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(54) **WIRELESS MEASUREMENT OF THE POSITION OF A PISTON IN AN ACCUMULATOR**

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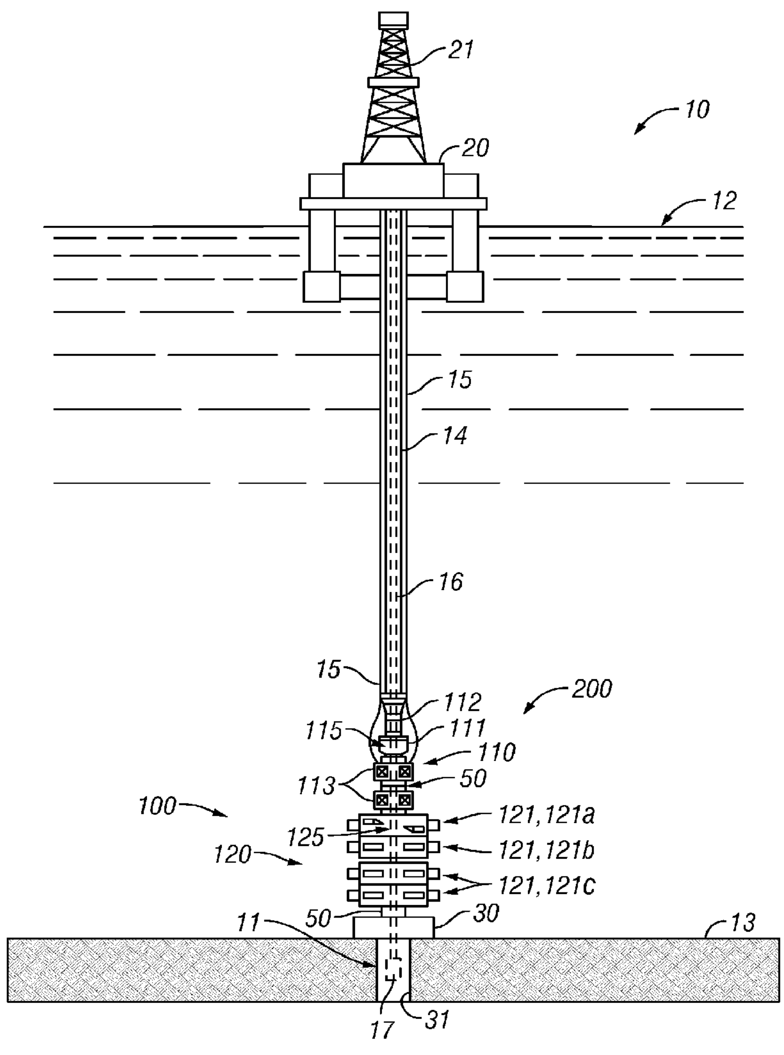
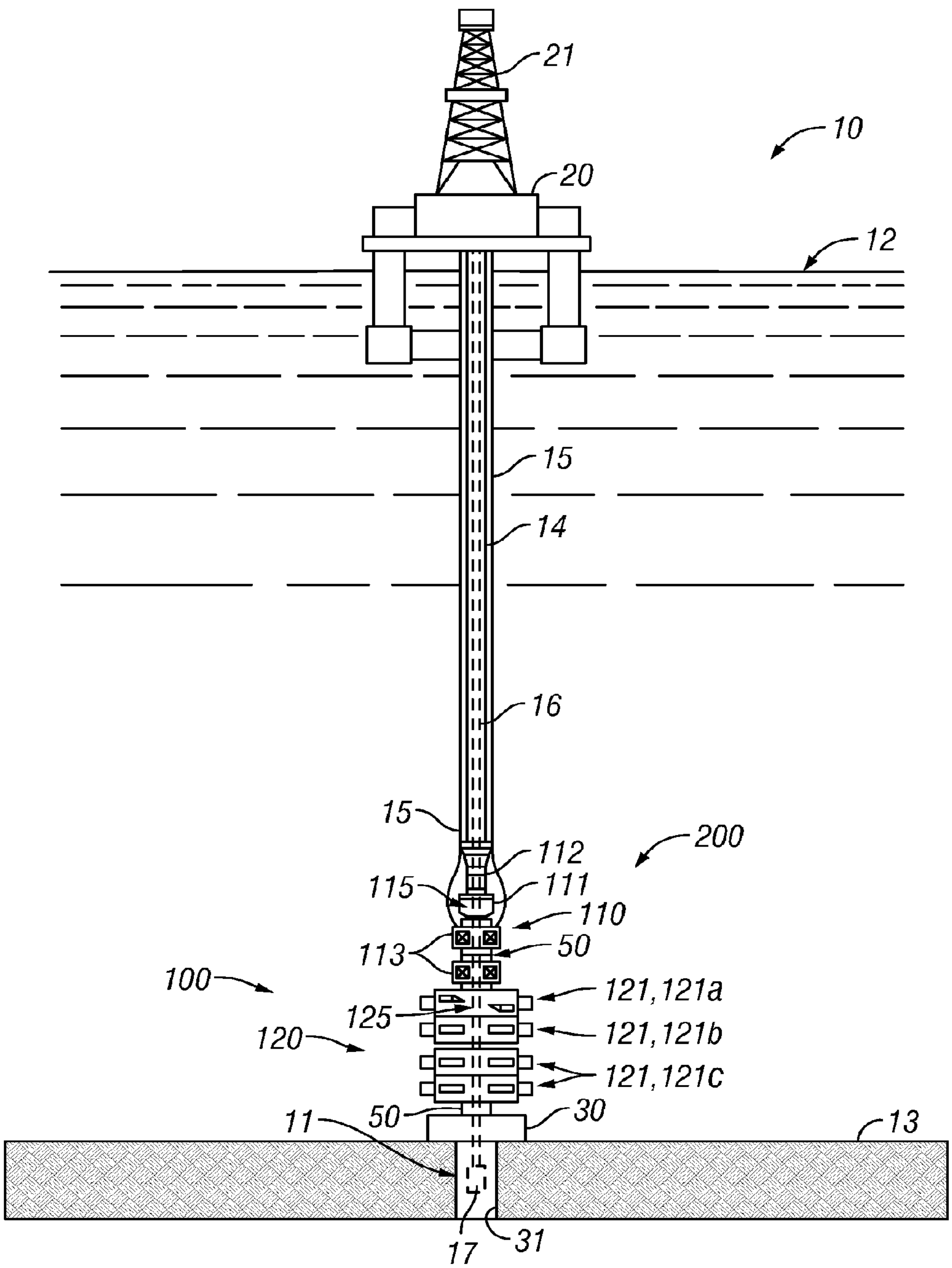
(57) **ABSTRACT**

A measurement system including a container including an element moveable within an internal volume of the container. A sensor wirelessly measures the position of the element within the container and transmits the measured position information. Also included is an information system capable of reading the position information from the sensor.

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12
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16
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200
112
115
111
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121,121a
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121,121b
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121,121c
11
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17
31

FIG. 1

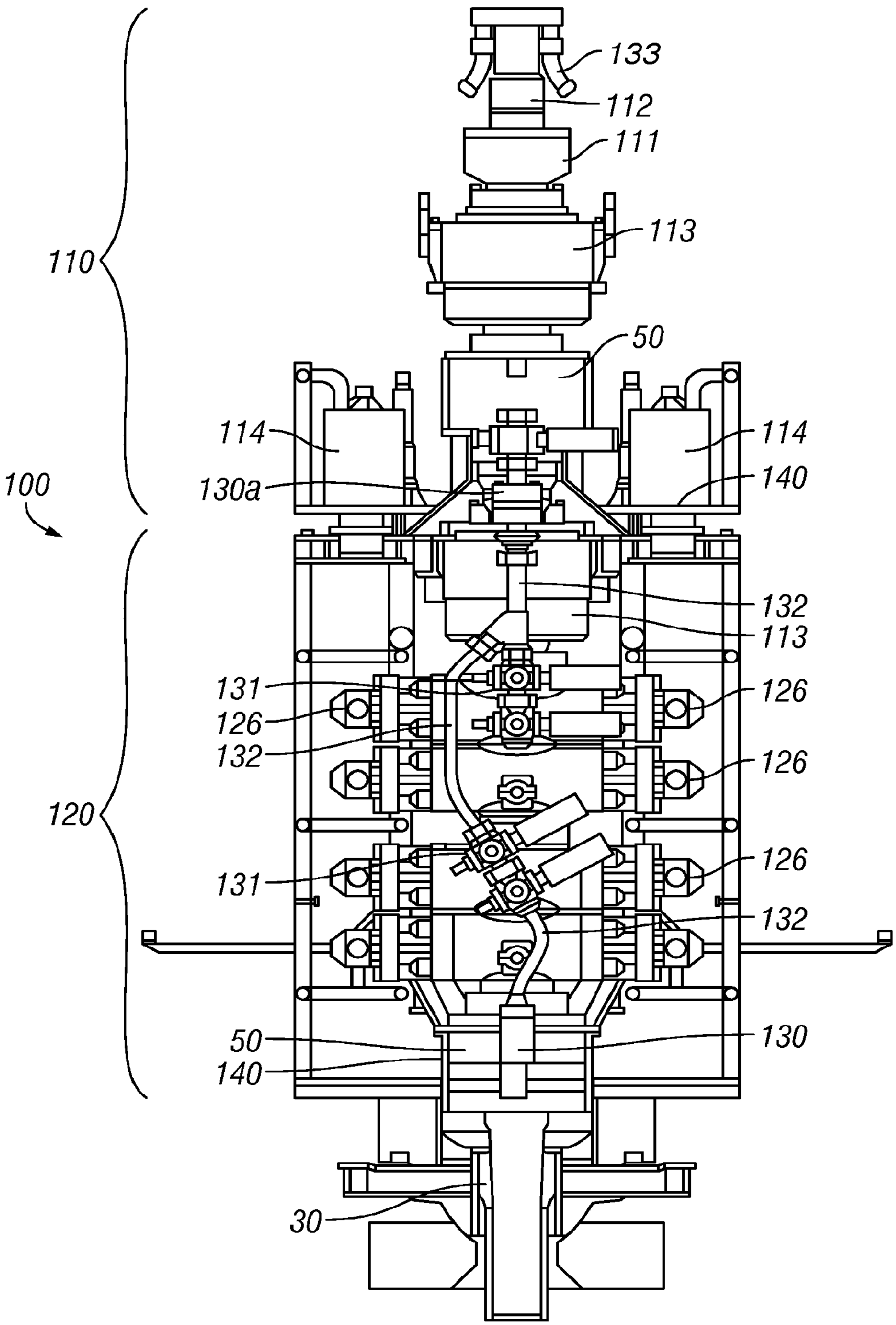
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FIG. 2

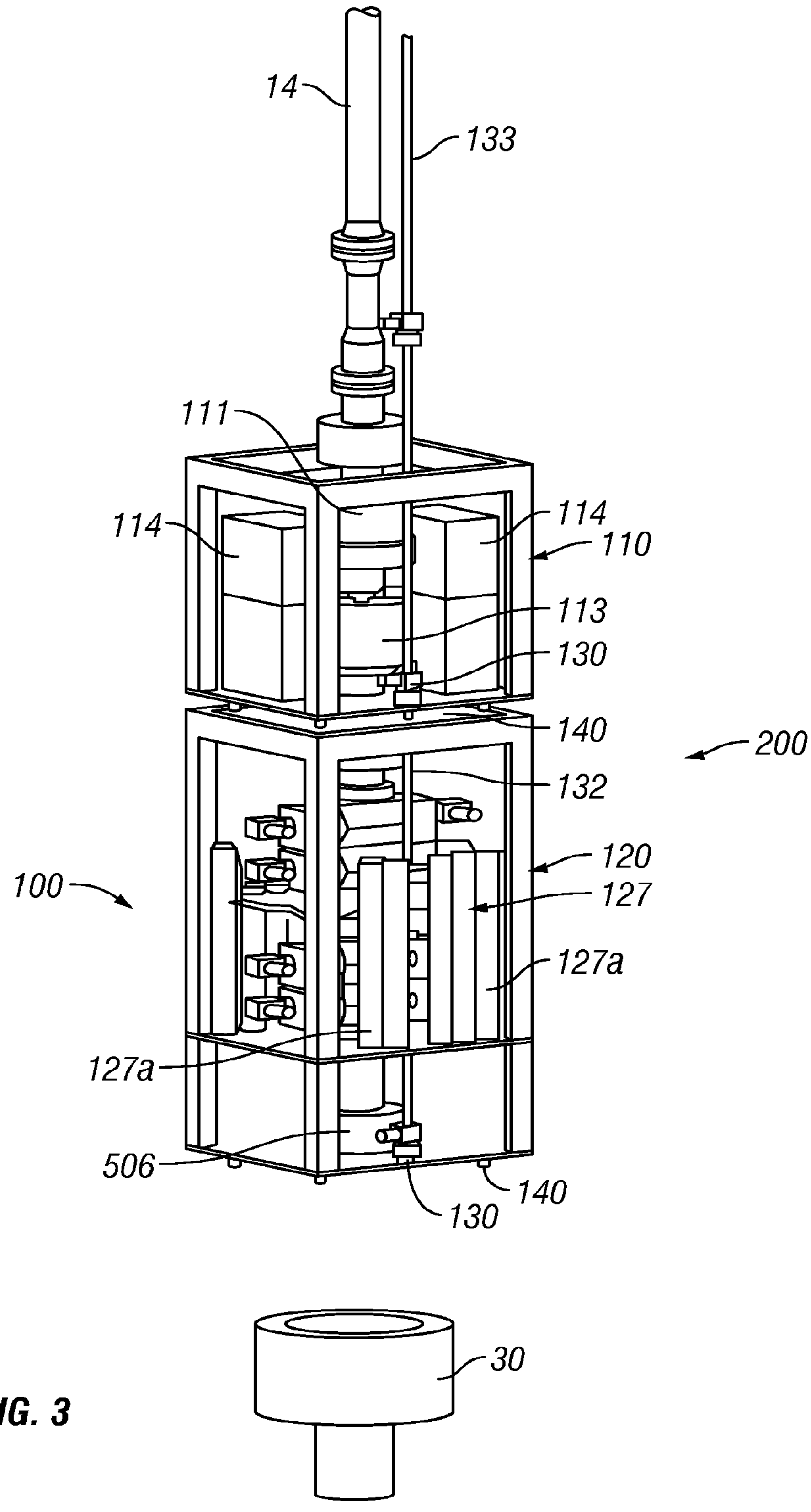
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FIG. 3

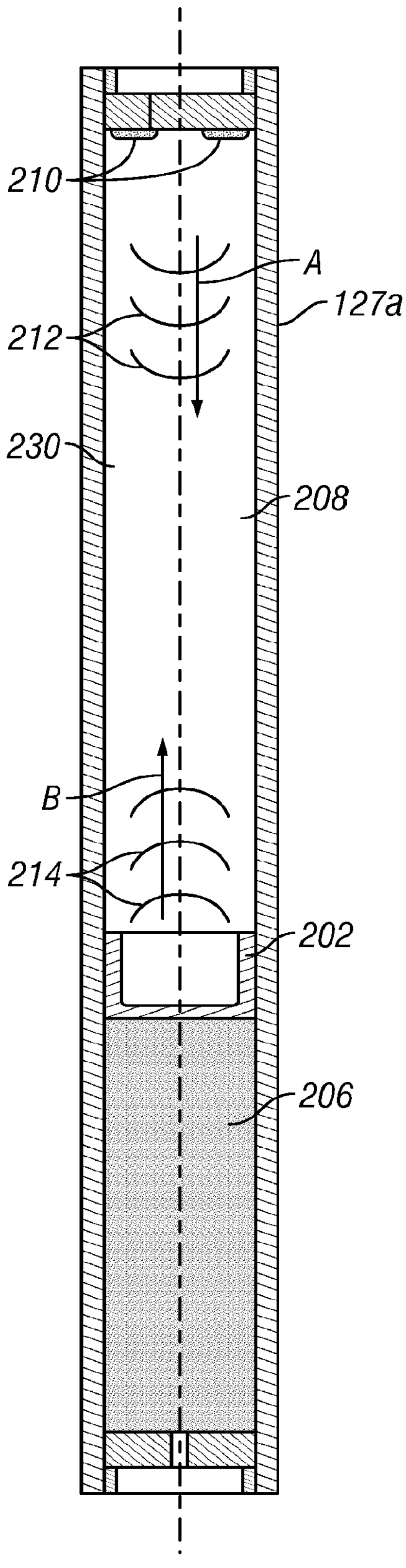

FIG. 4

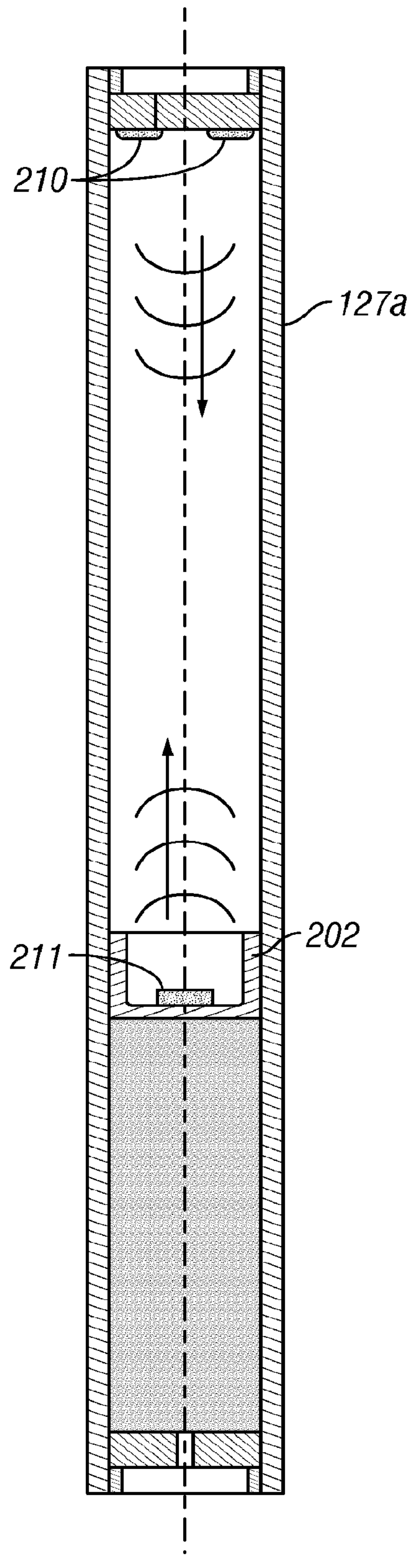

FIG. 5

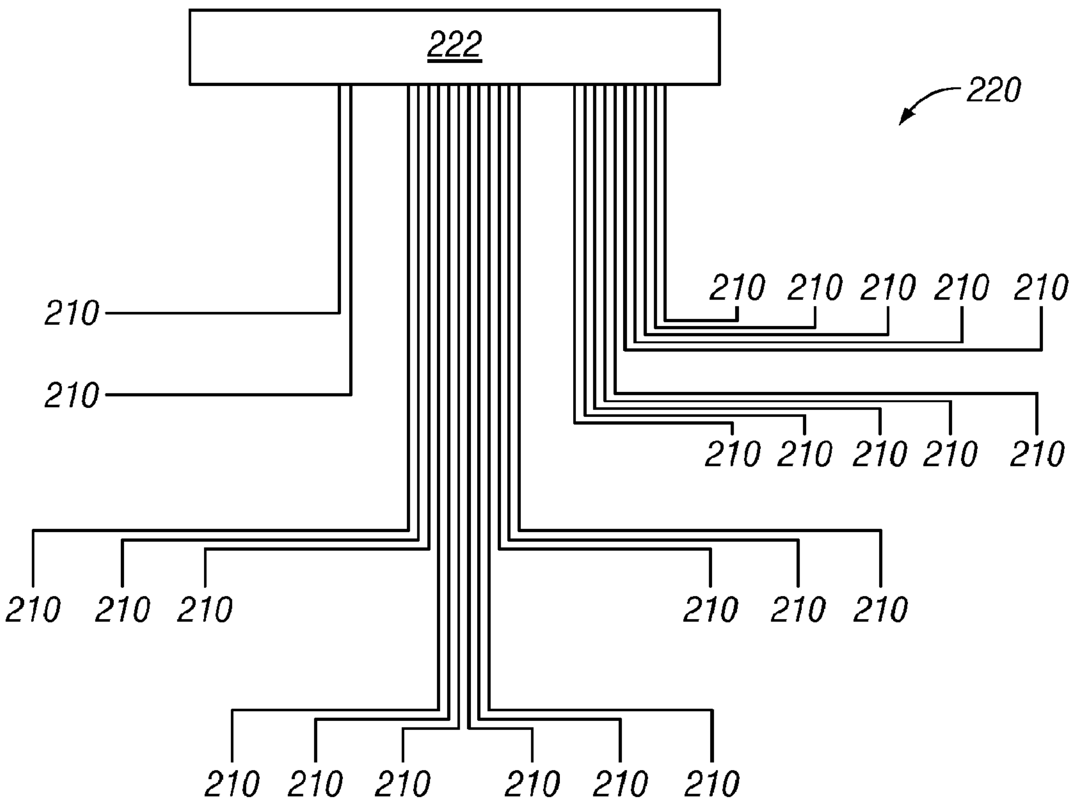
222
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FIG. 6

WIRELESS MEASUREMENT OF THE POSITION OF A PISTON IN AN ACCUMULATOR

BACKGROUND

[0001] In most offshore drilling operations, a wellhead at the sea floor is positioned at the upper end of the subterranean wellbore lined with casing, a blowout preventer (BOP) stack is mounted to the wellhead, and a lower marine riser package (LMRP) is mounted to the BOP stack. The upper end of the LMRP typically includes a flex joint coupled to the lower end of a drilling riser that extends upward to a drilling vessel at the sea surface. A drill string is hung from the drilling vessel through the drilling riser, the LMRP, the BOP stack, and the wellhead into the wellbore.

[0002] During drilling operations, drilling fluid, or mud, is pumped from the sea surface down the drill string, and returns up the annulus around the drill string. In the event of a rapid invasion of formation fluid into the annulus, commonly known as a "kick," the BOP stack and/or LMRP may actuate to help seal the annulus and control the fluid pressure in the wellbore. In particular, the BOP stack and the LMRP include closure members, or cavities, designed to help seal the wellbore and prevent the release of high-pressure formation fluids from the wellbore. Thus, the BOP stack and LMRP function as pressure control devices.

[0003] For most subsea drilling operations, hydraulic fluid for operating the BOP stack and the LMRP is provided using a common control system physically located on the surface drilling vessel. However, the common control system may become inoperable, resulting in a loss of the ability to operate the BOP stack. As a backup, or even possibly a primary means of operation, hydraulic fluid accumulators are filled with hydraulic fluid under pressure. The amount and size of the accumulators depends on the anticipated operation specifications for the well equipment.

[0004] An example of an accumulator includes a piston accumulator, which includes a hydraulic fluid section and a gas section separated by a piston moveable within the accumulator. The hydraulic fluid is placed into a fluid section of the accumulator and pressurized by injecting gas (typically Nitrogen) into the gas section. The fluid section is connected to a hydraulic circuit so that the hydraulic fluid may be used to operate the well equipment. As the fluid is discharged, the piston moves within the accumulator under pressure from the gas to maintain pressure on the remaining hydraulic fluid until full discharge.

[0005] The ability of the accumulator to operate a piece of equipment depends on the amount of hydraulic fluid in the accumulator and the pressure of the fluid. Thus, there may be a need to know the volume of the hydraulic fluid remaining in an accumulator so that control of the well equipment may be managed. Measuring the volume of hydraulic fluid in the accumulator over time can also help identify if there is a leak in the accumulator or hydraulic circuit or on the gas side of the piston.

[0006] Currently, the ability of an accumulator to power equipment is determined by measuring the pressure in the hydraulic circuit downstream of the accumulator. However, pressure is not an indicator of the overall capacity of an accumulator to operate equipment because the volume of hydraulic fluid remaining in the accumulator is not known. Also, accumulators are typically arranged in banks of multiple accumulators all connected to a common hydraulic circuit, therefore, the downstream pressure measurement is only an indication of the overall pressure in the bank, not per individual accumulator.

[0007] A possible way of determining the volume of hydraulic fluid remaining in the accumulator is to use a linear position sensor such as a cable-extension transducer or linear potentiometer that attaches inside the accumulator to measure the movement of the internal piston. However, these electrical components may fail and because the discharge of hydraulic fluid may be abrupt, the sensors may not be able to sample fast enough to obtain an accurate measurement.

[0008] Another method of determining the volume of hydraulic fluid is through the use of physical position indicators that extend from the accumulator. These indicators only offer visual feedback though and are insufficient for remote monitoring and pose a significant challenge to maintaining the integrity of the necessary mechanical seals under full operating pressures.

[0009] Through-the-wall sensors (e.g., Hall effect sensors) have also been considered. However, the thickness and specifications of an accumulator wall is such that these types of sensors are not always able to penetrate the material.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0011] FIG. **1** shows a schematic view of an offshore system for drilling and/or producing a subterranean wellbore with an embodiment of a measurement system;

[0012] FIG. **2** shows an elevation view of the subsea BOP stack assembly and measurement system of FIG. **1**;

[0013] FIG. **3** shows a perspective view of the subsea BOP stack assembly and measurement system of FIGS. **1** and **2**;

[0014] FIG. **4** shows a cross section view of an embodiment of a container with a sensor for use with the measurement system;

[0015] FIG. **5** is a cross section view of an alternative container with sensor for use in the measurement system; and

[0016] FIG. **6** is a schematic view of the measurement system, including the information system.

DETAILED DESCRIPTION

[0017] The following discussion is directed to various embodiments of the invention. The drawing figures are not necessarily to scale. Certain features of the embodiments may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness. Although one or more of these embodiments may be preferred, the embodiments disclosed should not be interpreted, or otherwise used, as limiting the scope of the disclosure, including the claims. It is to be fully recognized that the different teachings of the embodiments discussed below may be employed separately or in any suitable combination to produce the desired results. In addition, one skilled in the art will understand that the following description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to intimate that the scope of the disclosure, including the claims, is limited to that embodiment.

[0018] Certain terms are used throughout the following description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names This document does not intend to distinguish between components or features that differ in name but not function. The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

[0019] In the following discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to . . . ” Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be through a direct connection, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a central axis (e.g., central axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the central axis. For instance, an axial distance refers to a distance measured along or parallel to the central axis, and a radial distance means a distance measured perpendicular to the central axis.

[0020] Referring now to FIG. **1**, an embodiment of an offshore system **10** for drilling and/or producing a wellbore **11** is shown. In this embodiment, the system **10** includes an offshore vessel or platform **20** at the sea surface **12** and a subsea BOP stack assembly **100** mounted to a wellhead **30** at the sea floor **13**. The platform **20** is equipped with a derrick **21** that supports a hoist (not shown). A tubular drilling riser **14** extends from the platform **20** to the BOP stack assembly **100**. The riser **14** returns drilling fluid or mud to the platform **20** during drilling operations. One or more hydraulic conduit(s) **15** extend along the outside of the riser **14** from the platform **20** to the BOP stack assembly **100**. The conduit(s) **15** supply pressurized hydraulic fluid to the assembly **100**. Casing **31** extends from the wellhead **30** into the subterranean wellbore **11**.

[0021] Downhole operations are carried out by a tubular string **16** (e.g., drillstring, production tubing string, coiled tubing, etc.) that is supported by the derrick **21** and extends from the platform **20** through the riser **14**, through the BOP stack assembly **100**, and into the wellbore **11**. A downhole tool **17** is connected to the lower end of the tubular string **16**. In general, the downhole tool **17** may comprise any suitable downhole tool(s) for drilling, completing, evaluating, and/or producing the wellbore **11** including, without limitation, drill bits, packers, cementing tools, casing or tubing running tools, testing equipment, perforating guns, and the like. During downhole operations, the string **16**, and hence the tool **17** coupled thereto, may move axially, radially, and/or rotationally relative to the riser **14** and the BOP stack assembly **100**.

[0022] Referring now to FIGS. **1-3**, the BOP stack assembly **100** is mounted to the wellhead **30** and is designed and configured to control and seal the wellbore **11**, thereby containing the hydrocarbon fluids (liquids and gases) therein. In this embodiment, the BOP stack assembly **100** comprises a lower marine riser package (LMRP) **110** and a BOP or BOP stack **120**.

[0023] The BOP stack **120** is releasably secured to the wellhead **30** as well as the LMRP **110** and the LMRP **110** is releasably secured to the BOP stack **120** and the riser **14**. In this embodiment, the connections between the wellhead **30**, the BOP stack **120**, and the LMRP **110** include hydraulically actuated, mechanical wellhead-type connections **50**. In general, the connections **50** may comprise any suitable releasable wellhead-type mechanical connection such as the DWHC or HC profile subsea wellhead system available from Cameron International Corporation of Houston, Tex., or any other such wellhead profile available from several subsea wellhead manufacturers. Typically, such hydraulically actuated, mechanical wellhead-type connections (e.g., the connections **50**) include an upward-facing male connector or “hub” that is received by and releasably engages a downward-facing mating female connector or receptacle **50***b*. In this embodiment, the connection between LMRP **110** and the riser **14** is a flange connection that is not remotely controlled, whereas the connections **50** may be remotely, hydraulically controlled.

[0024] Referring still to FIGS. **1-3**, the LMRP **110** includes a riser flex joint **111**, a riser adapter **112**, an annular BOP **113**, and a pair of redundant control units or pods **114**. A flow bore **115** extends through the LMRP **110** from the riser **14** at the upper end of the LMRP **110** to the connection **50** at the lower end of the LMRP **110**. The riser adapter **112** extends upward from the flex joint **111** and is coupled to the lower end of the riser **14**. The flex joint **111** allows the riser adapter **112** and the riser **14** connected thereto to deflect angularly relative to the LMRP **110** while wellbore fluids flow from the wellbore **11** through the BOP stack assembly **100** into the riser **14**. The annular BOP **113** comprises an annular elastomeric sealing element that is mechanically squeezed radially inward to seal on a tubular extending through the LMRP **110** (e.g., the string **16**, casing, drillpipe, drill collar, etc.) or seal off the flow bore **115**. Thus, the annular BOP **113** has the ability to seal on a variety of pipe sizes and/or profiles, as well as perform a “Complete Shut-off” (CSO) to seal the flow bore **115** when no tubular is extending therethrough.

[0025] In this embodiment, the BOP stack **120** comprises an annular BOP **113** as previously described, choke/kill valves **131**, and choke/kill lines **132**. The choke/kill line connections **130** connect the female choke/kill connectors of the LMRP **110** with the male choke/kill adapters of the BOP stack **120**, thereby placing the choke/kill connectors of the LMRP **110** in fluid communication with the choke lines **132** of the BOP stack **120**. A main bore **125** extends through the BOP stack **120**. In addition, the BOP stack **120** includes a plurality of axially stacked ram BOPs **121**. Each ram BOP **121** includes a pair of opposed rams and a pair of actuators **126** that actuate and drive the matching rams. In this embodiment, the BOP stack **120** includes four ram BOPs **121**—an upper ram BOP **121** including opposed blind shear rams or blades **121***a* for severing the tubular string **16** and sealing off the wellbore **11** from the riser **14**; and the three lower ram BOPs **120** including the opposed pipe rams **121***c* for engaging the string **16** and sealing the annulus around the tubular string **16**. In other embodiments, the BOP stack (e.g., the stack **120**) may include a different number of rams, different types of rams, one or more annular BOPs, or combinations thereof. As will be described in more detail below, the control pods **114** operate the valves **131**, the ram BOPs, and the annular BOPs **113** of the LMRP **110** and the BOP stack **120**.

[0026] The opposed rams **121***a,* c are located in cavities that intersect the main bore **125** and support the rams **121***a, c* as they move into and out of the main bore **125**. Each set of rams **121***a, c* is actuated and transitioned between an open position and a closed position by matching actuators **126**. In particular, each actuator **126** hydraulically moves a piston within a cylinder to move a connecting rod coupled to one ram **121***a, c*. In the open positions, the rams **121***a, c* are radially withdrawn from the main bore **125**. However, in the closed positions, the rams **121***a, c* are radially advanced into the main bore **125** to close off and seal the main bore **125** (e.g., rams **121***a*) or the annulus around the tubular string **16** (e.g., **121***c*). The main bore **125** is substantially coaxially aligned with the flow bore **115** of the LMRP **110**, and is in fluid communication with the flow bore **115** when the rams **121***a, c* are open.

[0027] As best shown in FIG. **3**, the BOP stack **120** also includes a set or bank **127** of hydraulic accumulators **127***a* mounted on the BOP stack **120**. While the primary hydraulic pressure supply is provided by the hydraulic conduits **15** extending along the riser **14**, the accumulator bank **127** may be used to support operation of the rams **121***a, c* (i.e., supply hydraulic pressure to the actuators **126** that drive the rams **121***a, c* of the stack **120**), the choke/kill valves **131**, the connector **50***b* of the BOP stack **120**, and the choke/kill connectors **130** of the BOP stack **120**. As will be explained in more detail below, the accumulator bank **127** serves as a backup means to provide hydraulic power to operate the rams **121***a, c*, the valves **131**, the connector **50***b,* and the connectors **130** of the BOP stack **120**.

[0028] Although the control pods **114** may be used to operate the BOPs **121** and the choke/kill valves **131** of the BOP stack **120** in this embodiment, in other embodiments, the BOPs **121** and the choke/kill valves **131** may also be operated by one or more subsea remotely operated vehicles (ROVs).

[0029] As previously described, in this embodiment, the BOP stack **120** includes one annular BOP **113** and four sets of rams (one set of shear rams **121***a,* and three sets of pipe rams **121***c*). However, in other embodiments, the BOP stack **120** may include different numbers of rams, different types of rams, different numbers of annular BOPs (e.g., annular BOP **113**), or combinations thereof Further, although the LMRP **110** is shown and described as including one annular BOP **113**, in other embodiments, the LMRP (e.g., LMRP **110**) may include a different number of annular BOPs (e.g., two sets of annular BOPs **113**). Further, although the BOP stack **120** may be referred to as a "stack" because it contains a plurality of ram BOPs **121** in this embodiment, in other embodiments, BOP **120** may include only one ram BOP **121**.

[0030] Both the LMRP **110** and the BOP stack **120** comprise re-entry and alignment systems **140** that allow the LMRP **110**—BOP stack **120** connections to be made subsea with all the auxiliary connections (i.e. control units, choke/kill lines) aligned. The choke/kill line connectors **130** interconnect the choke/kill lines **132** and the choke/kill valves **131** on the BOP stack **120** to the choke/kill lines **133** on the riser adapter **112**. Thus, in this embodiment, the choke/kill valves **131** of the BOP stack **120** are in fluid communication with the choke/kill lines **133** on the riser adapter **112** via the connectors **130**. However, the alignment systems **140** are not always necessary and need not be included.

[0031] As shown in FIGS. **3-6**, the subsea BOP stack assembly **100** further includes a measurement system **200**, which includes at least one container (e.g., the hydraulic accumulators **127***a* mounted on the BOP stack **120**), at least one sensor **210**, and an information system **220**.

[0032] In this embodiment, the containers are the hydraulic accumulators **127***a,* which are piston-type accumulators that include an element **202** moveable within their internal volume, or cavity, **230**. In this case, the moveable elements **202** are the pistons separating the hydraulic fluid **206** from the gas **208** within the internal volumes of the accumulators **127***a*. It should be appreciated by those of skill in the art that the containers may be any type of container with an internal volume and an element moveable within the internal volume.

[0033] The measurement system **200** includes at least one sensor **210** that wirelessly measures the position of the element **202** within the container(s) and transmits the measured position information. As shown in FIG. **4**, the sensor may be installed inside an end cap of the container **127***a* and the container **127***a* may contain more than one sensor **210**. The sensor **210** may also be any suitable type of sensor. For example, the sensor **210** may be a radio-frequency, a far field electromagnetic (microwave), a near field electromagnetic, or an acoustic sensor capable of using one or more techniques (including but not limited to carrier phase detection) related to wave propagation and reflection characteristics to determine the distance between a position in the container (e.g., the inside face of the end cap) and the moveable element **202**. For example, the sensor **210** propagates electromagnetic waves **212** in the direction indicated by the arrow A. The waves travel through the internal volume of the container on the gas side of the movable element **202** and reflect off the moveable element **202**, resulting in reflection waves **214** traveling in the direction indicted by arrow B back to the sensor **210**. The sensor **210** receives the reflected waves and measures the distance to the moveable element. The sensor **210** can also transmit the position information as an analog or digital signal for storage or processing. The sensor **210** may measure at any suitable frequency rate, e.g. as 1 Hz, for taking accurate position measurements.

[0034] Examples of measurement techniques include, but are not limited to, cavity resonance, time of flight, phase measurement, and backscatter modulation techniques which may be exploited directly or indirectly. For example, the sensor **210** may use a cavity resonance approach and measure natural resonance frequencies determined by the cylinder diameter and cavity **230** length. The cavity **230** length changes with position of the element **202** and the corresponding change in resonance frequency can be translated to element **202** displacement via an inverse square range law. As a further example, the sensor **210** may operate using a phase reflectometry approach where a phase comparator is used to compare transmitted and reflected signal phase. Element **202** displacement serves to alter the phase relationship and this can be translated to element **202** displacement by a linear range law. Both methods require knowledge of electromagnetic propagation speed in the gas medium **208**.

[0035] On the gas **208** side of the element **202**, microwave propagation speed is a function of gas permittivity. Gas permittivity increases as the gas pressure is increased and this serves to reduce microwave propagation speed. Thus, propagation speed should be taken into account to reduce measurement errors due to the large variation and high absolute value of pressure experienced in the container **127***a* during its operational cycle.

[0036] As an example, if the container **127***a* is cylindrical, a proposed solution to in-situ propagation speed measurement is to use the cylindrical cavity radial resonance modes which are a function of the cylinder diameter only. The diameter of the cylinder is known so the frequency of resonance for these modes can be used to estimate propagation speed to high precision and so account for variations in propagation speed with gas pressure change. In this manner, the sensor **210** can self-calibrate to account for variations in propagation speed related to changes in pressure of the gas in the container **127***a*. An additional feature of this approach is that the measured propagation speed can be related directly to cavity pressure, and so the sensor **210** can be used to provide both element **202** range and cavity pressure measurement data.

[0037] Furthermore, the sensor **201** may operate combining the resonance approach, the phase approach, or any of the other techniques.

[0038] FIG. **5** shows an alternative embodiment further including a transponder **211** attached to the moveable element **202**. The transponder **211** communicates with the sensor **210** by retransmitting the signal received from the sensor **210**. The transponder **211** may also be any suitable type for communicating with the sensor **210**. For example, the sensor **210** may be a radio-frequency transceiver and the transponder **211** may be a radio-frequency identification (RFID) tag located on the element **202**. The sensor **210** would then take measurements by sending a radio-frequency signal to the RFID tag **211** and processing the response signal from the RFID tag **211** to determine the position of the element **202**. This processing can be done using any appropriate technique, such as time of flight, phase variance, or any other suitable technique. As an example, if the sensor **210** and the RFID tag **211** operate by passive RFID communication, the sensor **210** may use backscatter modulation, i.e., the modulation of the transponder antenna radar cross section.

[0039] The RFID transponder(s) **211** may include active or passive RFID technology, even within the same container **127***a*. The RFID transponders **211** may also transmit signals at the same or different frequencies to differentiate the signals. Further, an active RFID transponder **211** may include an antenna, a battery, a microchip, and a memory device. During use, the antenna may receive and transmit signals. The battery enables an active RFID transponder **211** to transmit communications over distances that a passive RFID transponder cannot. The microchip processes incoming and outgoing communications and may communicate with the memory. The microchip may be an application specific microchip specifically designed for RFID applications or a general-purpose microchip. In some embodiments, the microchip may include a memory within the chip, rather than communicate with an external memory. The memory may store information for transmission information system **220** or possibly other RFID transponders Similar to an active RFID transponder, a passive RFID transponder also may include an antenna, microchip, and memory.

[0040] The sensors **210** may operate by transmitting a first communication to the RFID transponder **211** to wake up the RFID transponder **211**. A second communication may then be used to communicate position or other data. Once the information is communicated, another signal may be used to shut down any active RFID transponders **211**.

[0041] With multiple containers **127***a*, each with a moveable element **202**, the transponders **211** may be included on one, some, or all of the moveable elements **202**, depending on how many accumulators are being monitored. The transponders **211** may also include identification functionality such that they are capable of communicating with the sensor **210** to identify each element **202** from the other elements **202**, preventing interference across accumulators. Using this configuration, there may be a sensor **210** for each container **127***a* or there may be a sensor **210** (or sensors) outside the containers **127***a* that communicates with more than one transponder **211**. In this manner, there may be fewer sensors **210** than containers **127***a*, with the potential for as little as one sensor **210** for the entire measurement system **200**.

[0042] In addition to measuring position, the measurement system **200** may also include a sensor **210** for measuring temperature within the internal volume of the container **127***a*. Because the temperature of the internal volume may change with a sudden change in pressure, measuring the temperature adds additional information regarding the remaining volume of hydraulic fluid in the accumulator **127***a*.

[0043] As shown in more detail in FIG. **6**, the measurement system **200** further includes an information system **220** capable of receiving the position information from the sensor(s) **210**. To collect the measurement information, the information system **220** includes an information hub **222** in communication with the sensors **210** to receive the measurement signals. The information hub **222** collects, processes, stores, and/or retransmits the measurement information from the sensors **210** using any suitable means. If the information hub **222** is used to store information, the information hub **222** may include a suitable memory device.

[0044] Although the present invention has been described with respect to specific details, it is not intended that such details should be regarded as limitations on the scope of the invention, except to the extent that they are included in the accompanying claims.

What is claimed is:

1. A measurement system, including:

blowout preventers (BOPs) configured in a blowout preventer (BOP) stack;

a hydraulic fluid accumulator mounted on the BOP stack and including a piston moveable within an internal volume of the accumulator, the piston dividing the internal volume into a first chamber having hydraulic fluid and a second chamber having a gas with the volumes of the first and second chambers depending on the position of the piston, and the accumulator being capable of providing the hydraulic fluid from the first chamber to operate a BOP of the BOP stack;

a sensor capable of wirelessly measuring the position of the piston within the accumulator and transmitting the measured position information, wherein the sensor is installed on a stationary portion of the accumulator and is positioned at a fixed location within the second chamber to emit a wireless signal from the sensor through the gas toward the piston for measuring the position of the piston within the accumulator; and

an information system capable of reading the position information from the sensor.

2. The system of claim **1**, further including:
a radio-frequency identification (RFID) tag located on the piston; and
the sensor including a radio-frequency transceiver capable of sending a radio-frequency signal to the RFID tag and reading a response signal from the RFID tag.

3. The system of claim **1**, wherein the sensor is at least one of a radio-frequency sensor, a far field electromagnetic (microwave) sensor, a near field electromagnetic sensor, and an acoustic sensor.

4. The system of claim **1**, further including:
more than one accumulator including a piston;
transponders located on each piston and capable of communicating with the sensor to identify each piston from the other pistons.

5. The system of claim **1**, wherein the information system includes an information hub located remotely from the sensors.

6. The system of claim **1**, further including a sensor capable of measuring the temperature inside the accumulator and transmitting the measured temperature information to the information system.

7. The system of claim **1**, wherein the BOP stack is a subsea BOP stack and the hydraulic fluid accumulator, sensor, and information system are all locatable subsea.

8. The system of claim **1**, further including:
more than one accumulator including a piston;
sensors capable of wirelessly measuring the position of the pistons within the accumulators and transmitting the measured position information; and
the information system capable of reading the position information from the sensors.

9. The system of claim **1**, wherein the sensor installed on the stationary portion of the accumulator and positioned at the fixed location within the second chamber is capable of self-calibration to account for variations in propagation speed related to changes in pressure of the gas in the accumulator.

10. A measurement system, including:
a container including an element moveable within an internal volume of the container, wherein the element includes a piston moveable within an internal volume of a hydraulic fluid accumulator, the piston dividing the internal volume into a first chamber having hydraulic fluid and a second chamber having a gas with the volumes of the first and second chambers depending on the position of the piston;
a sensor capable of wirelessly measuring the position of the piston within the hydraulic fluid accumulator and transmitting the measured position information, wherein the sensor is installed on a stationary portion of the accumulator and is positioned at a fixed location within the second chamber to emit a wireless signal from the sensor through the gas toward the piston for measuring the position of the piston within the accumulator; and
an information system capable of reading the position information from the sensor.

11. The system of claim **10**, further including:
a radio-frequency identification (RFID) tag located on the element; and
the sensor including a radio-frequency transceiver capable of sending a radio-frequency signal to the RFID tag and reading a response signal from the RFID tag.

12. The system of claim **10**, further including:
more than one container including a moveable element;
transponders located on each element and capable of communicating with the sensor to identify each element from the other elements.

13. The system of claim **10**, further including a sensor capable of measuring the temperature inside the container and transmitting the measured temperature information to the information system.

14. The system of claim **10**, further including:
more than one container including a moveable element;
sensors capable of wirelessly measuring the position of the elements within the containers and transmitting the measured position information; and
the information system capable of reading the position information from the sensors.

15. The system of claim **10**, wherein the sensor installed on the stationary portion of the accumulator and positioned at the fixed location within the second chamber is capable of self-calibration to account for variations in propagation speed related to changes in pressure of the gas in the container.

16. A method comprising:
measuring a position of a piston within an internal cavity of a hydraulic fluid accumulator; and
determining a volume of hydraulic fluid remaining in the hydraulic fluid accumulator based on the measured position of the piston within the hydraulic fluid accumulator.

17. The method of claim **16**, wherein measuring the position of the piston within the internal cavity of the hydraulic fluid accumulator includes wirelessly measuring the position of the piston via a sensor.

18. The method of claim **17**, wherein wirelessly measuring the position of the piston via the sensor includes emitting a wireless signal from the sensor toward the piston.

19. The method of claim **18**, wherein the sensor is an acoustic sensor and emitting the wireless signal from the sensor toward the piston includes emitting an acoustic signal from the sensor toward the piston, and wherein measuring the position of the piston within the internal cavity of the hydraulic fluid accumulator includes receiving a reflection of the emitted acoustic signal from the piston.

20. The method of claim **18**, wherein the piston divides the internal cavity into a first chamber having the hydraulic fluid and a second chamber having a gas with the volumes of the first and second chambers depending on the position of the piston, and wherein emitting the wireless signal from the sensor toward the piston includes emitting the wireless signal from the sensor through the gas toward the piston.

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