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(71) Applicant: **SAUDI ARABIAN OIL COMPANY**
[SA/SA]; 1 Eastern Avenue, Dhahran, 31311 (SA).

(71) Applicant (for AG only): **ARAMCO SERVICES COMPANY** [US/US]; 1200 Smith Street, Two Allen Building, Houston, Texas 77002 (US).

(72) Inventors: **NEACSU, Marius**; Saudi Aramco, P.O. Box: 11442, Dhahran, 31311 (SA). **AL-MOUSA, Ahmed**; Saudi Aramco, P.O. Box 13467, Dhahran, 31311 (SA). **AL-RA-**

MADHAN, Ahmed A.; Saudi Aramco, P.O. Box 13467, Dhahran, 31311 (SA).

(74) Agent: **BRUCE, Carl E.** et al.; FISH & RICHARDSON P.C., P.O. Box 1022, Minneapolis, Minnesota 55440-1022 (US).

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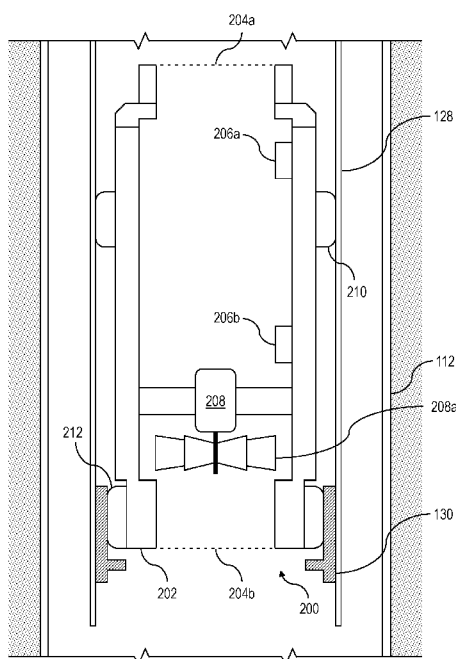


FIG. 2A

(57) Abstract: A kick detection system includes an apparatus configured to be retrievably attached to a production tubing in a well. The apparatus includes a housing, a first pressure sensor, a second pressure sensor, and a flow detection device. The first and second pressure sensors are configured to sense respective local pressure of downhole fluid flowing through the housing. The flow detection device is configured to detect a direction of downhole fluid flowing through the housing. The kick detection system includes a computer configured to determine one or more downhole well properties of the downhole fluid based on respective signals received from the first pressure sensor, the second pressure sensor, and the flow detection device. The computer is configured to determine whether a kick is occurring in the well based on the determined one or more downhole well properties of the downhole fluid.

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WELL KICK DETECTION

CLAIM OF PRIORITY

[0001] This application claims priority to U.S. Patent Application No. 16/254,757 filed on January 23, 2019, the entire contents of which are hereby
5 incorporated by reference.

TECHNICAL FIELD

[0002] This disclosure relates to well operations, for example, in wells formed in hydrocarbon-carrying reservoirs.

BACKGROUND

10 [0003] Hydrocarbons, such as oil or natural gas, can be retrieved from subsurface reservoirs by drilling wells. In some instances, a kick can occur in a well. A well kick is an undesirable subsurface fluid or gas flow influx from the subsurface reservoirs into a wellbore. Kicks can happen during drilling, tripping, completion, or other well operations. The influx can be caused by pressure imbalances between
15 formation fluids and wellbore fluids, such as drilling mud or cement. The likelihood of a kick increases as the well gets deeper due to increased pressures in deep wells. Uncontrolled kicks may result in blowouts, which can have severe environmental and financial ramifications. Thus, early detection and mitigation of well kicks are desirable in hydrocarbon exploration and production operations.

SUMMARY

20 [0004] This disclosure describes technologies relating to detecting well kicks.
[0005] Certain aspects of the subject matter described can be implemented as a kick detection system. A kick detection system includes an apparatus configured to be retrievably attached to a production tubing in a well. The apparatus includes a housing,
25 a first pressure sensor, a second pressure sensor, and a flow detection device. The second pressure sensor is spaced apart from the first pressure sensor. The first and second pressure sensors are configured to sense respective local pressure of downhole fluid flowing through the housing and transmit a respective signal representing the sensed respective local pressure. The flow detection device is configured to detect a
30 direction of downhole fluid flowing through the housing and transmit a respective signal

representing the detected direction of fluid flow. The kick detection system includes a computer configured to determine one or more downhole well properties of the downhole fluid based on respective signals received from the first pressure sensor, the second pressure sensor, and the flow detection device. The computer is configured to
5 determine whether a kick is occurring in the well based on the determined one or more downhole well properties of the downhole fluid.

[0006] This, and other aspects, can include one or more of the following features.

[0007] The computer can include a memory and a processor interoperably
10 coupled to the memory. The processor can be configured to determine a density of the downhole fluid flowing through the housing based on a distance between the first pressure sensor and the second pressure sensor and the respective signals received from the first pressure sensor and the second pressure sensor. The processor can be configured to transmit an alarm signal in response to determining that the kick is
15 occurring in the well.

[0008] The apparatus can include a centralizer surrounding an outer diameter of the housing. The centralizer can be configured to contact the production tubing of the well. The processor can be configured to be coupled to the production tubing of the well. The apparatus and processor can be cooperatively configured to establish
20 communication between each other via the production tubing of the well.

[0009] The housing can include a fishing neck configured to attach to a slickline, such that the apparatus can be installed within the production tubing and retrieved from the production tubing.

[0010] The processor can be communicatively coupled to a pump. The
25 processor can be configured to cause the pump to flow fluid into the well in response to determining that the kick is occurring in the well.

[0011] The processor can be communicatively coupled to a blowout preventer of the well. The processor can be configured to cause the blowout preventer to close in response to determining that the kick is occurring in the well.

[0012] The flow detection device can include a rotatable vane flowmeter. The
30 processor can be configured to determine a direction of the downhole fluid flowing through the housing based on a rotation direction of the rotatable vane flowmeter in response to the downhole fluid flowing through the rotatable vane flowmeter.

[0013] The apparatus can include a temperature sensor positioned within the housing. The temperature sensor is configured to sense a local temperature of the downhole fluid flowing through the housing and to transmit a respective signal representing the sensed local temperature. Determining whether the kick is occurring in the well can include determining whether a change in the sensed local temperature is equal to or greater than a threshold temperature change value within a predetermined time span.

[0014] The apparatus can include a seal on an outer circumferential surface of the housing. The seal can be configured to form a seal with the production tubing.

[0015] Certain aspects of the subject matter described can be implemented as a method using a kick detection system. A first local pressure of a downhole fluid is measured at a first location in a well. A first signal representing the first local pressure is transmitted. A second local pressure of the downhole fluid is measured at a second location in the well. The second location is spaced apart from the first location. A second signal representing the second local pressure is transmitted. A direction of flow of the downhole fluid is detected. A third signal representing the detected direction of flow is transmitted. One or more downhole well properties of the downhole fluid are determined based on receiving at least one of the first signal, the second signal, or the third signal. It is determined whether a kick is occurring in the well based on the determined one or more downhole well properties of the downhole fluid.

[0016] This, and other aspects, can include one or more of the following features.

[0017] Determining the one or more downhole well properties of the downhole fluid can include determining a density of the downhole fluid based on the first signal, the second signal, and a distance between the first location and the second location. Detecting the direction of flow of the downhole fluid can include determining a rotation direction of a rotatable vane flowmeter of the kick detection system in response to the downhole fluid flowing through the rotatable vane flowmeter.

[0018] A pump can be caused to flow fluid into the well in response to determining that the kick is occurring in the well.

[0019] A blowout preventer of the well can be caused to close in response to determining that the kick is occurring in the well.

[0020] An alarm signal can be transmitted in response to determining that the

kick is occurring in the well.

[0021] A local temperature of the downhole fluid can be measured, and a fourth signal representing the measured local temperature can be transmitted. It can be determined whether a change in the measured local temperature is equal to or greater than a threshold temperature change value within a predetermined time span. An alarm signal can be transmitted in response to determining that the change in the measured local temperature is equal to or greater than the threshold temperature change value within the predetermined time span.

[0022] At least a portion of the kick detection system can be attached to a downhole portion of a production tubing positioned in the well.

[0023] The portion of the kick detection system can be detached from the production tubing, and the portion of the kick detection system can be retrieved from the well.

[0024] Certain aspects of the subject matter described can be implemented as a kick detection system. The kick detection system includes an apparatus configured to be retrievable attached to a production tubing positioned in a well. The apparatus includes a housing including a first end and a second end. The housing has a longitudinal axis defined through the first end and the second end. The housing is configured to, while attached to the production tubing positioned in the well, allow downhole fluid to flow through the first end and the second end. The apparatus includes a first pressure sensor positioned within the housing at a first distance from the first end. The first pressure sensor is configured to measure a first local pressure of the downhole fluid flowing through the housing and to transmit a first signal representing the first local pressure. The apparatus includes a second pressure sensor positioned within the housing at a second distance from the first end. The second distance is different from the first distance. The second pressure sensor is configured to measure a second local pressure of the downhole fluid flowing through the housing and to transmit a second signal representing the second local pressure. The apparatus includes a flow detection device within the housing. The flow detection device is configured to detect a direction of the downhole fluid flowing through the housing and to transmit a third signal representing the detected direction of downhole fluid flow. The kick detection system includes a memory and a processor interoperably coupled to the memory. The processor is configured to be communicatively coupled to the first pressure sensor, the second

pressure sensor, and the flow detection device. The processor is configured to determine a density of the downhole fluid flowing through the housing based on the first signal, the second signal, and the difference between the first distance and the second distance. The processor is configured to determine whether a kick is occurring in the well based on at least one of determining that a difference between the determined density of the downhole fluid flowing through the housing and a predetermined fluid density is equal to or greater than a threshold density difference value or determining a change in direction of the downhole fluid flowing through the housing based on the third signal. The processor is configured to transmit an alarm signal in response to determining that the kick is occurring in the well.

[0025] The details of one or more implementations of the subject matter of this disclosure are set forth in the accompanying drawings and the description. Other features, aspects, and advantages of the subject matter will become apparent from the description, the drawings, and the claims.

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DESCRIPTION OF DRAWINGS

[0026] FIG. 1 is a schematic diagram of an example system that can be used to detect a kick in a well.

[0027] FIG. 2A is a schematic diagram of an example apparatus that can be implemented in the system of FIG. 1.

20 [0028] FIG. 2B is a schematic diagram of an example apparatus that can be implemented in the system of FIG. 1.

[0029] FIG. 3 is a block diagram of an example computer system that can be implemented in the system of FIG. 1.

25 [0030] FIG. 4 is a flowchart of an example method that can be used to detect a kick in a well.

DETAILED DESCRIPTION

[0031] This disclosure describes a system for detection of well kicks by monitoring downhole well conditions. One issue in kick detection is that conditions indicating that a kick has occurred, or is about to occur, typically develop downhole. Often, these downhole conditions are not readily detectable by conventional methods, such as monitoring mud pit volume. Although some conditions can be detected

eventually at the surface of the well, the delay between occurrence downhole and detection at the surface can delay a timely reaction that could minimize undesirable consequences of the kick. Another drawback associated with conventional methods is the inability to detect a kick in total loss circulation conditions because wellbore fluids are lost to the formation and do not return to the surface. Another potential issue is reliance on an operator's judgment. For example, many of the measured well conditions may be correlated to the kick without the operator recognizing their significance in a timely manner or the urgent need to take action.

[0032] The subject matter in this disclosure is directed to resolving, or at least reducing, the problems associated with delayed well kick detection. The disclosed early kick detection system monitors various downhole well conditions, such as direction of fluid flow and changes in fluid density, and transmits alarm signals to alert operators at the surface. The system includes pressure sensors placed apart in the wellbore to measure the difference in hydrostatic pressure, which can be used to calculate wellbore fluid density. The system also includes a flowmeter to measure the direction of wellbore fluid flow. A certain magnitude of change in fluid density or flow direction can be indicative of a kick and can trigger an alarm. The alarm is communicated to the surface where an operator can intervene to counter the influx entering the wellbore before the kick becomes uncontrollable.

[0033] The subject matter described in this disclosure can be implemented in particular implementations so as to realize one or more of the following advantages. The system can be used, retrieved, and reused in drilling, tripping, completion, or other phases of well operations. The system can be mounted on a drill or tubing string without the use of downhole cables to transmit measurements without modifying the tubing or drill string designs themselves. In total loss circulation conditions, the system can detect the rate and direction of wellbore fluids, regardless of the mud pit volume. Because the system monitors conditions downhole, it can detect an early influx before developing into a kick. Also, measuring pressure at certain points downhole to calculate the density of wellbore fluids is more accurate than other methods that use acoustic tools to estimate density, which could be affected by the existence of impurities. The kick detection tool can be retrieved, for example, by slickline intervention.

[0034] FIG. 1 shows an example well 100 with an example kick detection system. The well 100 extends from surface 106 into the Earth 108. The well 100 is

shown as a vertical well, but in other instances, the well 100 can be a deviated well with a wellbore deviated from vertical (for example, horizontal or slanted). The wellbore of the well 100 is typically, although not necessarily, cylindrical. All or a portion of the wellbore is lined with a tubing, such as casing 112. The casing 112 extends from the surface 106 downhole into the wellbore. The casing 112 operates to isolate the bore of the well 100 and a tubular 128, from the surrounding Earth 108. The casing 112 can be formed of a single continuous tubing or multiple lengths of tubing joined (for example, threaded, welded, or both) end-to-end. In some cases, the wellbore of the well 100 is uncased (for example, openhole).

[0035] The well 100 includes a tubular 128. In some implementations, the tubular 128 is a production tubing positioned within the casing 112 and used to produce reservoir fluids. The tubular 128 is made of materials compatible with the wellbore geometry, production requirements, and well fluids. In some implementations, the tubular 128 is a drill string. As shown in FIG. 1, the tubular 128 can be suspended from a top drive 150. The top drive 150 is a device that suspends and holds the tubular 128 in the wellbore. In some implementations, the top drive 150 applies torque to turn a drill string. In some implementations, the top drive 150 can include one or more hydraulic or electric motors. Although not shown, a rotary table and kelly drive can be used instead of the top drive 150.

[0036] The well 100 also includes a kick detection apparatus 200 residing in the wellbore, as illustrated by FIG. 1. The kick detection apparatus 200 is of a type configured in size and robust construction for installation within the tubular 128 inside the well 100. The apparatus 200 is configured to attach to, and be retrieved from, an inner wall of the tubular 128. In some implementations, the apparatus 200 is attached to a downhole portion of the tubular 128 positioned within the well 100. In this disclosure, in the context of a wellbore, an “uphole portion” means closer to the surface while a “downhole portion” means farther from the surface. In vertical wells, for example, an uphole portion is synonymous to above and a downhole portion is synonymous to below. The apparatus 200 measures one or more operating parameters of downhole fluids and transmits corresponding signals to a kick detection computer 300. The signals are transmitted from the apparatus 200 to the computer 300 via the tubular 128.

[0037] The kick detection computer 300 is a data-processing computing device located at surface 106 and connected to the tubular 128 via one or more cables, as shown by FIG. 1. The computer 300 receives signals from the kick detection apparatus 200 representing the one or more operating parameters of the downhole fluids. The computer 300 can calculate one or more downhole well properties based on the signals received from the apparatus 200. The computer 300 can determine, based on the one or more calculated downhole well properties, whether a kick is occurring in the well 100, and transmit an alarm signal to an operator who can take action to counter the influx entering the wellbore. In some implementations, the computer 300 can transmit a signal to automatically drive a controllable device to implement a countermeasure against the kick (for example, close a blowout preventer or pump fluid into the well 100). Although shown as being located at the surface in FIG. 1, in some implementations, the computer 300 (or an additional computer 300) can be disposed downhole to perform calculations downhole (for example, a fluid density calculation based on measured pressure values) and transmit calculation results to another computer located at the surface.

[0038] FIG. 2A shows a schematic of an example kick detection apparatus 200 lowered into a tubular 128. The apparatus 200 includes a housing 202, which is a tube that has a first end 204a and a second end 204b. The housing 202 has a longitudinal axis that passes through the first end 204a and the second end 204b. For example, when the kick detection apparatus 200 is positioned in the well 100, the first end 204a is an uphole end of the housing 202, and the second end 204b is a downhole end of the housing 202. The housing 202 is configured in size to fit inside the tubular 128 and is made of materials robust enough to withstand the downhole environment (for example, the downhole operating temperatures and pressures and exposure to downhole fluids). The downhole fluids can include one or a combination of the following: oil, natural gas, formation water, brine or drilling fluids (also known as drilling mud). The housing 202 can be attached to an inner circumferential wall of the tubular 128, for example, through a tubing nipple 130 with a tubing nipple latching mechanism secured against a seal 212. In some implementations, the tubing nipple 130 can have an X or XN nipple profile. In some implementations, the tubing nipple latching mechanism can be a PX or PXN tubing plug. The latching mechanism can latch to the profile of the tubing nipple 130 using matching slips. The matching slips can engage and disengage by jarring. Because an outside diameter of the nipple tubing 130 can have the same dimension as an inside

diameter of the tubular 128, the tubing nipple 130 can lock to the tubular 128, for example, through an interference or friction fit. The housing 202 can form a seal with the tubing nipple 130 using the seal 212. The seal 212 can therefore seal the annulus between the housing 202 and tubular 128 to prevent downhole fluids from bypassing the kick detection apparatus 200.

[0039] In some implementations, the housing 202 has a fishing neck configured to attach to a slickline to facilitate lowering and retrieving the apparatus 200 from the tubular 128. The fishing neck can be positioned, for example, at the first end 204a. In some implementations, the first end 204a is formed as a fishing neck. In some implementations, the fishing neck is a separate component that is attached to the first end 204a. During completion or other well operation, the apparatus 200 can be temporarily installed on the tubular 128 to detect kicks. In some implementations, the length of the housing 202, including the fishing neck, does not exceed the typical length of a slickline lubricator of 40 feet.

[0040] The kick detection apparatus 200 includes a first pressure sensor 206a and a second pressure sensor 206b. The first pressure sensor 206a and second pressure sensor 206b (in some instances, collectively referred to as the pressure sensors) are positioned within the housing 202. The first pressure sensor 206a is positioned at a first distance from the first end 204a, and the second pressure sensor 206b is positioned at a second distance from the first end 204a. The first distance is different than the second distance. In some implementations, the first distance is less than the second distance. The difference between the first distance and second distance (that is, the distance between the pressure sensors 206a and 206b) is at least a minimum distance to attain an adequate true vertical depth separation even at a maximum inclination for slickline accessibility and tool retrieval. In some implementations, the difference between the first distance and second distance is approximately 20 feet or at least 20 feet. For example, the distance between the pressure sensors can be set to be approximately 20 feet, to be able to attain an adequate true vertical depth separation at inclinations of up to 48° (which is the typical maximum inclination for a slickline accessibility for tube retrieval). In this disclosure, “approximately” means a deviation or allowance of up to 10 percent (%) and any variation from a mentioned value is within the tolerance limits of any machinery used to manufacture the part.

[0041] The pressure sensors are configured to measure the hydrostatic pressures of the downhole fluid flowing through the housing 202. The first pressure sensor 206a measures a first local pressure of the downhole fluid, and the second pressure sensor 206b measure a second local pressure of the downhole fluid. In this disclosure, “local” means in close vicinity of—for example, the first pressure sensor 206a measures a first local pressure, which is a pressure local to (in close vicinity of) the first pressure sensor 206a. In this context, the pressure sensors 206a and 206b are spaced apart from each other within the housing 202 to allow each sensor (206a, 206b) to measure a local pressure corresponding to its location and different from the other sensor, from which a pressure differential can be determined. Further, the pressure sensors are configured to transmit electromagnetic signals representing the local pressures to the kick detection computer 300 (FIG. 1). For example, each of the pressure sensors 206a and 206b include a transmitter. The first pressure sensor 206a transmits a first signal representing the first local pressure, and the second pressure sensor 206b transmits a second signal representing the second local pressure. In some implementations, the pressure sensors 206a and 206b are high resolution pressure gauges. In some implementations, the high resolution pressure gauges require a minimum resolution of 0.1 pounds per square inch (psi), 0.01 psi, 0.001 psi, or smaller. “Minimum resolution” means that the gauge can measure a fluid pressure within an accuracy of the minimum resolution. For example, a high resolution pressure gauge with a minimum resolution of 0.001 psi can measure a fluid pressure within an accuracy of 0.001 psi. This fine resolution allows measuring the pressure difference between the two high resolution pressure gauges within the short separation distance inside the housing 202 at high accuracy.

[0042] The kick detection apparatus 200 includes a flow detection device 208 that is installed within the housing 202. The flow detection device 208 (in some instances, referred to as a flowmeter) can detect a direction of flow of the downhole fluid flowing through the housing 202. The flow detection device 208 can include a transmitter, so that the flow detection device 208 can transmit a third signal representing the detected direction of the downhole fluid flow to the computer 300 (FIG. 1). In some implementations, the flow detection device 208 can detect a rate of flow of the downhole fluid flowing through the housing 202, and the third signal can also represent the detected rate of flow. In some implementations, the flow detection device 208 can be a spinner type. The flow detection device 208 can include rotatable vanes 208a. The flow

detection device 208 can be a device for measuring the velocity of downhole fluid flow in a production or injection well based on the speed of rotation of the vanes 208a. The vanes 208a rotate in response to the downhole fluid flow. The clockwise or counter-clockwise rotational direction of the vanes 208a depends on whether the downhole fluid is flowing upward (indicating a kick) or downward (indicating normal well operation conditions). The flow detection device 208 is of a size that could fit within an inside diameter of the housing 202 and of material robust enough to withstand the downhole fluids flow. In some implementations, the flow detection device 208 is a spinner type flowmeter covering the full-bore area of the housing 202 that can capture all of the downhole fluid flowing through the housing 202. In some implementations, the flow detection device 208 is a spinner type flowmeter covering less than the full-bore area of the housing 202.

[0043] As illustrated by FIG. 2B, other implementations are contemplated. FIG. 2B shows an example kick detection apparatus 200 installed within a tubular 128. The kick detection apparatus 200 can include a slips mechanism 222. The seal 212 and slips mechanism 222 are positioned at an outer circumferential surface of the housing 202. The seal 212 and slips mechanism 222 secure the housing 202 against the tubular 128 by forming a seal. As the kick detection apparatus 200 is lowered inside the tubular 128, the seal 212 and slips mechanism 222 seal off the annulus between the housing 202 and the tubular 128. Thus, the seal 212 and slips 222 prevent the downhole fluids from bypassing the apparatus 200.

[0044] In some implementations, as illustrated by FIGs. 2A and 2B, the kick detection apparatus 200 includes a centralizer 210. The centralizer 210 is a device that surrounds an outer circumferential surface of the housing 202 and maintains the apparatus 200 in the center of the tubular 128. Maintaining the apparatus 200 centralized can prevent the apparatus 200 from obstructing the downhole fluids and allow the fluids to flow efficiently through the housing 202 for better measurements. The centralizer 210 can ensure proper mounting of the housing 202 inside the tubular 128 (against the tubing nipple 130 or the seal 212 and slips mechanism 222). The centralizer 210 can align the housing 202 with a retrieving tool (for example, a slickline) to facilitate lowering and retrieving the apparatus 200. The centralizer 210 can also serve as a metal contact to the tubular 128, such that signals from the pressure sensors 206a and 206b and flow detection device 208 can be transmitted to the kick detection computer 300

(shown in FIG. 1), without the need for cables inside the wellbore. Cable connections running from the computer 300 to the downhole apparatus 200 can slow down the lowering and retrieval of the apparatus 200. The tubular 128 and centralizer 210 are conductive and can transmit signals from sensors to the computer 300 in a comparable rate of speed to a cable or wired connection.

[0045] In some implementations, as illustrated by FIG. 2B, the kick detection apparatus 200 can include a temperature sensor 214 positioned within the housing 202. The temperature sensor 214 is configured to sense a local temperature of the downhole fluid flowing through the housing 202. The temperature sensor 214 can include a transmitter, so that the temperature sensor 214 can transmit a signal representing the sensed local temperature to the kick detection computer 300 (FIG. 1). The temperature sensor 214, along with the pressure sensors and flow detection device 208, are, in some instances, referred to collectively as the sensors. Each one of the sensors transmits a respective signal, which is referred to collectively as the signals. The signals can be transmitted from the sensors to the computer 300 (FIG. 1) through the centralizer 210 and tubular 128. Each respective signal can be transmitted to the computer 300 in a different digital coding to prevent interference between the signals. Although shown in FIG. 2A as being located between the second end 204b and the second pressure sensor 206b, the flow detection device 208 can, in some implementations, be located between the second pressure sensor 206b and the first pressure sensor 206a (as shown in FIG. 2B). In some implementations, the flow detection device 208 is located between the first pressure sensor 206b and the first end 204a.

[0046] FIG. 3 is a block diagram of an example computer system 300 that is used to detect a kick in a well 100 (FIG. 1). The kick detection computer 300 is communicatively coupled to the sensors through the tubular 128 (for example, by one or more cables, as shown in FIG. 1). The computer 300 is configured to determine one or more downhole well properties of the downhole fluid based on respective signals received from the sensors. In some implementations, pressure, temperature, and flow rate measured at various positions within the tubular 128 (FIG. 1) may be used as relevant parameters. As further described below and with reference to FIG. 4, the computer 300 detects a kick by comparing data measurements received from the sensors corresponding with one or more downhole well properties with pre-determined values associated with occurrence of a kick. If data measurements received from the

sensors exceeds these pre-determined values, the computer 300 transmits an alarm signal indicating that a kick is about to occur.

[0047] The computer 300 includes a processor 305. Although illustrated as a single processor 305 in FIG. 3, two or more processors may be used according to particular needs, desires, or particular implementations of the computer 300. Generally, the processor 305 executes instructions and manipulates data to perform the operations of the computer 300 and any algorithms, methods, functions, processes, flows, and procedures as described in this specification. The processor 305 and the kick detection apparatus 200 are cooperatively configured to establish communication between each other via the tubular 128 of the well 100 (FIG. 1). The processor 305 is configured to receive data measurements from the apparatus 200 (FIG. 1) and determine a density of the downhole fluid flowing through the housing 202 based on a distance between the first pressure sensor 206a and the second pressure sensor 206b and the respective signals received from the first pressure sensor 206a and the second pressure sensor 206b (FIGs. 2A-2B). The processor 305 is also configured to determine a direction of the downhole fluid flowing through the housing 202 based on a rotation direction of the flow detection device 208 in response to the downhole fluid flowing through the flow detection device 208 (FIGs. 2A-2B). In some implementations, the processor 305 is configured to receive measurements of a local temperature of the downhole fluid from a temperature sensor 214 and determine whether a change in the measured local temperature is equal to or greater than a threshold temperature change value within a predetermined time span (FIGs. 2A-2B).

[0048] The processor 305 is the component in the computer 300 responsible for manipulating data received from the sensors and making a determination whether a kick is occurring in the well 100. In some implementations, the processor 305 is communicatively coupled to a pump, and the processor 305 is configured to cause the pump to flow fluid into the well 100 in response to determining that the kick is occurring in the well. In some implementations, the processor 305 is communicatively coupled to a blowout preventer of the well 100, and the processor 305 is configured to cause the blowout preventer to close in response to determining that the kick is occurring in the well 100.

[0049] The computer 300 also includes a memory 307 that is interoperably coupled to the processor 305. The memory 307 can hold measurement data, received

from the sensors, for the computer 300. Although illustrated as a single memory 307, two or more memories 307 (of the same or combination of types) can be used according to particular needs, desires, or particular implementations of the computer 300 and the described functionality. While memory 307 is illustrated as an integral component of the computer 300, memory 307 can be external to the computer 300. The memory 307 can be a transitory or non-transitory storage medium. The memory 307 stores computer-readable instructions executable by the processor 305 that, when executed, cause the processor 305 to perform operations, such as transmit an alarm signal in response to detecting a kick.

[0050] The computer 300 includes an interface 304. Although illustrated as a single interface 304 in FIG. 3, two or more interfaces 304 may be used according to particular needs, desires, or particular implementations of the computer 300. Although not shown in FIG. 3, the computer 300 can be communicably coupled with a network. The interface 304 is used by the computer 300 for communicating with other systems that are connected to the network in a distributed environment. Generally, the interface 304 comprises logic encoded in software or hardware (or a combination of software and hardware) and is operable to communicate with the network. More specifically, the interface 304 may comprise software supporting one or more communication protocols associated with communications such that the network or interface's hardware is operable to communicate physical signals within and outside of the illustrated computer 300.

[0051] The computer 300 can also include a database 306 that can hold data for the computer 300 or other components (or a combination of both) that can be connected to the network. Although illustrated as a single database 306 in FIG. 3, two or more databases (of the same or combination of types) can be used according to particular needs, desires, or particular implementations of the computer 300 and the described functionality. While database 306 is illustrated as an integral component of the computer 300, database 306 can be external to the computer 300.

[0052] The computer 300 can also include a power supply 314. The power supply 314 can include a rechargeable or non-rechargeable battery that can be configured to be either user- or non-user-replaceable. The power supply 314 can be hard-wired. There may be any number of computers 300 associated with, or external to, a computer system containing computer 300, each computer 300 communicating over

the network. Further, the term “client,” “user,” “operator,” and other appropriate terminology may be used interchangeably, as appropriate, without departing from this specification. Moreover, this specification contemplates that many users may use one computer 300, or that one user may use multiple computers 300.

5 [0053] The illustrated computer 300 is intended to encompass any computing device such as a server, desktop computer, laptop/notebook computer, one or more processors within these devices, or any other suitable processing device, including physical or virtual instances (or both) of the computing device. Additionally, the computer 300 can include a computer that includes an input device, such as a keypad,
10 keyboard, touch screen, or other device that can accept user information, and an output device that conveys information associated with the operation of the computer 300, including digital data, visual, audio information, or a combination of information.

[0054] FIG. 4 shows a flowchart of an example method 400 to detect a kick in a well 100 using the kick detection apparatus 200. At step 402, the downhole fluid is
15 allowed to flow through the housing 202 of the kick detection apparatus 200, such that the downhole fluid can be monitored. At step 404a, the first pressure sensor 206a measures a first local pressure of the downhole fluid at a first location in the well 100 (i.e., the location of the first pressure sensor 206a). Similarly, at step 404b, the second pressure sensor 206b measures a second local pressure of the downhole fluid at a second
20 location in the well 100 (i.e., the location of the second pressure sensor 206b), the second location spaced apart from the first location. In some implementations, the distance between the first and second locations is approximately 20 feet. At steps 406a and 406b, the pressure sensors transmit respective first and second signals representing the first local pressure and second local pressure, for example, to the computer 300. The
25 frequency of signal transmission can be set based on one or a combination of the following factors: the length of the tubular 128, well type (for example, gas or oil well), expected type of kick (for example, gas or oil kick), expected deployment time of the tubular 128 inside the wellbore, and battery life of the sensors. For example, the frequency of signal transmission can be set at one signal per minute for an oil well. For
30 example, the frequency of signal transmission can be set at four signals per minute for a gas well.

[0055] At step 408, one or more downhole well properties of the downhole fluid are determined based on receiving the signals from the pressure sensors. The one or

more downhole well properties can be determined using the computer 300. For example, the processor 305 can calculate a density of the downhole fluid based on the first signal, the second signal, and the distance between the first location and the second location. In some implementations, the calculation is a result of converting the differential pressure between the two pressure sensors into a pressure gradient based on a true vertical distance between the two pressure sensors (taking into account the deviation inclination of the tubular 128). For example, the pressure gradient can be calculated by Equation 1:

$$\text{Pressure gradient} = \frac{\Delta P}{\text{TVD}} \quad (1)$$

where ΔP is the difference in pressure between the two local pressure values measured by the pressure sensors 206a and 206b, and TVD is the true vertical distance between the pressure sensors 206a and 206b.

[0056] The TVD can be calculated by Equation 2:

$$\text{TVD} = d \cos \theta_{\text{incline}} \quad (2)$$

where d is the distance between the pressure sensors 206a and 206b, and θ_{incline} is the angle of inclination of the kick detection apparatus 200 with respect to the vertical (for example, θ_{incline} is 0° for a vertical well and 90° for a horizontal well).

[0057] Once the pressure gradient is calculated, the density of the fluid can be determined by simple unit conversion. An example unit conversion in English units is shown in Equation 3:

$$\rho = (\text{Pressure gradient}) \times \left(\frac{144 \text{ in}^2}{1 \text{ ft}^2} \right) \quad (3)$$

where pressure gradient is in pounds per square inch (psi) per foot (ft), and ρ is density in pounds per cubic foot (pcf). Although Equation 3 is in English units, any suitable unit conversion can be used to obtain the density in desired units. Unit conversion can also be used to convert from density to pressure gradient.

[0058] The pressure gradient indicates the type of fluid flowing inside the tubular 128 (for example, brine > 0.456 psi/ft; 0.43 psi/ft $<$ water < 0.456 psi/ft; 0.25 psi/ft $<$ oil < 0.35 psi/ft; and gas < 0.1 psi/ft). The pressure gradient is the rate of change in downhole fluid pressure with depth (that is, the change of pressure per unit distance or depth). The downhole fluid can be a formation fluid, such oil or water, or a wellbore fluid, such as brine or mud. The downhole fluid pressure increases with depth and, thus,

the pressure gradient is used to calculate the pressure of any downhole fluid with a known depth. The pressure gradient of any given fluid can be calculated from the density of that fluid, as previously described.

[0059] In some implementations, data of properties of known fluids (such as brine, water, oil, and gas) can be input to the computer 300 (for example, stored in the memory 307) and the calculated properties of the downhole fluid can be compared to the stored data. At step 410, if the calculated property of the downhole fluid (ρ) is different from the expected value for that property of the brine (ρ_0) used as killing fluid in workover operations, it can be determined that a kick is occurring in the well 100. In some implementations, at step 410, the computer 300, via the processor 305, transmits an alarm signal to the interface 304 to alert operators if the calculated property is not within a 5%-10% margin of the expected (known) property. The kill brine density (gradient), the formation fluid density (gradient) range, the well deviation survey of the well, and any other useful information can be input as input data to the computer 300, such that the necessary calculations and comparisons can be performed by the processor 305. For example, a calculated pressure gradient can be compared to an expected pressure gradient. For example, a calculated density can be compared to an expected density.

[0060] Another monitored downhole well property is flow direction passing through the housing 202 (step 402). At step 412, the flow detection device 208 detects a direction of flow of the downhole fluid. At step 414, the flow detection device 208 transmits a third signal representing the detected direction of flow to the processor 305. At step 416, the processor 305 determines the direction of flow of the downhole fluid by determining a rotation direction of the rotatable vanes 208a of the flow detection device 208 in response to the downhole fluid flowing through the flow detection device 208. In some implementations, a clockwise rotation can be attributed to upward fluid flow, and a counter-clockwise rotation can be attributed to downward fluid flow. In some implementations, a clockwise rotation can be attributed to downward fluid flow, and a counter-clockwise rotation can be attributed to upward fluid flow. In cases where the direction of fluid flow is expected to be downward, if the rotation direction of the flow detection device 208 detects an upward fluid flow (towards the surface 106), the method 400 proceeds to step 410, and the processor 305 transmits an alarm signal that signifies a kick is occurring in the well 100. In cases

where the direction of fluid flow is expected to be upward, if the flow detection device 208 detects an increase in the rate of upward fluid flow (for example, an increase of 15%), the method 400 proceeds to step 410, and the processor 305 transmits an alarm signal that signifies a kick is occurring in the well 100. In some implementations, the threshold change value in fluid flow rate that indicates a kick can be set to an increase of 15%-20%. The threshold value can be adjusted while running the tubular 128 in hole based on downhole well conditions. The tubular 128 can initially be maintained at a fixed running speed while measuring the rate of tubing fill-up to determine the threshold value of flow rate increase.

[0061] Although differential pressure can be enough to identify the density (gradient) of the downhole fluid, a sudden increase in the fluid temperature can also indicate the presence of wellbore influx. In some implementations, the temperature sensor 214 measures a local temperature of the downhole fluid at step 418 and transmits a fourth signal representing the measured local temperature to the processor 305 at step 420. The processor 305 determines whether a change in the measured local temperature is equal to or greater than a threshold temperature change value within a predetermined time span at step 422. The processor 305 determines that a kick is occurring in the well 100 if change in the sensed local temperature is equal to or greater than the threshold temperature change value (for example, a change of 10%) within the predetermined time span (for example, 10 seconds). The method then proceeds to step 410, and the computer 300, via the processor 305, transmits an alarm signal to alert operators that a kick is occurring in the well 100.

[0062] In some implementations, the method 400 proceeds from step 410 to step 410a. The processor 305 can be communicatively coupled to a pump, and the processor 305 can cause the pump to flow fluid into the well 100 in response to determining that the kick is occurring in the well. In some implementations, the method 400 proceeds from step 410 to step 410b. The processor 305 can be communicatively coupled to a blowout preventer of the well, and the processor 305 can cause the blowout preventer to close in response to determining that the kick is occurring in the well.

[0063] In some implementations, the kick detection computer 300 can be connected to a rig's computing system to receive other data related to current tubing depth and pumping rate. The computer 300 can also be connected to the rig

computing system to receive data of the current speed of tripping in tripping operations. Once the tripping speed stops which indicated that the tubular 128 is put on slips and kept stationary, the computer 300 transmits an alarm signal if any upward flow is detected by the flow detection device 208.

5 [0064] In some implementations, the kick detection apparatus 200 is attached, at least partially, to a downhole portion of the tubular 128 positioned in the well 100. The kick detection apparatus 200 can then be detached from the tubular 128 and retrieved from the well 100.

[0065] EXAMPLE

10 [0066] The kick detection apparatus 200 measured local pressure values using the first pressure sensor 206a and the second pressure sensor 206b. The first pressure sensor 206a read $P_1 = 2,423.678$ pounds per square inch gauge (psig), and the second pressure sensor 206b read $P_2 = 2,430.556$ psig. The pressure sensors 206a and 206b were set apart at a distance of 20 feet and an inclination angle of 45° . The true vertical distance (TVD) between the pressure sensors 206a and 206b was calculated (refer to
15 Equation 2): $20 \text{ feet} \times \cos(45^\circ) = 14.147 \text{ feet (ft)}$.

[0067] The kill fluid used in the wellbore (in this example, brine) had a known density of 70 pounds per cubic feet (pcf). The pressure gradient of the kill fluid was calculated as 0.486 psi/ft (refer to Equation 3). This was the reference pressure
20 gradient to which the measured pressure gradient was compared.

[0068] The downhole fluid pressure gradient was calculated (refer to Equation 1) from the measured pressure values (P_1 and P_2) and the true vertical distance (TVD) between the pressure sensors (206a and 206b) to determine whether an influx (kick) of a fluid other than the kill fluid has occurred in the wellbore:

25
$$\text{Downhole fluid pressure gradient} = \frac{P_2 - P_1}{\text{TVD}} = \frac{2430.556 - 2423.678}{14.147} = 0.486 \frac{\text{psi}}{\text{ft}}$$

[0069] The kick detection computer 400 was pre-set to send an alarm signal if the calculated downhole fluid pressure gradient falls out of a $\pm 5\%$ margin of the kill fluid known gradient range (that is, if the calculated downhole fluid pressure gradient is less than 0.4617 psi/ft or greater than 0.5103 psi/ft). In this example, the calculated
30 downhole fluid gradient is the same as the pre-determined kill fluid pressure gradient, meaning no kick is occurring, and no alarm was triggered.

[0070] In this disclosure, the terms “a,” “an,” or “the” are used to include one or more than one unless the context clearly dictates otherwise. The term “or” is used to

refer to a nonexclusive “or” unless otherwise indicated. The statement “at least one of A and B” has the same meaning as “A, B, or A and B.” In addition, it is to be understood that the phraseology or terminology employed in this disclosure, and not otherwise defined, is for the purpose of description only and not of limitation. Any use of section
5 headings is intended to aid reading of the document and is not to be interpreted as limiting; information that is relevant to a section heading may occur within or outside of that particular section.

[0071] Values expressed in a range format should be interpreted in a flexible manner to include not only the numerical values explicitly recited as the limits of the
10 range, but also to include all the individual numerical values or sub-ranges encompassed within that range as if each numerical value and sub-range is explicitly recited. For example, a range of “0.1% to about 5%” or “0.1% to 5%” should be interpreted to include about 0.1% to about 5%, as well as the individual values (for example, 1%, 2%, 3%, and 4%) and the sub-ranges (for example, 0.1% to 0.5%, 1.1% to 2.2%, 3.3% to
15 4.4%) within the indicated range. The statement “X to Y” has the same meaning as “about X to about Y,” unless indicated otherwise. Likewise, the statement “X, Y, or Z” has the same meaning as “about X, about Y, or about Z,” unless indicated otherwise. “About” can allow for a degree of variability in a value or range, for example, within 10%, within 5%, or within 1% of a stated value or of a stated limit of a range.

[0072] While this disclosure contains many specific implementation details,
20 these should not be construed as limitations on the subject matter or on what may be claimed, but rather as descriptions of features that may be specific to particular implementations. Certain features that are described in this disclosure in the context of separate implementations can also be implemented, in combination, in a single
25 implementation. Conversely, various features that are described in the context of a single implementation can also be implemented in multiple implementations, separately, or in any suitable sub-combination. Moreover, although previously described features may be described as acting in certain combinations and even initially claimed as such, one or more features from a claimed combination can, in some cases, be excised from
30 the combination, and the claimed combination may be directed to a sub-combination or variation of a sub-combination.

[0073] Particular implementations of the subject matter have been described. Nevertheless, it will be understood that various modifications, substitutions, and

alterations may be made. While operations are depicted in the drawings or claims in a particular order, this should not be understood as requiring that such operations be performed in the particular order shown or in sequential order, or that all illustrated operations be performed (some operations may be considered optional), to achieve
5 desirable results. Accordingly, the previously described example implementations do not define or constrain this disclosure.

CLAIMS

WHAT IS CLAIMED IS:

1. A kick detection system, comprising:
 - an apparatus configured to be retrievably attached to a production tubing
 - 5 positioned in a well, the apparatus comprising:
 - a housing configured to, while the apparatus is attached to the
 - production tubing positioned in the well, allow downhole fluid to flow through
 - the housing;
 - a first pressure sensor positioned within the housing;
 - 10 a second pressure sensor positioned within the housing, the second
 - pressure sensor spaced apart from the first pressure sensor, the first pressure
 - sensor and the second pressure sensor configured to sense respective local
 - pressure of the downhole fluid flowing through the housing and to transmit a
 - respective signal representing the sensed respective local pressure; and
 - 15 a flow detection device within the housing, the flow detection device
 - configured to detect a direction of the downhole fluid flowing through the
 - housing and to transmit a respective signal representing the detected direction
 - of fluid flow; and
 - a computer configured to:
 - 20 determine one or more downhole well properties of the downhole fluid
 - based on respective signals received from the first pressure sensor, the second
 - pressure sensor, and the flow detection device; and
 - determine whether a kick is occurring in the well based on the
 - determined one or more downhole well properties of the downhole fluid.
 - 25
2. The kick detection system of claim 1, wherein the computer comprises:
 - a memory; and
 - a processor interoperably coupled to the memory and configured to:
 - determine a density of the downhole fluid flowing through the housing
 - 30 based on a distance between the first pressure sensor and the second pressure
 - sensor and the respective signals received from the first pressure sensor and the
 - second pressure sensor; and

transmit an alarm signal in response to determining that the kick is occurring in the well.

3. The kick detection system of claim 2, wherein:

5 the apparatus comprises a centralizer surrounding an outer diameter of the housing;

 the centralizer is configured to contact the production tubing of the well;

 the processor is configured to be coupled to the production tubing of the well; and

10 the apparatus and processor are cooperatively configured to establish communication between each other via the production tubing of the well.

4. The kick detection system of claim 3, wherein the housing comprises a fishing neck configured to attach to a slickline, such that the apparatus can be installed
15 within the production tubing and retrieved from the production tubing.

5. The kick detection system of claim 4, wherein:

 the flow detection device comprises a rotatable vane flowmeter; and

20 the processor is configured to determine a direction of the downhole fluid flowing through the housing based on a rotation direction of the rotatable vane flowmeter in response to the downhole fluid flowing through the rotatable vane flowmeter.

6. The kick detection system of claim 4, wherein:

25 the apparatus comprises a temperature sensor positioned within the housing;

 the temperature sensor is configured to sense a local temperature of the downhole fluid flowing through the housing and to transmit a respective signal representing the sensed local temperature; and

30 determining whether the kick is occurring in the well comprises determining whether a change in the sensed local temperature is equal to or greater than a threshold temperature change value within a predetermined time span.

7. The kick detection system of claim 4, wherein the apparatus comprises a seal on an outer circumferential surface of the housing, the seal configured to form a seal with the production tubing.
- 5
8. A method, comprising:
- with a kick detection system,
- measuring a first local pressure of a downhole fluid at a first location in a well;
- 10 transmitting a first signal representing the first local pressure;
- measuring a second local pressure of the downhole fluid at a second location in the well, the second location spaced apart from the first location;
- transmitting a second signal representing the second local pressure;
- detecting a direction of flow of the downhole fluid;
- 15 transmitting a third signal representing the detected direction of flow;
- determining one or more downhole well properties of the downhole fluid based on receiving at least one of the first signal, the second signal, or the third signal; and
- determining whether a kick is occurring in the well based on the
- 20 determined one or more downhole well properties of the downhole fluid.
9. The method of claim 8, wherein determining the one or more downhole well properties of the downhole fluid comprises determining a density of the downhole fluid based on the first signal, the second signal, and a distance
- 25 between the first location and the second location.
10. The method of claim 8, wherein detecting the direction of flow of the downhole fluid comprises determining a rotation direction of a rotatable vane flowmeter of the kick detection system in response to the downhole fluid
- 30 flowing through the rotatable vane flowmeter.
11. The method of claim 8, comprising causing a pump to flow fluid into the well in response to determining that the kick is occurring in the well.

12. The method of claim 8, comprising causing a blowout preventer of the well to close in response to determining that the kick is occurring in the well.
- 5 13. The method of claim 8, comprising transmitting an alarm signal in response to determining that the kick is occurring in the well.
14. The method of claim 8, comprising:
measuring a local temperature of the downhole fluid; and
10 transmitting a fourth signal representing the measured local temperature.
15. The method of claim 14, comprising:
determining whether a change in the measured local temperature is equal to or greater than a threshold temperature change value within a predetermined
15 time span; and
transmitting an alarm signal in response to determining that the change in the measured local temperature is equal to or greater than the threshold temperature change value within the predetermined time span.
- 20 16. The method of claim 8, comprising attaching at least a portion of the kick detection system to a downhole portion of a production tubing positioned in the well.
17. The method of claim 16, comprising:
25 detaching the portion of the kick detection system from the production tubing; and
retrieving the portion of kick detection system from the well.
18. A kick detection system, comprising:
30 an apparatus configured to be retrievably attached to a production tubing positioned in a well, the apparatus comprising:
a housing comprising a first end and a second end, the housing having a longitudinal axis defined through the first end and the second end, the housing

configured to, while attached to the production tubing positioned in the well, allow downhole fluid to flow through the first end and the second end;

5 a first pressure sensor positioned within the housing at a first distance from the first end, the first pressure sensor configured to measure a first local pressure of the downhole fluid flowing through the housing and to transmit a first signal representing the first local pressure;

10 a second pressure sensor positioned within the housing at a second distance from the first end, the second distance different from the first distance, the second pressure sensor configured to measure a second local pressure of the downhole fluid flowing through the housing and to transmit a second signal representing the second local pressure; and

15 a flow detection device within the housing, the flow detection device configured to detect a direction of the downhole fluid flowing through the housing and to transmit a third signal representing the detected direction of downhole fluid flow;

a memory; and

a processor interoperably coupled to the memory and configured to be communicatively coupled to the first pressure sensor, the second pressure sensor, and the flow detection device, the processor configured to:

20 determine a density of the downhole fluid flowing through the housing based on the first signal, the second signal, and the difference between the first distance and the second distance;

determine whether a kick is occurring in the well based on at least one of:

25 determining that a difference between the determined density of the downhole fluid flowing through the housing and a predetermined fluid density is equal to or greater than a threshold density difference value; or

determining a change in direction of the downhole fluid flowing through the housing based on the third signal; and

30 transmit an alarm signal in response to determining the kick is occurring in the well.

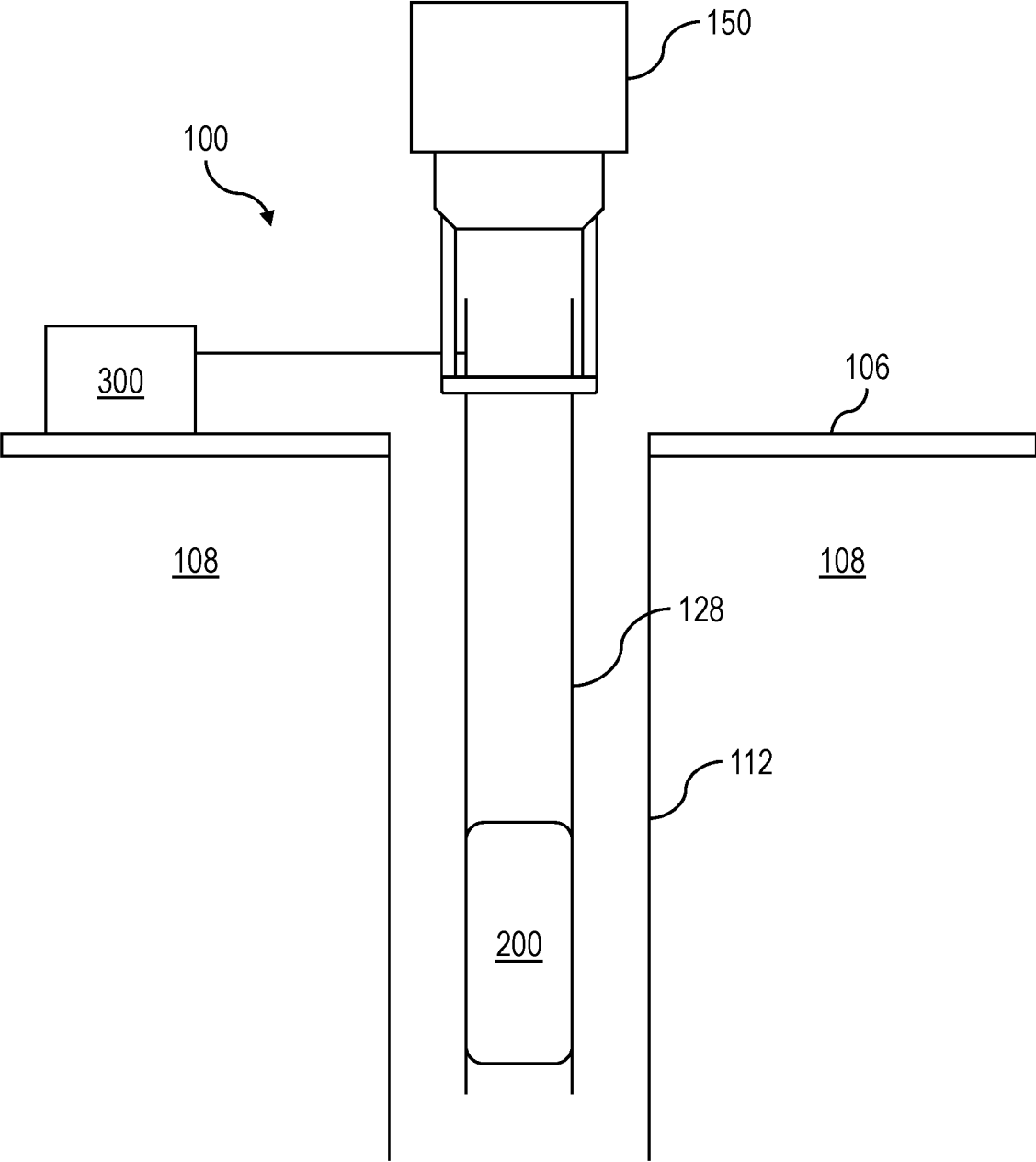


FIG. 1

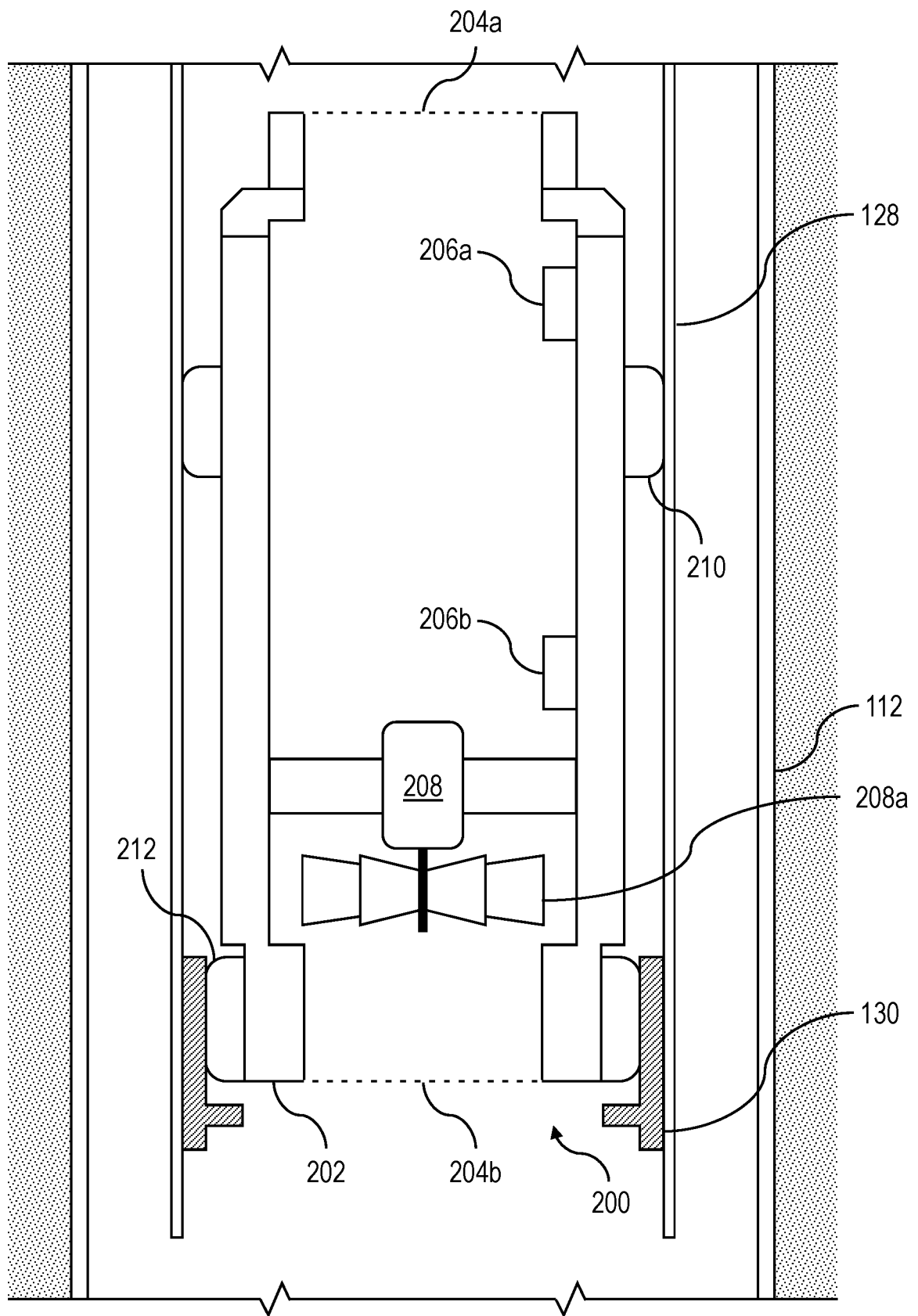


FIG. 2A

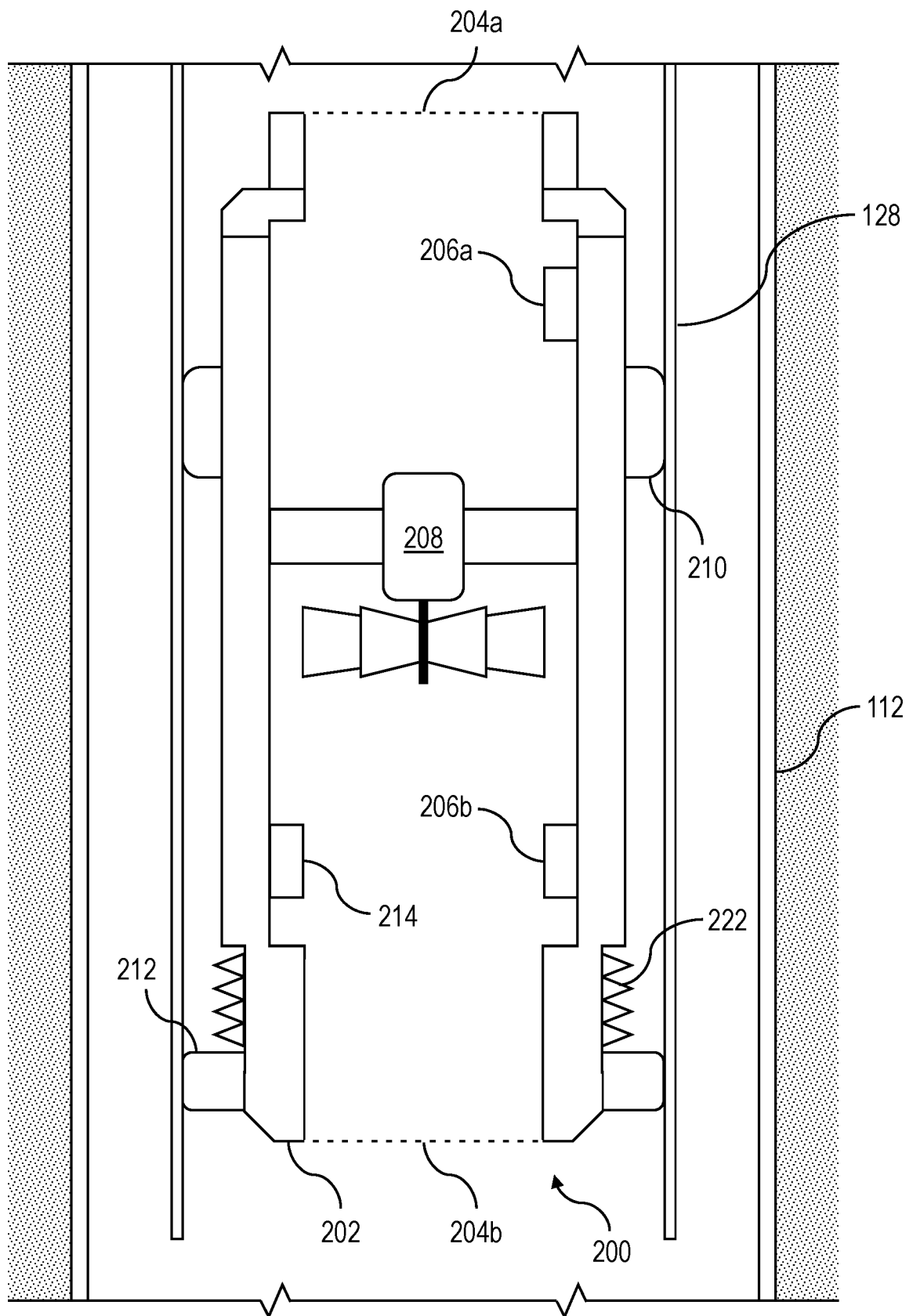
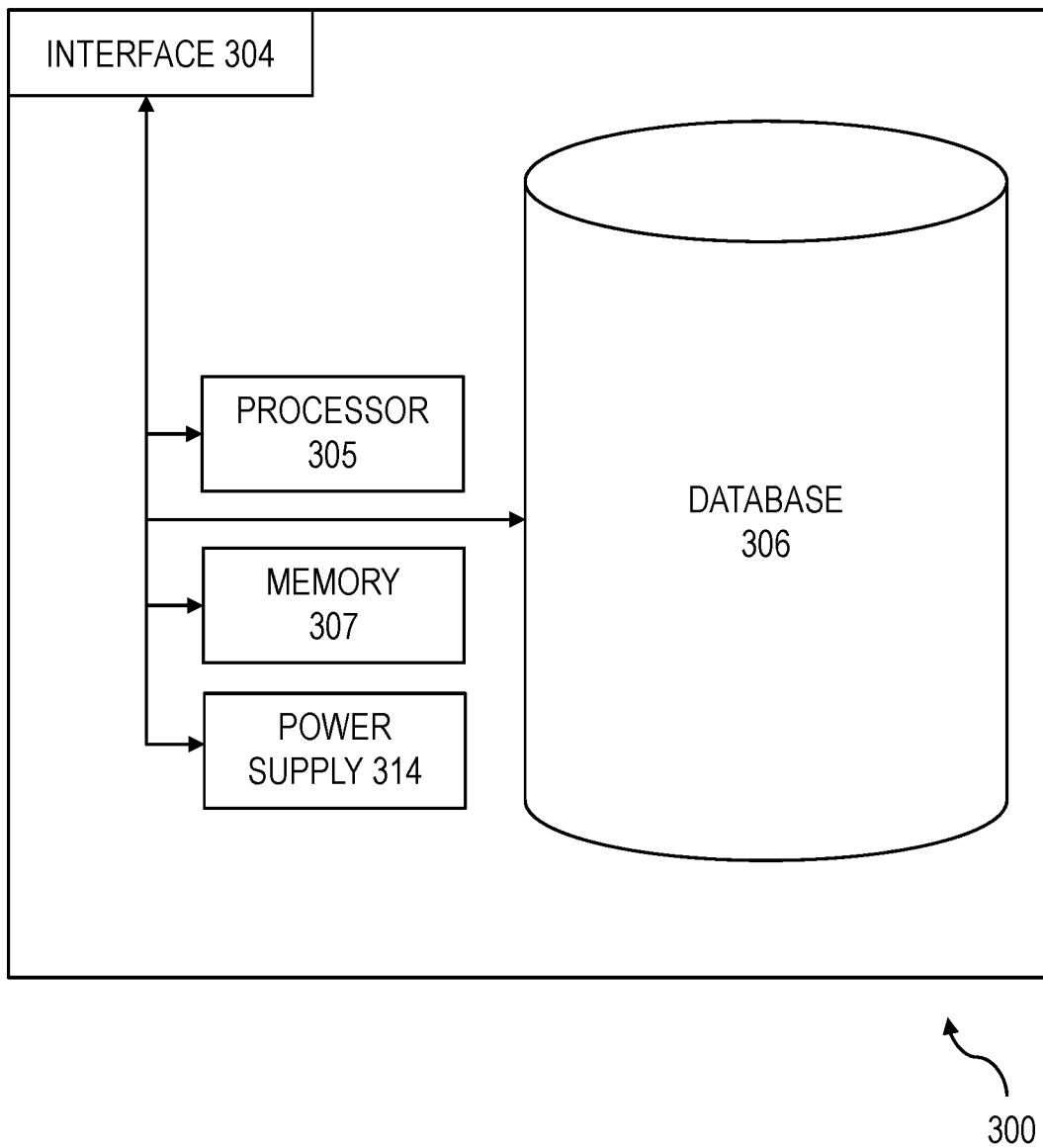


FIG. 2B

**FIG. 3**

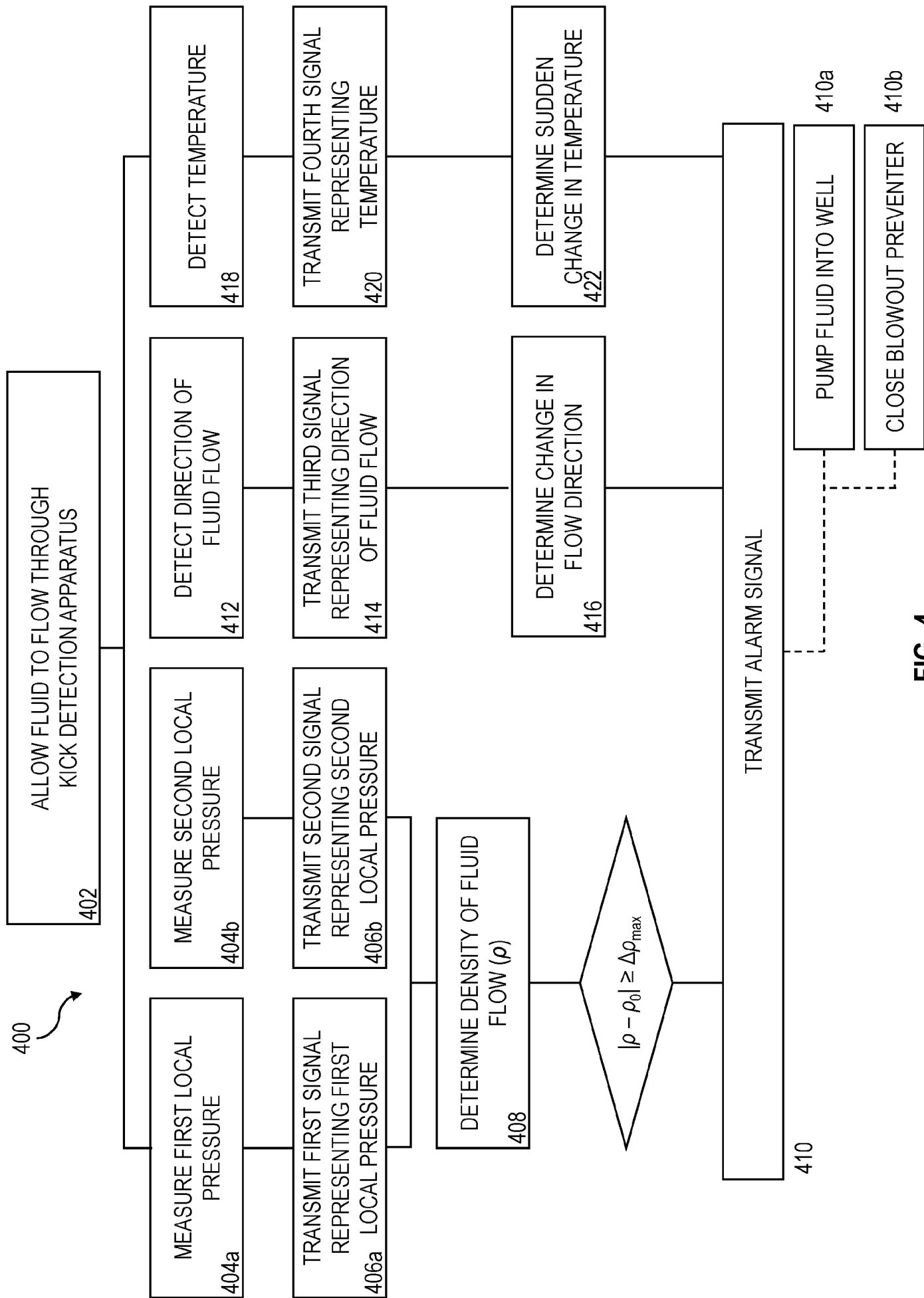


FIG. 4

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2020/014726

A. CLASSIFICATION OF SUBJECT MATTER INV. E21B47/10 E21B21/08 E21B44/00 E21B7/00 E21B43/12 ADD.		
According to International Patent Classification (IPC) or to both national classification and IPC		
B. FIELDS SEARCHED Minimum documentation searched (classification system followed by classification symbols) E21B		
Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched		
Electronic data base consulted during the international search (name of data base and, where practicable, search terms used) EPO-Internal, WPI Data		
C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X A A	WO 2016/040310 A1 (UNIV TEXAS [US]) 17 March 2016 (2016-03-17) paragraphs [0021], [0027], [0029], [0031], [0048] - [0063]; figures 1-5 ----- CN 104 712 320 B (UNIV CHINA PETROLEUM; CNOOC RES INST ET AL.) 14 December 2016 (2016-12-14) paragraphs [0017], [0022]; figures 1-4 abstract -----	8,11-14, 16,17 1-7,9, 10,15,18 1-18
☐ Further documents are listed in the continuation of Box C. ☒ See patent family annex.		
* Special categories of cited documents : "A" document defining the general state of the art which is not considered to be of particular relevance "E" earlier application or patent but published on or after the international filing date "L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified) "O" document referring to an oral disclosure, use, exhibition or other means "P" document published prior to the international filing date but later than the priority date claimed "T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention "X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone "Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art "&" document member of the same patent family		
Date of the actual completion of the international search 23 April 2020	Date of mailing of the international search report 11/05/2020	
Name and mailing address of the ISA/ European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Authorized officer Brassart, P	

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/US2020/014726

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
WO 2016040310	A1	17-03-2016	NONE

CN 104712320	B	14-12-2016	NONE
