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(54) **TACHOMETER FOR A ROTATING CONTROL DEVICE**

(71) Applicant: **Weatherford/Lamb, Inc.**, Houston, TX (US)

(72) Inventor: **Kevin L. GRAY**, Houston, TX (US)

(73) Assignee: **Weatherford/Lamb, Inc.**, Houston, TX (US)

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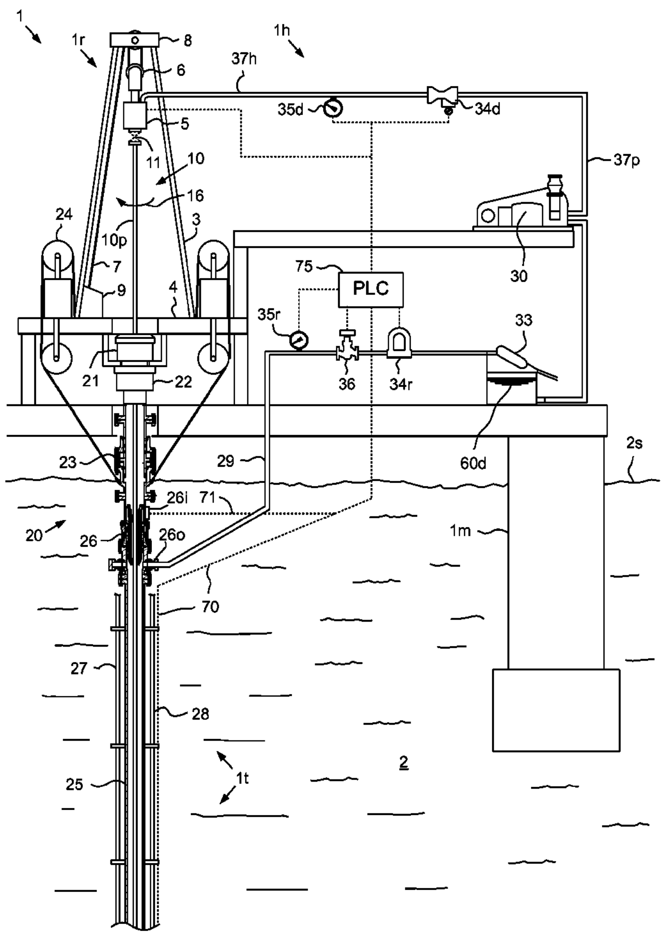
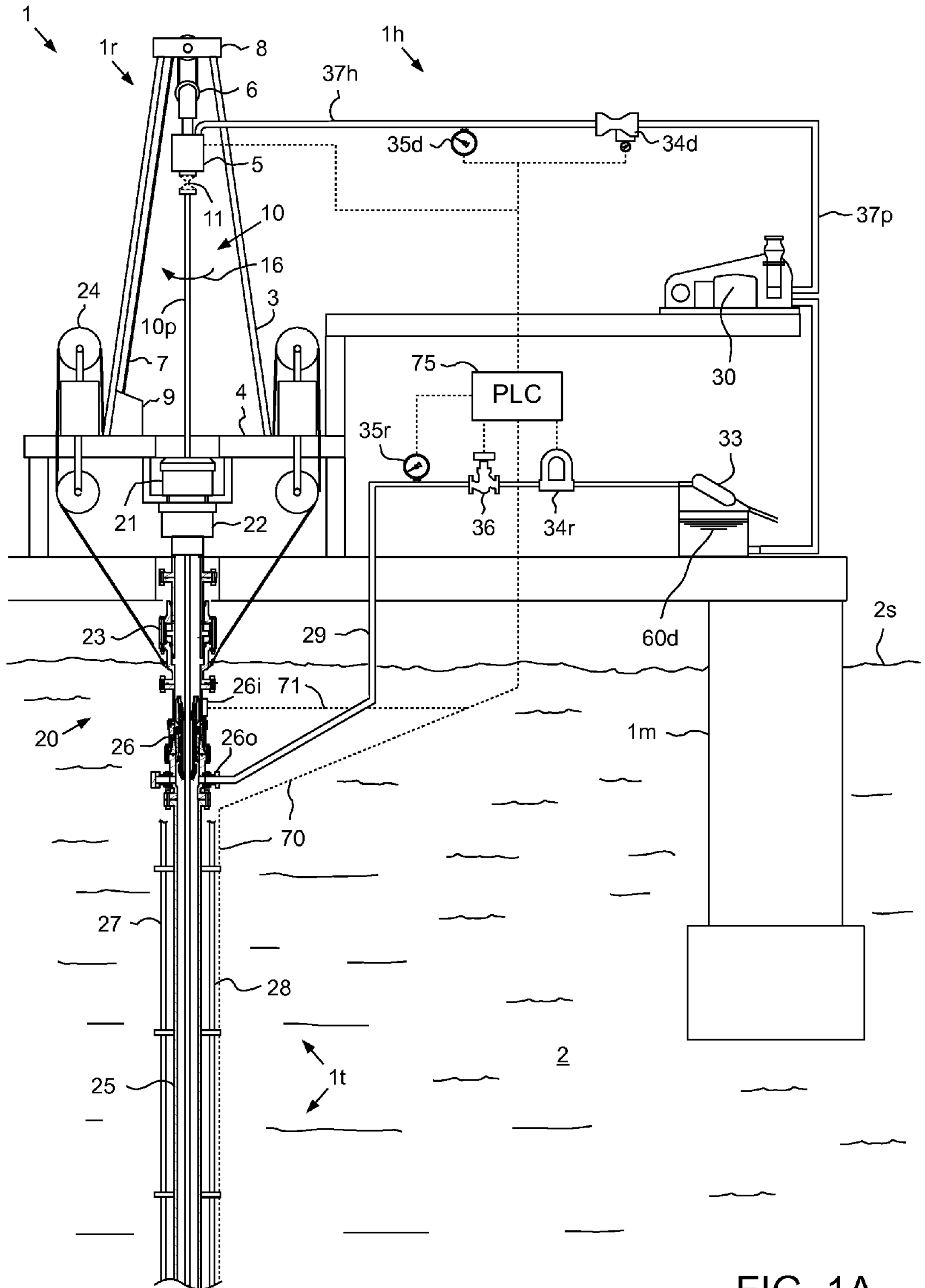
(57) **ABSTRACT**

A rotating control device (RCD) includes: a tubular housing having a flange formed at each end thereof; a stripper seal for receiving and sealing against a tubular; a bearing for supporting rotation of the stripper seal relative to the housing; a retainer for connecting the stripper seal to the bearing; and a tachometer. The tachometer includes a probe connected to the retainer and including: a tilt sensor; an angular speed sensor; an angular acceleration sensor; a first wireless data coupling; and a microcontroller operable to receive measurements from the sensors and to transmit the measurements to a base using the first wireless data coupling. The tachometer further includes the base connected to the housing and including: a second wireless data coupling operable to receive the measurements; and an electronics package in communication with the second wireless data coupling and operable to relay the measurements to an offshore drilling unit.

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1r
8
6
1h
37h
35d
34d
5
11
10
37p
16
24
10p
3
7
30
9
4
75
PLC
35r
33
21
22
36
34r
23
29
60d
2s
26i
71
20
26
26o
1m
70
27
28
2
1t
25

FIG. 1A

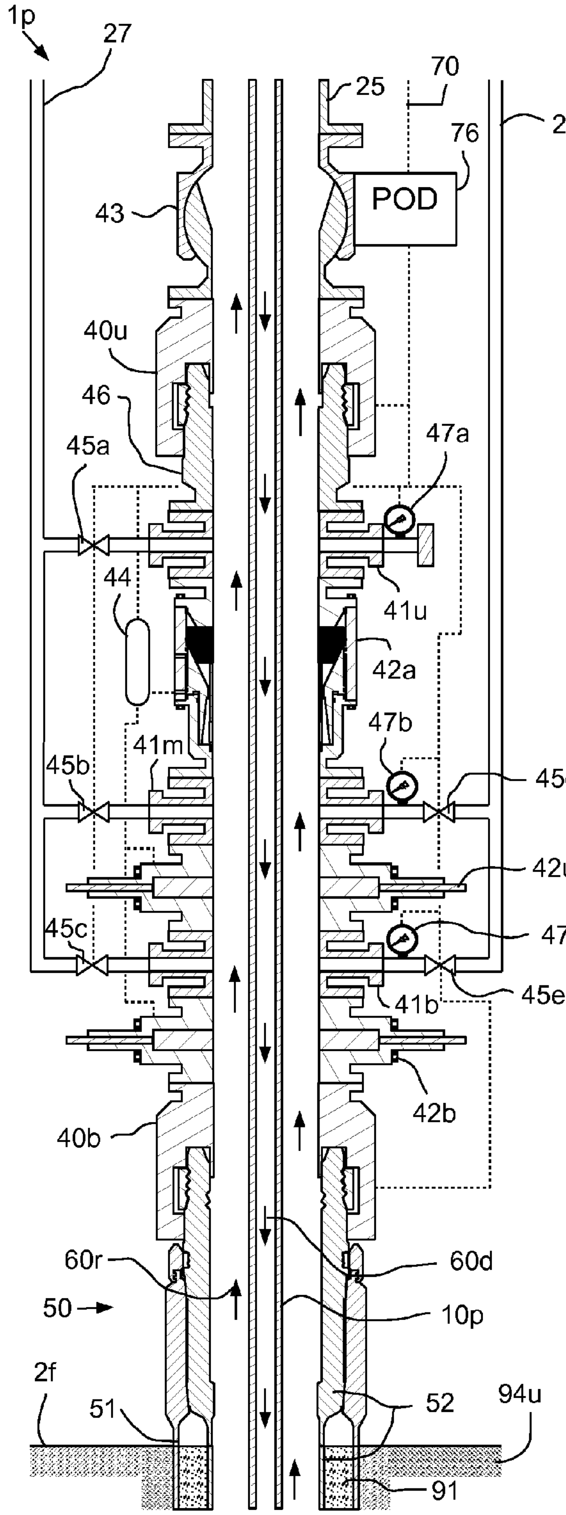

1p
27
25
70
76
28
POD
43
40u
46
47a
45a
41u
44
42a
47b
41m
45b
45d
42u
45c
47c
41b
45e
42b
40b
60r
60d
50
10p
2f
51
52
94u
91

FIG. 1B

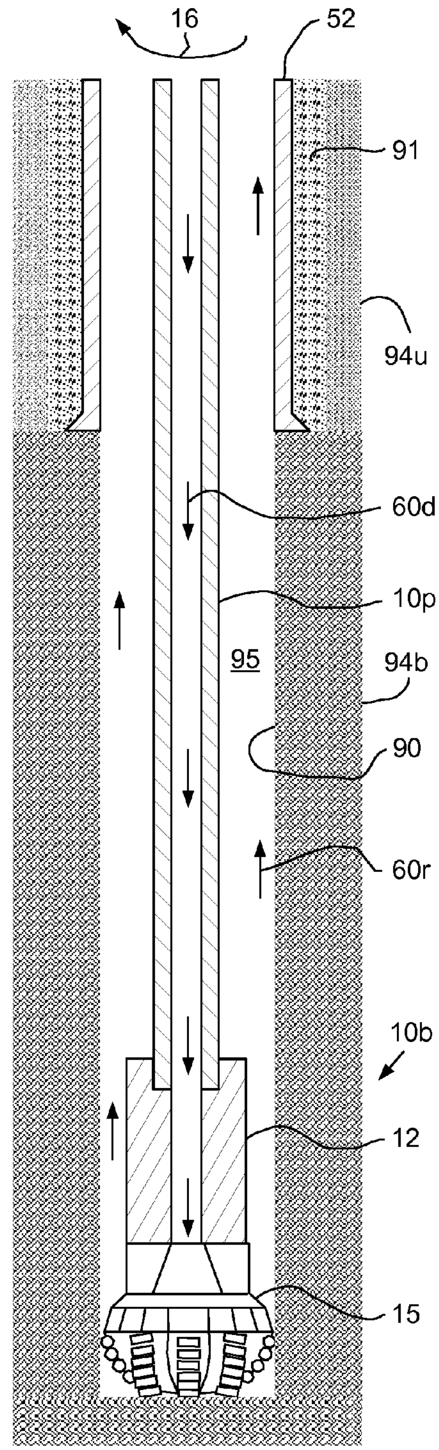

16
52
91
94u
60d
10p
95
94b
90
60r
10b
12
15

FIG. 1C

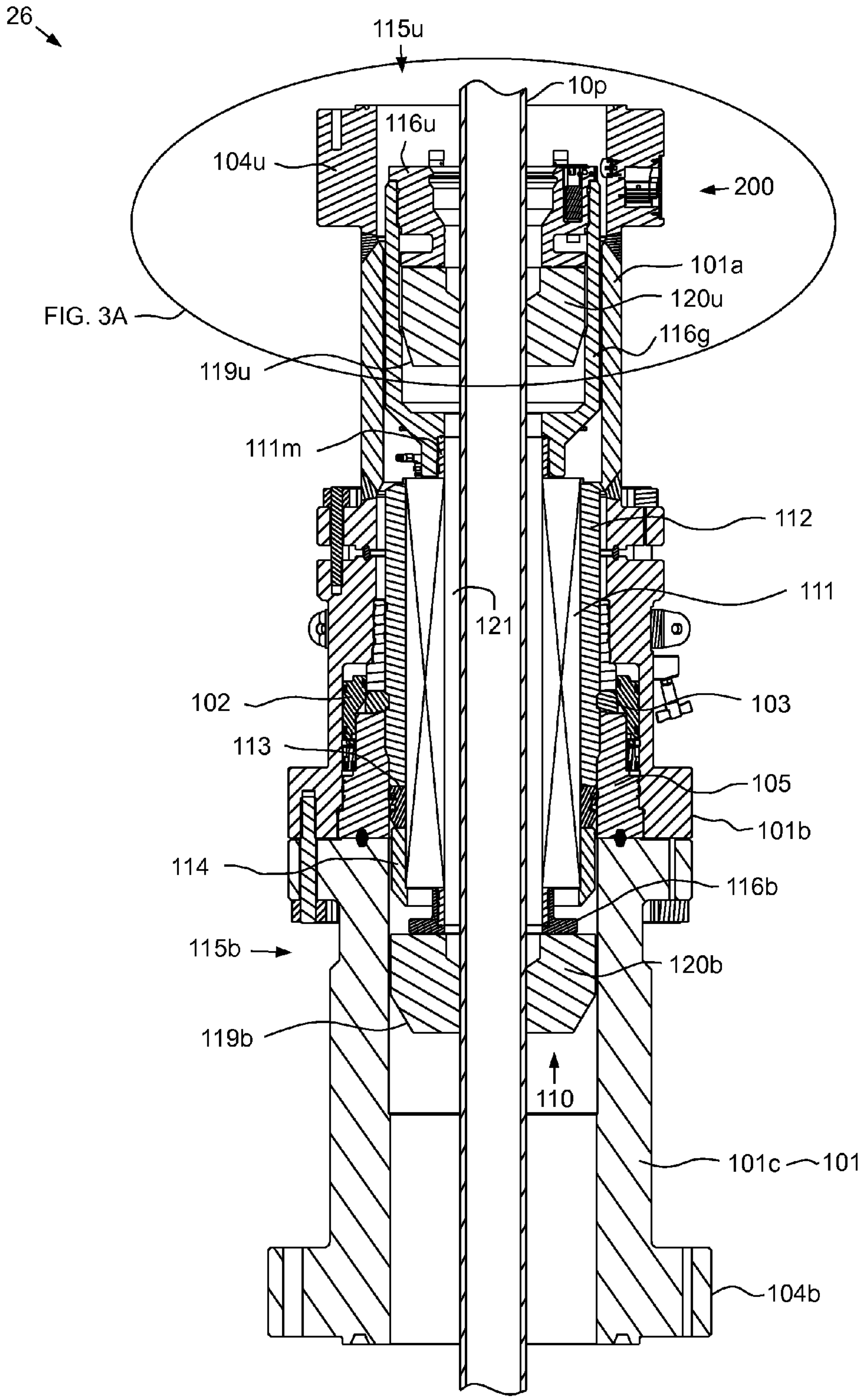

26
115u
10p
116u
104u
200
101a
120u
FIG. 3A
116g
119u
111m
112
111
121
102
103
113
105
101b
114
116b
115b
120b
119b
110
101c
101
104b

FIG. 2

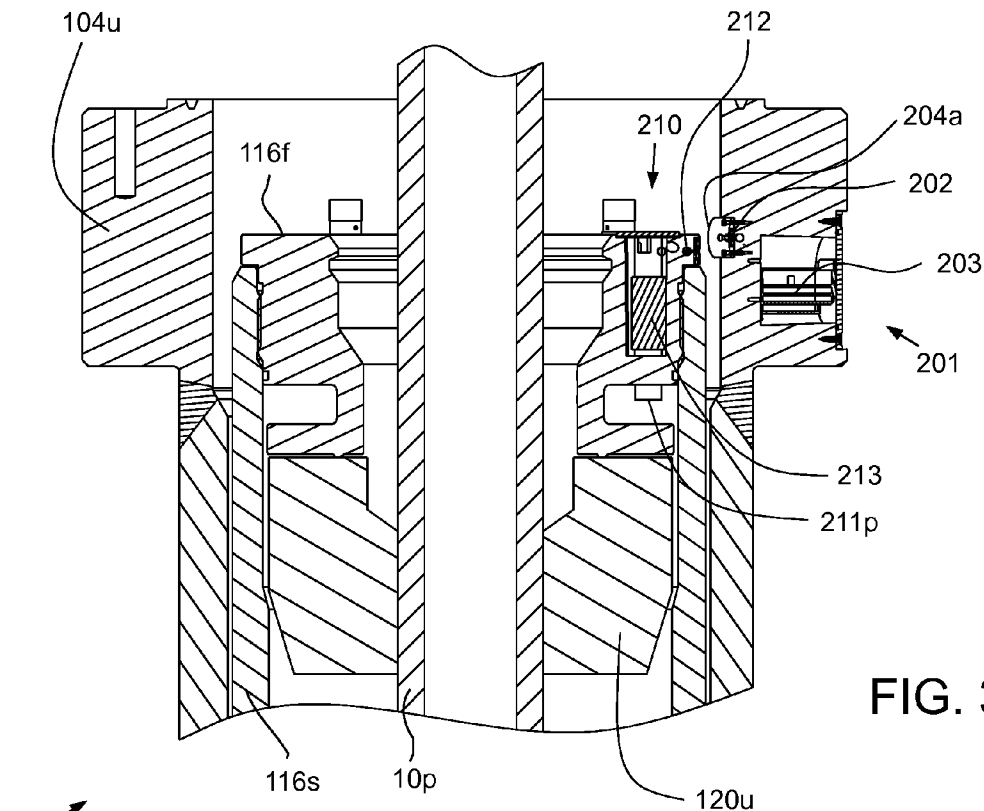


FIG. 3A

200

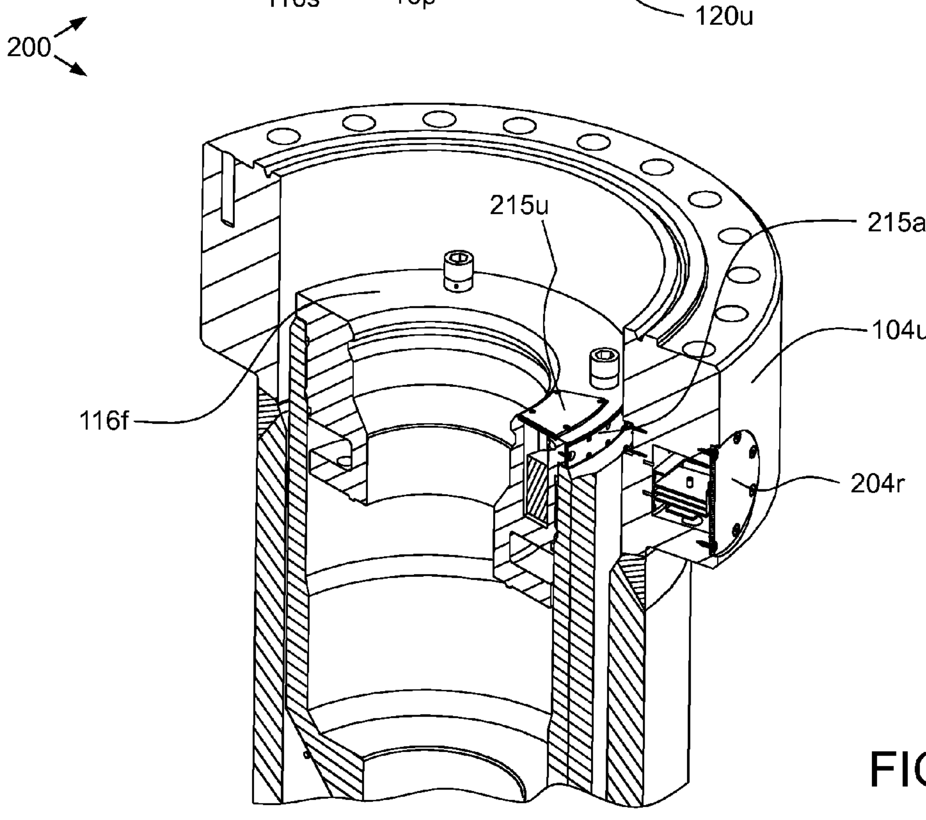


FIG. 3B

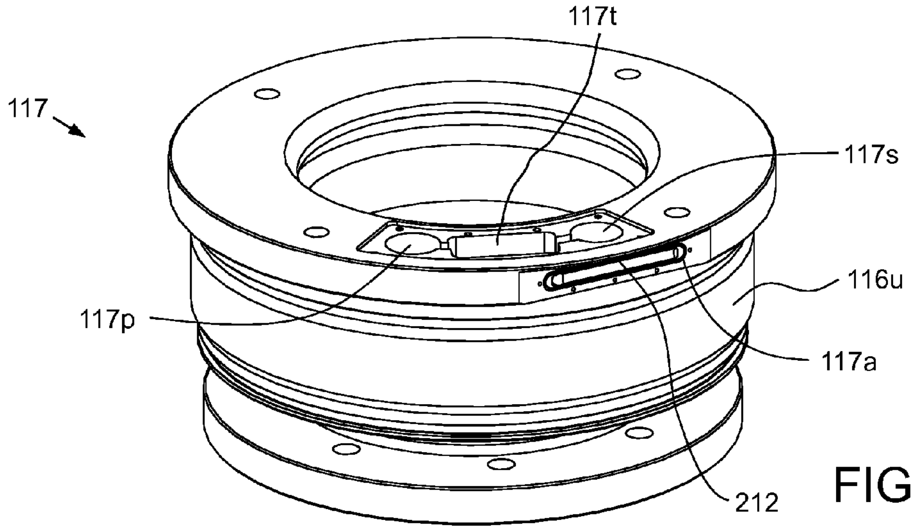


FIG. 4A

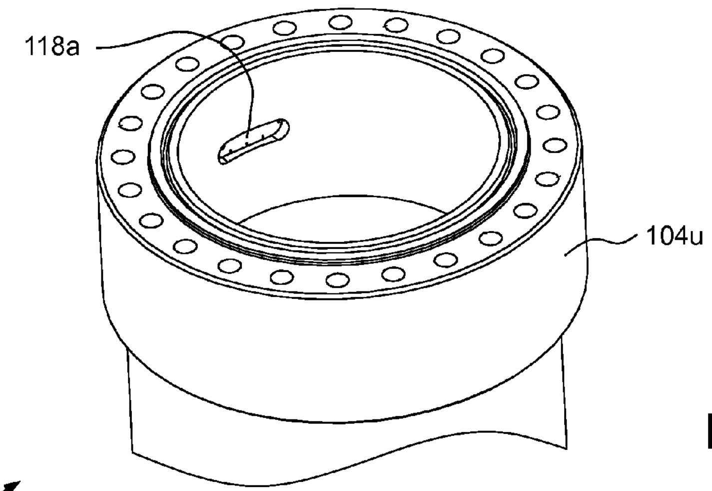


FIG. 4B

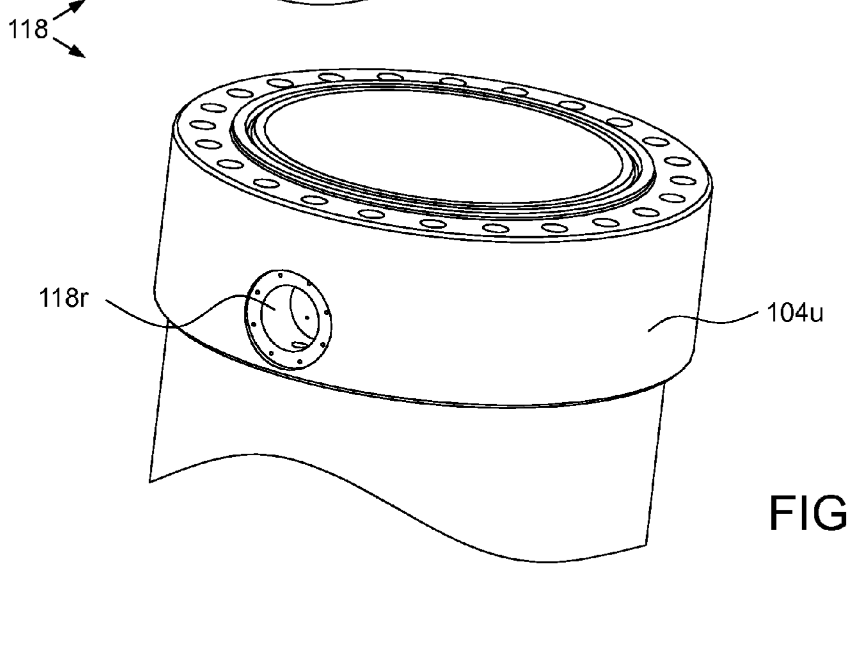
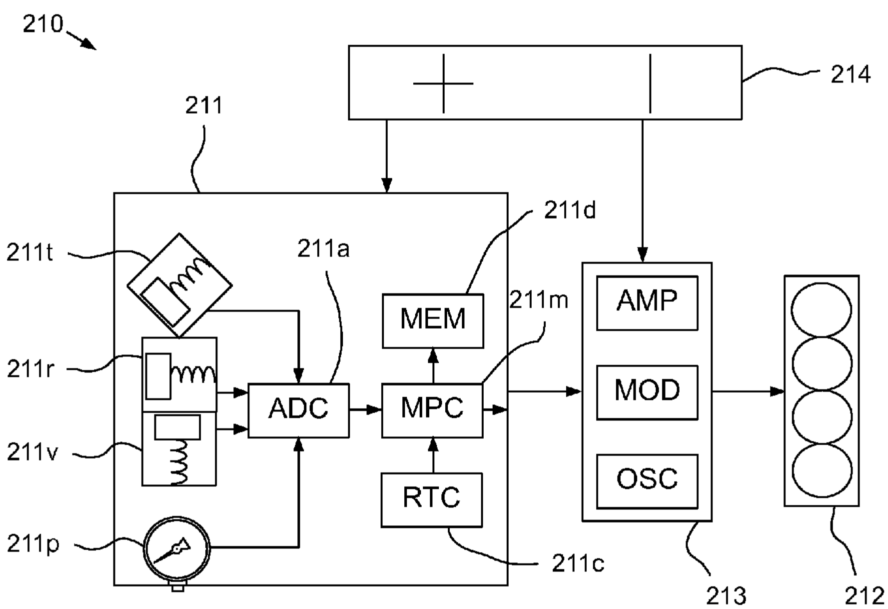


FIG. 4C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211
211d
211t
211a
211m
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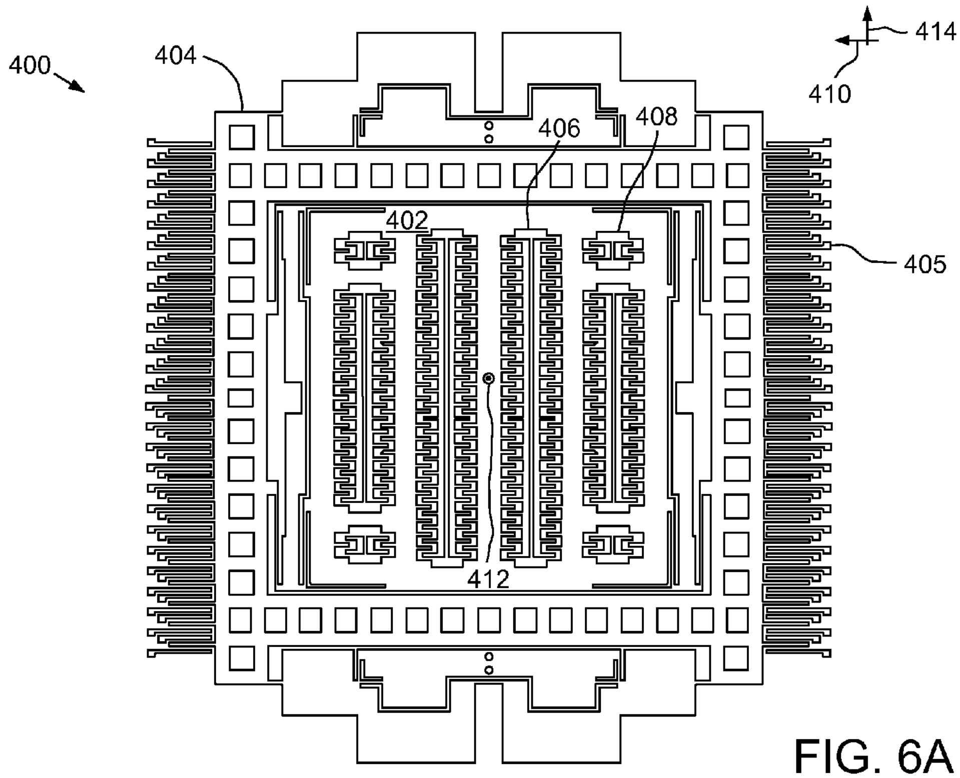
AMP
211r
ADC
MPC
MOD
211v
RTC
OSC
211p
211c
213
212

FIG. 5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404
414
410
406
408
402
405
412

FIG. 6A

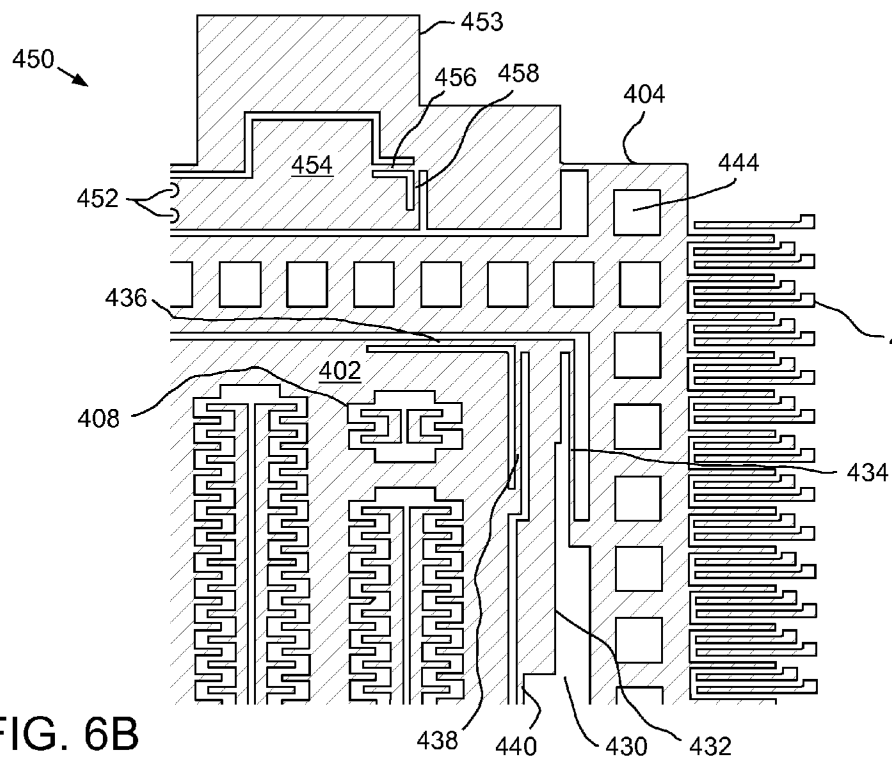
450
453
456
458
404
444
452
454
436
405
402
408
434
438
440
430
432

FIG. 6B

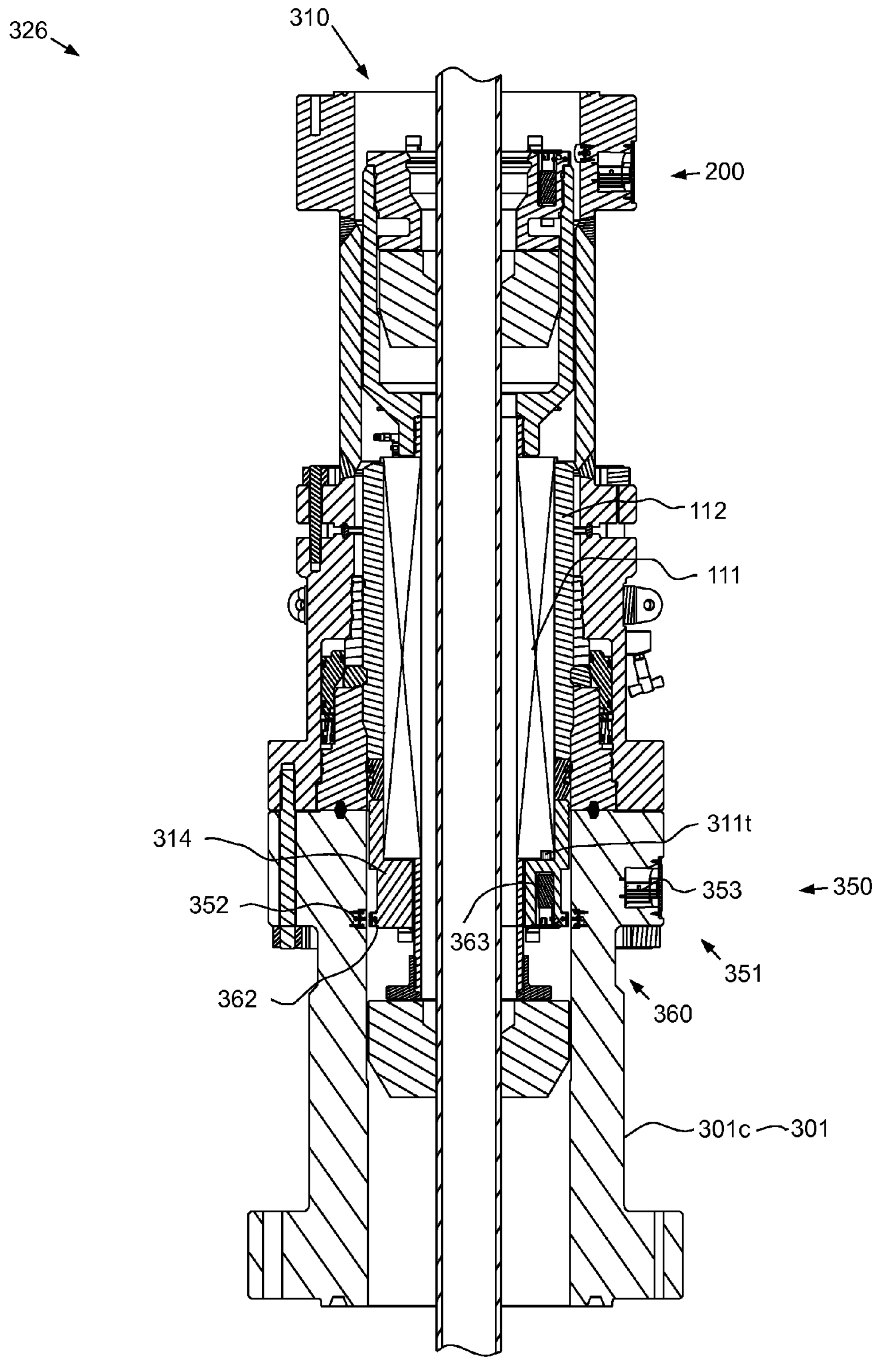
326
310
200
112
111
311t
314
353
350
352
363
351
362
360
301c
301

FIG. 7

TACHOMETER FOR A ROTATING CONTROL DEVICE

BACKGROUND OF THE DISCLOSURE

[0001] 1. Field of the Disclosure

[0002] The present disclosure generally relates to a tachometer for a rotating control device.

[0003] 2. Description of the Related Art

[0004] Drilling a wellbore for hydrocarbons requires significant expenditures of manpower and equipment. Thus, constant advances are being sought to reduce any downtime of equipment and expedite any repairs that become necessary. Rotating equipment is particularly prone to maintenance as the drilling environment produces abrasive cuttings detrimental to the longevity of rotating seals, bearings, and packing elements.

[0005] In a typical drilling operation, a drill bit is attached to a drill pipe. Thereafter, a drive unit rotates the drill pipe using a drive member as the drill pipe and drill bit are urged downward to form the wellbore. Several components are used to control the gas or fluid pressure. Typically, one or more blow out preventers (BOP) are used to seal the mouth of the wellbore. In many instances, a rotating control device is mounted above the BOP stack. An internal portion of the conventional rotating control device is designed to seal and rotate with the drill pipe. The internal portion typically includes an internal sealing element mounted on a plurality of bearings. Over time, the seal arrangement may leak (or fail) due to wear.

SUMMARY OF THE DISCLOSURE

[0006] The present disclosure generally relates to a tachometer for a rotating control device. In one embodiment, a rotating control device (RCD) for use with an offshore drilling unit includes: a tubular housing having a flange formed at each end thereof; a stripper seal for receiving and sealing against a tubular; a bearing for supporting rotation of the stripper seal relative to the housing; a retainer for connecting the stripper seal to the bearing; and a tachometer. The tachometer includes a probe connected to the retainer and including: a tilt sensor; an angular speed sensor; an angular acceleration sensor; a first wireless data coupling; and a microcontroller operable to receive measurements from the sensors and to transmit the measurements to a base using the first wireless data coupling. The tachometer further includes the base connected to the housing and including: a second wireless data coupling operable to receive the measurements; and an electronics package in communication with the second wireless data coupling and operable to relay the measurements to the offshore drilling unit.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, 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 disclosure and are therefore not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

[0008] FIGS. **1**A-**1**C illustrate a drilling system utilizing a rotating control device, according to one embodiment of the present disclosure.

[0009] FIG. **2** illustrates the rotating control device.

[0010] FIGS. **3**A and **3**B illustrate a tachometer of the rotating control device.

[0011] FIG. **4**A illustrates a pocket formed in a stripper retainer of the rotating control device for receiving a probe of the tachometer. FIGS. **4**B and **4**C illustrate a pocket formed in a flange of the rotating control device for receiving a base of the tachometer.

[0012] FIG. **5** illustrates a probe of the tachometer.

[0013] FIGS. **6**A and **6**B illustrate a gyroscope usable with the probe, according to another embodiment of the present disclosure.

[0014] FIG. **7** illustrates a rotating control device having a data sub, according to another embodiment of the present disclosure.

DETAILED DESCRIPTION

[0015] FIGS. **1**A-**1**C illustrate a drilling system **1** utilizing a rotating control device (RCD) **26**, according to one embodiment of the present disclosure. The drilling system **1** may include a mobile offshore drilling unit (MODU) **1***m*, such as a semi-submersible, a drilling rig **1***r*, a fluid handling system **1***h*, a fluid transport system **1***t*, a pressure control assembly (PCA) **1***p*, and a drill string **10**. The MODU **1***m* may carry the drilling rig **1***r* and the fluid handling system **1***h* aboard and may include a moon pool, through which drilling operations are conducted. The semi-submersible MODU **1***m* may include a lower barge hull which floats below a surface (aka waterline) **2***s* of sea **2** and is, therefore, less subject to surface wave action. Stability columns (only one shown) may be mounted on the lower barge hull for supporting an upper hull above the waterline. The upper hull may have one or more decks for carrying the drilling rig **1***r* and fluid handling system **1***h*. The MODU **1***m* may further have a dynamic positioning system (DPS) (not shown) or be moored for maintaining the moon pool in position over a subsea wellhead **50**.

[0016] Alternatively, the MODU **1***m* may be a drill ship. Alternatively, a fixed offshore drilling unit or a non-mobile floating offshore drilling unit may be used instead of the MODU **1***m*. Alternatively, the wellbore may be subsea having a wellhead located adjacent to the waterline and the drilling rig may be a located on a platform adjacent the wellhead. Alternatively, the wellbore may be subterranean and the drilling rig located on a terrestrial pad.

[0017] The drilling rig **1***r* may include a derrick **3**, a floor **4**, a top drive **5**, and a hoist. The top drive **5** may include a motor for rotating **16** the drill string **10**. The top drive motor may be electric or hydraulic. A frame of the top drive **5** may be linked to a rail (not shown) of the derrick **3** for preventing rotation thereof during rotation **16** of the drill string **10** and allowing for vertical movement of the top drive with a traveling block **6** of the hoist. The frame of the top drive **5** may be suspended from the derrick **3** by the traveling block **6**. A Kelly valve **11** may be connected to a quill of a top drive **5**. The quill may be torsionally driven by the top drive motor and supported from the frame by bearings. The top drive **5** may further have an inlet connected to the frame and in fluid communication with the quill.

[0018] The traveling block **6** may be supported by wire rope **7** connected at its upper end to a crown block **8**. The wire rope **7** may be woven through sheaves of the blocks **6**, **8** and extend to drawworks **9** for reeling thereof, thereby raising or lowering the traveling block **6** relative to the derrick **3**. The drilling rig **1***r* may further include a drill string compensator (not shown) to account for heave of the MODU **1***m*. The drill string compensator may be disposed between the traveling block **6** and the top drive **5** (aka hook mounted) or between the crown block **8** and the derrick **3** (aka top mounted).

[0019] An upper end of the drill string **10** may be connected to the Kelly valve **11**, such as by threaded couplings. The drill string **10** may include a bottomhole assembly (BHA) **10***b* and joints of drill pipe **10***p* connected together, such as by threaded couplings. The BHA **10***b* may be connected to the drill pipe **10***p*, such as by threaded couplings, and include a drill bit **15** and one or more drill collars **12** connected thereto, such as by threaded couplings. The drill bit **15** may be rotated **16** by the top drive **5** via the drill pipe **10***p* and/or the BHA **10***b* may further include a drilling motor (not shown) for rotating the drill bit. The BHA **10***b* may further include an instrumentation sub (not shown), such as a measurement while drilling (MWD) and/or a logging while drilling (LWD) sub.

[0020] The fluid transport system **1***t* may include an upper marine riser package (UMRP) **20**, a marine riser **25**, a booster line **27**, and a choke line **28**. The UMRP **20** may include a diverter **21**, a flex joint **22**, a slip (aka telescopic) joint **23**, a tensioner **24**, and a rotating control device (RCD) **26**. A lower end of the RCD **26** may be connected to an upper end of the riser **25**, such as by a flanged connection. The slip joint **23** may include an outer barrel connected to an upper end of the RCD **26**, such as by a flanged connection, and an inner barrel connected to the flex joint **22**, such as by a flanged connection. The outer barrel may also be connected to the tensioner **24**, such as by a tensioner ring.

[0021] The flex joint **22** may also connect to the diverter **21**, such as by a flanged connection. The diverter **21** may also be connected to the rig floor **4**, such as by a bracket. The slip joint **23** may be operable to extend and retract in response to heave of the MODU **1***m* relative to the riser **25** while the tensioner **24** may reel wire rope in response to the heave, thereby supporting the riser **25** from the MODU **1***m* while accommodating the heave. The riser **25** may extend from the PCA **1***p* to the MODU **1***m* and may connect to the MODU via the UMRP **20**. The riser **25** may have one or more buoyancy modules (not shown) disposed therealong to reduce load on the tensioner **24**.

[0022] The PCA **1***p* may be connected to the wellhead **50** adjacently located to a floor **2***f* of the sea **2**. A conductor string **51** may be driven into the seafloor **2***f*. The conductor string **51** may include a housing and joints of conductor pipe connected together, such as by threaded couplings. Once the conductor string **51** has been set, a subsea wellbore **90** may be drilled into the seafloor **2***f* and a casing string **52** may be deployed into the wellbore. The casing string **52** may include a wellhead housing and joints of casing connected together, such as by threaded couplings. The wellhead housing may land in the conductor housing during deployment of the casing string **52**. The casing string **52** may be cemented **91** into the wellbore **90**. The casing string **52** may extend to a depth adjacent a bottom of an upper formation **94***u*. The upper formation **94***u* may be non-productive and a lower formation **94***b* may be a hydrocarbon-bearing reservoir.

[0023] Alternatively, the lower formation **94***b* may be non-productive (e.g., a depleted zone), environmentally sensitive, such as an aquifer, or unstable. Although shown as vertical, the wellbore **90** may include a vertical portion and a deviated, such as horizontal, portion.

[0024] The PCA **1***p* may include a wellhead adapter **40***b*, one or more flow crosses **41***u,m,b*, one or more blow out preventers (BOPs) **42***a,u,b*, a lower marine riser package (LMRP), one or more accumulators **44**, and a receiver **46**. The LMRP may include a control pod **76**, a flex joint **43**, and a connector **40***u*. The wellhead adapter **40***b*, flow crosses **41***u,m,b*, BOPs **42***a,u,b*, receiver **46**, connector **40***u*, and flex joint **43** may each include a housing having a longitudinal bore therethrough and may each be connected, such as by flanges, such that a continuous bore is maintained therethrough. The bore may have drift diameter, corresponding to a drift diameter of the wellhead **50**. The flex joints **23**, **43** may accommodate respective horizontal and/or rotational (aka pitch and roll) movement of the MODU **1***m* relative to the riser **25** and the riser relative to the PCA **1***p*.

[0025] Each of the connector **40***u* and wellhead adapter **40***b* may include one or more fasteners, such as dogs, for fastening the LMRP to the BOPs **42***a,u,b* and the PCA **1***p* to an external profile of the wellhead housing, respectively. Each of the connector **40***u* and wellhead adapter **40***b* may further include a seal sleeve for engaging an internal profile of the respective receiver **46** and wellhead housing. Each of the connector **40***u* and wellhead adapter **40***b* may be in electric or hydraulic communication with the control pod **76** and/or further include an electric or hydraulic actuator and an interface, such as a hot stab, so that a remotely operated subsea vehicle (ROV) (not shown) may operate the actuator for engaging the dogs with the external profile.

[0026] The LMRP may receive a lower end of the riser **25** and connect the riser to the PCA **1***p*. The control pod **76** may be in electric, hydraulic, and/or optical communication with a programmable logic controller (PLC) **75** and/or a rig controller (not shown) onboard the MODU **1***m* via an umbilical **70**. The control pod **76** may include one or more control valves (not shown) in communication with the BOPs **42***a,u,b* for operation thereof. Each control valve may include an electric or hydraulic actuator in communication with the umbilical **70**. The umbilical **70** may include one or more hydraulic and/or electric control conduit/cables for the actuators. The accumulators **44** may store pressurized hydraulic fluid for operating the BOPs **42***a,u,b*. Additionally, the accumulators **44** may be used for operating one or more of the other components of the PCA **1***p*. The PLC **75** and/or rig controller may operate the PCA **1***p* via the umbilical **70** and the control pod **76**.

[0027] A lower end of the booster line **27** may be connected to a branch of the flow cross **41***u* by a shutoff valve **45***a*. A booster manifold may also connect to the booster line lower end and have a prong connected to a respective branch of each flow cross **41***m,b*. Shutoff valves **45***b,c* may be disposed in respective prongs of the booster manifold. Alternatively, a separate kill line (not shown) may be connected to the branches of the flow crosses **41***m,b* instead of the booster manifold. An upper end of the booster line **27** may be connected to an outlet of a booster pump (not shown). A lower end of the choke line **28** may have prongs connected to respective second branches of the flow crosses **41***m,b*. Shutoff valves **45***d,e* may be disposed in respective prongs of the choke line lower end.

[0028] A pressure sensor **47***a* may be connected to a second branch of the upper flow cross **41***u*. Pressure sensors **47***b,c* may be connected to the choke line prongs between respective shutoff valves **45***d,e* and respective flow cross second branches. Each pressure sensor **47***a-c* may be in data communication with the control pod **76**. The lines **27**, **28** and umbilical **70** may extend between the MODU **1***m* and the PCA **1***p* by being fastened to brackets disposed along the riser **25**. Each shutoff valve **45***a-e* may be automated and have a hydraulic actuator (not shown) operable by the control pod **76**.

[0029] Alternatively, the umbilical may be extend between the MODU and the PCA independently of the riser. Alternatively, the valve actuators may be electrical or pneumatic.

[0030] The fluid handling system **1***h* may include a return line **29**, mud pump **30**, a solids separator, such as a shale shaker **33**, one or more flow meters **34***d,r*, one or more pressure sensors **35***d,r*, a variable choke valve, such as returns choke **36**, a supply line **37***p,h*, and a reservoir for drilling fluid **60***d*, such as a tank. A lower end of the return line **29** may be connected to an outlet **26***o* of the RCD **26** and an upper end of the return line may be connected to an inlet of the mud pump **30**. The returns pressure sensor **35***r*, returns choke **36**, returns flow meter **34***r*, and shale shaker **33** may be assembled as part of the return line **29**. A lower end of standpipe **37***p* may be connected to an outlet of the mud pump **30** and an upper end of Kelly hose **37***h* may be connected to an inlet of the top drive **5**. The supply pressure sensor **35***d* and supply flow meter **34***d* may be assembled as part of the supply line **37***p,h*.

[0031] The returns choke **36** may include a hydraulic actuator operated by the PLC **75** via a hydraulic power unit (HPU) (not shown). The returns choke **36** may be operated by the PLC **75** to maintain backpressure in the riser **25**. Each pressure sensor **35***d,r* may be in data communication with the PLC **75**. The returns pressure sensor **35***r* may be operable to measure backpressure exerted by the returns choke **36**. The supply pressure sensor **35***d* may be operable to measure standpipe pressure.

[0032] Alternatively, the choke actuator may be electrical or pneumatic.

[0033] The returns flow meter **34***r* may be a mass flow meter, such as a Coriolis flow meter, and may be in data communication with the PLC **75**. The returns flow meter **34***r* may be connected in the return line **29** downstream of the returns choke **36** and may be operable to measure a flow rate of the drilling returns **60***r*. The supply **34***d* flow meter may be a volumetric flow meter, such as a Venturi flow meter and may be in data communication with the PLC **75**. The supply flow meter **34***d* may be operable to measure a flow rate of drilling fluid **60***d* supplied by the mud pump **30** to the drill string **10** via the top drive **5**. The PLC **75** may receive a density measurement of the drilling fluid **60***d* from a mud blender (not shown) to determine a mass flow rate of the drilling fluid from the volumetric measurement of the supply flow meter **34***d*.

[0034] Alternatively, the supply flow meter **34***d* may be a mass flow meter or a stroke counter of the mud pump **30**.

[0035] To conduct a drilling operation, the mud pump **30** may pump drilling fluid **60***d* from the drilling fluid tank, through the pump outlet, standpipe **37***p* and Kelly hose **37***h* to the top drive **5**. The drilling fluid **60***d* may include a base liquid. The base liquid may be refined or synthetic oil, water, brine, or a water/oil emulsion. The drilling fluid **60***d* may further include solids dissolved or suspended in the base liquid, such as organophilic clay, lignite, and/or asphalt, thereby forming a mud.

[0036] The drilling fluid **60***d* may flow from the Kelly hose **37***h* and into the drill string **10** via the top drive **5** and open Kelly valve **11**. The drilling fluid **60***d* may flow down through the drill string **10** and exit the drill bit **15**, where the fluid may circulate the cuttings away from the bit and return the cuttings up an annulus **95** formed between an inner surface of the casing **91** or wellbore **90** and an outer surface of the drill string **10**. The returns **60***r* (drilling fluid **60***d* plus cuttings) may flow through the annulus **95** to the wellhead **50**. The returns **60***r* may continue from the wellhead **50** and into the riser **25** via the PCA **1***p*. The returns **60***r* may flow up the riser **25** to the RCD **26**. The returns **60***r* may be diverted by the RCD **26** into the return line **29** via the RCD outlet **26***o*. The returns **60***r* may continue through the returns choke **36** and the flow meter **34***r*. The returns **60***r* may then flow into the shale shaker **33** and be processed thereby to remove the cuttings, thereby completing a cycle. As the drilling fluid **60***d* and returns **60***r* circulate, the drill string **10** may be rotated **16** by the top drive **5** and lowered by the traveling block **6**, thereby extending the wellbore **90** into the lower formation **94***b*.

[0037] The PLC **75** may be programmed to operate the returns choke **36** so that a target bottomhole pressure (BHP) is maintained in the annulus **95** during the drilling operation. The target BHP may be selected to be within a drilling window defined as greater than or equal to a minimum threshold pressure, such as pore pressure, of the lower formation **94***b* and less than or equal to a maximum threshold pressure, such as fracture pressure, of the lower formation, such as an average of the pore and fracture BHPs.

[0038] Alternatively, the minimum threshold may be stability pressure and/or the maximum threshold may be leakoff pressure. Alternatively, threshold pressure gradients may be used instead of pressures and the gradients may be at other depths along the lower formation **94***b* besides bottomhole, such as the depth of the maximum pore gradient and the depth of the minimum fracture gradient. Alternatively, the PLC **75** may be free to vary the BHP within the window during the drilling operation.

[0039] A static density of the drilling fluid **60***d* (typically assumed equal to returns **60***r*; effect of cuttings typically assumed to be negligible) may correspond to a threshold pressure gradient of the lower formation **94***b*, such as being equal to a pore pressure gradient. During the drilling operation, the PLC **75** may execute a real time simulation of the drilling operation in order to predict the actual BHP from measured data, such as standpipe pressure from sensor **35***d*, mud pump flow rate from the supply flow meter **34***d*, wellhead pressure from any of the sensors **47***a-c*, and return fluid flow rate from the return flow meter **34***r*. The PLC **75** may then compare the predicted BHP to the target BHP and adjust the returns choke **36** accordingly.

[0040] Alternatively, a static density of the drilling fluid **60***d* may be slightly less than the pore pressure gradient such that an equivalent circulation density (ECD) (static density plus dynamic friction drag) during drilling is equal to the pore pressure gradient. Alternatively, a static density of the drilling fluid **60***d* may be slightly greater than the pore pressure gradient.

[0041] During the drilling operation, the PLC **75** may also perform a mass balance to monitor for a kick (not shown) or lost circulation (not shown). As the drilling fluid **60***d* is being pumped into the wellbore **90** by the mud pump **30** and the returns **60***r* are being received from the return line **29**, the PLC **75** may compare the mass flow rates (i.e., drilling fluid flow rate minus returns flow rate) using the respective flow meters **34***d,r*. The PLC **75** may use the mass balance to monitor for formation fluid (not shown) entering the annulus **95** and contaminating the returns **60***r* or returns entering the formation **94***b*.

[0042] Alternatively, the return line **29** may further include a gas detector (not shown) assembled as part thereof and the gas detector may capture and analyze samples of the returns **60***r* as an additional safeguard for kick detection during drilling. The gas detector may include a probe having a membrane for sampling gas from the returns **60***r*, a gas chromatograph, and a carrier system for delivering the gas sample to the chromatograph.

[0043] Upon detection of a kick or lost circulation, the PLC **75** may take remedial action, such as diverting the flow of returns **60***r* from an outlet of the returns flow meter **34***r* to a degassing spool (not shown). The degassing spool may include automated shutoff valves at each end and a mud-gas separator (MGS). A first end of the degassing spool may be connected to the return line **29** between the returns flow meter **34***r* and the shaker **33** and a second end of the degasser spool may be connected to an inlet of the shaker. The MGS may include an inlet and a liquid outlet assembled as part of the degassing spool and a gas outlet connected to a flare or a gas storage vessel. The PLC **75** may also adjust the returns choke **36** accordingly, such as tightening the choke in response to a kick and loosening the choke in response to loss of the returns.

[0044] Alternatively, the booster pump may be operated during drilling to compensate for any size discrepancy between the riser annulus and the casing/wellbore annulus and the PLC may account for boosting in the BHP control and mass balance using an additional flow meter. Alternatively, the PLC **75** may estimate a mass rate of cuttings (and add the cuttings mass rate to the intake sum) using a rate of penetration (ROP) of the drill bit or a mass flow meter may be added to the cuttings chute of the shaker and the PLC may directly measure the cuttings mass rate.

[0045] Alternatively, the RCD **26** may be used with a riserless drilling system. The RCD **26** may then be assembled as part of a riserless package connected to the annular BOP **47***a* and the return line **29** and RCD umbilical **71** may extend from the riserless package to the MODU **1***m*. Alternatively, the LMRP may further include a returns pump. Alternatively, the drilling system may be dual gradient including a lifting fluid pump or compressor connected to the LMRP.

[0046] FIG. **2** illustrates the RCD **26**. The RCD **26** may include a docking station, a bearing assembly **110**, and a tachometer **200**. The docking station may be located adjacent to the waterline **2***s* and may be submerged. The docking station may include the outlet **260** (not shown, see FIG. **1**A), an interface **26***i* (not shown, see FIG. **1**A), a housing **101**, and a latch **102**, **103**, **105**. The housing **101** may be tubular and include one or more sections **101***a-c* connected together, such as by flanged connections. The housing **101** may further include an upper flange **104***u* connected to an upper housing section **101***a*, such as by welding, and a lower flange **104***f* connected to a lower housing section **101***c*, such as by welding. The upper flange **104***u* may connect the docking station to the slip joint **23** and the lower flange may connect the housing **101** to the outlet **26***o*.

[0047] The latch **102**, **103**, **105** may include a hydraulic actuator, such as a piston **102**, one or more (two shown) fasteners, such as dogs **103**, and a body **105**. The latch body **105** may be connected to the housing **101**, such as by threaded couplings. A piston chamber may be formed between the latch body **105** and a mid housing section **101***b*. The latch body **105** may have openings formed through a wall thereof for receiving the respective dogs **103**. The latch piston **102** may be disposed in the piston chamber and may carry seals isolating an upper portion of the chamber from a lower portion of the chamber. A cam surface may be formed on an inner surface of the piston **102** for radially displacing the dogs **103**. The latch body **105** may further have a landing shoulder formed in an inner surface thereof for receiving a protective sleeve (not shown) or the bearing assembly **110**. The protective sleeve may be installed for operation of the drilling system is in an overbalanced mode.

[0048] Hydraulic passages (not shown) may be formed through the mid housing section **101***b* and may provide fluid communication between the interface **26***i* and respective portions of the hydraulic chamber for selective operation of the piston **103**. An RCD umbilical **71** (not shown, see FIG. **1**A) may have hydraulic conduits and may provide fluid communication between the RCD interface **26***i* and the HPU of the PLC **75**.

[0049] The bearing assembly **110** may include a bearing pack **111**, a housing seal assembly **113**, **114**, one or more strippers **115***u,b*, and a catch, such as a sleeve **112**. The upper stripper **115***u* may include a gland **116***g*, an upper retainer **116***u*, and a seal **120***u*. The gland **116***g* and the upper retainer **116***u* may be connected together, such as by threaded couplings. The upper stripper seal **120***u* may be longitudinally and torsionally connected to the upper retainer **116***u*, such as by fasteners (not shown). The gland **116***g* may be longitudinally and torsionally connected to a rotating mandrel **111***m* of the bearing pack **111**, such as by threaded couplings. The lower stripper **115***b* may include a lower retainer **116***b* and a seal **120***b*. The lower stripper seal **120***b* may be longitudinally and torsionally connected to the lower retainer **116***b*, such as by fasteners (not shown). The lower retainer **116***b* may be longitudinally and torsionally connected to the rotating mandrel **111***m*, such as by threaded couplings.

[0050] Each stripper seal **120***u,b* may be directional and oriented to seal against the drill pipe **10***p* in response to higher pressure in the riser **25** than the UMRP **20** (components thereof above the RCD **26**). Each stripper seal **120***u,b* may have a conical shape for fluid pressure to act against a respective tapered surface **119***u,b* thereof, thereby generating sealing pressure against the drill pipe **10***p*. Each stripper seal **120***u,b* may have an inner diameter slightly less than a pipe diameter of the drill pipe **10***p* to form an interference fit therebetween. Each stripper seal **120***u,b* may be made from a flexible material, such as an elastomer or elastomeric copolymer, to accommodate and seal against threaded couplings of the drill pipe **10***p* having a larger tool joint diameter.

[0051] The drill pipe **10***p* may be received through a bore of the bearing assembly **110** so that the stripper seals **120***u,b* may engage the drill pipe. The stripper seals **120***u,b* may provide a desired barrier in the riser **25** either when the drill pipe **10***p* is stationary or rotating. The lower stripper seal **120***b* may be exposed to the returns **60***r* to serve as the primary seal. The upper stripper seal **120***u* may be idle as long as the lower stripper seal **120***b* is functioning. Should the lower stripper seal **120***b* fail, the returns **60***r* may leak therethrough and exert pressure on the upper stripper seal **120***u* via an annular fluid passage **121** formed between the bearing mandrel **111***m* and the drill pipe **10***p*.

[0052] The bearing pack **111** may support the strippers **115***u,b* from the catch sleeve **112** such that the strippers may rotate relative to the housing **101** (and the catch sleeve). The bearing pack **111** may include one or more radial bearings, one or more thrust bearings, and a self contained lubricant system. The lubricant system may include a reservoir having a lubricant, such as bearing oil, and a balance piston in communication with the returns **60***r* for maintaining oil pressure in the reservoir at a pressure equal to or slightly greater than the returns pressure. The bearing pack **111** may be disposed between the strippers **115***u,b* and be housed in and connected to the catch sleeve **112**, such as by threaded couplings and/or fasteners.

[0053] The catch sleeve **112** may have a landing shoulder and a catch profile formed in an outer surface thereof. The bearing assembly **110** may be fastened to the housing **101** by engagement of the dogs **103** with the catch profile of the catch sleeve **112**. The housing seal assembly **113**, **114** may include a body **113** carrying one or more seals, such as o-rings, and a retainer **114**. The retainer **114** may be connected to the sleeve **112**, such as by threaded couplings (not shown), and the seal body **113** may be trapped between a shoulder of the catch sleeve **112** and the retainer **114**. The housing seals may isolate an annulus formed between the housing **101** and the bearing assembly **110**. The catch sleeve **112** may be torsionally coupled to the housing **101**, such as by seal friction. The upper retainer **116***u* may have a landing shoulder and a catch profile formed in an inner surface thereof for retrieval of the bearing assembly **110** by a running tool (not shown).

[0054] Alternatively, each of the housing **101** and the sleeve **112** may have mating anti-rotation profiles. Alternatively, each stripper seal **120***u,b* inner diameter may be equal to or slightly greater than the pipe diameter. Alternatively, the latch may include a spring instead of or in addition to one of the hydraulic ports. Alternatively, the latch actuator may be electric or pneumatic instead of hydraulic. Alternatively, the bearing assembly **110** may be non-releasably connected to the housing **101**. Alternatively, the docking station may be located above the waterline **2***s* and/or along the UMRP **20** at any other location besides a lower end thereof. Alternatively, the docking station may be located at an upper end of the UMRP **20** and the slip joint **23** and bracket connecting the UMRP to the rig may be omitted or the slip joint may be locked instead of being omitted. Alternatively, the docking station may be assembled as part of the riser **25** at any location therealong or as part of the PCA **1***p*.

[0055] Alternatively, an active seal RCD may be used. The active seal RCD may include one or more bladders (not shown) instead of the stripper seals and may be inflated to seal against the drill pipe by injection of inflation fluid. The active seal RCD bearing assembly may also serve as a hydraulic swivel to facilitate inflation of the bladders. Alternatively, the active seal RCD may include one or more packings and the bearing assembly may have one or pistons for selectively engaging the packings with the drill string.

[0056] FIGS. **3**A and **3**B illustrate the tachometer **200**. FIG. **4**A illustrates a pocket **117** formed in the upper retainer **116***u* for receiving a probe **210** of the tachometer **200**. FIGS. **4**B and **4**C illustrate a pocket **118** formed in the upper flange **104***u* for receiving a base **201** of the tachometer **200**. FIG. **5** illustrates the probe **210**.

[0057] The tachometer **200** may include the base **201** and the probe **210**. The base **201** may include an electronics package **203** and a wireless data coupling, such as an antenna **202** and a receiver of the electronics package. The receiver of the electronics package **203** may include an amplifier and a demodulator for processing a signal received from the probe **210**. The electronics package **203** may be in communication with the interface **26***i* via leads or jumper cable (not shown) and further include a relay, such as a modem, for transmitting data received from the probe **210** to the PLC **75** via an electric cable of the RCD umbilical **71**. The electronics package **203** may also be supplied with power by the electric cable of the RCD umbilical **71**.

[0058] The base **201** may be longitudinally and torsionally connected to the housing **101**, such as by being disposed in the pocket **118** formed in the upper flange **104***u*. The pocket **118** may include a receiver portion **118***r* formed in an outer surface of the upper flange **104***u* and an antenna portion **118***a* formed in an inner surface of the upper flange for receiving the respective electronics package **203** and the antenna **202**. A receiver cover **204***r* may seal and retain the electronics package **203** in the receiver pocket portion **118***r* and an antenna cover **204***a* may seal and retain the antenna **202** in the antenna pocket portion **118***a*. One or more fasteners may connect the receiver cover **204***r* to the upper flange **104***u* and one or more fasteners may connect the antenna cover **204***a* to the upper flange. Leads (not shown) may connect the electronics package **203** to the RCD interface **26***i*.

[0059] Alternatively, the base **201** may include a transmitter and power source for wireless communication with the PLC **75** instead of using the RCD umbilical **75**.

[0060] The probe **210** may include a sensor package **211**, a wireless data coupling, such as an antenna **212** and a transmitter **213**, and a power source **214**. Respective components of the probe **210** may be in electrical communication with each other by leads or a bus. The power source **214** may be a battery. The probe **210** may be longitudinally and torsionally connected to the upper stripper **115***u*, such as by being disposed in the pocket **117** formed in the upper retainer **116***u*. The pocket **117** may include a power portion **117***p*, a transmitter portion **117***t*, and a sensor portion **117***s*, each formed in an upper surface of the upper retainer **116***u*, and an antenna portion **117***a* formed in an outer surface of the upper retainer for receiving respective components of the probe **210**. An upper cover **215***u* may seal and retain the sensor package **211**, transmitter **213**, and power source **214** in the respective pocket portions **117***s,t,p* and an antenna cover **215***a* may seal and retain the antenna **212** in the antenna pocket portion **117***a*. One or more fasteners may connect the upper cover **215***u* to the upper retainer **116***u* and one or more fasteners may connect the antenna cover **215***a* to the upper retainer.

[0061] Alternatively, the probe battery may be omitted and the probe may be powered using wireless power couplings, further using the data couplings as wireless power couplings, or adding a generator to the tachometer **200** utilizing the rotation of the probe relative to the base to generate electricity. The generator may deliver electricity to the probe and may also allow substitution of a capacitor for the probe battery.

[0062] The sensor package **211** may include a microcontroller (MPC) **211***m*, a data recorder **211***d*, a clock (RTC) **211***c*, an analog-digital converter (ADC) **211***a*, a pressure sensor **211***p*, an angular speed sensor **211***r*, a tilt sensor **211***v*, and an angular acceleration sensor **211***t*. The data recorder **211***d* may be a solid state drive. The pressure sensor **211***p* may be in fluid communication with the fluid passage **121** to monitor integrity of the lower stripper **119***b*.

[0063] The sensors **211**r,v,t may each be a single axis accelerometer and may be unidirectional or bidirectional. The accelerometers may be piezoelectric, magnetostrictive, servo-controlled, reverse pendular, or microelectromechanical (MEMS). The tilt sensor **211**v may be oriented along a longitudinal axis of the bearing assembly **110** to measure inclination relative to gravitational direction. Tilting of the bearing assembly **110** may be caused by misalignment of the top drive **5** with the UMRP **20**, which may shorten the lifespan of the RCD **26**. The angular speed sensor **211**r may be oriented along a radial axis of the bearing assembly **110** to measure the centrifugal acceleration due to rotation of the bearing assembly for determining the angular speed. The angular acceleration sensor **211**t may be oriented along a circumferential axis of the bearing assembly **110**. The angular acceleration sensor **211**t is depicted as inclined between the radial and longitudinal axes for two-dimensional illustration.

[0064] Alternatively, the sensor package **211** may include any subset of the sensors **211**p,r,v,t instead of all of the sensors, including a subset of only one thereof. Alternatively, the angular speed **211**r sensor may be a proximity sensor, such as a Hall effect sensor. The sensor package **211** may then have a Hall target and the base **201** may then have a Hall receiver. The frequency of the Hall response may then be monitored to determine angular speed and the amplitude of the Hall response may be monitored to determine eccentricity of the bearing assembly rotation. Alternatively, the angular speed sensor **211**r may be a magnetometer.

[0065] The transmitter **213** may include an amplifier (AMP), a modulator (MOD), and an oscillator (OSC). Raw analog signals from the sensors may be received by the converter **211**a, converted to digital signals, and supplied to the controller **211**m. The controller **211**m may process the converted signals to determine the respective parameters, and send the processed data to the recorder **211**d for later recovery should the wireless data coupling fail. The controller **211**m may also multiplex the processed data and supply the multiplexed data to the transmitter **213**. The transmitter **213** may then condition the multiplexed data and supply the conditioned signal to the antenna **212** for electromagnetic transmission to the base antenna **202**, such as at radio frequency. The base antenna **202** may receive the electromagnetic signal from the probe antenna **212** and supply the received signal to the electronics package **203**. The electronics package **203** may then relay the received signal to the PLC **75** via the RCD umbilical **71**. The probe controller **211**m may iteratively monitor the sensors **211**p,r,t,v during drilling in real time.

[0066] The PLC **75** may display the angular speed, pressure, tilt angle, and angular acceleration for the driller. The PLC **75** may determine both instantaneous angular speed and average angular speed (i.e., using five or more instantaneous measurements) and may display one or both for the driller. The PLC **75** may also compare the angular speed to the angular speed of the drill string **10** (received from the top drive **5**) to determine if the bearing assembly **110** is slipping relative to the drill string. The PLC **75** may also monitor the sensor data to determine vibration of the drill string **10**, such as stick-slip (torsional vibration) from the angular acceleration data, bit-bounce (longitudinal vibration) from the tilt data, and/or whirl (lateral vibration) from the angular speed and angular acceleration data. The PLC **75** may include predetermined criteria for monitoring health of the RCD **26**. The PLC **75** may compare the parameters to the criteria and predict remaining lifespan of the strippers **115**u,b and/or bearing pack **111**. The remaining lifespan of the strippers **115**u,b may be forecasted either collectively or individually and display the prediction to the driller. The PLC **75** may also make recommendations for adjustments to drilling parameters to optimize remaining lifespan of the RCD **26**.

[0067] Additionally, the probe **210** may include an antenna and receiver for receiving telemetry signals from the drill string **10**. The probe **210** may then communicate the signals to the PLC **75** via the base **201**.

[0068] The riser **25** and LMRP **20** may be filled with liquid when the bearing assembly **110** is installed into the docking station for managed pressure drilling. As such, the antennas **202**, **212** may be aligned and adjacently positioned to minimize attenuation of the radio frequency signal transmitted from the probe antenna to the base antenna through the liquid medium. A gap formed between the antennas **202**, **212** may be specified, such as between two to four inches.

[0069] FIGS. **6**A and **6**B illustrate a gyroscope **400** usable with the probe **110**, according to another embodiment of the present disclosure. The gyroscope **400** may be used as the angular speed sensor **211**r instead of the accelerometer, discussed above. The gyroscope **400** may have an inner frame **402** surrounded by an outer frame **404**. Inner frame **402** may be dithered along a dither axis **410** through the use of a dither driver **406**. The dither driver **406** may be formed with combs of drive fingers that interdigitate with fingers on the inner frame **402** and may be driven with alternating voltage signals to produce sinusoidal motion. The voltage signal may be supplied by a modulator (not shown) and the voltage may be supplied at a frequency corresponding to a resonant frequency of the inner frame **402**. The inner frame **402** may have one or more, such as four, elongated and parallel apertures that include the drive fingers. A dither sensor **408** may be formed by one or more, such as four, corners of inner frame **402** having apertures that have dither pick-off fingers for sensing the dithering motion. The sensed dithering motion may be used as feedback control for the dither driver **406**.

[0070] In response to rotation of the bearing assembly **110** (about longitudinal axis thereof, depicted by **412**), inner frame **402** may be caused to move along the Coriolis axis **414**. Since the inner frame **402** may be dithered relative to outer frame **404** while being coupled thereto, the inner frame **402** may drive the outer frame along the Coriolis axis **414**. The gyro **400** may further include a Coriolis sensor **405** for tracking this movement. The Coriolis sensor **405** may include fingers extending from the outer frame **404** along axes parallel to the dither axes and interdigitated with first and second fixed fingers anchored to the substrate. The first fixed fingers may be connected to a first direct voltage source and the second fixed fingers may be connected to a second direct voltage source having a different voltage. As the outer frame **404** moves relative to the fixed fingers, the voltage on the outer frame changes and the size and direction of movement can be determined.

[0071] This sensed Coriolis movement may be communicated to the controller **211**m, which may then determine the angular speed of the bearing assembly **110** as follows. If the dither motion is $x=X \sin(wt)$, the dither velocity is $x'=wX \cos(wt)$, where w is the angular frequency and is directly proportional to the resonant frequency of the inner frame **402** by a factor of 2 pi. In response to an angular rate of motion R about the sensitive axis, a Coriolis acceleration $y''=2Rx'$ is induced along the Coriolis axis **414**. The signal of the acceleration thus has the same angular frequency w as dither velocity x'. By sensing the movement along the Coriolis axis **414**, angular speed R can thus be determined.

[0072] FIG. **6**B shows one-quarter of gyro **400**. The other three quarters of the gyro **400** may be substantially identical to the portion shown. A dither flexure mechanism **430** may be coupled between inner frame **402** and outer frame **404** to allow inner frame **402** to move along dither axis **410**, but to prevent inner frame **402** from moving along Coriolis axis **414** relative to outer frame **404**, but rather to move along Coriolis axis **414** only with outer frame **404**.

[0073] The dither flexure **430** may have a dither lever arm **432** connected to the outer frame **404** through a dither main flexure **434**, and connected to inner frame **402** through pivot flexures **436** and **438**. Identical components may be connected through a small central beam **440** to lever arm **432**. A central beam **440** may encourage the lever arm **432** and the corresponding lever arm connected on the other side of beam **440** to move in the same direction along dither axis **410**. At the other end of lever arm **432**, flexures **436** and **438** extend toward inner frame **402** at right angles to each other to create a pivot point near the junction of flexures **436** and **438**.

[0074] Flexures **436** and **438** may be made long, thereby reducing tension for a given dither displacement. The flexures **436** and **438** may be connected to inner frame **402** at points adjacent to the center of the inner frame in the length and width directions. The two pivoting flexures may be perpendicular to each other. To keep lever arm **432** stiff compared to central beam **440**, the lever arm **432** may be made wide.

[0075] To reduce the mass of the outer frame **404**, a number of holes **444** maybe cut out of outer frame **404**. While the existence of holes **444** reduces the mass, they do not have any substantial effect on the stiffness because they create, in effect, a number of connected I-beams. The outer frame **404** may be coupled and anchored to the substrate through a connection mechanism **450** and a pair of anchors **452** that are connected together. Connection mechanism **450** may include plates **453** and **454** connected together with short flexures **456** and **458**, which are perpendicular to each other.

[0076] The masses and flexures may be made from a semiconductor, such as structural polysilicon. The pivot points may be defined by flexures **456** and **458** so that outer frame **404** can easily move perpendicular to the dither motion by pivoting plate **453** relative to plate **454** thereby giving a single bending action to flexures **456** and **458** at the ends and in the center. To accomplish this, the center beam **440** may be colinear with the pivot points.

[0077] Alternatively, the gyroscope may be any (other) embodiment discussed and/or illustrated in U.S. Pat. No. 6,122,961, which is herein incorporated by reference in its entirety.

[0078] FIG. **7** illustrates an RCD **326** having a data sub **350**, according to another embodiment of the present disclosure. The RCD **326** may be similar to the RCD **26** except for the inclusion of the data sub **350**. The data sub **350** may include a base **351** and a probe **360**. The base **351** may include an electronics package **353** (similar to electronics package **203**) and a wireless data coupling, such as an antenna **352** and a receiver of the electronics package. The base **351** may be longitudinally and torsionally connected to the housing **301**, such as by the receiver **353** being disposed in a pocket formed in an upper flange of a lower housing section **301***c* and the antenna **352** being disposed in a groove formed in an inner surface of the lower housing section. A jumper cable (not shown) may connect the receiver **353** to the RCD interface **26***i*.

[0079] The probe **360** may include the sensor package (not shown), a wireless data coupling, such as an antenna **362**, the transmitter **363** (similar to transmitter **213**), and the power source (not shown, see power source **214**). The sensor package of the probe **360** may be similar to the sensor package **211** except for the substitution of a temperature sensor **311***t* for the pressure sensor **211***p*. The temperature sensor **311***t* may be in fluid communication with the bearing lubricant reservoir to monitor performance of the bearing assembly **111**. Components of the probe **360** may be in electrical communication with each other by leads or a bus. The probe **360** may be longitudinally and torsionally connected to the catch sleeve **112**, such as by the sensor package, transmitter, and power source being disposed in a pocket formed in a seal retainer **314** (the seal retainer may be connected to the sleeve **112**, such as by threaded couplings) and the antenna **352** being disposed in a groove formed in an inner surface of the seal retainer.

[0080] Since the probe **360** remains torsionally still relative to the strippers, the antennas may be circumferential instead of corresponding to a shape of the respective pocket. The PLC **75** may utilize the still measurements from the probe **360** to distinguish vibration components from the tachometer measurements. Further, the tilt measurement from the still probe **360** may be utilized by the PLC **75** in favor of the tachometer tilt measurement. The still probe **360** may also be utilized during installation of the bearing assembly **310**. The bearing assembly **310** may be installed by being carried on the running tool assembled as part of the drill string **10**. As the bearing assembly **310** enters the housing **301**, the probe **360** may emit a homing signal. Detection of the homing signal by the tachometer receiver may establish a first reference point thereto and detection of the homing signal by the data sub receiver may establish a second reference point thereto. Further, the homing signals may be time stamped and detection lag time may be used from one or both receivers to pinpoint location of the bearing assembly **310** relative to the housing **110**.

[0081] While the foregoing is directed to embodiments of the present disclosure, other and further embodiments of the disclosure may be devised without departing from the basic scope thereof, and the scope of the invention is determined by the claims that follow.

1. A rotating control device (RCD) for use with an offshore drilling unit, comprising:
- a tubular housing having a flange formed at each end thereof;
- a stripper seal for receiving and sealing against a tubular;
- a bearing for supporting rotation of the stripper seal relative to the housing;
- a retainer for connecting the stripper seal to the bearing; and
- a tachometer, comprising:
  - a probe connected to the retainer and comprising:
    - a tilt sensor;
    - an angular speed sensor;
    - an angular acceleration sensor;
    - a first wireless data coupling; and
    - a microcontroller operable to receive measurements from the sensors and to transmit the measurements to a base using the first wireless data coupling;

the base connected to the housing and comprising:
a second wireless data coupling operable to receive the measurements; and
an electronics package in communication with the second wireless data coupling and operable to relay the measurements to the offshore drilling unit.

2. The RCD of claim **1**, wherein:
the stripper seal is an upper stripper seal,
the retainer is an upper retainer, and
the RCD further comprises a lower stripper seal and a lower retainer for connecting the lower stripper seal to the bearing.

3. The RCD of claim **2**, wherein the tachometer further comprises a pressure sensor in communication with a pathway for measuring pressure between the stripper seals.

4. The RCD of claim **1**, wherein the probe further comprises a battery.

5. The RCD of claim **1**, wherein the sensors are accelerometers.

6. The RCD of claim **1**, wherein the angular speed sensor is a gyroscope, comprising:
an outer frame;
an inner frame;
a dither driver operable to dither the inner frame relative to the outer frame; and
a Coriolis sensor for tracking movement of the outer frame.

7. The RCD of claim **1**, wherein:
the stripper seal, bearing, and retainer are part of a bearing assembly,
the bearing is part of a bearing pack having a self contained lubricant system,
the bearing assembly further comprises a catch sleeve,
the housing is part of a docking station, and
the docking station further comprises a latch operable to engage the catch sleeve, thereby fastening the bearing assembly to the docking station.

8. The RCD of claim **7**, further comprising a data sub, comprising:
a second probe connected to the catch sleeve and comprising:
a second tilt sensor;
a temperature sensor in fluid communication with the lubricant system;
a third wireless data coupling; and
a second microcontroller operable to receive measurements from the second tilt and temperature sensors and to transmit the measurements to a second base using the third wireless data coupling;
the second base connected to the housing and comprising:
a fourth wireless data coupling operable to receive the measurements; and
an electronics package in communication with the fourth wireless data coupling and operable to relay the measurements to the offshore drilling unit.

9. The RCD of claim **8**, wherein:
the second tilt sensor is a first accelerometer,
the second probe further comprises second and third accelerometers, and
the accelerometers are triaxially oriented.

10. A method for drilling a subsea wellbore using the RCD of claim **1**, comprising:
injecting drilling fluid down a drill string while rotating the drill string having a drill bit located at a bottom of the subsea wellbore,
wherein the RCD is engaged with the drill string, thereby diverting returns from the wellbore to an outlet of the RCD; and
monitoring the measurements while drilling the wellbore.

11. The method of claim **10**, wherein the measurements are monitored by forecasting a remaining lifespan of the stripper seal.

12. The method of claim **11**, wherein the lifespan is forecast using the tilt measurement.

13. The method of claim **11**, further comprising adjusting a drilling parameter to optimize the remaining lifespan.

14. The method of claim **10**, wherein the measurements are monitored by comparing the angular speed of the RCD to the angular speed of the drill string.

15. The method of claim **10**, wherein the measurements are monitored by determining vibration of the drill string.

16. The method of claim **15**, wherein the determined vibration includes stick-slip, bit-bounce, and whirl.

17. The method of claim **10**, further comprising exerting backpressure on the returns.

18. The method of claim **10**, further comprising, while drilling the wellbore:
measuring a flow rate of the drilling fluid;
measuring a flow rate of the returns; and
comparing the returns flow rate to the drilling fluid flow rate to ensure control of an exposed formation adjacent to the wellbore.

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