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(54) **EMERGENCY SHUTDOWN AND DISCONNECT OF SUBSEA TOOLS USING ORIENTATION**

(57) Initiating an emergency shutdown and disconnect (ESD) sequence for subsea well systems includes measuring an angle of the tubular member (22) with respect to vertical using a sensor (96) that is coupled to the tubular member (22). It will also be determined by a controller (48) whether the angle exceeds a predetermined threshold for a predetermined amount of time. The ESD sequence is initiated when the angle exceeds the predetermined threshold for the predetermined amount of time.

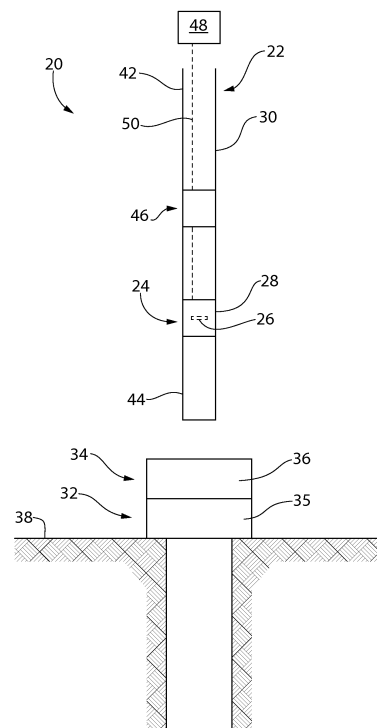


FIG. 1

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Description

Background

[0001] In subsea landing string systems ("SLSS"), a tubular string may extend downward from a vessel (e.g., a ship) floating on the surface of the water to a wellhead positioned on the seafloor. The tubular string may be affected by weather conditions. For example, during bad weather, the wind and/or the waves may cause the vessel to move around on the surface of the water. The upper end of the tubular string moves together with the vessel. The lower end of the tubular string, however, remains stationary, as it is coupled to the wellhead. Thus, the tubular string may tilt with respect to vertical, which may exert a force on the tubular string. When the force exceeds a predetermined threshold, a blow-out preventer ("BOP") positioned near the wellhead may be automatically actuated, causing one or more rams of the BOP to cut the tubular string to alleviate the force and prevent the leakage of hydrocarbons into the water. Cutting the tubular string, however, increases the time to restart operations.

[0002] In some instances, an emergency shutdown and disconnect ("ESD") system may be coupled to the wellhead. If a user on the vessel determines that the force on the tubular string is approaching or exceeding the predetermined threshold, the user may actuate the ESD, causing the ESD system to shut-in the well and unlatch the tubular string from the wellhead. The tubular string may then drift with the vessel. If the user actuates the ESD system quickly enough, the ESD system may unlatch the tubular string before the BOP is actuated, preserving the tubular string and reducing the time to restart operations. However, if the user does not actuate the ESD system quickly enough, the BOP may cut the tubular string.

Summary

[0003] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0004] A method for initiating an emergency shutdown and disconnect (ESD) sequence is disclosed. The method includes measuring an angle of the tubular member with respect to vertical using a sensor that is coupled to the tubular member. The method also includes determining whether the angle exceeds a predetermined threshold for a predetermined amount of time. The ESD sequence is initiated when the angle exceeds the predetermined threshold for the predetermined amount of time.

[0005] In another embodiment, the method includes measuring a first angle of the tubular member using a first sensor that is coupled to the tubular member at a

first location and measuring a second angle of the tubular member using a second sensor that is coupled to the tubular member at a second location that is different than the first location. The method also includes determining whether the first angle exceeds a first predetermined threshold a first predetermined number of times that is greater than one, or the second angle exceeds a second predetermined threshold a second predetermined number of times that is greater than one. The method also includes initiating the ESD sequence when the first angle exceeds the first predetermined threshold the first predetermined number of times or when the second angle exceeds the second predetermined threshold the second predetermined number of times.

[0006] A system is also disclosed. The system includes a tubular member, and instrumentation module, and a controller. The instrumentation module is coupled to the tubular member, and the instrumentation module includes a sensor that measures an angle of the tubular member. The controller determines whether the angle exceeds a predetermined threshold for a predetermined amount of time, a predetermined number of times that is greater than one, or both. In response to the angle exceeding the predetermined threshold for the predetermined amount of time, the predetermined number of times that is greater than one, or both, the controller disconnects at least a portion of the tubular member from subsea well equipment, shut-in a well, or both.

Brief Description of the Drawings

[0007] The accompanying drawings, which are incorporated in and constitute a part of this specification, illustrate embodiments of the present teachings and together with the description, serve to explain the principles of the present teachings. In the figures:

Figure 1 illustrates a schematic view of a well system, according to an embodiment.

Figure 2 illustrates a more detailed schematic view of the well system, according to an embodiment.

Figure 3 illustrates a perspective view of an illustrative instrumentation module in the well system, according to an embodiment.

Figure 4 illustrates a schematic view of an inclination angle between the tubular member and a vertical axis, according to an embodiment.

Figure 5A illustrates a schematic view of a tubular member extending between the vessel and the blow-out preventer in shallow water, according to an embodiment.

Figure 5B illustrates a schematic view of the tubular member extending between the vessel and the blow-out preventer in deep water, according to an embodiment.

Figure 5C illustrates a schematic view of the tubular member extending between the vessel and the blow-out preventer in deep water showing greater local-

ized bending closer to the blowout preventer, according to an embodiment.

Figure 5D illustrates a schematic view of the tubular member extending between the vessel and the blowout preventer in deep water showing greater localized bending closer to the vessel, according to an embodiment.

Figure 6 illustrates a flowchart of a method for disconnecting a tubular member from subsea well equipment, according to an embodiment.

Figure 7 illustrates a perspective view of a housing for the instrumentation module 46, according to an embodiment.

Figure 8 illustrates a perspective view of another housing for the instrumentation module, according to an embodiment.

Figure 9 illustrates a perspective view of another housing for the instrumentation module, according to an embodiment.

Figure 10 illustrates a schematic view of a computing system for performing at least a portion of the method, according to an embodiment.

Detailed Description

[0008] Reference will now be made in detail to embodiments, examples of which are illustrated in the accompanying figures. In the following detailed description, numerous specific details are set forth in order to provide a thorough understanding of the present disclosure. However, it will be apparent to one of ordinary skill in the art that the system and method disclosed herein may be practiced without these specific details.

[0009] Figure 1 illustrates a schematic view of a well system 20. The well system 20 may be or include a tubular member 22. The tubular member 22 may be or include at least a portion of a landing string, a riser string, a drill string, a completion string, a coiled tubing, a wireline, a measurement-while-drilling ("MWD") tool, a logging-while-drilling ("LWD") tool, or the like. In one example, the tubular member 22 may be a subsea landing string for use in offshore well applications. The tubular member 22 may be used to perform completion installation, tubing hanger installation, completion testing, flow testing, well intervention (e.g., removal/retrieval of completions, tubing hangers, etc.), and/or other subsea well operations to be performed from a floating vessel or other surface vessel or structure. The tubular member 22 may include a latch assembly 24 that enables disconnection (i.e., separation) of the tubular member 22 at the latch assembly 24. In at least one embodiment, the latch assembly 24 may be configured to subsequently re-connect the disconnected portions of the tubular member 22.

[0010] In at least one embodiment, the latch assembly 24 may include a latch mandrel having a weakened area 26. The weakened area 26 may be positioned in a housing 28 that protects the latch assembly 24 against bending loads while still allowing the latch assembly 24 to

disconnect and separate upon application of a predetermined tensile load on the latch assembly 24. The weakened area 26 may allow the tubular member 22 to separate into an upper portion 42 and a lower portion 44 upon application of the predetermined tensile load. For example, the predetermined tensile load may be applied by providing a sufficient lifting force on the tubular member 22 from the surface; however, the tensile load also may also or instead be applied by hydraulic pistons or other mechanisms. In another example, the latch assembly 24 may include a release mechanism (e.g. a collet or other releasable assembly), which may enable a controlled disconnect of the tubular member 22 at the latch assembly 24. In this latter example, the controlled disconnect may be accomplished via a suitable hydraulic actuator or other type of actuator constructed to enable selective separation of the release mechanism and thus release of an upper latch assembly portion from a lower latch assembly portion.

[0011] As shown in Figure 1, the tubular member 22 may be configured to be introduced into a well 32. For example, the tubular member 22 may be received by subsea well equipment 34, such as a subsea wellhead 35. The wellhead 35 may include or be coupled with a blowout preventer ("BOP") 36. The subsea wellhead 35 may be located along a seafloor 38 and above the well 32.

[0012] The well system (e.g., the tubular member 22) may also include one or more instrumentation modules (one is shown: 46), which measures one or more parameters. As discussed in greater detail below, when the parameter(s) exceed a predetermined threshold, the well 32 may be shut-in and/or the tubular member 22 may be separated at the latch assembly 24. This may be referred to as an emergency shut-down and disconnect ("ESD") sequence.

[0013] The well system 20 may also include a controller 48. The instrumentation module 46 may transmit the measured parameters to the controller 48. The controller 48 may be positioned in the tubular member 22 (e.g., in the instrumentation module 46) or at the surface (e.g., on the vessel). The measured parameters may be transmitted through a communication line 50, such as an electrical line or optical fiber. In other embodiments, the measured parameters may be transmitted as electromagnetic, hydraulic, mechanical, or acoustic signals. In response to the measured parameters, the controller 48 may autonomously initiate the ESD sequence (e.g., by transmitting one or more signals through the communication line 50).

[0014] Figure 2 illustrates a more detailed schematic view of the well system 20, according to an embodiment. As shown in Figure 2, the subsea well equipment 34 may include the BOP 36 mounted above the wellhead 35 and above a tree 52. The tree 52 may be or include a horizontal tree having a production line 54 and an annulus line 56. The BOP 36 may also include at least one pipe ram 58 (e.g., a pair of pipe rams 58), and at least one shear ram 60 (e.g., a pair of shear rams 60). The BOP

36 may also include a BOP disconnect 62 and an annular ram 64. A riser 66 may extend upwardly from the subsea well equipment 34 (e.g., upwardly from BOP 36). The tubular member 22 may be positioned within the riser 66.

[0015] In addition to the latch assembly 24 and instrumentation module 46, the tubular member 22 may also include a plurality of valves located above and/or below the latch assembly 24. For example, the valves may include a retainer valve 68 and a bleed valve 70 positioned above the latch assembly 24. The valves also may include a flapper valve 72 and a ball valve 74 positioned below the latch assembly 24. The valves 68, 70, 72, 74 may be used to selectively block or direct fluid flow along an interior of the tubular member 22. As will be appreciated, other types of valves and other arrangements of valves also may be employed to selectively block or direct fluid flow along an interior of the tubular member 22.

[0016] The tubular member 22 also may include a tubing hanger and running tool assembly 76 and a seal assembly 78 (e.g., a packer) positioned below the latch assembly 24. The tubular member 22 may further include a space out sub 80 positioned above the retainer valve 68 and the bleed off valve 70, and a ported joint 81 positioned below the ball valve 74. The latch assembly 24 may also include a shear sub or mandrel 82 that includes the weakened area 26 to facilitate the ESD sequence.

[0017] Figure 3 illustrates a perspective view of the instrumentation module 46, according to an embodiment. The instrumentation module 46 may include a housing 84. The instrumentation module 46 may also include one or more connectors 86 positioned at least partially within the housing 84 for coupling with the communication line 50. The instrumentation module 46 may also include an additional external cable 88 and a plurality of hydraulic bypass tubes 90 that are positioned at least partially within the housing 84. The hydraulic bypass tubes 90 may be coupled to hydraulic stabs 92. The cable 88 and bypass tubes 90 may be enclosed with a protective cover 94. As shown, the instrumentation module 46 has connection ends 97 (e.g. threaded connection ends) that may be coupled to the tubular member 22.

[0018] One or more sensors 96 may be positioned at least partially within and/or be coupled to the housing 84. The sensors 96 may be configured to measure one or more parameters related to the tubular member 22. The parameters may be or include inclination, orientation (e.g., a gyroscope sensor), acceleration (e.g., an accelerometer sensor), tilt, bending, corkscrewing, fatigue, cyclical stress, tension, strain, torque, pressure, temperature, inertial measurements, depth, and the like.

[0019] In one example, the sensors 96 may be configured to measure the angle of the tubular member 22 with respect to at least one axis (e.g., the vertical axis). In another example, the sensors 96 may include three sensors, each configured to measure the angle of the tubular member 22 with respect to a different axis (e.g., X, Y, and Z axes). In another example, the sensors 96 may include three sensors, each configured to measure the

angle of the tubular member 22 with respect to a different axis (e.g., X, Y, and Z axes) over time to detect corkscrewing of the tubular member 22. In another example, the sensors 96 may be configured to measure the angles of the tubular member 22 with respect to one or more axes (e.g., X, Y, and Z axes) over time to derive the cyclical stresses, which may be used to estimate a fatigue level of the tubular member 22. In another example, the sensors 96 may include three accelerometers (e.g., one for each axis), and three gyroscopes (e.g., one for each axis). In another example, the sensors 96 may also include one or more depth sensors that affect priority assigned to the measured angles. The sensors 96 may be coupled with the communication line 50 via the connectors 86. Thus, the measurements from the sensors 96 may be transmitted to the controller 48 via the communication line 50.

[0020] The controller 48 may be or include the SENTREE® system, which is a deep-water control system, available from Schlumberger Corporation, for providing fast acting control of subsea test trees/landing strings. The controller 48 may further include an electro-hydraulic control system, such as the SENTURIAN® system, available from Schlumberger Corporation, which provides electro-hydraulic controls with fast response times and hydraulic power accumulation. This enables the SENTURIAN® portion of the controller 48 to control, for example, the SENTREE® functionality, including closing of valves (e.g., closing of flapper valve 72 and retainer valve 68), as well as actuation of the latch assembly 24 to disconnect the tubular member 22. The controller 48 may be programmable so that the various control system components (e.g., the instrumentation module 46, SENTURIAN®, and SENTREE®), respond automatically when the measured parameters exceed a predetermined threshold so as to initiate the ESD sequence. If, for example, the sensors 96 of the instrumentation module 46 detect an angle that exceeds the predetermined threshold, the controller 48 may autonomously initiate the ESD sequence via, for example, the deep water control and operating systems such as SENTREE® and SENTURIAN®.

[0021] In at least one embodiment, the controller 48 may include an electrical module including at least one microcontroller and at least one data-logger board. The electrical module may receive and process the measurements from the sensors 96. For example, the microcontroller may calculate the angles of the tubular member 22 from the accelerometer and gyro data. The gyro data and an algorithm (e.g., Kalman filter) may be used to improve the estimate by filtering out the effects from non-gravitational acceleration and noise. As mentioned above, the electrical module may use additional data from other sensors 96 (e.g., a depth sensor) to assign weights to the different measured parameters to improve the decision-making process (e.g., by improving measurements and/or calculations). For example, the gravitational acceleration may be different at different depths.

The data-logger board may record the parameters. For example, the data-logger board may record the angles over time. The data-logger board may also record any processed and/or analyzed data, such as the number of stress cycles for fatigue or the values that triggered the ESD sequence so that the operator can investigate afterwards to understand if it is safe to continue. This information may be communicated with the operator when desired via a subsea electrical module ("SEM") or via a direct communication path to the surface. In another embodiment, this information may be checked by the operator after a job to keep track of the wear on the equipment. This information may also be sold to the client.

[0022] The electrical module may interface with the SEM of the subsea control system (e.g., SENTURIAN®). Once the predetermined threshold is exceeded, the electrical module may transmit a signal to the SEM to initiate the ESD. The level/degree of the ESD may be preselected. The electrical module may be powered by surface or subsea sources. The electrical module may communicate using an electrical cable, acoustic telemetry, electromagnetic telemetry, mud pulse telemetry, a fiber optic line, or the like. For example, one or more telemetry modules may be spaced axially-apart along the tubular member 22 to relay data.

[0023] Figure 4 illustrates a schematic view of an inclination angle α between the tubular member 22 and a vertical "Z" axis, according to an embodiment. The sensor(s) 96 may measure the inclination angle α between the tubular member 22 and the vertical axis. The vertical axis may be perpendicular to the seafloor 38. The inclination angle α may be proportional to the tensile stress on the tubular member 22. As described in greater detail below, when the controller 48 determines that the inclination angle α is greater than or equal to the predetermined threshold (e.g., angle), the controller 48 may initiate the ESD sequence. In at least one embodiment, the tubular member 22 may include a plurality of instrumentation modules 46 that are spaced axially-apart along the length of the tubular member 22. This may be done, for example, when the water is deep, and the tubular member 22 is long, because the tubular member 22 may have localized bending that may not be sufficiently measured by a single instrumentation module 46, as described in Figures 5A-5D.

[0024] Figure 5A illustrates a schematic view of the tubular member 22 extending between a vessel 10 and the BOP 36 in shallow water, according to an embodiment. The tubular member 22 may include an upper flex joint 23 that is coupled to the vessel 10 and a lower flex joint 25 that is coupled to the BOP 36. As shown in Figure 5A, the inclination angle α is proximate to the lower flex joint 25. In shallow water (i.e., when the tubular member 22 is short), the tubular member 22 may be less susceptible to local bending.

[0025] Figure 5B illustrates a schematic view of the tubular member 22 extending between the vessel 10 and the BOP 36 in deep water, according to an embodiment.

The lateral distance between the vessel 10 and the BOP 36 is the same in Figures 5A and 5B. However, because the length of the tubular member 22 is longer in Figure 5B, the inclination angle α is less in Figure 5B than in Figure 5A. Thus, in some embodiments, the inclination angle α may decrease as the length of the tubular member 22 increases.

[0026] Figure 5C illustrates a schematic view of the tubular member 22 extending between the vessel 10 and the BOP 36 in deep water showing greater localized bending closer to the BOP 36, and Figure 5D illustrates a schematic view of the tubular member 22 extending between the vessel 10 and the BOP 36 in deep water showing greater localized bending closer to the vessel 10, according to an embodiment. The situations shown in Figures 5C and 5D may happen due to subsurface currents, drifting of the vessel 10, bad weather, or a combination thereof.

[0027] In deep water (i.e., when the tubular member 22 is long), the tubular member 22 may be more susceptible to local bending. Localized bending is present in the lower portion of the tubular member 22 in Figure 5C. As a result, the inclination angle α proximate to the BOP 36 may be greater than the inclination angle β proximate to the vessel 10. Localized bending is present in the upper portion of the tubular member 22 in Figure 5D. As a result, the inclination angle β proximate to the vessel 10 may be greater than the inclination angle α proximate to the BOP 36.

[0028] As will be appreciated, a single instrumentation module 46 at a fixed position in the tubular member 22 may measure the inclination angle at one point in the tubular member 22 (e.g., inclination angle α or inclination angle β), but not two or more angles α , β at different locations. Thus, in the example of Figure 5C, if the instrumentation module 46 is positioned in the upper portion of the tubular member 22, the instrumentation module 46 may not be able to detect the inclination angle α . This may pose a problem if the inclination angle α is greater than the predetermined threshold. However, by including a plurality of instrumentation modules 46 along the tubular member 22, the inclination angle may be measured at various points along the tubular member 22. For example, a first landing string instrumentation module 46 may be positioned proximate to the BOP 36 to measure the inclination angle α , and a second landing string instrumentation module 46 may be positioned proximate to the vessel 10 to measure the inclination angle β . One or more additional landing string instrumentation modules 46 may be positioned between the first and second landing string instrumentation modules 46.

[0029] Figure 6 illustrates a flowchart of a method 600 for disconnecting the tubular member 22 from subsea well equipment 34, according to an embodiment. The method 600 may include arming the well system 20, as at 602. More particularly, the method 600 may include arming the well system 20, or determining whether the well system 20 is already armed, such that the well sys-

tem 20 may initiate an ESD.

[0030] The method 600 may also include measuring a parameter (e.g., inclination angle α , β) of the tubular member 22 using the instrumentation module 46, as at 604. As mentioned above, the sensors 96 in the instrumentation module 46 may measure the parameter. In one example, the well system 20 may include a plurality of instrumentation modules 46 that are axially-offset from one another along the length of the tubular member 22, and the method 600 may include measuring a parameter of the tubular member 22 with each of the instrumentation modules 46. The measured parameter may be transmitted from the instrumentation module 46 to the controller 48 (e.g., using the communication line 50).

[0031] The method 600 may also include determining whether the measured parameter exceeds a predetermined threshold, as at 606. As mentioned above, the controller 48 may determine whether the measured parameter exceeds the predetermined threshold. In at least one embodiment, determining whether the measured parameter exceeds the predetermined threshold may include determining whether the measured parameter exceeds the predetermined threshold for a predetermined amount of time (e.g., 30 seconds). The predetermined amount of time may be a single, continuous interval of time or multiple intervals of time in the aggregate. In another embodiment, determining whether the measured parameter exceeds the predetermined threshold may include determining whether the measured parameter exceeds a first predetermined threshold for a first predetermined amount of time and/or determining whether the measured parameter exceeds a second predetermined threshold for a second predetermined amount of time. The first predetermined threshold may be greater than the second predetermined threshold (e.g., 20° vs. 10°), and the first predetermined amount of time may be less than the second predetermined amount of time (e.g., 1 second vs. 30 seconds). In another embodiment, determining whether the measured parameter exceeds the predetermined threshold may include determining whether the measured parameter exceeds the predetermined threshold a predetermined number of times. The predetermined number of times may be greater than one (e.g., 5 times). This may be used to, for example, determine that the tubular member 22 is making a corkscrewing movement, reaching upper fatigue levels, etc.

[0032] When the parameter is an inclination angle (e.g., α or β), the predetermined threshold may be about 5°, about 10°, about 15°, about 20°, or more. When the well system 20 includes a plurality of instrumentation modules 46, the method 600 may include determining whether a parameter measured by at least one of the instrumentation modules 46 is greater than the predetermined threshold. In at least one embodiment, different instrumentation modules 46 may have different predetermined thresholds. For example, when the parameter is an inclination angle, a first instrumentation module 46 may have a threshold of 10°, and a second instrumenta-

tion module 46 may have a threshold of 15°. The threshold values may be selected based upon depth, client choice, software used, etc. If the measured parameter exceeds the predetermined threshold (i.e., YES), the method 600 may proceed to 608. If the measured parameter is less than the predetermined threshold (i.e., NO), the method 600 may wait for a predetermined period of time and loop back to 602.

[0033] The method 600 may also optionally include disconnecting at least a portion of the tubular member 22 from the subsea well equipment 34 when the measured parameter exceeds the predetermined threshold, as at 608. More particularly, the controller 48 may autonomously initiate the ESD sequence via, for example, the deep water control and operating systems such as SENTREE® and SENTURIAN®. In at least one embodiment, this may cause the surface vessel or other surface equipment to apply a tensile pulling/lifting force on the tubular member 22. For example, the latch assembly 24 may be actuated by the controller 48 to a release position so that application of a tensile pulling force above a predetermined break level causes disconnection of the tubular member 22 at the latch assembly 24. In this example, the tensile pulling force causes the weakened area 26 to break so that the upper portion 42 may separate from the lower portion 44. In another embodiment, a cutter module in the SENTREE® system may cut the coiled tubing running inside the latch assembly 24. This may allow the valves to close when disconnection occurs.

[0034] The upper portion 42 may thus be separated from the subsea well equipment 34 and be able to float/drift with the vessel 10. Before or after separation, the controller 48 may close the retainer valve 68 in a short period of time (e.g., approximately 6 seconds or less) to prevent fluid from exiting the upper portion 42 of the tubular member 22. With the tubular member 22 disconnected from the subsea well equipment 34 in this way, the BOP 36 may not cut the tubular member 22, thus preserving the tubular member 22 for an easy reconnection to the subsea well equipment 34.

[0035] The method 600 may also include shutting-in the well 32 when the measured parameter exceeds the predetermined threshold, as at 610. In at least one embodiment, the well 32 may be shut-in without the tubular member 22 being disconnected. More particularly, the controller 48 may autonomously initiate the ESD sequence via, for example, the deep water control and operating systems such as SENTREE® and SENTURIAN®, which may block upward flow of well fluid via closure of the flapper valve 72 and/or the ball valve 74 in a short period of time (e.g., approximately one second or less). For example, the ball valve 74 may be closed as the primary barrier.

[0036] Figure 7 illustrates a perspective view of a housing 700 for the instrumentation module 46, according to an embodiment. The housing 700 may be at least partially arcuate so as to fit around at least a portion of the tubular member 22. As shown, the housing 700 is annular. The

housing 700 may be coupled to the tubular member 22 (e.g., Figure 1) via magnetic attachment, mechanical fastening (e.g., bolts, straps), or the like. The magnetic attachment may include a magnetic clamp that is twisted to release from the tubular member 22. The housing 700 may define an interior volume. A lid 702 may be coupled to the housing 700 to ensure a predetermined pressure (e.g., 1 atm) inside the interior volume and to prevent the electronics from coming in contact with the riser liquid, which may be conductive. The instrumentation module 46 may be positioned in the interior volume. In at least one embodiment, the electrical module and/or a battery may also be positioned within the interior volume. An outer surface 704 of the housing 700 may be arcuate so as to fit around at least a portion of the tubular member 22. The communication line 50 or another line may be coupled to the housing 700 via an electrical connector 706.

[0037] Figure 8 illustrates a perspective view of another housing 800 for the instrumentation module 46, according to an embodiment. The housing 800 may be substantially cylindrical and define an interior volume in which the instrumentation module 46, the electrical module, the battery, or a combination thereof may be positioned. The housing 800 may define one or more holes (e.g., through-holes or blind holes) 802 for receiving a fastening mechanism such as a bolt. The fastening mechanism may be used to couple the housing 800 to the tubular member 22. The holes 802 and the fastening mechanisms may be positioned radially-outward from the housing 800 or axially-aligned with the housing 800. One or more cap seals 804 may seal the housing 800 to ensure a predetermined pressure (e.g., 1 atm) inside the interior volume.

[0038] Figure 9 illustrates a perspective view of another housing 900 for the instrumentation module 46, according to an embodiment. The housing 900 may be substantially cylindrical and define an interior volume in which the instrumentation module 46, the electrical module, the battery, or a combination thereof may be positioned. A liquid, such as oil, may be positioned in the interior volume. In this instance, the electrical module may be pressure tolerant. A pressure compensator 902 may be coupled to the housing 900 to help regulate the pressure in the interior volume along with hydraulic safety components (e.g., relief valves or rupture disks).

[0039] In some embodiments, any of the methods of the present disclosure may be executed by a computing system. Figure 10 illustrates an example of such a computing system 1000, in accordance with some embodiments. The computing system 1000 may include a computer or computer system 1001A, which may be an individual computer system 1001A or an arrangement of distributed computer systems. The computer system 1001A includes one or more analysis module(s) 1002 configured to perform various tasks according to some embodiments, such as one or more methods disclosed herein. To perform these various tasks, the analysis module

1002 executes independently, or in coordination with, one or more processors 1004, which is (or are) connected to one or more storage media 1006. The processor(s) 1004 is (or are) also connected to a network interface 1007 to allow the computer system 1001A to communicate over a data network 1009 with one or more additional computer systems and/or computing systems, such as 1001B, 1001C, and/or 1001D (note that computer systems 1001B, 1001C and/or 1001D may or may not share the same architecture as computer system 1001A, and may be located in different physical locations, e.g., computer systems 1001A and 1001B may be located in the tubular member 22, while in communication with one or more computer systems such as 1001C and/or 1001D that are located at the surface).

[0040] A processor can include a microprocessor, microcontroller, processor module or subsystem, programmable integrated circuit, programmable gate array, or another control or computing device.

[0041] The storage media 1006 can be implemented as one or more computer-readable or machine-readable storage media. Note that while in the example embodiment of Figure 10 storage media 1006 is depicted as within computer system 1001A, in some embodiments, storage media 1006 may be distributed within and/or across multiple internal and/or external enclosures of computing system 1001A and/or additional computing systems. Storage media 1006 may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories, magnetic disks such as fixed, floppy and removable disks, other magnetic media including tape, optical media such as compact disks (CDs) or digital video disks (DVDs), BLURAY® disks, or other types of optical storage, or other types of storage devices. Note that the instructions discussed above can be provided on one computer-readable or machine-readable storage medium, or, in other embodiments, can be provided on multiple computer-readable or machine-readable storage media distributed in a large system having possibly plural nodes. Such computer-readable or machine-readable storage medium or media is (are) considered to be part of an article (or article of manufacture). An article or article of manufacture can refer to any manufactured single component or multiple components. The storage medium or media can be located either in the machine running the machine-readable instructions, or located at a remote site from which machine-readable instructions can be downloaded over a network for execution.

[0042] In some embodiments, computing system 1000 contains one or more ESD module(s) 1008. In the example of computing system 1000, computer system 1001A includes the ESD module 1008. In some embodiments, a single ESD module may be used to perform at least

some aspects of one or more embodiments of the methods. In another embodiment, a plurality of ESD modules may be used to perform at least some aspects of methods.

[0043] It should be appreciated that computing system 1000 is one example of a computing system, and that computing system 1000 may have more or fewer components than shown, may combine additional components not depicted in the example embodiment of Figure 10, and/or computing system 1000 may have a different configuration or arrangement of the components depicted in Figure 10. The various components shown in Figure 10 may be implemented in hardware, software, or a combination of both hardware and software, including one or more signal processing and/or application specific integrated circuits.

[0044] Further, the methods described herein may be implemented by running one or more functional modules in information processing apparatus such as general purpose processors or application specific chips, such as ASICs, FPGAs, PLDs, or other appropriate devices. These modules, combinations of these modules, and/or their combination with general hardware are included within the scope of protection of the invention.

[0045] As used herein, the terms "inner" and "outer"; "up" and "down"; "upper" and "lower"; "upward" and "downward"; "above" and "below"; "inward" and "outward"; and other like terms as used herein refer to relative positions to one another and are not intended to denote a particular direction or spatial orientation. The terms "couple," "coupled," "connect," "connection," "connected," "in connection with," and "connecting" refer to "in direct connection with" or "in connection with via one or more intermediate elements or members."

[0046] The foregoing description, for purpose of explanation, has been described with reference to specific embodiments. However, the illustrative discussions above are not intended to be exhaustive or to limit the invention to the precise forms disclosed. Many modifications and variations are possible in view of the above teachings. Moreover, the order in which the elements of the methods described herein are illustrate and described may be rearranged, and/or two or more elements may occur simultaneously. The embodiments were chosen and described in order to best explain the principals of the invention and its practical applications, to thereby enable others skilled in the art to best utilize the invention and various embodiments with various modifications as are suited to the particular use contemplated.

Claims

1. A method for initiating an emergency shutdown and disconnect (ESD) sequence, comprising:

measuring an angle of the tubular member with respect to vertical using a sensor that is coupled

to the tubular member;
determining whether the angle exceeds a predetermined threshold for a predetermined amount of time; and
initiating the ESD sequence when the angle exceeds the predetermined threshold for the predetermined amount of time.

2. The method of claim 1, wherein the predetermined amount of time comprises a single, continuous interval of time.

3. The method of claim 1, wherein the predetermined amount of time comprises multiple intervals of time in the aggregate.

4. The method of claim 1, wherein determining whether the angle exceeds the predetermined threshold for the predetermined amount of time comprises:

determining whether the angle exceeds a first predetermined threshold for a first predetermined amount of time; and
determining whether the angle exceeds a second predetermined threshold for a second predetermined amount of time.

5. The method of claim 4, wherein the first predetermined threshold is greater than the second predetermined threshold, and wherein the first predetermined amount of time is less than the second predetermined amount of time.

6. The method of claim 1, wherein the sensor comprises:

a first sensor that is coupled to the tubular member proximate to an upper flex joint; and
a second sensor that is coupled to the tubular member proximate to a lower flex joint.

7. The method of claim 6, wherein the predetermined threshold comprises:

a first predetermined threshold for the first sensor; and
a second predetermined threshold for the second sensor, wherein the first and second predetermined thresholds are different.

8. The method of claim 6, further comprising measuring a depth of the first sensor, the second sensor, or both using a depth sensor, wherein a weight assigned to the angle is dependent upon the depth.

9. The method of claim 1, wherein a weight assigned to the angle is pre-programmed.

10. The method of claim 1, wherein the angle comprises three angles, one with respect to a vertical axis, one with respect to a first horizontal axis, and one with respect to a second horizontal axis.
11. The method of claim 10, wherein at least one of the three angles exceeding the predetermined threshold for the predetermined amount of time indicates a corkscrewing movement of the tubular member.
12. The method of claim 1, wherein determining whether the angle exceeds the predetermined threshold for the predetermined amount of time indicates a fatigue level of the tubular member.
13. The method of claim 1, wherein the sensor comprises at least three accelerometers and at least three gyroscopes.
14. The method of claim 1, wherein initiating the ESD sequence comprises disconnecting at least a portion of the tubular member from subsea well equipment.
15. The method of claim 1, wherein initiating the ESD sequence comprises shutting-in a well.
16. A method for initiating an emergency shutdown and disconnect (ESD) sequence, comprising:
- measuring a first angle of the tubular member using a first sensor that is coupled to the tubular member at a first location;
 - measuring a second angle of the tubular member using a second sensor that is coupled to the tubular member at a second location that is different than the first location;
 - determining whether the first angle exceeds a first predetermined threshold a first predetermined number of times that is greater than one, or the second angle exceeds a second predetermined threshold a second predetermined number of times that is greater than one; and
 - initiating the ESD sequence when the first angle exceeds the first predetermined threshold the first predetermined number of times or when the second angle exceeds the second predetermined threshold the second predetermined number of times.
17. A system, comprising:
- a tubular member;
 - an instrumentation module coupled to the tubular member, wherein the instrumentation module comprises one or more sensors configured to measure an angle of the tubular member; and
 - a controller configured to determine whether the angle exceeds a predetermined threshold for a predetermined amount of time, a predetermined number of times that is greater than one, or both, and wherein, in response to the angle exceeding the predetermined threshold for the predetermined amount of time, the predetermined number of times that is greater than one, or both, the controller is configured to disconnect at least a portion of the tubular member from subsea well equipment, shut-in a well, or both.
18. The system of claim 17, wherein the one or more sensors comprise:
- a first sensor configured to measure a first angle of the tubular member with respect to a vertical axis;
 - a second sensor configured to measure a second angle of the tubular member with respect to a first horizontal axis; and
 - a third sensor configured to measure a third angle of the tubular member with respect to a second horizontal axis that is perpendicular to the first horizontal axis.
19. The system of claim 17, wherein the one or more sensors also comprise:
- a first accelerometer and a first gyroscope corresponding to a vertical axis;
 - a second accelerometer and a second gyroscope corresponding to a first horizontal axis; and
 - a third accelerometer and a third gyroscope corresponding to a second horizontal axis that is perpendicular to the first horizontal axis.
20. The system of claim 17, wherein the instrumentation module comprises:
- a first instrumentation module coupled to the tubular member at a first location; and
 - a second instrumentation module coupled to the tubular member at a second location that is below the first location.

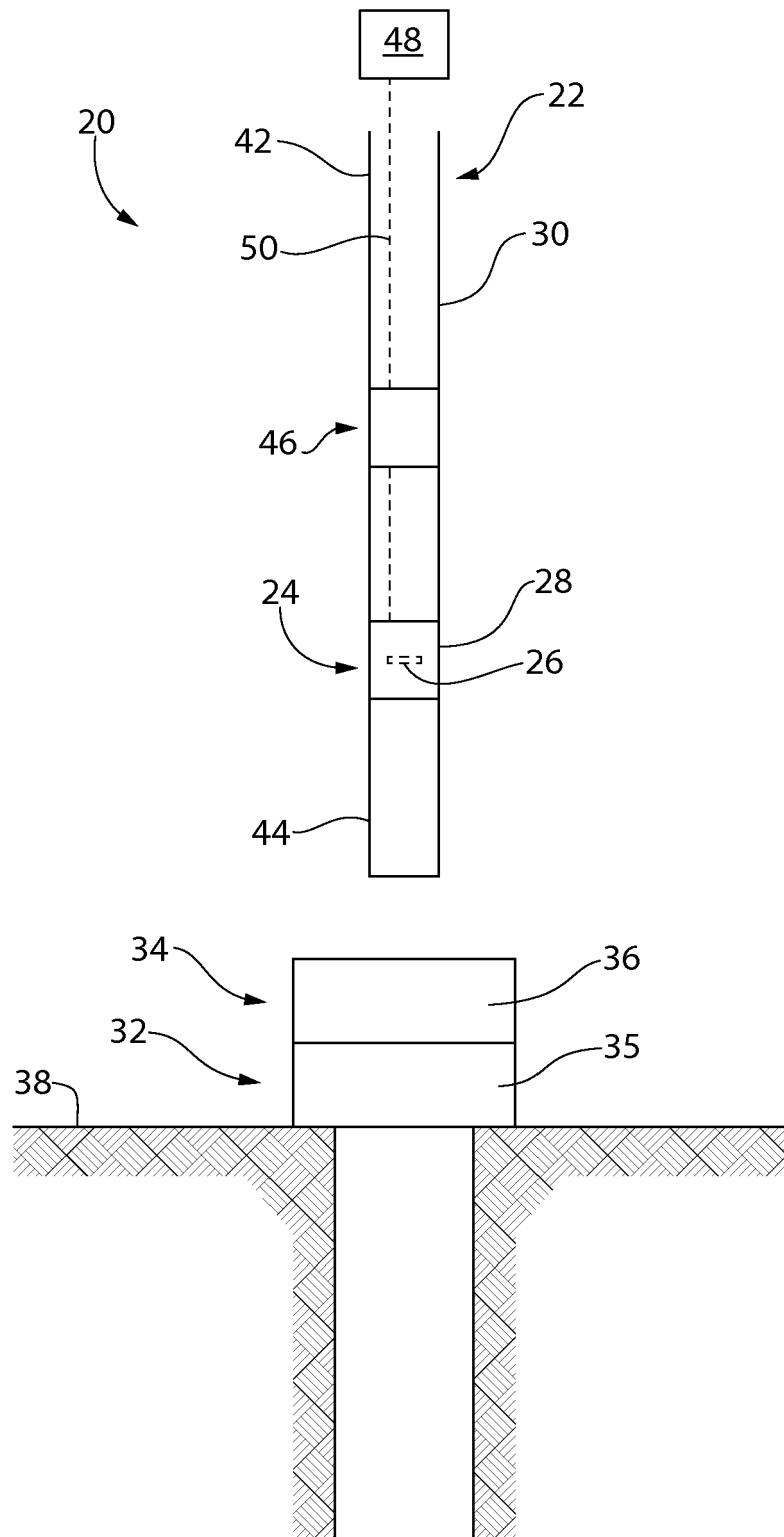


FIG. 1

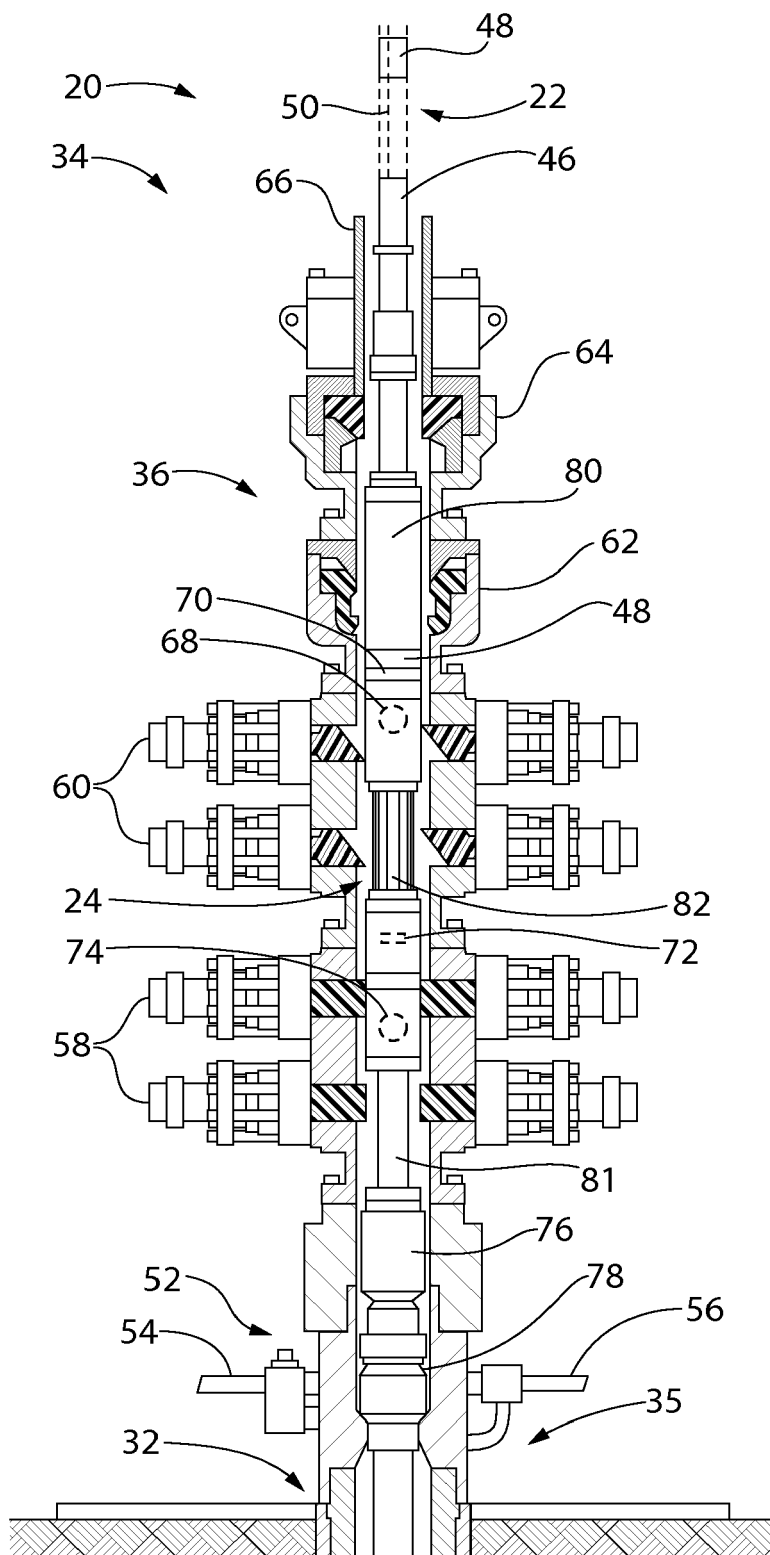
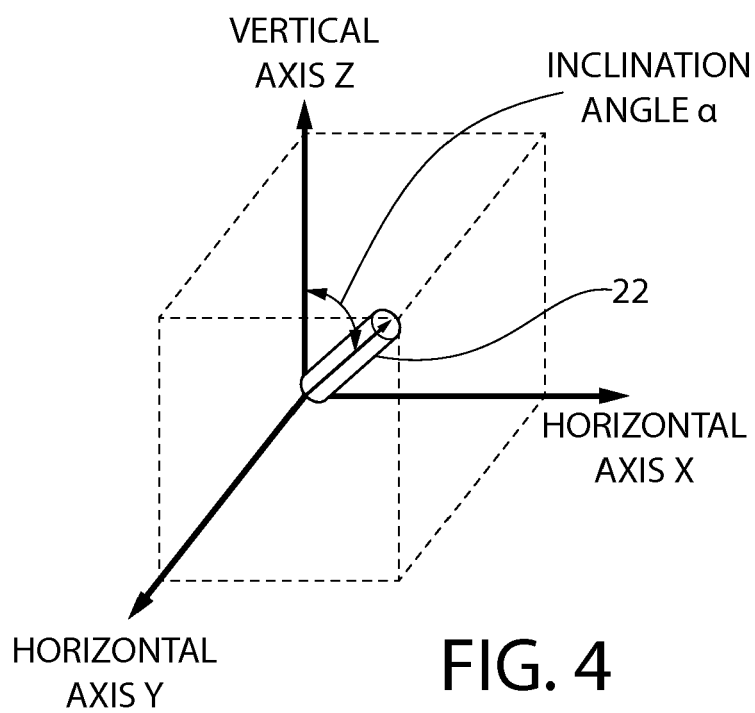
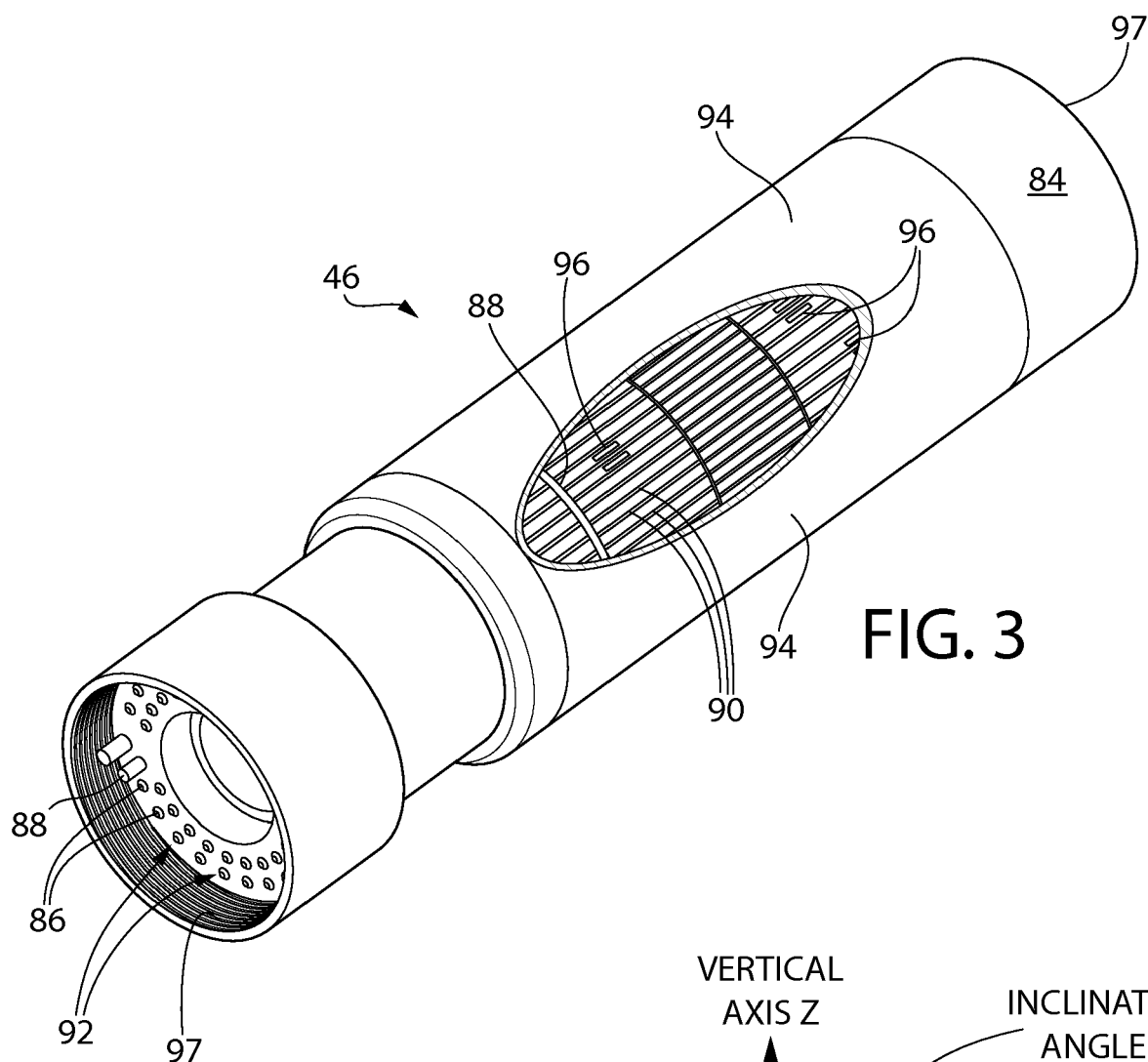


FIG. 2



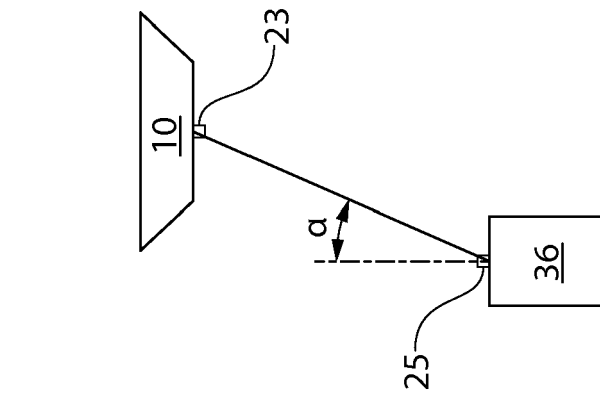


FIG. 5A

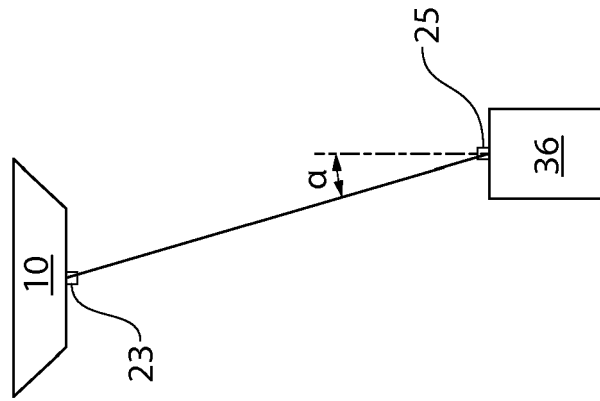


FIG. 5B

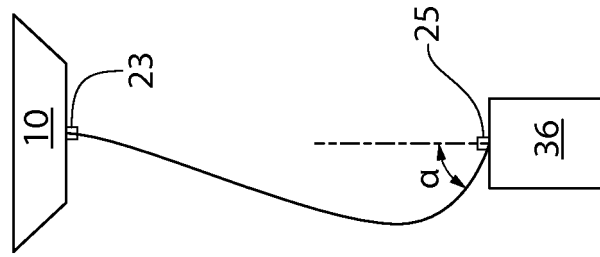


FIG. 5C

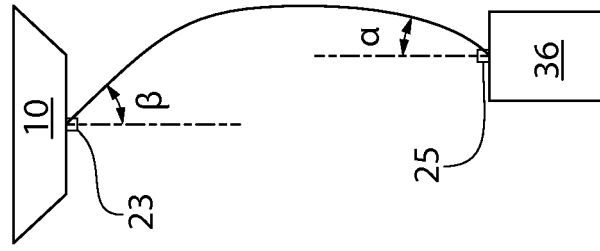


FIG. 5D

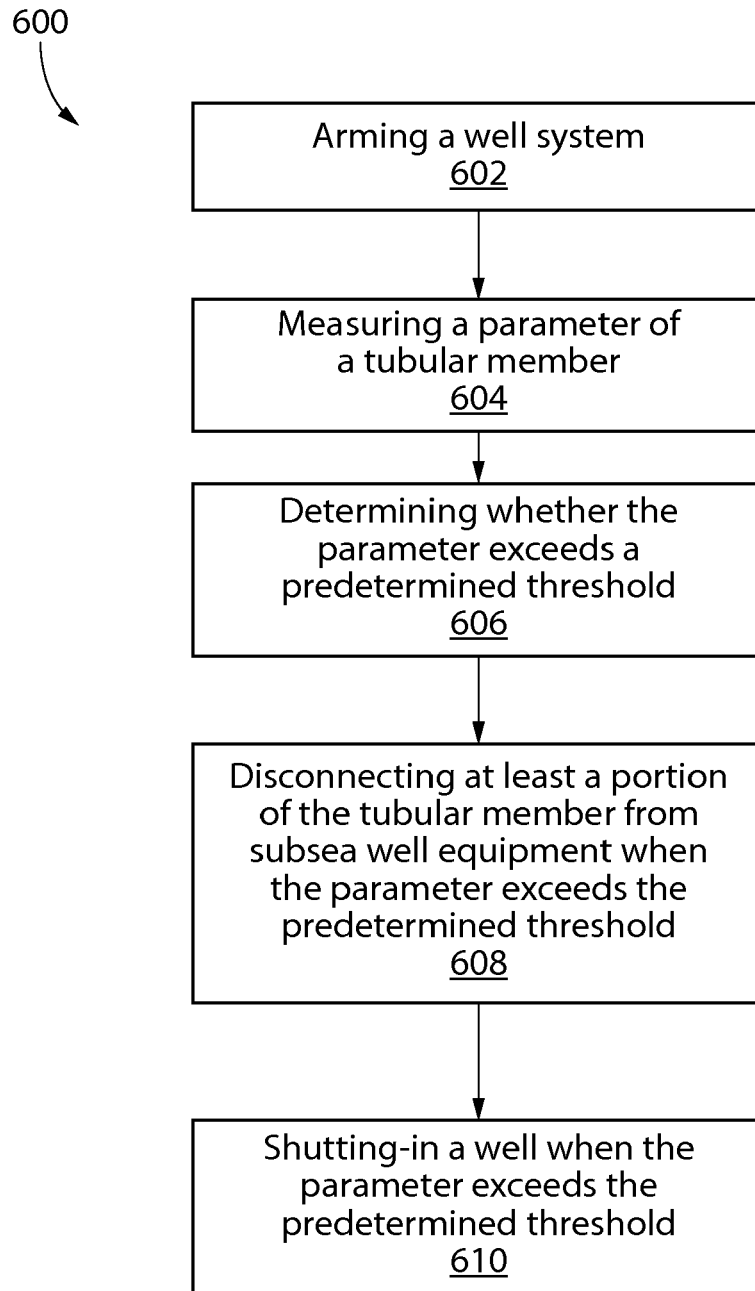


FIG. 6

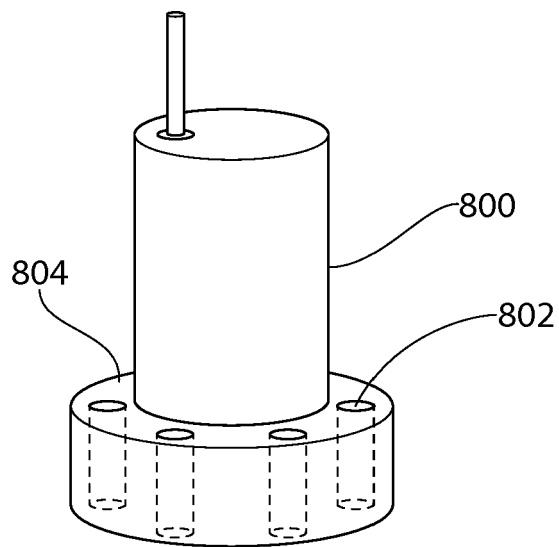
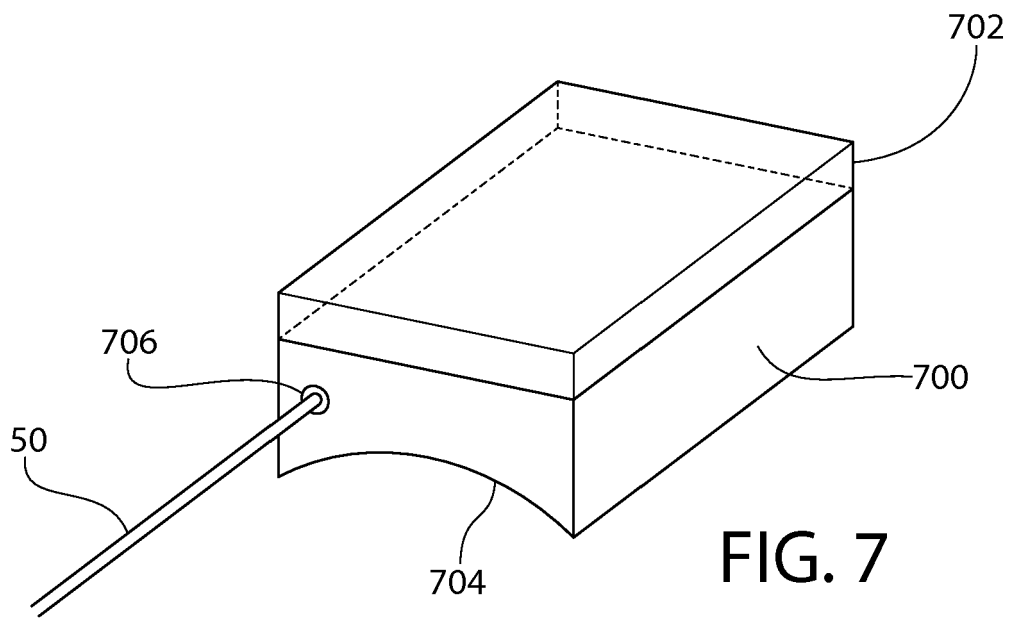


FIG. 8

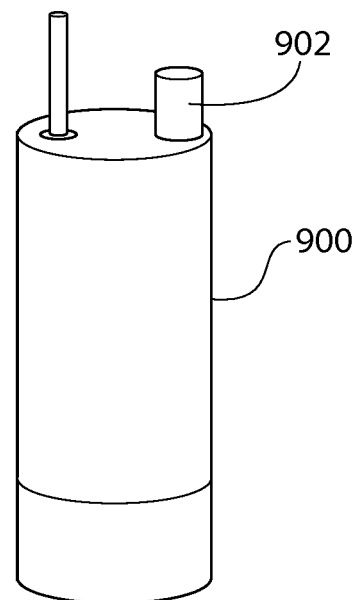


FIG. 9

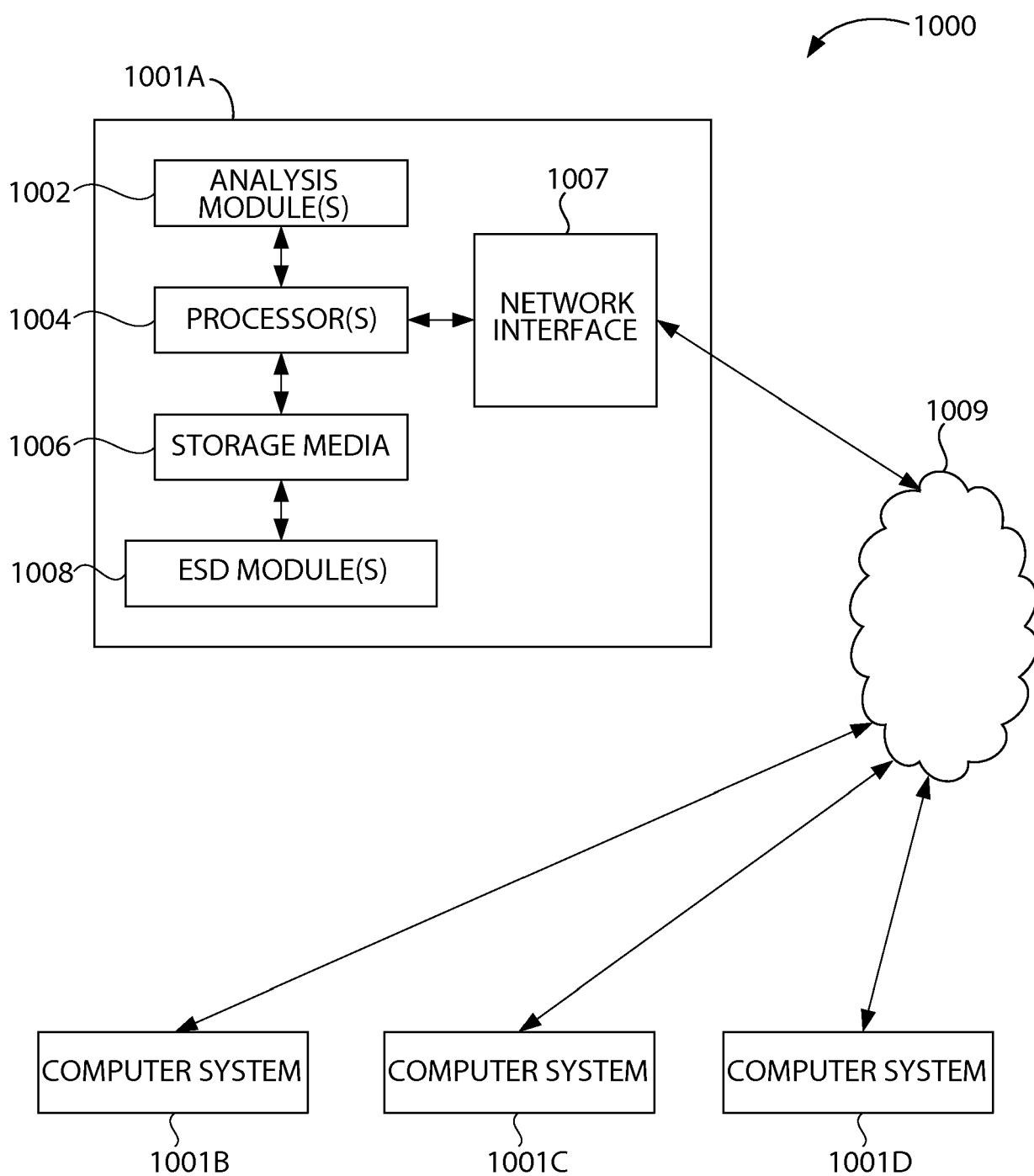


FIG. 10



PARTIAL EUROPEAN SEARCH REPORT

Application Number

under Rule 62a and/or 63 of the European Patent Convention.
This report shall be considered, for the purposes of
subsequent proceedings, as the European search report

EP 18 15 0292

DOCUMENTS CONSIDERED TO BE RELEVANT

Category	Citation of document with indication, where appropriate, of relevant passages	Relevant to claim	CLASSIFICATION OF THE APPLICATION (IPC)
X	US 5 978 739 A (STOCKTON THOMAS R [US]) 2 November 1999 (1999-11-02) * column 2, line 42 - line 62 * * column 5, line 37 - column 6, line 21 * * column 6, line 60 - column 7, line 20; figures 2-5 *	1-15, 17-20	INV. E21B17/01 E21B47/02 E21B33/035
X	WO 2014/210435 A1 (SCHLUMBERGER CA LTD [CA]; SCHLUMBERGER SERVICES PETROL [FR]; SCHLUMBER) 31 December 2014 (2014-12-31) * paragraphs [0011], [0024] - [0027]; figures 1-3 *	1-3, 10-15, 17-19	
A	US 2006/065401 A1 (ALLEN JOHN [US] ET AL) 30 March 2006 (2006-03-30) * paragraphs [0002], [0007], [0012], [0015], [0020] - [0021], [0039], [0050], [0051]; figures 1-5 *	1-15, 17-20	
			TECHNICAL FIELDS SEARCHED (IPC)
			E21B

INCOMPLETE SEARCH

The Search Division considers that the present application, or one or more of its claims, does/do not comply with the EPC so that only a partial search (R.62a, 63) has been carried out.

Claims searched completely :

Claims searched incompletely :

Claims not searched :

Reason for the limitation of the search:

see sheet C

1

EPO FORM 1503 03.02 (P04E07)

Place of search	Date of completion of the search	Examiner
The Hague	17 August 2018	Jucker, Chava
CATEGORY OF CITED DOCUMENTS X : particularly relevant if taken alone Y : particularly relevant if combined with another document of the same category A : technological background O : non-written disclosure P : intermediate document T : theory or principle underlying the invention E : earlier patent document, but published on, or after the filing date D : document cited in the application L : document cited for other reasons & : member of the same patent family, corresponding document		

**INCOMPLETE SEARCH
SHEET C**

Application Number

EP 18 15 0292

Claim(s) completely searchable:
1-15, 17-20

Claim(s) not searched:
16

Reason for the limitation of the search:

In reply to the invitation to indicate the claims on which the search is to be based, the applicant failed to supply the requested indication in due time.

Thus, the search report has been drawn up on the basis of the first independent claim of each category (Rule 62a(1) EPC):

Method claims 1-15 and product claims 17-20

The applicant's attention is drawn to the fact that the application will be further prosecuted on the basis of subject-matter for which a search has been carried out and that the claims should be limited to that subject-matter at a later stage of the proceedings (Rule 62a(2) EPC).

**ANNEX TO THE EUROPEAN SEARCH REPORT
ON EUROPEAN PATENT APPLICATION NO.**

EP 18 15 0292

5

This annex lists the patent family members relating to the patent documents cited in the above-mentioned European search report.
The members are as contained in the European Patent Office EDP file on
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17-08-2018

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For more details about this annex : see Official Journal of the European Patent Office, No. 12/82