a production or
Christmas tree and the intervention equipment is attached to the tree with a blowout
preventer (BOP).

[0004] The commonly used method for accessing a subsea well first requires
installation of a BOP with a pre-attached tree running tool (TRT) for guiding the BOP
25 to correctly align and interface with the tree. The BOP/running tool is lowered from a
derrick that is mounted on a mobile offshore drilling unit (MODU), such as a drill ship
or semi-submersible platform. The BOP/TRT is lowered on a segmented length of
pipe called a workover riser string. The BOP/TRT is lowered by adding sections of
pipe to the riser string until the BOP/TRT is sufficiently deep to allow landing on the
30 tree. After the BOP is attached to the tree, the workover tool is lowered into the well
through a lubricator mounted on the top of the riser string. The lubricator provides a

sealing system at the entrance of the wireline that maintains the pressure and fluids inside the well and the riser string. The main disadvantage of this method is the large, specialized MODU that is required to deploy the riser string and the riser string needed to deploy the BOP.

5 [0005] Figure 1A illustrates a prior art completed subsea well. A wellbore 10 has been drilled from a floor 1f of the sea 1 into a hydrocarbon-bearing (i.e., crude oil and/or natural gas) reservoir (not shown). A string of casing (not shown) has been run into the wellbore and set therein with cement (not shown). The casing has been perforated to provide to provide fluid communication between the reservoir and a bore
10 of the casing. A wellhead (not shown) has been mounted on an end of the casing string. A string of production tubing 10p (see Figure 1B) may extend from the wellhead (not shown) to the formation to transport production fluid from the formation to the seafloor 1f. A packer (not shown) may be set between the production tubing 10p and the casing to isolate an annulus 10a (see Figure 1B) formed between the
15 production tubing 10p and the casing (not shown) from production fluid.

[0006] Figure 1B illustrates a prior art horizontal production tree 50. The production tree 50 may be connected to the wellhead, such as by a collet, mandrel, or clamp tree connector. The tree 50 may be vertical or horizontal. If the tree is vertical (not shown), it may be installed after the production tubing 10p is hung from the
20 wellhead. If the tree 50 is horizontal (as shown), the tree may be installed and then the production tubing 10p may be hung from the tree 50. The tree 50 may include fittings and valves to control production from the wellbore into a pipeline (not shown) which may lead to a production facility (not shown), such as a production vessel or platform. The tree 50 may also be in fluid communication with a hydraulic conduit (not
25 shown) controlling a subsurface safety valve SSV 10v (see Figure 4F).

[0007] The tree 50 may include a head 51, a wellhead connector 52, a tubing hanger 53, an internal cap 54, an external cap 55, an upper crown plug 56u, a lower crown plug 56l, a production valve 57p, and one or more annulus valves 57u,l. Each of the components 51-54 may have a longitudinal bore extending therethrough. The
30 tubing hanger 53 and head 51 may each have a lateral production passage formed through walls thereof for the flow of production fluid. The tubing hanger 53 may be disposed in the head bore. The tubing hanger 53 may support the production tubing 10p. The tubing hanger 53 may be fastened to the head by a latch 53l. The latch 53l

may include one or more fasteners, such as dogs, and an actuator, such as a cam sleeve. The cam sleeve may be operable to push the dogs outward into a profile formed in an inner surface of the tree head 51. The latch 53 ℓ may further include a collar for engagement with a running tool (not shown) for installing and removing the tubing hanger 53.

[0008] The tubing hanger 53 may be rotationally oriented and longitudinally aligned with the tree head 51. The tubing hanger 53 may further include seals 53s disposed above and below the production passage and engaging the tree head inner surface. The tubing hanger 53 may also have a number of auxiliary ports/conduits (not shown) spaced circumferentially there-around. Each port/conduit may align with a corresponding port/conduit (not shown) in the tree head 51 for communicating hydraulic fluid or electricity for various purposes to tubing hanger 53, and from tubing hanger 53 downhole, such as for operation of the SSV 10v. The tubing hanger 53 may have an annular, partially spherical exterior portion that lands within a partially spherical surface formed in tree head 51.

[0009] The annulus 10a may communicate with an annulus passage formed through and along the head 51 for and bypassing the seals 53s. The annulus passage may be accessed by removing internal tree cap 54. The tree cap 54 may be disposed in head bore above tubing hanger 53. The tree cap 54 may have a downward depending isolation sleeve received by an upper end of tubing hanger 53. Similar to the tubing hanger 53, the tree cap 54 may include a latch 54 ℓ fastening the tree cap to the head 51. The tree cap 54 may further include a seal 54s engaging the head inner surface. The production valve 57p may be disposed in the production passage and the annulus valves 57u, ℓ may be disposed in the annulus passage. Ports/conduits (not shown) may extend through the tree head 51 to a tree controller (not shown) for electrical or hydraulic operation of the valves.

[0010] The upper crown plug 56u may be disposed in tree cap bore and the lower crown plug 56 ℓ may be disposed in the tubing hanger bore. Each crown plug 56u, ℓ may have a body with a metal seal on its lower end. The metal seal may be a depending lip that engages a tapered inner surface of the respective cap and hanger. The body may have a plurality of windows which allow fasteners, such as dogs, to extend and retract. The dogs may be pushed outward by an actuator, such as a central cam. The cam may have a profile on its upper end. The cam may move

between a lower locked position and an upper position freeing dogs to retract. A retainer may secure to the upper end of body to retain the cam.

SUMMARY OF THE INVENTION

[0011] Embodiments of the present invention generally relate to a coiled tubing module for a riserless subsea well intervention system. In one embodiment, a method for riserless intervention of a subsea well includes connecting an intervention assembly to a bottom hole assembly (BHA). The BHA is connected to coiled tubing. The method further includes lowering the intervention assembly to a blowout preventer (BOP) fastened to a subsea production tree using an injector of a support vessel engaged with the coiled tubing; fastening the intervention assembly to the BOP; slacking the coiled tubing using the vessel injector; engaging a stripper of the intervention assembly with the coiled tubing; and driving the BHA through the tree and into a wellbore using a subsea injector of the intervention assembly while synchronizing both injectors to maintain the slack in the coiled tubing.

[0012] In another embodiment, a coiled tubing module for a riserless subsea intervention system includes: a stripper operable to seal against coiled tubing and a subsea injector. The subsea injector has opposed chain loops having grippers operable to grip the coiled tubing and longitudinally move the coiled tubing; outboard bearing assemblies operable to guide the chain loops; a motor and sealed gear case operable to drive the chain loops, the gear case having lubricant; and a pressure compensator operable to pressurize the lubricant to a pressure equal to or substantially equal to subsea pressure. The module further includes a controller operable to synchronize an injector of a support vessel engaged with the coiled tubing with the subsea injector to maintain slack in the coiled tubing.

BRIEF DESCRIPTION OF THE DRAWINGS

[0013] So that the manner in which the above recited features of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

[0014] Figure 1A illustrates a prior art completed subsea well. Figure 1B illustrates a prior art horizontal production tree.

[0015] Figure 2A illustrates a pressure control assembly (PCA), according to one embodiment of the present invention. Figure 2B illustrates a wireline module, according to another embodiment of the present invention.

[0016] Figure 3A illustrates deployment of the PCA to the subsea production tree. Figure 3B illustrates connection of the PCA to the tree and connection of the umbilical to the PCA.

[0017] Figure 4A illustrates deployment of the wireline module to the tree. Figure 4B illustrates connection of the wireline module to the PCA. Figure 4C illustrates deployment of a plug running tool (PRT) into the tree and connection of the PRT with the upper crown plug. Figure 4D illustrates retrieval of the PRT and upper crown plug into the tool housing. Figure 4E illustrates retrieval of the wireline module to the vessel. Figure 4F illustrates the tree ready for intervention.

[0018] Figure 5A illustrates deployment of the coiled tubing module. Figure 5B illustrates connection of the coiled tubing module to the PCA. Figure 5C illustrates slacking of the coiled tubing and movement of the vessel away from the tree. Figure 5D illustrates deployment of the BHA into the wellbore.

DETAILED DESCRIPTION

[0019] Figure 2A illustrates a pressure control assembly (PCA) 100, according to one embodiment of the present invention. The PCA 100 may include a tree adapter 105, a fluid sub 110, an isolation valve 115, a blow out preventer (BOP) stack 120, a tool housing (aka lubricator riser) 125, a frame 130, a control pod 135, a manifold 140, and one or more accumulators 145 (two shown). The tree connector 105, fluid sub 110, isolation valve 115, BOP stack 120, and tool housing 125 may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough. The bore may have a large drift diameter, such as greater than or equal to four, five, six, or seven inches to accommodate a bottom hole assembly (BHA) of a workstring (discussed more below) and the crown plugs 56u,l of the tree 50.

[0020] The tree adapter 105 may include a connector, such as dogs 105d, for fastening the PCA 100 to an external profile 51p of the tree 50 and a seal sleeve 105s for engaging an internal profile 54p of the tree. The tree adapter 105 may further include an electric or hydraulic actuator and an interface, such as a hot stab, so that a remotely operated subsea vehicle (ROV) 415 (see Figure 3A) may operate the actuator for engaging the dogs 105d with the external profile 51p. The frame 130 may be connected to the tree connector 50, such as by fasteners (not shown). The control pod 135 and manifold 140 may be fastened to the frame 130. The fluid sub 110 may include a housing having a bore therethrough and a port 110p in communication with the bore. The port 110p may be in fluid communication with the manifold 140 via a conduit (not shown).

[0021] The isolation valve 115 may include a housing, a valve member 115v disposed in the housing bore and operable between an open position and a closed position, and an actuator 115a operable to move the valve member between the positions. The actuator 115a may be electric or hydraulic and may be in communication with the control pod 135 via a conduit/cable (not shown). The actuator 115a may fail to the closed position in the event of an emergency. The isolation valve 115 may further operate as a check valve in the closed position: allowing fluid flow downward from the tool housing into the wellbore and preventing reverse fluid flow therethrough. Alternatively, the isolation valve 115 may be bi-directional when closed, the PCA 100 may further include a bypass conduit (not shown) connected to a port of a drain sub (not shown) disposed between the isolation valve and the BOP stack, and the drain port may include a check valve allowing downward flow and preventing reverse flow.

[0022] The BOP stack 120 may include one or more hydraulically operated ram preventers 120b,w, such as a blind-shear preventer 120b and one or more workstring preventers 120w, such as a wireline preventer and a coiled tubing preventer (only one workstring preventer shown) connected together via bolted flanges. Each ram preventer 120b,w may include two opposed rams disposed within a body. The body may have a bore that is aligned with the wellbore. Opposed cavities may intersect the bore and support the rams as they move radially into and out of the bore. A bonnet may be connected to the body on the outer end of each cavity and may support an actuator that provides the force required to move the rams into and out of the bore.

Each actuator may include a hydraulic piston to radially move each ram and a mechanical lock to maintain the position of the ram in case of hydraulic pressure loss. The lock may include a threaded rod, a motor (not shown) for rotationally driving the rod, and a threaded sleeve. Once each ram is hydraulically extended into the bore, the motor may be operated to push the sleeve into engagement with the piston. Each actuator may include single (shown) or dual pistons (not shown). The blind-shear preventer 120b may cut the workstring, such as coiled tubing, wireline, and even drill pipe, when actuated and seal the bore. The coiled tubing preventer may seal against an outer surface of coiled tubing when actuated and the wireline preventer may seal against an outer surface of the wireline when actuated.

[0023] The tool housing 125 may be of sufficient length to contain either a plug running tool (PRT) 462 (Figure 4A) or a BHA 464 (Figure 5A) so that the PCA 100 may be closed while deploying either a wireline module 200 (Figure 2B) or a coiled tubing module 300 (Figure 2C). The tool housing 125 may have a connector profile 125c for receiving an adapter of a workstring module 200, 300.

[0024] The subsea control pod 135 may be in electrical and/or hydraulic communication with a support vessel 400 (Figure 3A) via an umbilical 450u (Figure 3B). The pod 135 may include one or more control valves (not shown) in communication with the BOP stack and the accumulators for operating the BOP stack. Each control valve may include an electric or hydraulic actuator in communication with the umbilical. The umbilical may include one or more hydraulic or electric control conduit/cables for each actuator. The accumulators may store pressurized hydraulic fluid for operating the BOP stack. The accumulators may be charged via a conduit of the umbilical or by the ROV 415.

[0025] The umbilical 450u may further include hydraulic or electric control conduit/cables for operating valves of the manifold 140, the actuator 115a, tree valves 57p,u,l and the various functions of the workstring modules 200, 300 (discussed below). The control pod 135 may further include an output for the workstring modules 200, 300 and an output for the tree 50. Each output may include an ROV operable connector for receiving a respective jumper 451t,w (aka flying lead) (Figure 4B). The ROV 415 may connect the tree jumper 451t to a control panel (not shown) of the tree 50 and the workstring jumper 451w to a control relay 235, 335 of one of the workstring modules 200, 300.

[0026] The subsea control pod 135 may further include a microprocessor based controller, a modem, a transceiver, and a power supply. The power supply may receive an electric power signal from a power cable of the umbilical 450u and convert the power signal to usable voltage for powering the pod components as well as any of the PCA components. The PCA 100 may further include one or more pressure sensors (not shown) in communication with the PCA bore at various locations. The workstring modules 200, 300 may also include one or more pressure sensors in communication with a respective bore thereof at various locations. The pressure sensors may be in data communication with the pod controller. The modem and transceiver may be used to communicate with an operator on the vessel via the umbilical. The power cable may be used for data communication or the umbilical 450u may further include a separate data cable (electric or optic). The vessel may include a control system (not shown) so that the various functions of the PCA, the tree, and the workstring modules may be operated by an operator on the vessel.

[0027] The control pod 135 may also include a dead-man's switch (not shown) for closing the BOP stack in response to a loss of communication with the vessel. Alternatively, instead of having individual conduits/cables for controlling each function of the PCA 100, tree 50, and workstring modules 200, 300, the pod controller may receive multiplexed instruction signals from the vessel operator via a single electric, hydraulic, or optical control conduit/cable of the umbilical 450u and then operate the various functions using individual conduits/cables extending from the control pod 135.

[0028] The manifold 140 may include one or more control valves and one or more ROV operable connectors, such as hot stabs, for receiving a respective fluid conduit 450f (Figure 3B) from the vessel 400. Actuators of the control valves may be in electric/hydraulic communication with the control pod 135. Two fluid conduits 450f (only one shown) may extend from the vessel 400 to the manifold 140 for fluid circulation. The fluid conduits 450f may each be coiled tubing. A first one of the control valves may be in fluid communication with a first one of the connectors and a fluid conduit extending to the port 110p. A second one of the control valves may be in fluid communication with a second one of the connectors and another ROV operable connector for receiving a jumper 452 (Figure 4B) providing fluid communication with one of the junction plates 240, 340 of the workstring modules 200, 300.

[0029] Figure 2B illustrates a wireline module 200, according to another embodiment of the present invention. The wireline module 200 may include an adapter 205, a fluid sub 210, an isolation valve 215, one or more stuffing boxes 220u,l, a grease injector 225, a frame 230, a control relay 235, an interface 240, such as a junction plate, a grease reservoir 245r, a grease pump 245p, and a tool catcher 250. The adapter 205, fluid sub 210, isolation valve 215, stuffing boxes 220u,l, grease injector 225, and tool catcher 250 may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough.

[0030] The adapter 205 may include a connector for mating with the connector profile 125c, thereby fastening the wireline module 200 to the PCA 100. The connector may be dogs or a collet. The adapter 205 may further include a seal face or sleeve and a seal. The adapter 205 may further include an actuator, such as a piston and a cam, for operating the connector. The adapter 205 may further include an ROV interface so that the ROV 415 may connect to the connector, such as by a hot stab, and operate the connector actuator. Alternatively, the adapter 205 may have the connector profile instead of the connector and the tool housing 125 may have the connector in communication with the control pod 135 for operation by the vessel operator.

[0031] The fluid sub 210 may include a housing having a bore therethrough and a port 210p in communication with the bore. The port 210p may be in fluid communication with the junction plate 240 via a conduit (not shown). The frame 230 may be fastened to the adapter 205 and the relay 235 and interface 240 may be fastened to the frame. The pump 245p and reservoir 245r may also be fastened to the frame 230.

[0032] The isolation valve 215 may include a housing, a valve member 215v disposed in the housing bore and operable between an open position and a closed position, and an actuator 215a operable to move the valve member between the positions. The actuator 215a may be electric or hydraulic and may be in communication with the control relay 235 via a conduit (not shown). The actuator 215a may fail to the closed position in the event of an emergency. The isolation valve 215 may be further operable to cut wireline 460w (Figure 4A) when closed or the wireline module 200 may further include a separate wireline cutter. The isolation

valve 215 may further operate as a check valve in the closed position: allowing fluid flow downward from the stuffing box 220_l toward the PCA 100 and preventing reverse fluid flow therethrough.

[0033] Each stuffing box 220_{u,l} may include a seal 220_s, a piston 220_a, and a spring 220_b disposed in the housing. A port 220_p may be formed through the housing in communication with the piston 220_a. The port 220_p may be connected to the control relay 235 via a hydraulic conduit, not shown. When operated by hydraulic fluid, the piston 220_a may longitudinally compress the seal 220_s, thereby radially expanding the seal inward into engagement with the wireline 460_w. The spring 220_b may bias the piston 220_a away from the seal 220_s and be set to balance hydrostatic pressure. Alternatively, an electric actuator may be used instead of the piston 220_a.

[0034] The grease injector 225 may include a housing integral with the stuffing box housing and one or more seal tubes 225_t. Each seal tube 225_t may have an inner diameter slightly larger than an outer diameter of the wireline, thereby serving as a controlled gap seal. An inlet port 225_i and an outlet port 225_o may be formed through the grease injector/stuffing box housing. A grease conduit (not shown) may connect an outlet of the grease pump 245_p with the inlet port 225_i and another grease conduit (not shown) may connect the outlet port 225_o with the grease reservoir 245_r. Another grease conduit (not shown) may connect an inlet of the pump 245_p to the reservoir 245_r. Alternatively, the outlet port 225_o may discharge into the sea 1. The grease pump 245_p may be electrically or hydraulically driven via cable/conduit connected to the control relay 235 and may be operable to pump grease from the grease reservoir 245_r into the inlet port 225_i and along the slight clearance formed between the seal tube 225_t and the wireline to lubricate the wireline 460_w, reduce pressure load on the stuffing box seals 220_s, and increase service life of the stuffing box seals. The grease reservoir 245_r may be recharged by the ROV 415.

[0035] The tool catcher 250 may include a piston 250_a, a latch, such as a collet 250_c, a stop 250_s, a piston spring 250_b, and a latch spring 250_d disposed in a housing thereof. The collet 250_c may have an inner cam surface for engagement with a fishing neck of the PRT 462 and the catcher housing may have an inner cam surface for operation of the collet. The latch spring 250_d may bias the collet 250_c toward a latched position. The collet 250_c may be movable from the latched position to an unlatched position either by engagement with a cam surface of the fishing neck

and relative longitudinal movement of the fishing neck upward toward the stop 250s or by operation of the piston 250a. Once the cam surface of the fishing neck has passed the cam surface of the collet 250c, the latch spring 250d may return the collet to the latched position where the collet engages a shoulder of the fishing neck, thereby preventing longitudinal downward movement of the PRT 462 relative to the catcher 250. The catcher housing may have a hydraulic port 250p formed through a wall thereof in fluid communication with the piston 250a. A hydraulic conduit (not shown) may connect the hydraulic port 250p to the control relay 235. The piston 250a may be biased away from engagement with the collet 250c by the piston spring 250b. When operated, the piston 250a may engage the collet 250c and move the collet upward along the housing cam surface to a latched position. Alternatively, an electric actuator may be used instead of the piston 250a.

[0036] Figure 2C illustrates a coiled tubing module 300, according to another embodiment of the present invention. The coiled tubing module 300 may include an adapter 305, a fluid sub 310, an isolation valve 315, a stripper 320, a subsea coiled tubing injector 325, a frame 330, a control relay 335, an interface 340, such as a junction plate, and a tool catcher 350. The adapter 305, fluid sub 310, isolation valve 315, stripper 320, and tool catcher 350 may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough. The adapter 305 may be similar to the adapter 205. The frame 330 may be fastened to the adapter 305 and the relay 335 and interface 340 may be fastened to the frame. The fluid sub 310 may include a housing having a bore therethrough and a port 310p in communication with the bore. The port 310p may be in fluid communication with the junction plate 340 via a conduit (not shown). The tool catcher 350 may be similar to the tool catcher 250.

[0037] The isolation valve 315 may include a housing, a valve member 315v disposed in the housing bore and operable between an open position and a closed position, and an actuator 315a operable to move the valve member between the positions. The actuator 315a may be electric or hydraulic and may be in communication with the control relay 335 via a conduit (not shown). The actuator 315a may fail to the closed position in the event of an emergency. The isolation valve 315 may be further operable to cut coiled tubing 460t (Figure 5A) when closed or the coiled tubing module 300 may further include a separate coiled tubing cutter. The

isolation valve 315 may further operate as a check valve in the closed position: allowing fluid flow downward from the stripper 320 toward the PCA 100 and preventing reverse fluid flow therethrough.

[0038] The stripper 320 may include a seal 320s and a piston 320a disposed in the housing. A hydraulic packoff port 320p and a hydraulic release port 320r may be formed through the housing in fluid communication with a respective face of the piston 320a. Each port 320p,r may be connected to the control relay 335 via a respective hydraulic conduit (not shown). When operated by pressurized hydraulic fluid via the pack-off port 320p, the piston 320a may longitudinally compress the seal 320s, thereby radially expanding the seal inward into engagement with the coiled tubing 460t. The seal 320s may be released by application of pressurized hydraulic fluid via the release port 320r. Alternatively, an electric actuator may be used instead of the piston 320a. Alternatively, the stripper 320 may include a spring instead of the release port 320r.

[0039] The injector 325 may include a traction assembly 325t to engage the coiled tubing 460t and drive the coiled tubing into or out of the wellbore 10. The traction assembly 325t may include opposing chain loops 325l guided by bearing assemblies 325b. Gripping members 325g may be secured to individual links 325i of the chain loops, so as to grip the coiled tubing. The gripping members 325g and the chain loops 325l may thus move together longitudinally at the area of contact with the coiled tubing 460t to move the coiled tubing into or out of the wellbore 10. A plurality of rollers 325r may be secured to the links 325i of the chain loops 325l, and roll along support members 325s. The support members 325s may be moved laterally inwardly to urge the gripping members 325g into engagement with the coiled tubing 460t with sufficient force to grip the coiled tubing. The rollers 325r may allow for a large lateral load to be applied without inducing a significant longitudinal drag load.

[0040] The bearing assemblies 325b and an injector gear case 325c may both be sealed to retain lubricant and prevent intrusion of seawater. The bearing assemblies 325b may be outboard bearing assemblies because the portion of the housing 325h adjacent the sealed gear case 325c may be open to seawater to accommodate the chain loops 325l. The chain loops 325l may be routed over sprockets or gears (not shown) within the housing 325h, rotating about the axis of the bearings assemblies 325b, and the chain loops may thus be guided by the bearing assemblies. A hydraulic

or electric drive motor 325m may drive the chain loops. The drive motor may be in hydraulic/electric communication with the control relay 335 via a conduit/cable (not shown). The gear case 325c may house a plurality of gears (not shown) which may be driven by the drive motor 325m and which may drive the chain loops 325l via a drive shaft (not shown) sealably extending from the sealed gear case 325c.

[0041] The injector 325 may further include a lubricant reservoir 325o. The reservoir 325o may compensate pressure within the gear case 325c, each outboard bearing assembly 325b, and other components of the injector 325 that are sealed and sensitive to pressure differentials, such as the rollers 325r. The reservoir 325o may include a housing structurally separate from and attached to an outer housing of the gear case 325c. The reservoir housing may be divided into a compensator chamber and a lubricant chamber by a pressure compensator (not shown), such as a piston or diaphragm. The lubricant chamber may be filled with a lubricant. A conduit 325p may be used to fluidly connect and pass lubricant between the reservoir 325o and the gear case 325c, the bearing assemblies 325b, the rollers 325r, and other sealed components. The compensator chamber may be in fluid communication with the sea by a port (not shown) formed through the reservoir housing. As the hydrostatic pressure surrounding the reservoir 325o increases, such as when the injector 325 is lowered into a subsea environment, the compensator may pressurize the lubricant, thereby equalizing or substantially equalizing the lubricant pressure and the hydrostatic seafloor pressure. The compensator may be biased so that the lubricant pressure is slightly greater than the seafloor pressure. Accordingly, the pressure differential that would otherwise exist between the seawater environment and the interior of the sealed components is reduced or eliminated.

[0042] Figure 3A illustrates deployment of the PCA 100 to the subsea production tree 50. Figure 3B illustrates connection of the PCA 100 to the tree 50 and connection of the umbilical 450u to the PCA 100. The support vessel 400 may be deployed to a location of the subsea tree 50. The support vessel 400 may be a light or medium intervention vessel and include a dynamic positioning system to maintain position of the vessel 400 on the surface 1s over the tree 50 and a heave compensator (not shown) to account for vessel heave due to wave action of the sea 1. Alternatively, the vessel 400 may be a MODU. The vessel 400 may further include a tower 411 located over a moonpool 405 and a winch 413. The winch 413 may

include a drum having wire rope 460d wrapped therearound and a motor for winding and unwinding the wire rope, thereby raising and lowering a distal end of the wire rope relative to the tower. Alternatively, a crane (not shown) may be used instead of the winch and tower. The vessel may further include umbilical drum 402, coiled tubing drums 403 (only one shown), and wireline winch 413.

[0043] The ROV 415 may be deployed into the sea 1 from the vessel 400. The ROV 415 may be an unmanned, self-propelled submarine that includes a video camera, an articulating arm, a thruster, and other instruments for performing a variety of tasks. The ROV 415 may further include a chassis made from a light metal or alloy, such as aluminum, and a float made from a buoyant material, such as syntactic foam, located at a top of the chassis. The ROV 415 may be controlled and supplied with power from vessel 400. The ROV 415 may be connected to support vessel 400 by an umbilical 416. The umbilical 416 may provide electrical (power), hydraulic, and/or data communication between the ROV 415 and the support vessel 400. An operator on the support vessel 400 may control the movement and operations of ROV 415. The umbilical 416 may be wound or unwound from drum 417.

[0044] The ROV 415 may be deployed to the tree 50. The ROV 415 may transmit video to the operator on the vessel 400 for inspection of the tree 50. The ROV 415 may remove the external cap 55 from the tree 50 and carry the cap to the vessel 400. Alternatively, the winch 413 may be used to transport the external cap 55 to the waterline 1w. The ROV 115 may then inspect an internal profile of the tree 50.

[0045] The wire rope 460d may then be used to lower the PCA 100 to the tree 50 through the moonpool 405 of the vessel 400. The ROV 415 may guide landing of the PCA 100 on the tree 50. The ROV 415 may then operate the adapter connector 105d to fasten the PCA 100 to the tree 50. The ROV 415 may then deploy the umbilical 450u from the vessel 400 and connect the umbilical to the control pod 135. The ROV 415 may then connect the jumper 451t to the tree control panel. The operator on the vessel may then close then close the tree valves 57u,l,p and the SSV 10v via the umbilical 450u. The ROV 415 may then deploy and connect the fluid conduits 450f to the manifold 140.

[0046] Figure 4A illustrates deployment of the wireline module 200 to the tree 50. Figure 4B illustrates connection of the wireline module 200 to the PCA 100. Figure

4C illustrates deployment of the PRT 462 into the tree 50 and connection of the PRT with the upper crown plug 56u. Figure 4D illustrates retrieval of the PRT 462 and upper crown plug 56u into the tool housing 125. Figure 4E illustrates retrieval of the wireline module 200 to the vessel 400. Figure 4F illustrates the tree 50 ready for intervention.

[0047] The wireline 460w may be fed through the tower 411 and inserted through the wireline module 200 and connected to the PRT 462. The PRT 462 may then be connected to the tool catcher 250. The wireline module 200 may then be deployed through the moonpool 405 using the wireline winch 404 and landed on the tool housing 125. The ROV 415 may operate the adapter connector, thereby fastening the wireline module 200 to the PCA 100. The ROV 415 may then connect jumper 451w to the control pod 135 and control relay 235 and connect fluid conduit 452 to the manifold 140 and the junction box 240. The vessel operator may then engage one or both of the stuffing boxes 220u,l with the wireline 460w. The vessel operator may then release the PRT 462 from the tool catcher 250 via the umbilical 450u and control relay 235. The PRT 462 may be lowered to the upper crown plug 56u and operated to engage the upper crown plug by sending a signal through electrical conductors of the wireline 460w. The PRT 462 and upper crown plug 56u may then be raised until the PRT reengages the tool catcher 250. The isolation valve 115 may then be closed. The PRT 462 and upper crown plug 56u may then be washed by injecting a hydrates inhibitor from the vessel 400, through the fluid conduit 450f, the manifold, the conduit 451w, the junction plate, and into the port 210p. The spent inhibitor may be returned to the vessel 400 through the port 110p, the manifold, and the second fluid conduit (as discussed above, isolation valve 115 may allow downward flow when closed or the PCA 100 may include a bypass). Once washing is complete, the blind-shear preventer 120b may also be closed. The adapter connector may then be released by the ROV 415 and the wireline module 200 and upper crown plug 56u may be retrieved to the vessel 400. The operation may then be repeated for the lower crown plug 56l.

[0048] The wireline module 200 and PRT 462 may then be deployed again with a tree saver 490. The tree saver 490 may include a sleeve with a metal seal on its outer surface. The metal seal may be a depending lip that engages a tapered inner surface of the internal tree cap 54. Alternatively, the tree saver may be engage the

tubing hanger instead of the tree cap. The sleeve may have a plurality of windows which allow fasteners, such as dogs, to extend and retract. The dogs may be pushed outward by an actuator, such as a central cam. The cam may have a profile on its upper end. The cam may move between a lower locked position and an upper position freeing dogs to retract. A retainer may secure to the upper end of body to retain the cam. The tree saver 490 may further include one or more seals 490u,ℓ. The seals 490u,ℓ may each be made from a polymer, such as an elastomer. The sleeve may have a length sufficient to extend past the production passage and the lower seal 490ℓ may engage an inner surface of the tubing hanger 53, thereby isolating the production passage from any harmful fluids used during the intervention operation, such as cement or fracing fluid. Alternatively, the sleeve may extend into the production tubing 10p and the lower seal 490ℓ may engage an inner surface of the production tubing. The sleeve may also extend upward to the tree adapter 105 and the upper seal may engage an inner surface of the adapter sleeve 105s. Alternatively, the sleeve portion extending from the dogs to the tree connector and the upper seal 490u may be omitted.

[0049] Alternatively, the coiled tubing module 300 may be used to deploy the PRT 462 instead of the wireline module 200.

[0050] Figure 5A illustrates deployment of the coiled tubing module 300. Figure 5B connection of the coiled tubing module 300 to the PCA 100. Figure 5C illustrates slacking of the coiled tubing 460t and movement of the vessel 400 away from the tree 50. Figure 5D illustrates deployment of the BHA 464 into the wellbore 10. The vessel 400 may further include a coiled tubing injector 410. The vessel injector 410 may include a head for driving the coiled tubing 460t, controls, and a power unit. The power unit may be electric or hydraulic. The coiled tubing 460t may be inserted through the coiled tubing module 300 and connected to the BHA 464. The BHA 464 may include one or more tools operable to perform an intervention or abandonment operation in the wellbore 10. The BHA 464 may then be connected to the tool catcher 350. The injector head may be deployed over the moon pool 405 and the coiled tubing module 300 may be lowered to the tree 50 using the vessel injector 410 and the coiled tubing 460t.

[0051] Once the CT adapter 305 has landed onto the PCA 100, the ROV 415 may operate the adapter connector, thereby fastening the coiled tubing module 300 to the

PCA 100. The ROV 415 may then connect jumper 451w to the control pod 135 and control relay 335 and connect fluid conduit 452 to the manifold 140 and the junction box 340. Once fastened, the vessel injector 410 may feed the coiled tubing toward the tree 50, thereby creating slack 470 in the coiled tubing 460t. The vessel 400 may then (or simultaneously) be moved a distance from the tree 50 ensuring safety of the vessel 400 should a blowout occur during the intervention operation. The slack 470 may also serve to compensate for heave of the vessel 400.

[0052] The stripper 320 may be engaged with the coiled tubing 460t by the vessel operator and then the isolation valve 115, blind-shear BOP 120b, and SSV 10v may be opened. The vessel operator may then release the BHA 464 from the tool catcher 350 via the umbilical 450u and control relay 335. The subsea drive motor 325m may then be operated by the vessel operator, thereby advancing the BHA 464 toward the tree 50. The slack 470 may be maintained through synchronization of the vessel injector 410 with the subsea injector 325 by communication with the surface controller. The coiled tubing 460t may continue be advanced (while maintaining the slack 470 via synchronous operation of the vessel injector 410) into the wellbore 10 by the subsea injector 325 until the BHA 464 reaches a desired depth in the wellbore. The intervention or abandonment operation may then be conducted using the coiled tubing 460t and the BHA 464. To facilitate the intervention or abandonment operation, fluid may be pumped through the coiled tubing 460t and the BHA 464 and returned to the vessel via the port 110p. Further, fluid may be pumped into the wellbore 10 before or after deployment of the BHA 464 through the port 110p with the isolation valve 115 closed, thereby protecting the BOP stack 120 from the fluid.

[0053] Once the intervention or abandonment operation has concluded, the BHA 464 and coiled tubing 460t may be retrieved from the wellbore 10 by reversing the subsea drive motor 325m (while maintaining the slack 470 via synchronous operation of the surface injector 410) until the BHA 464 engages the tool catcher 350. The isolation valve 115 and SSV 351 may then be closed by the vessel operator. The BHA 464 may then be washed as discussed above for the upper crown plug 56u. The blind-shear preventer 120b may then be closed. The vessel 400 may return to the position over the tree 50. The slack 470 may be removed from the coiled tubing by the vessel injector (after or simultaneously with vessel movement). The ROV 415 may disconnect the adapter connector and the coiled tubing module 300 may be

retrieved from the tree 50 using the vessel injector. If an intervention operation was conducted, the tree saver 490 may be removed and the crown plugs 56u,l reinstalled using the wireline module 200 and PRT 462. The PCA 100 may then be retrieved and the well returned to production.

- 5 [0054] While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

Claims:

1. A method for riserless intervention of a subsea well, comprising:
connecting an intervention assembly to a bottom hole assembly (BHA),
5 wherein the BHA is connected to coiled tubing;
lowering the intervention assembly to a blowout preventer (BOP) fastened to a
subsea production tree using an injector of a support vessel engaged with the coiled
tubing;
fastening the intervention assembly to the BOP;
10 slacking the coiled tubing using the vessel injector;
engaging a stripper of the intervention assembly with the coiled tubing; and
driving the BHA through the tree and into a wellbore using a subsea injector of
the intervention assembly while synchronizing both injectors to maintain the slack in
the coiled tubing.
15
2. The method of claim 1, further comprising releasing the BHA from the
intervention assembly.
3. The method of claim 1, wherein:
20 the BOP is part of a pressure control assembly (PCA), and
the BHA is disposed in a tool housing of the PCA after fastening the
intervention assembly to the BOP.
4. The method of claim 3, further comprising opening an isolation valve of the
25 PCA before driving the BHA.
5. The method of claim 3, further comprising washing the BHA after driving the
BHA.
- 30 6. The method of claim 1, further comprising:
injecting fluid through the coiled tubing and into the wellbore; and
returning fluid from the wellbore to the vessel.

7. The method of claim 1, further comprising performing an intervention operation in the wellbore using the BHA.

8. The method of claim 1, further comprising moving the vessel a safe distance
5 from the tree.

9. A coiled tubing module for a riserless subsea intervention system, comprising:
a stripper operable to seal against coiled tubing;
a subsea injector having:

10 opposed chain loops having grippers operable to grip the coiled tubing
and longitudinally move the coiled tubing;

 outboard bearing assemblies operable to guide the chain loops;

 a motor and sealed gear case operable to drive the chain loops, the
gear case having lubricant; and

15 a pressure compensator operable to pressurize the lubricant to a
pressure equal to or substantially equal to subsea pressure; and

 a controller operable to synchronize an injector of a support vessel engaged
with the coiled tubing with the subsea injector to maintain slack in the coiled tubing.

20 10. The module of claim 9, further comprising a tool catcher operable to connect a
bottom hole assembly connected to the coil tubing with the module.

11. The module of claim 9, further comprising an isolation valve operable to
prevent flow from a subsea wellbore through a bore of the module in a closed
25 position.

12. The module of claim 9, wherein the isolation valve is further operable to cut the
coiled tubing or the module further comprises a coiled tubing cutter.

30 13. The module of claim 9, further comprising an adapter having a connector
operable by a remotely operated vehicle (ROV) for fastening the module to a pressure
control assembly fastened to a subsea production tree.

14. The module of claim 13, further comprising:

a control relay in communication with the stripper and the motor; and
a frame fastened to the adapter and the control relay,
wherein the control relay is operable to receive a subsea jumper providing
communication with the controller.

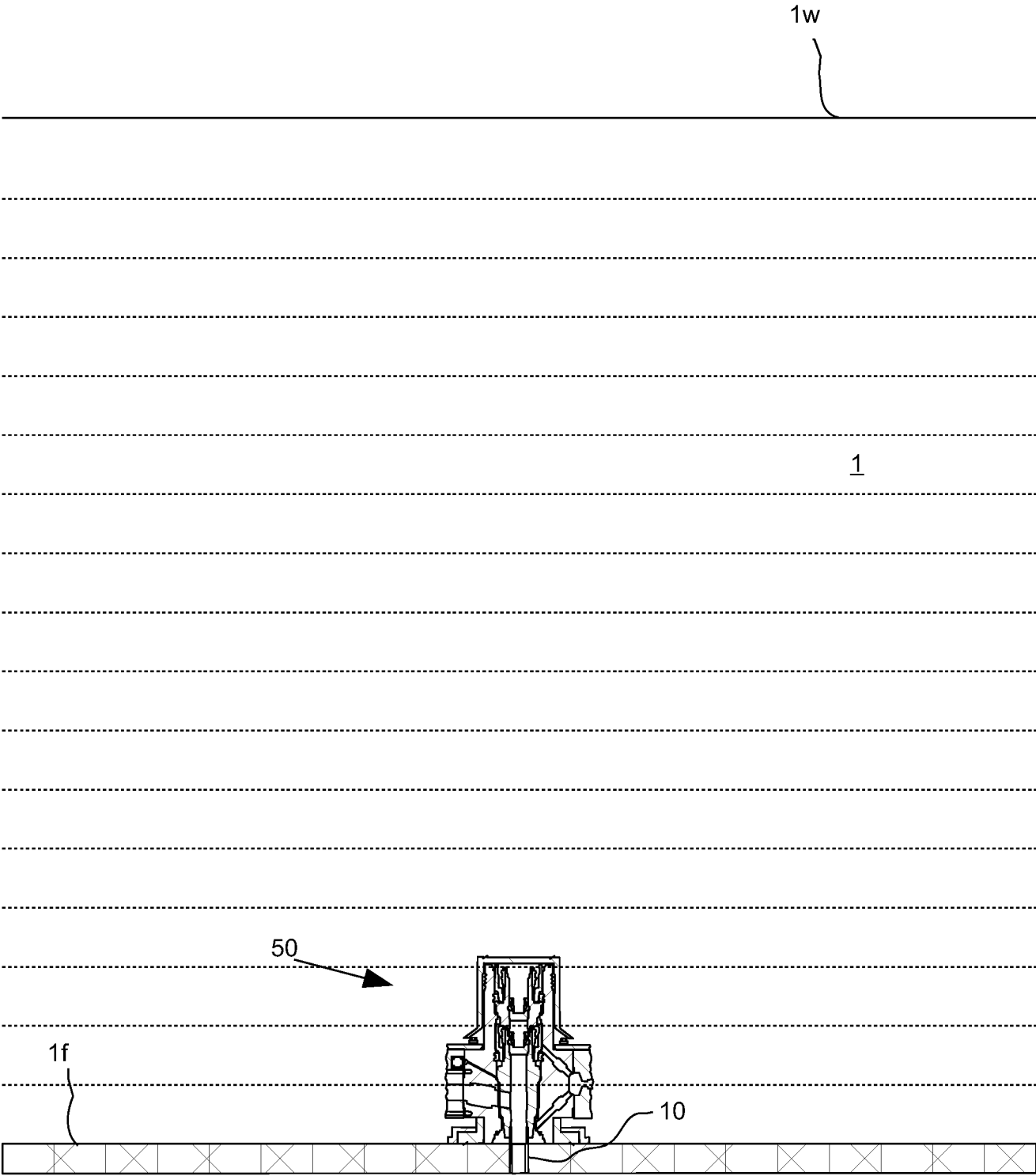
5

15. The module of claim 14, further comprising a fluid sub having a port in
communication with a bore of the module.

16. The module of claim 15, further comprising a junction plate for providing fluid
10 communication between the fluid sub and a fluid conduit extending from a support
vessel.

FIG. 1A
(Prior Art)

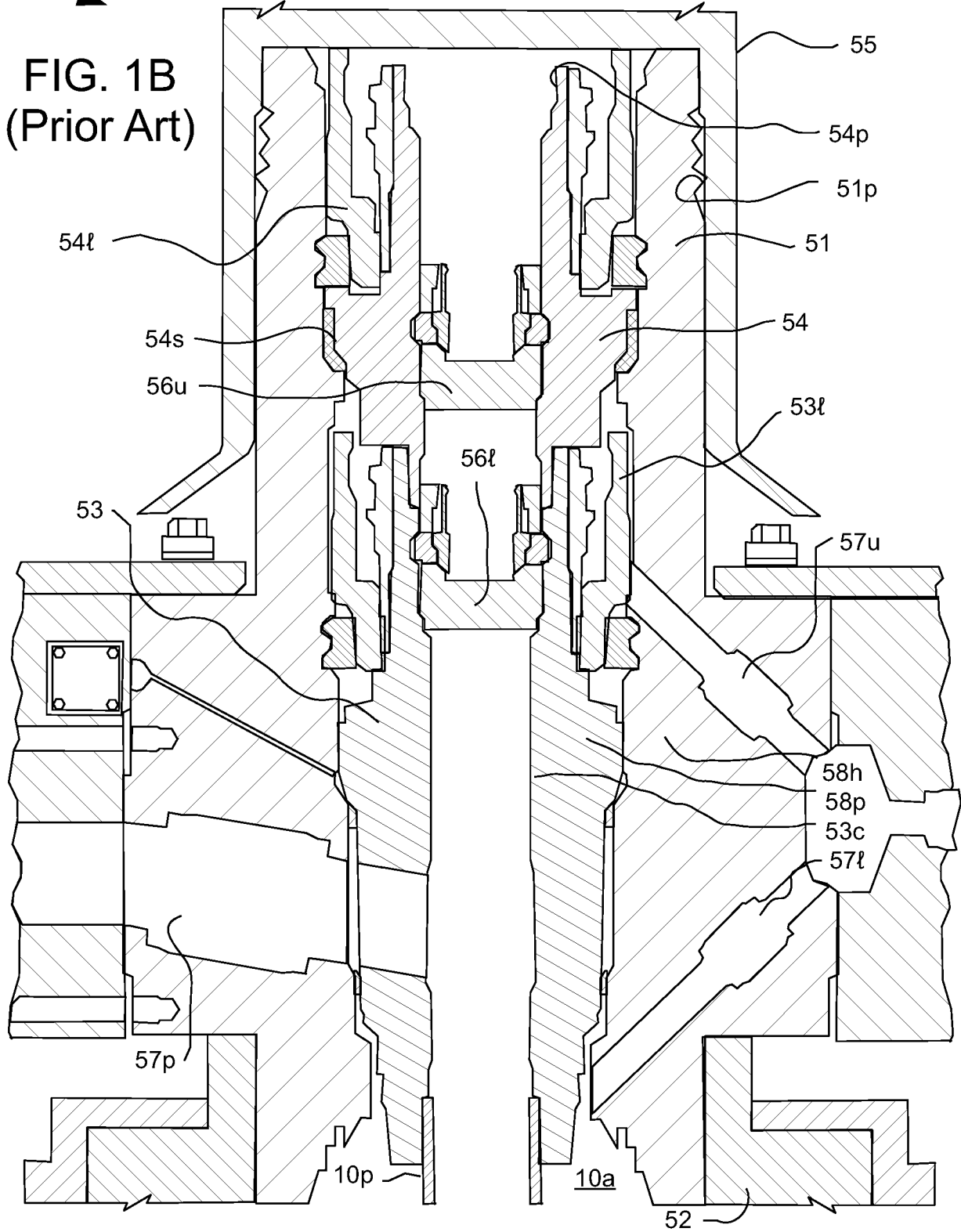
1/17



2/17

50

FIG. 1B
(Prior Art)



3/17

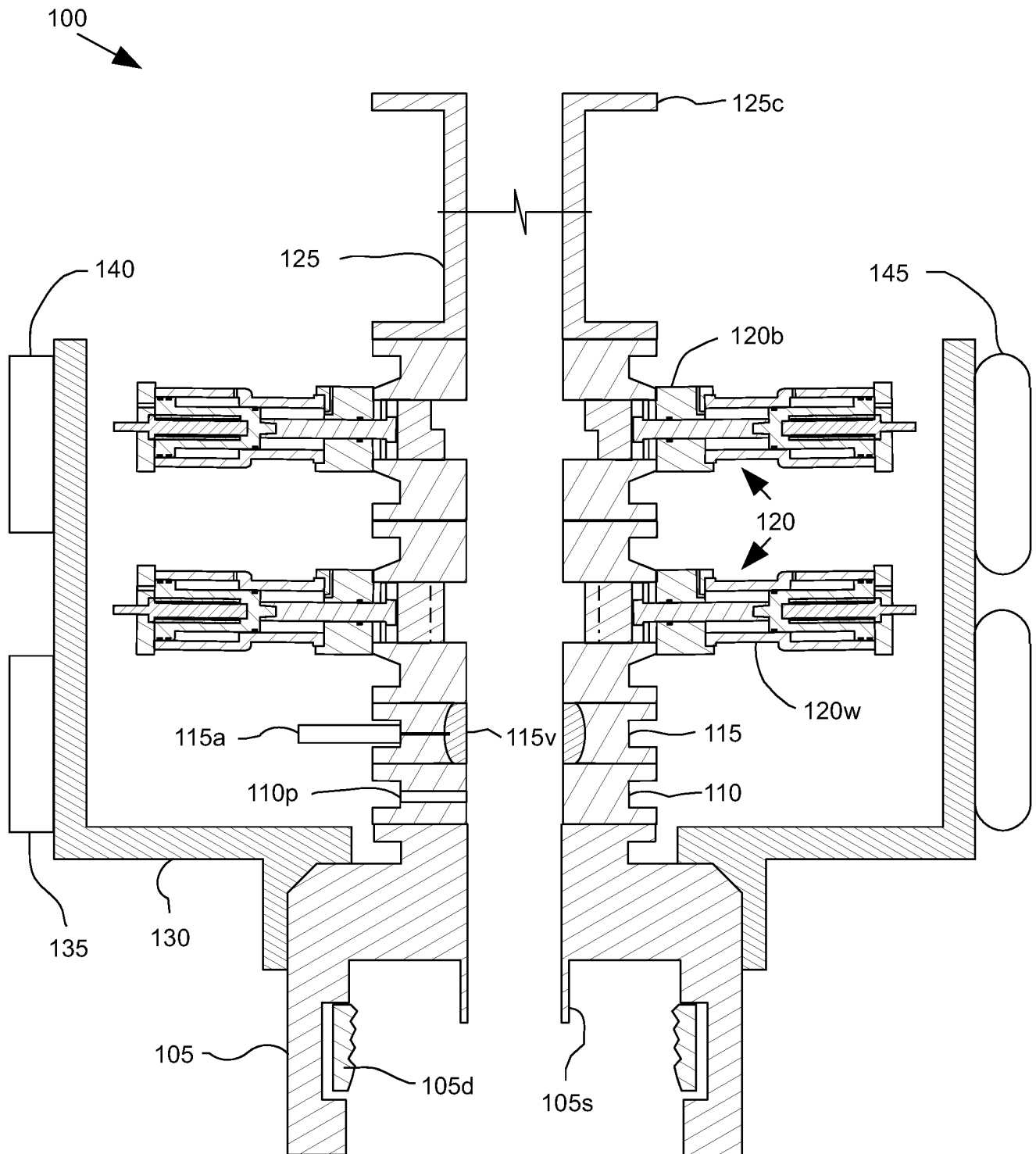


FIG. 2A

4/17

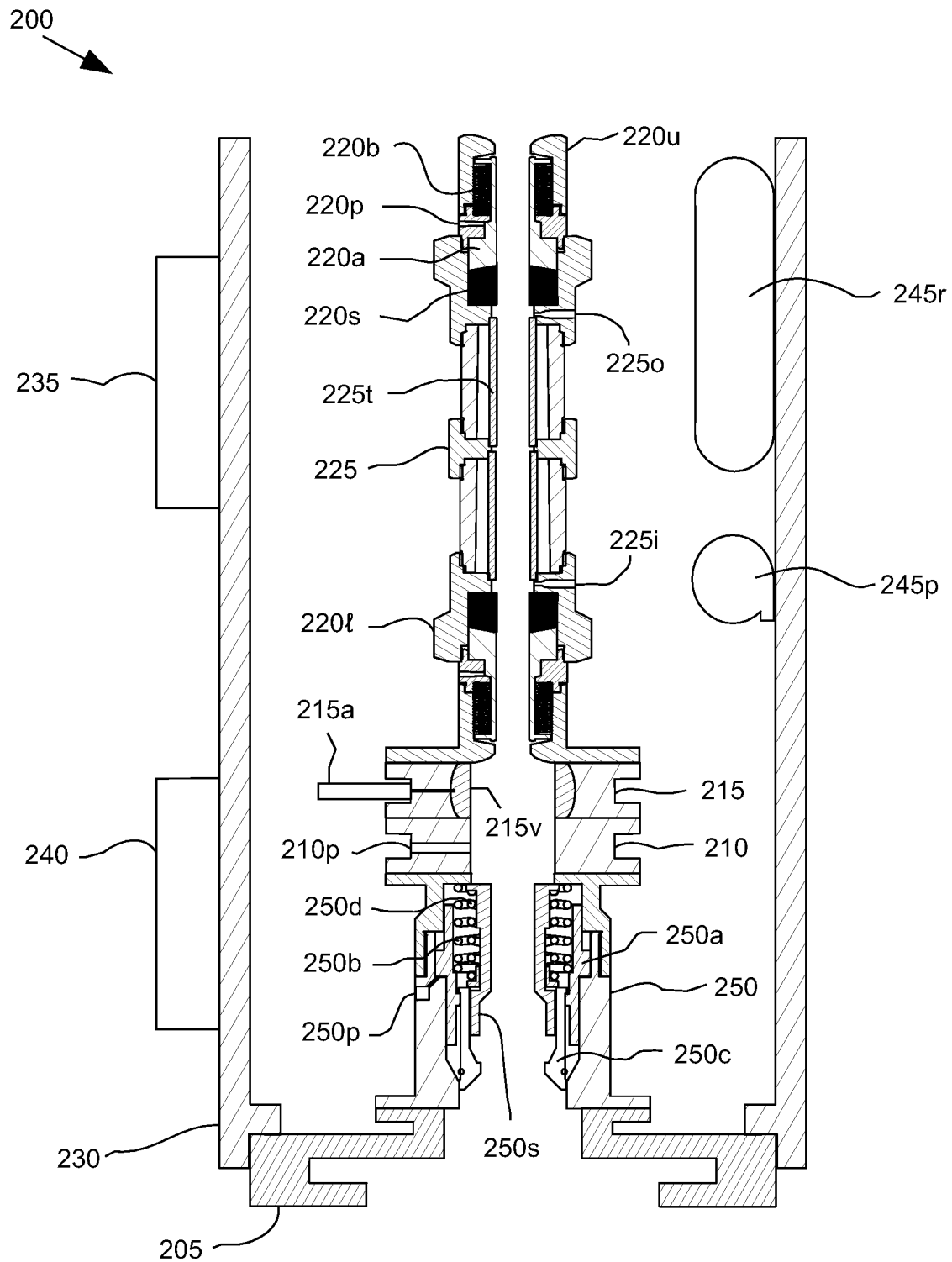


FIG. 2B

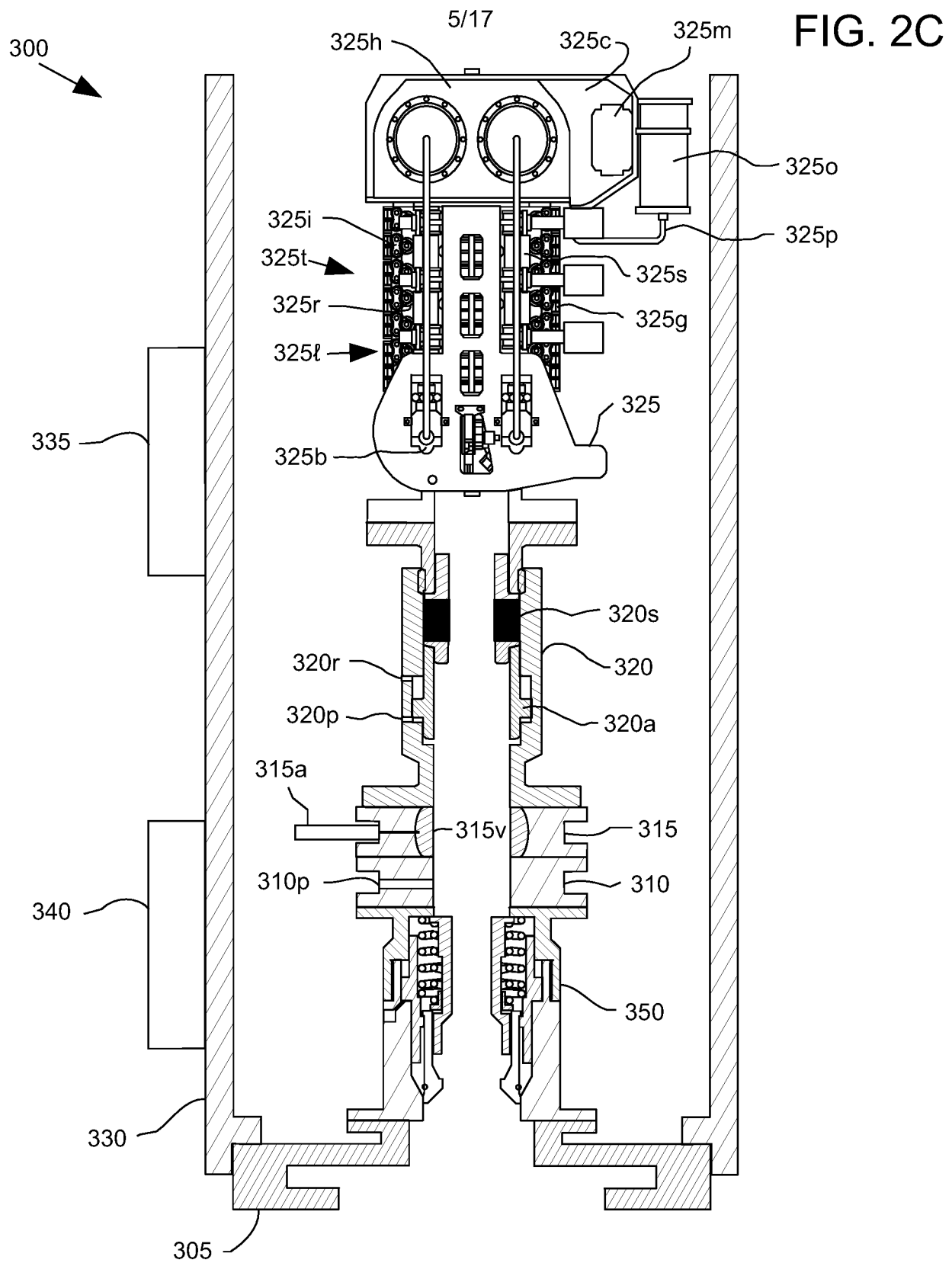


FIG. 3A

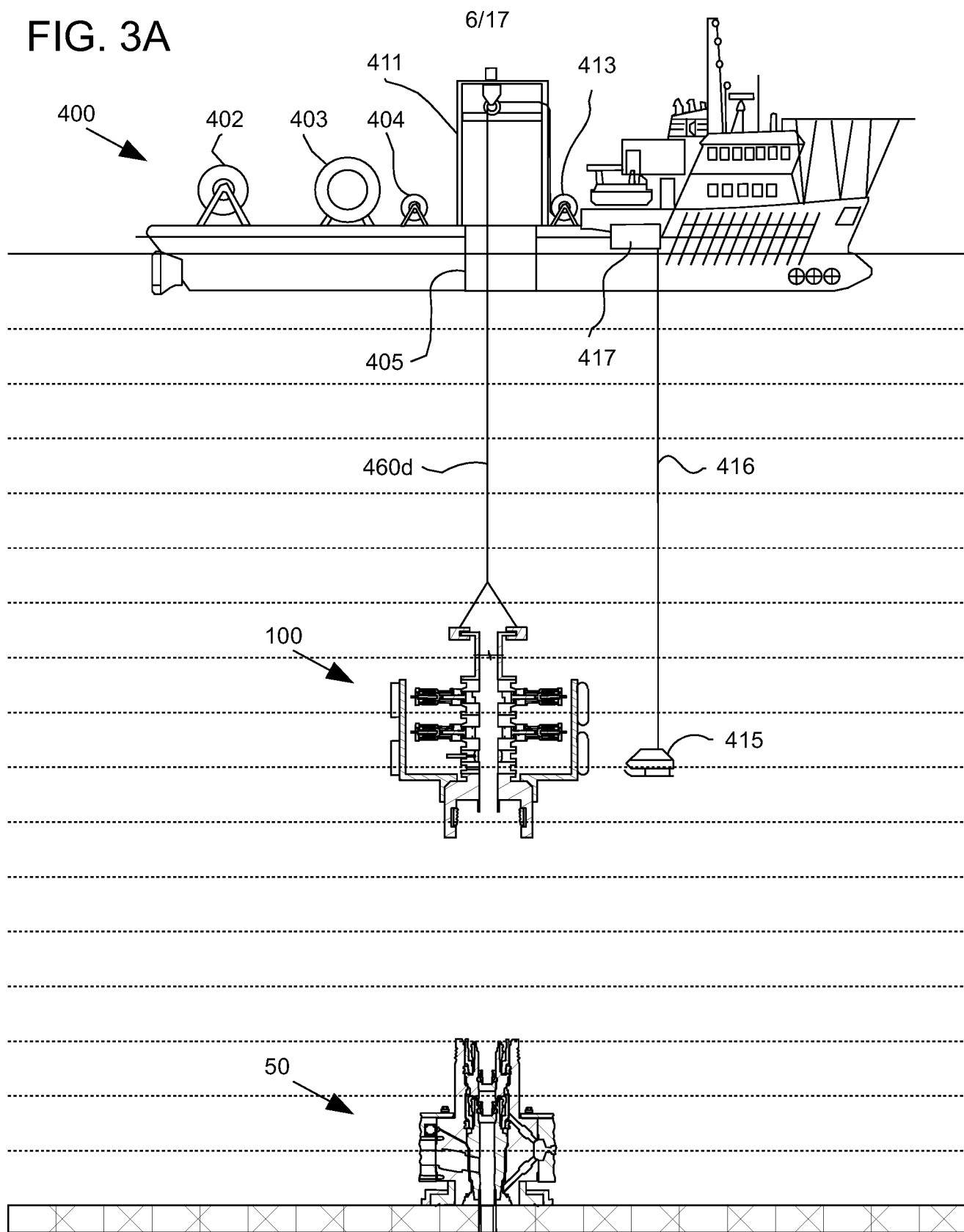


FIG. 3B

7/17

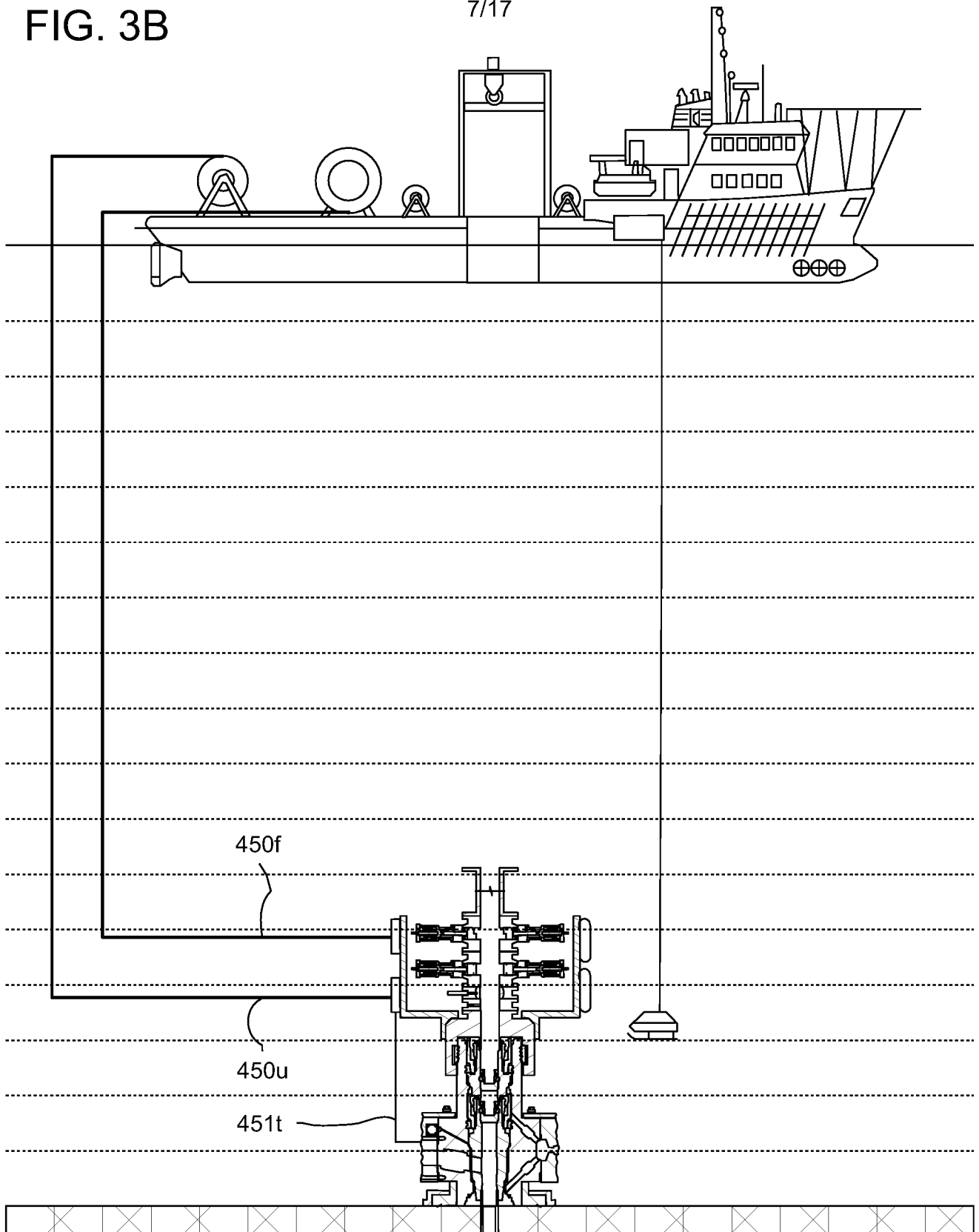


FIG. 4A

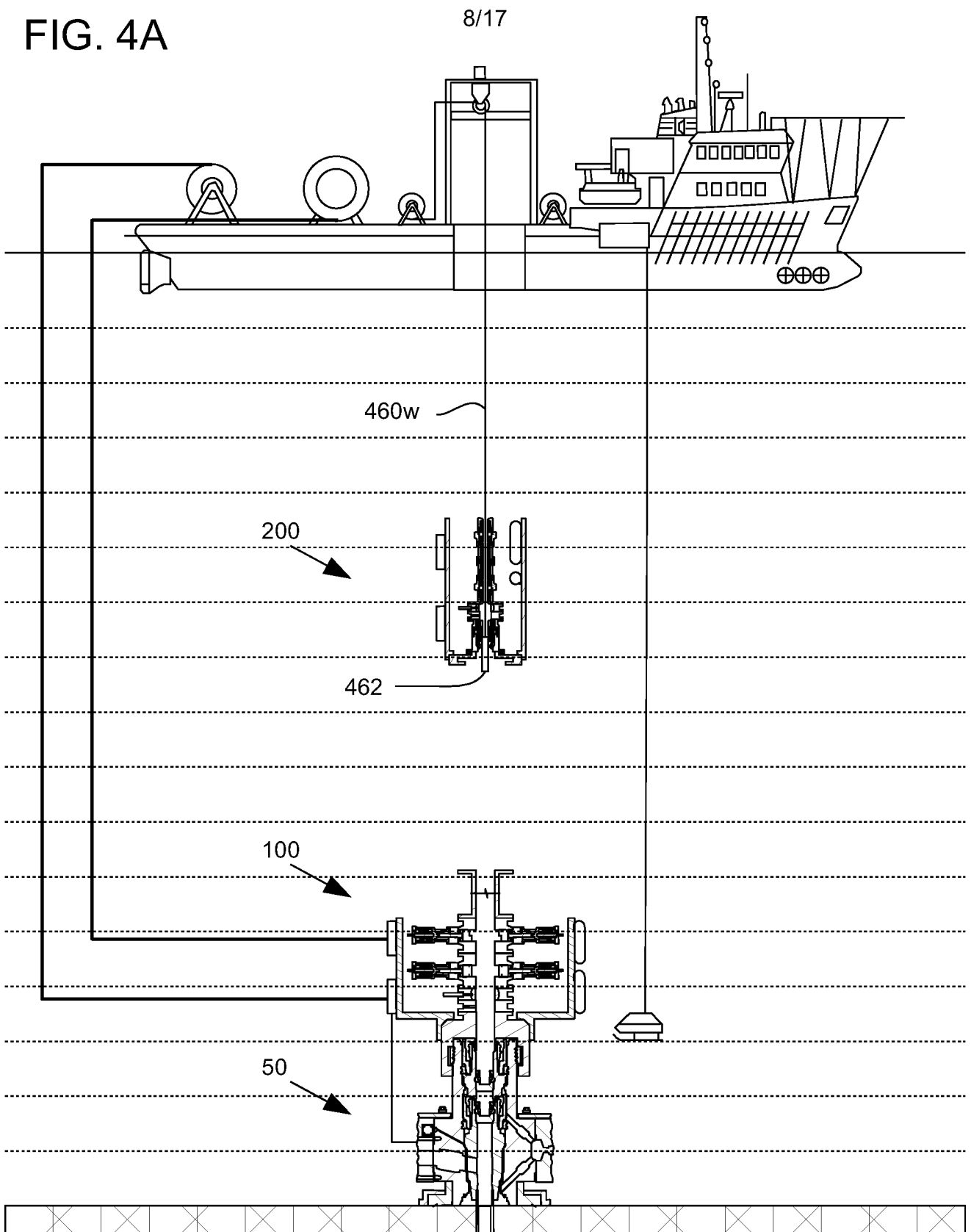


FIG. 4B

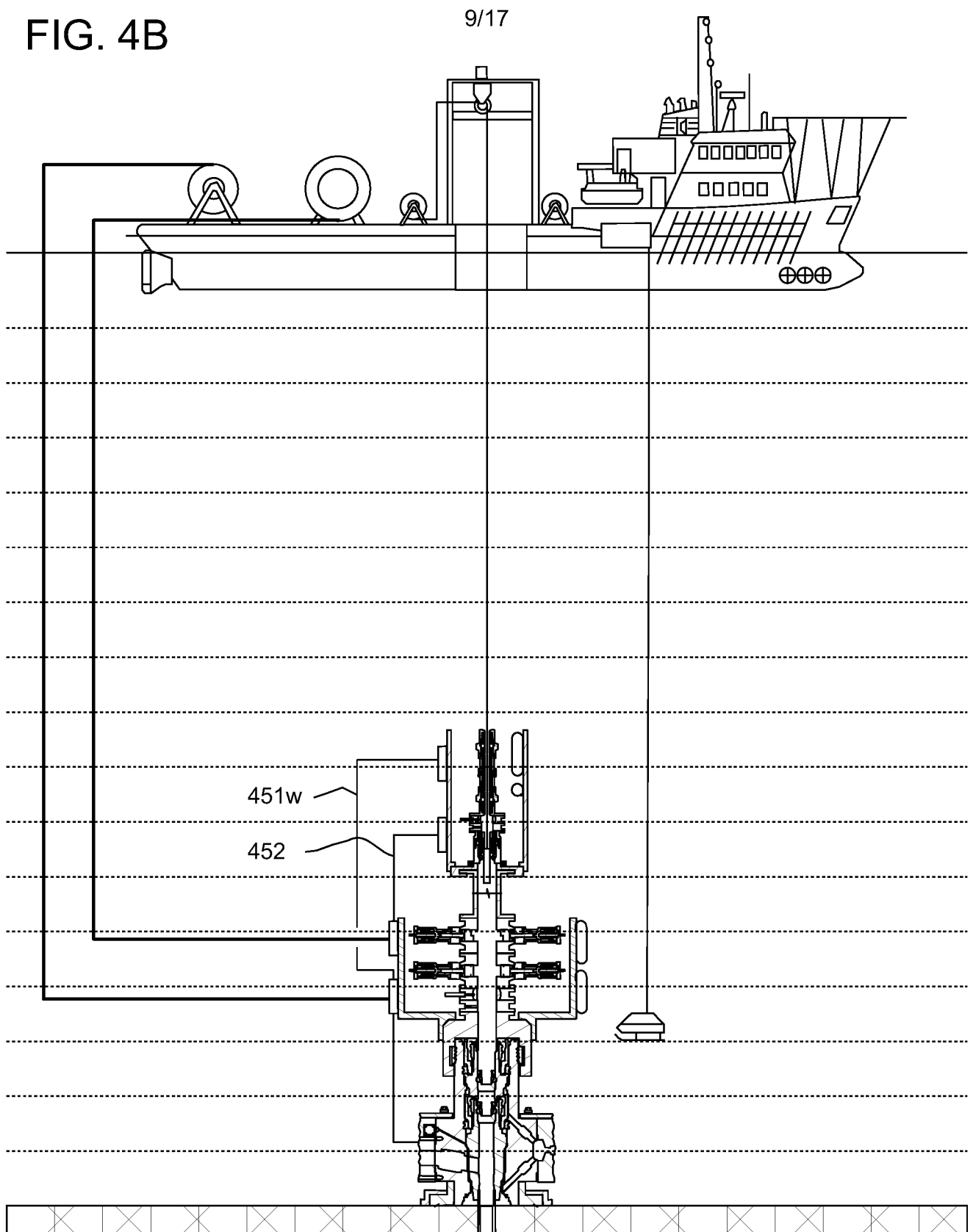


FIG. 4C

10/17

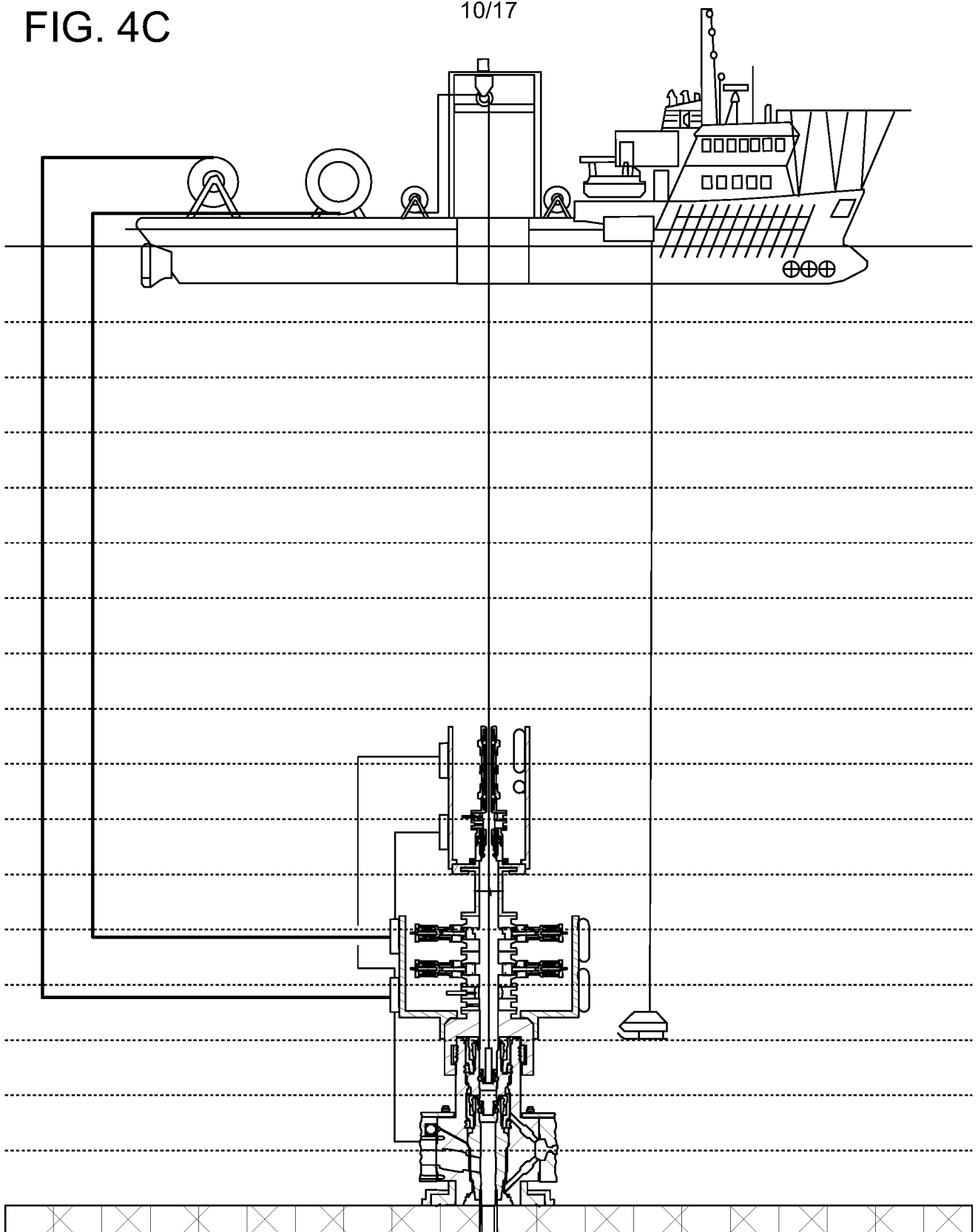


FIG. 4D

11/17

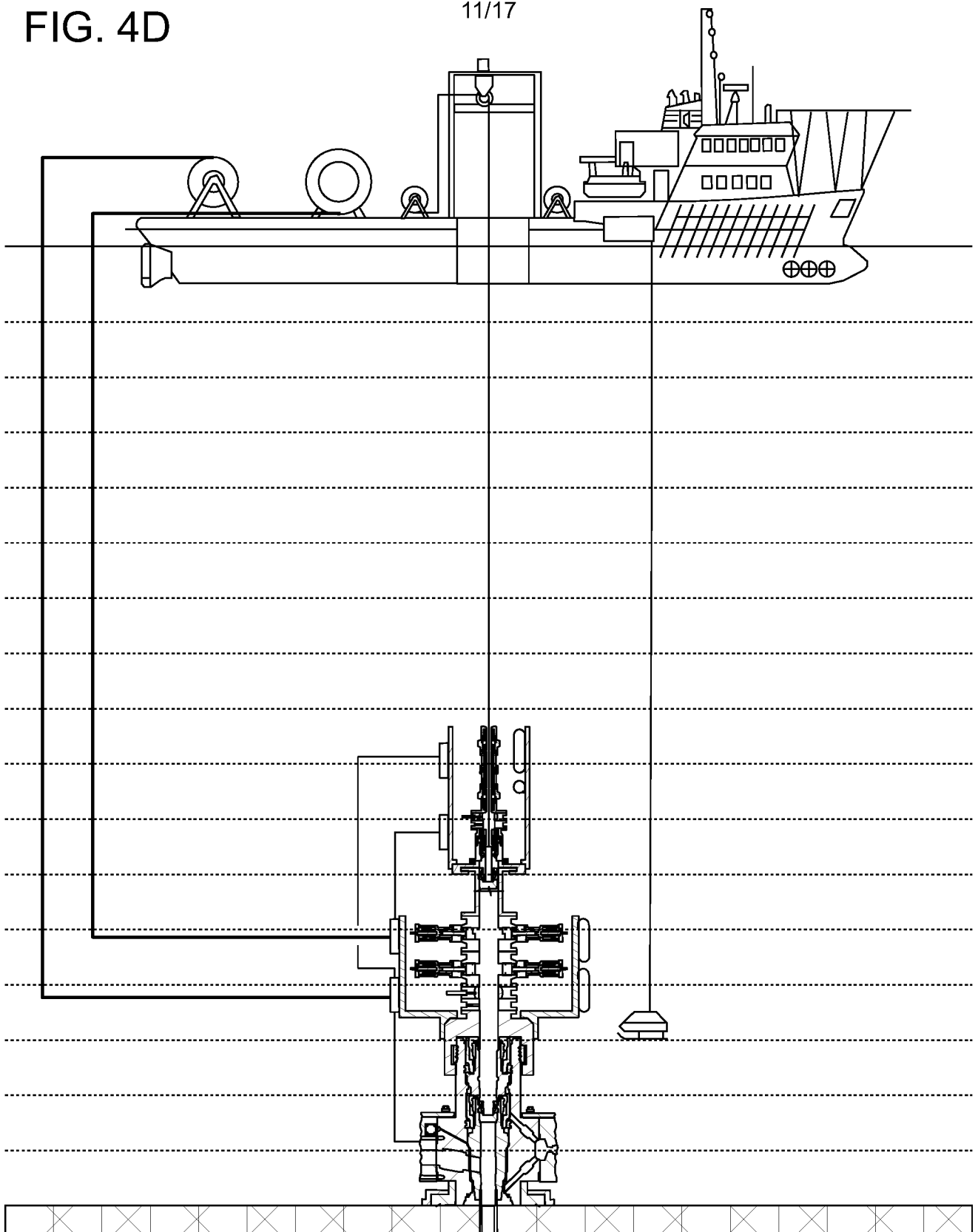
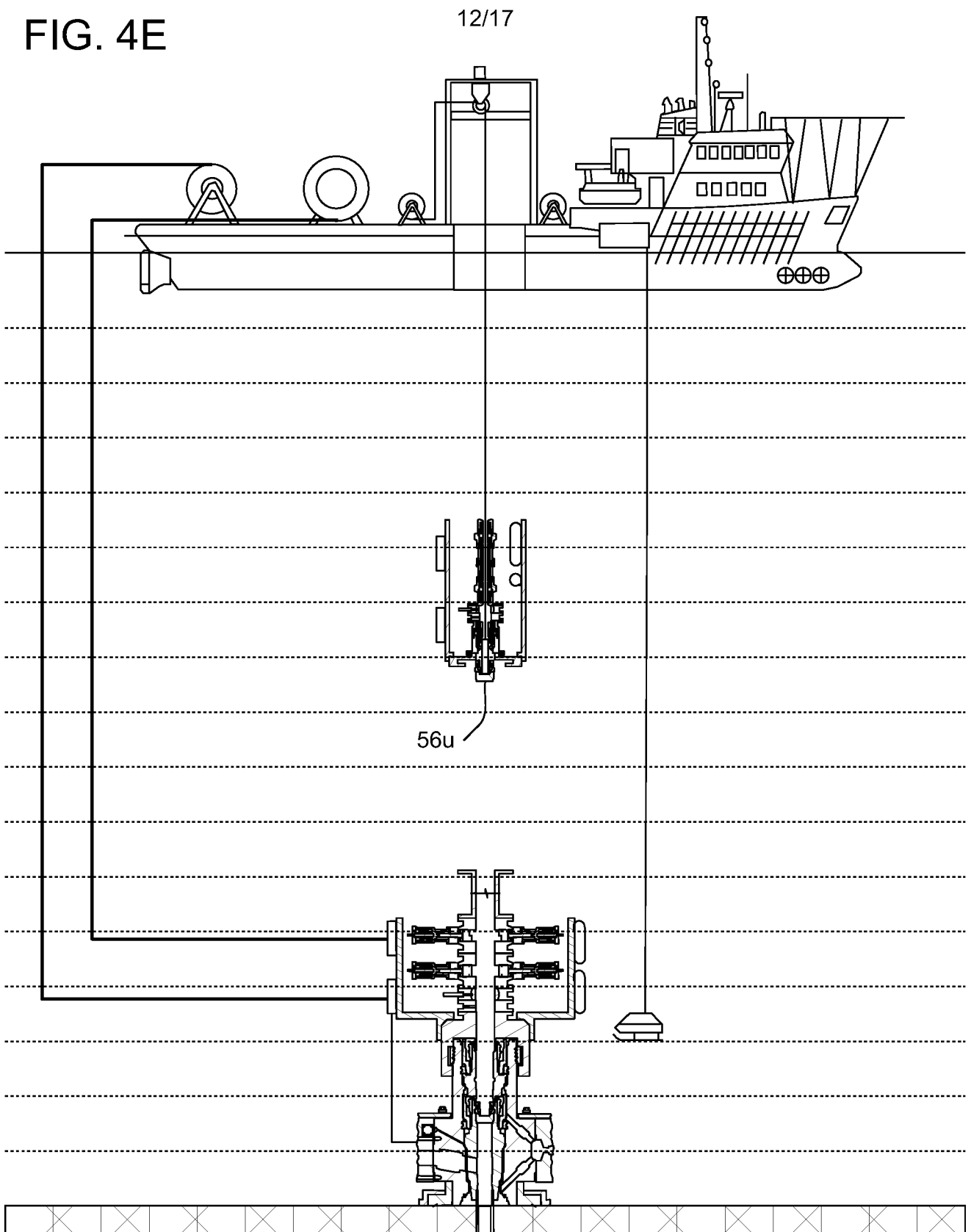


FIG. 4E



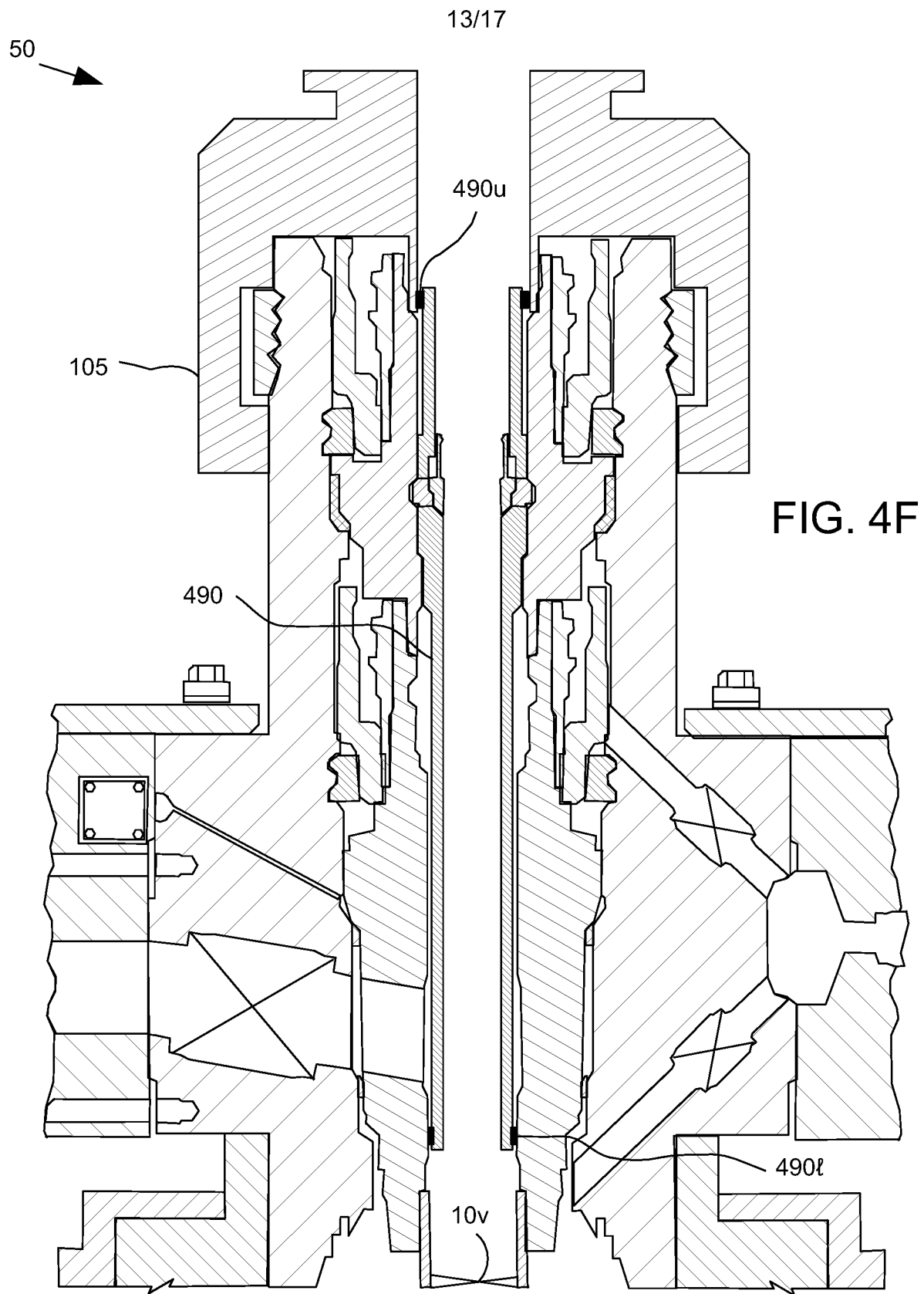


FIG. 5A

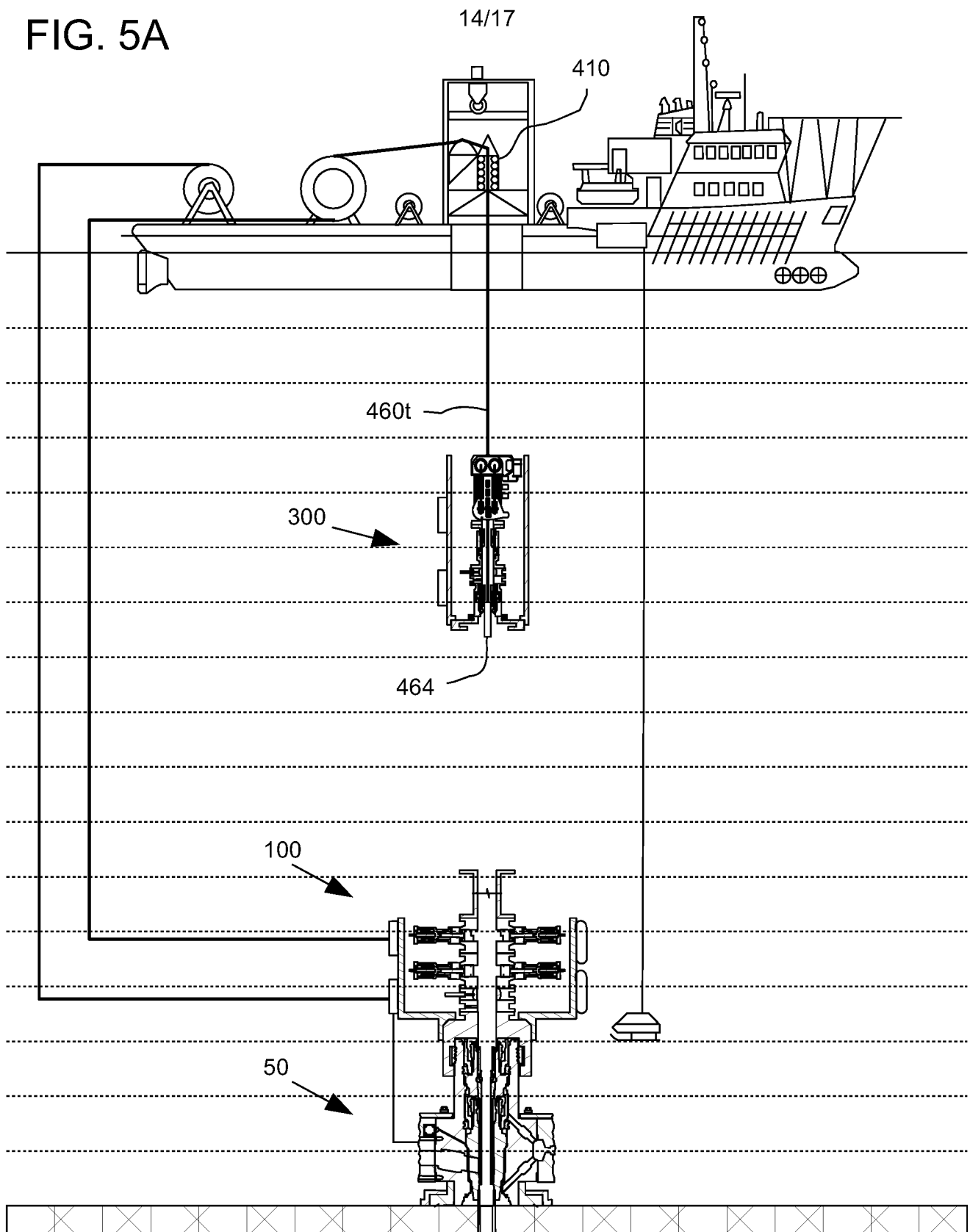


FIG. 5B

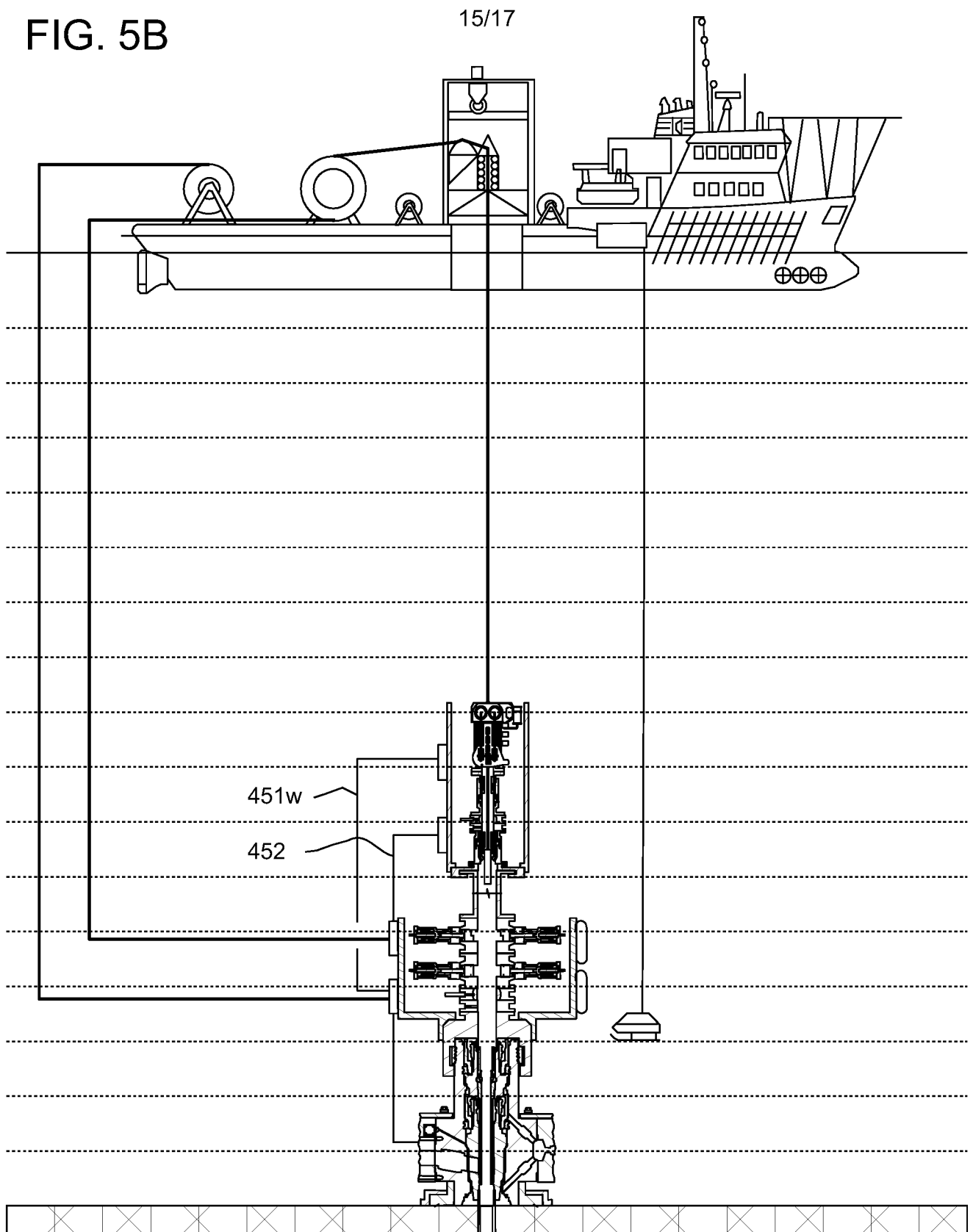
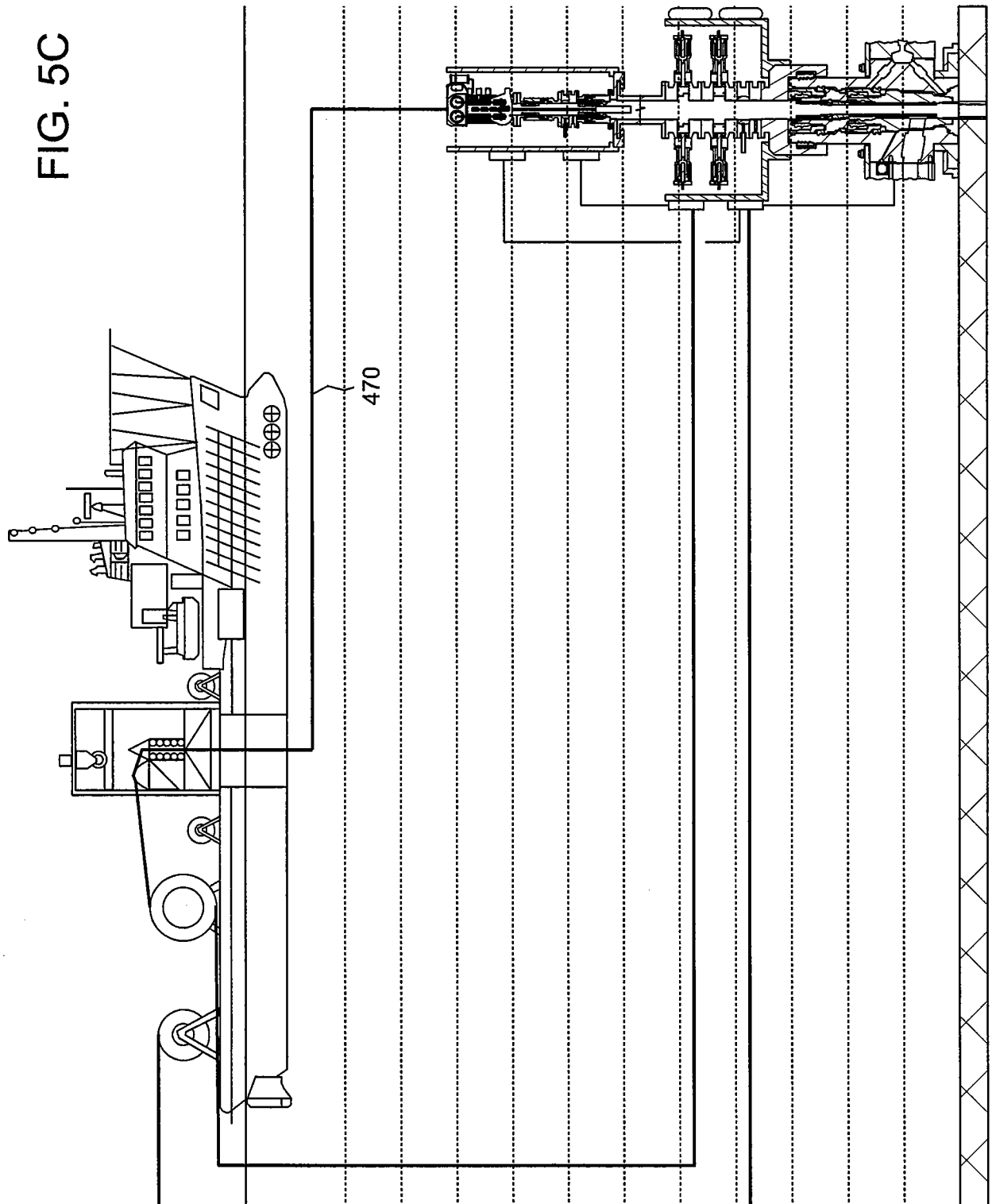


FIG. 5C



17/17

FIG. 5D

