(19) Europäisches Patentamt
European Patent Office
Office européen des brevets

(11) EP 3 387 221 B1

(12) **EUROPEAN PATENT SPECIFICATION**

(45) Date of publication and mention of the grant of the patent:
22.02.2023 Bulletin 2023/08

(21) Application number: **16873674.2**

(22) Date of filing: **06.12.2016**

(51) International Patent Classification (IPC):
E21B 47/18 *(2006.01)* ***E21B 21/10*** *(2006.01)*
E21B 21/01 *(2006.01)*

(52) Cooperative Patent Classification (CPC):
E21B 47/18; E21B 21/01; E21B 21/106

(86) International application number:
PCT/US2016/065146

(87) International publication number:
WO 2017/100189 (15.06.2017 Gazette 2017/24)

(54) **MUD PULSE TELEMETRY WITH CONTINUOUS CIRCULATION DRILLING**

DRUCKIMPULSTELEMETRIE MIT KONTINUIERLICHEM ZIRKULATIONSBOHREN

TÉLÉMÉTRIE PAR IMPULSIONS DANS LA BOUE DE FORAGE À FORAGE AVEC CIRCULATION CONTINUE

(84) Designated Contracting States:
AL AT BE BG CH CY CZ DE DK EE ES FI FR GB GR HR HU IE IS IT LI LT LU LV MC MK MT NL NO PL PT RO RS SE SI SK SM TR

(30) Priority: **07.12.2015 US 201514961364**

(43) Date of publication of application:
17.10.2018 Bulletin 2018/42

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Description

BACKGROUND OF THE DISCLOSURE

1. Field of the Disclosure

[0001] This disclosure relates generally to mud pulse telemetry systems for oilfield systems.

2. Background of the Art

[0002] To obtain hydrocarbons such as oil and gas, boreholes or wellbores are drilled by rotating a drill bit attached to the bottom of a drilling assembly (also referred to herein as a "Bottom Hole Assembly" or ("BHA"). The drilling assembly is attached to the bottom of a tubing, which is usually either a jointed rigid pipe or a relatively flexible spoolable tubing commonly referred to in the art as "coiled tubing." The string comprising the tubing and the drilling assembly is usually referred to as the "drill string." During drilling, surface personnel may "break" the drill in order to add or remove a joint or other piece of equipment. The process of breaking and making-up the drill string may interrupt communication links used by conventional drilling systems.

[0003] From US 2014/216816 A1 an apparatus for performing a wellbore operation is known. The apparatus includes a drill string having a rigid tubular section formed of a plurality of jointed tubulars and a plurality of valves positioned along the rigid tubular section. Each valve may have a radial valve controlling flow through a wall of the rigid tubular section and a signal relay device configured to convey information-encoded signals. Wellbore operations may be performed by transmitting signals using the signal relay devices.

[0004] WO 2015/065419 A1 refers to a pulse telemetry system for communicating digital data from a wellbore to a surface unit. The system includes a valve fluidly coupled to drilling fluid. The valve adjusts pressure in a drill pipe to cause pressure transitions within the drilling fluid within the drill pipe to transmit data over the drilling fluid. The valve includes a voice coil actuator for developing the pressure transitions within the drilling fluid.

[0005] From US 2007/137898 A1 a controller for a pump for pumping a drilling fluid from a storage unit to a downhole tool is known. The pump includes at least one actuation device coupled to a control console of the pump, at least one connector coupled to the at least one actuation device and a pump control mechanism of the control console.

[0006] US 2015/275658 A1 refers to methods for expanded mud pulse telemetry. One method includes measuring pressure proximate at least one of first and second pressure control modules along a drilling apparatus and telemetering the measured pressure to a surface controller. A command is transmitted from the surface controller to at least one of the first and second pressure control modules or one of first and second controllable flow restrictors via mud pulse telemetry while mud is not being pumped through a main standpipe.

[0007] In aspects, the present disclosure provides communication links and telemetry systems that provide communication even during such interruptions.

SUMMARY OF THE DISCLOSURE

[0008] According to a first aspect of the invention, there is provided a system for performing a wellbore operation while a fluid circulates in a wellbore as defined in claim 1. Further aspects of the system are defined in dependent claims 2 to 6.

[0009] According to a second aspect of the invention, there is provided a method for performing a wellbore operation while a fluid circulates in a wellbore as defined in claim 7. Further aspects of the method are defined in dependent claims 8 and 9.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] For a detailed understanding of the present disclosure, reference should be made to the following detailed description of the embodiments, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals, wherein:

> **FIG. 1** schematically illustrates an exemplary wellbore construction system made in accordance with one embodiment of the present disclosure;
> **FIG. 2** schematically illustrates a continuous circulation system that is used with the **FIG. 1** system;
> **FIG. 3** schematically illustrates a flow diverter that is used with the continuous circulation system of **FIG. 2;** and
> **FIG. 4** schematically illustrates a bore flow restriction device that may be used with the **FIG. 1** system.

DETAILED DESCRIPTION OF THE DISCLOSURE

[0011] As will be appreciated from the discussion below, aspects of the present disclosure provide a mud pulse telemetry system that can function continuously even when a drill string is "broken" to add or remove equipment. Generally, a mud pulse communication system uses pressure pulses transmitted along a column of drilling fluid (or "mud") to transmit data. The pressure pulses may be generated by a signal generator such as a valve, pulser, or pulse wave generator. Conventionally, an encoder generates a signal, *e.g.*, by either restricting mud flow or venting drilling fluid, and a decoder detects the signal.

[0012] Illustrative embodiments of the present disclosure use a mud pulse telemetry system in conjunction with a continuous circulation system in order to provide continuous or "real time" signal communication between the surface and one or more downhole locations. The system uses a drill string that includes one or more signal conveying and pressure sensitive devices that cooperate with corresponding devices on the surface to continuously detect transmitted pressure pulses. In one embodiment, at least a part of the signal conveying and pressure sensitive devices is be integrated into the flow diverters used with a continuous circulation system that circulates drilling fluid in the well. These and other embodiments are discussed in greater detail below.

[0013] Referring initially to **FIG. 1,** there is shown a system **10** in accordance with one embodiment of the present disclosure. The system **10** includes a drill string **11** and a bottomhole assembly (BHA) **20** suspended from a rig floor **13.** In one embodiment, the drill string **11** may be made up of a section of rigid tubulars **14** (*e.g.,* jointed tubular). In other embodiments, the drill string **11** may be made up of a rigid tubular section **14** and a non-rigid tubular section **16** *(e.g.,* coiled tubing). As used herein, the term rigid and non-rigid are used in the relative sense to indicate that the sections **14** and **16** exhibit different responses to an applied loading. For instance, an applied torque that a jointed tubular can readily transmit may cause coiled tubing to fail. In one sense, a non-rigid tubular may be a continuous tubular that may be coiled and uncoiled from a reel or drum **22** (i.e., 'coilable') whereas a rigid tubular section may include segmented joints that may be organized in pipe stands 12a and may be manipulated by a top drive **24.** The system **10** may also include rotary power devices **26, 28** *(e.g.,* mud motors, electric motors, turbines for rotating one or more portions of the drill string **11,** etc.). Rotary power for the drill bit **50** may be generated by a rotary power device **26** such as a motor at a connection between the rigid section **14** and the non-rigid section **16,** a near bit motor **28,** and / or the surface top drive **24.**

[0014] Referring now to **FIG. 2,** the system **10** includes a continuous circulation system **100** (CCS **100)** that maintains continuous drill mud circulation in the drill string **11** as jointed connections are made up or broken in or between the rigid or non-rigid tubular section **14** or **16.** In order to make up or break the drill string **11,** a pipe stand **12a** or a non-rigid tubular section **16** must be physically coupled or decoupled from the drill string **11.** This physical decoupling ordinarily requires prevention of fluid circulation in the drill string **11** because the drilling fluid would spill through the physical gap separating the pipe stand **12a** or the non-rigid tubular **16** and the remainder of the drill string **11.** The CCS **100** allows maintaining fluid circulation while a pipe stand **12a** or a non-rigid tubular section **16** is physically decoupled from the remainder of the drill string **11.** The CCS **100** includes a flow diverter control device **32,** an arm **34,** a fluid line **36,** and a manifold **102.** During operation, the CCS **100** uses the manifold **102** to selectively direct drilling fluid to either the top drive **24** or the flow diverters **30** that interconnect the non-rigid tubular sections **16** or the pipe stands **12a** of the rigid tubular section **14** of the remainder of the drill string **11.** Thus, two flow paths are selected for conveying fluid into the drill string **11.**

[0015] For example, during drilling, the manifold **102** directs drilling fluid into the top drive **24.** To add a pipe stand **12a,** drilling is stopped and the arm **34** moves the flow diverter control device **32** into engagement with a flow diverter **30** on top of the drill string **11.** Valves are activated internal to the flow diverter **30** that block axial flow from top drive **24** and allow radial flow from and to the flow diverter control device **32.** Thereafter, the manifold **102** switches drilling fluid flow from the top drive **24** to the fluid line **36,** which flows drilling fluid from the source **38** to the flow diverter control device **32.** The flow diverter control device **32** supplies the flow diverter **30** with pressurized fluid. The top drive **24 (FIG. 1)** is now isolated from the drill string **11** and can be disconnected from the rigid section **14.** Thus, drilling fluid is continuously supplied to the wellbore **13** even when the drill string **11** is not connected to the top drive **24.** That is, the physical decoupling and resulting gap between the top drive **24** and the drill string **11** does not prevent drilling fluid from continuing to flow in the drill string **11.** After disconnection of the top drive **24,** a new pipe stand **12a** or other equipment may be added to the drill string **11,** the top drive **24** may be reconnected to the drill string **11,** and the flow diverter control device may be disconnected from the flow diverter **30** after valves are adjusted to re-establish the fluid flow from the top drive **24** to the BHA **20** to allow drilling down another pipe stand **12a.**

[0016] Referring now to **FIG. 3,** the flow diverter **30** includes an upper end **110** and a lower end **112.** The flow diverter **30** is fitted with flow control devices that allow fluid communication to the lower end **112** via either the upper end **110** or a radial / lateral opening. The flow diverter **30** includes an upper circulation valve **114,** a lower circulation valve **116,** and an inlet **118.** The upper circulation valve **114** selectively blocks flow along a bore **120** connecting the upper and lower ends **110, 112.** The lower circulation valve **116** selectively blocks flow between the bore **120** and the inlet **118.** The flow diverter control device **32 (FIG. 2)** includes an upper valve actuator (not shown) that can shift the upper circulation valve **114** between an open and a closed position and a lower valve actuator (not shown) that can shift the lower circulation valve **116** between an open and a closed position. It should be appreciated that the CCS **100** has two separate fluid paths that can independently circulate drilling fluid into the drill string **11 (FIG. 1).** The first fluid path is formed when the upper circulation valve **114** is open and the lower circulation valve **116** is closed. In this axial flow path, drilling fluid flows along the bore **120** from the upper end **110** to the lower end **112.** The second fluid path is formed when the upper circulation valve **114** is closed and the lower circulation valve **116** is open. In this radial or lateral flow path, the drilling fluid flows along from the line **36 (FIG. 2),** across the inlet **118,** into the bore **120,** and down to the lower end **112.**

[0017] The flow diverter **30** is also configured to convey signals along the wellbore **13 (FIG. 1).** The signals may be conveyed in either the uphole or downhole direction.

The signals may be encoded with information from sensor downhole or on surface such as for monitoring downhole pressure conditions or inctructions for activating, deactivating, or controlling wellbore equipment such as equipment used to manage one or more pressure parameters. In one embodiment, the flow diverter **30** may include a short-hop telemetry module (not shown) that includes a signal relay device **60** energized by a power source **62.** The signal relay device **60** may be embedded in the flow diverter **30** or fixed to the flow diverter **30** in any other suitable manner. The signal relay device **60** includes a suitable transceiver for receiving and transmitting data signals. For example, the signal relay device **60** can include an antenna arrangement through which electromagnetic signals are sent and received through a short hop communication link. One non-limiting embodiment may include radio frequency (RF) signals. The signal relay device **60** may be a component of a one-way or a two-way telemetry system that can transmit signals (data and/or control) to the surface and/or downhole. In an exemplary short-hop telemetry system, data is transmitted from one relay point to an immediately adjacent relay point, or a relay point some distance away. In other embodiments, other waves may be used to transmit signals, *e.g.*, acoustical waves, pressure pulses, etc.

[0018] Transmission of pressure waves as arrays enables communication with all signal relay devices **30** and BHA modules along the entire drill-string at different points of time. Generation, repeating or magnification of the pulse pressure waves can be performed with positive or negative fluid displacement values. Some embodiments use battery or energy harvesting systems to drive pressure wave generating modules like piezo actuated pistons or membranes, or mud sirens, which are embedded in or connected to flow diverters **30** that include signal relay devices **60.**

[0019] The transmission of magnified pressure signal arrays, utilizing interference with other signal relay devices along the entire drill-string at about the same point of time forms an Interference Magnified Array System (IMARYS). U.S. Pat. No. 7,230,880 shows an independent working power and communication module that may be used as an interfering device and link between the pressure wave generator on surface **262** and other modules of the BHA.

[0020] Time synchronization of modules may be achieved by the atomic clock utilization. Generation or disturbance of interference may be used to transmit information. Some embodiments use switching between signal downlink and signal uplink transmission frequency at interference points to simplify the system. Another arrangement involves working with interfering pressure wave pairs (or triples, or more) traveling along the drill string, repeating signal to transmit at different point of times (repeating signal at least ones while traveling DH or UpHole). Built-in pressure sensors receiving signal close by interfering pair and generating an interfering pair with the next reachable signal relay device unit (s) after a "hand shake."

[0021] Referring back to **FIG. 1,** a communication system **200** uses the signal relay devices **60 (FIG. 3)** as part of a communication link with downhole equipment positioned along the drill string **11 (FIG. 1).** Additionally or alternatively, the signal relay devices may be included in wellbore equipment, such as a casing **17 (FIG. 1).** Illustrative wellbore equipment, include, but are not limited to, casings, liners, casing collars, casing shoes, devices embedded in the formation, conduits (e.g., hydraulic tubing, electrical cables, pipes, etc.). The downhole communication link may also include a signal carrier **66** disposed along the non-rigid carrier **16** or the rigid tubulars **14** commonly referred to as wired pipe in the drill string **11.** The signal carrier **66** may be metal wire, optical fibers, customized cement or any other suitable carrier for conveying information-containing signals. The signal carrier **66** may be embedded in the wall of the non-rigid section **16,** the rigid tubulars **14,** or the casing **17,** or disposed in any wellbore equipment at the surface or downhole. The signal carrier **66** may also be fixed inside or outside of the non-rigid section **16,** the rigid tubulars **14,** or the casing **17.** The signals may be transmitted between the signal carrier **66** and the signal relay devices **60** using a suitably configured connector **70.** Another connector **70** that may also house electronics, communication modules and processing equipment to exchange signals between the carrier **66** and the signal relay devices **60** may form a physical connection between the rigid section **14** and the non-rigid section **16.**

[0022] In some embodiments, signal exchange speed and bandwidth can be enhanced by continuous system analysis and consequent shift to the best fit configuration channel selection by the system (pre-programmed and autonomous) and the use of Ultimate Radio System Extension Lines (URSEL). An illustrative URSEL system may be already installed at the rig site and/or installed into the wellbore. For example, a signal carrier such as a fiber optic wire may be embedded in the cement used to set casing **17.** The wellbore construction equipped with signal exchange equipment/modules as mentioned may use the embedded signal carrier to transmit and receive information-bearing signals. In embodiments, radio over fiber (RoF) technology may be used to transmit information. RoF technology modulates light by radio signal and transmits the modulated light over an optical fiber. Thus, RF signals may be converted to light signals that are conveyed over fiber optic wires for a distance and then converted back to RF signals.

[0023] At the surface, the communication system **200** includes a controller **202** in signal communication with the signal relay devices **60.** The controller **202** may include suitable equipment such as a transceiver **204** to wirelessly communicate with the signal relay devices **60** using EM or RF waves **206.** This system **200** allows continuous communication while drilling and making and breaking jointed connections. The same RF transmitter or transceiver might be used for rig site and down hole transmission of the signals to reduce the complexity of the used equipment. Signal shape and strength might be adjusted depending on operational environment only.

[0024] The communication system **200** may be used to exchange information with the sensors and devices at the BHA **20** or positioned elsewhere on the string **11.** Illustrative sensors include, but are not limited to, sensors for estimating: annulus pressure, drill string bore pressure, flow rate, near-bit direction (*e.g.*, BHA azimuth and inclination, BHA coordinates, etc.), temperature, vibration/dynamics, RPM, weight on bit, whirl, radial displacement, stick-slip, torque, shock, strain, stress, bending moment, bit bounce, axial thrust, friction and radial thrust as well as formation evaluation sensors such as gamma radiation sensors, acoustic sensors, resistivity or permittivity sensors, NMR sensors, pressure testing tools and sampling or coring tools. Illustrative devices include, but are not limited to, the following: one or memory modules and a battery pack module to store and provide back-up electric power, an information processing device that processes the data collected by the sensors, and a bidirectional data communication and power module ("BCPM") that transmits control signals between the BHA **20** and the surface as well as supplies electrical power to the BHA **20.** The BHA **20** may also include processors programmed with instructions that can generate command signals to operate other downhole wellbore equipment. The commands may be generated using the measurements from downhole sensors such as pressure sensors.

[0025] Based on information obtained using the communication system **200,** the system **10** may be used to control out-of-norm wellbore conditions using well control equipment positioned in the wellbore **13.** The well control equipment may include an annulus flow restriction device **222** that hydraulically isolates one or more sections of a wellbore by selectively blocking fluid flow in the annulus **37,** a bore flow restriction device **224** that selectively blocks fluid flow along a bore **15** of the drill string **11,** and a bypass valve **250.**

[0026] The annulus flow restriction device **222** may be positioned along an uphole section of a non-rigid section **16** or anywhere else along the drill string **11.** In one embodiment, the annulus flow restriction device **222** may form a continuous circumferential seal against a wellbore wall that controls flow in the well annulus **37.** The terms seals, packers and valves are used herein interchangeably to refer to flow control devices that can selectively control flow across a fluid path by increasing or decreasing a cross-sectional flow area. The control can include providing substantially unrestricted flow, substantially blocked flow, and providing an intermediate flow regime. The intermediate flow regimes are often referred to as "choking" or "throttling," which can vary pressure in the annulus downhole of the annulus flow restriction device **222.** The fluid barrier provided by these devices can be "zero leakage" or allow some controlled fluid leakage. In some embodiments, the seals and valves may include suitable electronics in order to be responsive to control signals. Suitable flow control devices include packer-type devices, expandable seals, solenoid operated valves, hydraulically actuated devices, and electrically activated devices.

[0027] Referring to **FIG. 1,** the bore flow restriction device **224** may be at the uphole end of a non-rigid section **16.** Alternatively or additionally, the bore flow restriction device **224** may be positioned in the rigid section **14** of the drill string **11.** Referring now to **FIG. 4,** the bore flow restriction device **224** may include a flow path **226,** a sealing member **228,** a closure member **230,** a biasing member **232,** and a signal responsive actuator **234.** The sealing member **228** and the closure member **230** may be complementary in shape such that engagement forms a fluid-tight seal along the flow path **226.** The biasing member **232** is configured to bias the closure member **230** toward and against the sealing member **230.** In one embodiment, the biasing member **232** may include spring members (*e.g.*, disk springs or coil springs). The spring force of the biasing member **232** may be selected such that a preset value or range of flow rates or pressure will overcome the spring force and keep the closure member **230** in the open, unsealed position. A drop in flow rate or pressure below the range allows the biasing member **232** to urge the closure member **230** into sealing engagement with the sealing member **228** (the closed position). Thus, the bore flow restriction device **224** may be configured to close in response to an interruption in fluid flow and / or a backflow condition. A backflow condition may arise with the bore pressure downhole of the bore flow restriction device **224** is greater than the uphole bore pressure.

[0028] The signal responsive actuator **234** allows the bore flow restriction device **224** to be remotely actuated with a control signal. The signal may be transmitted from the surface and / or from a device located in the wellbore **13** (*e.g.*, the BHA **20).** For instance, the controller **202 (FIG. 1)** may transmit a control signal to instruct the bore flow restriction device **224** to open, close, or shift to an intermediate position. The signal response actuator **234** may be a hydraulic, electric, or mechanical device that can shift the closure member **230** into engagement with the sealing member **228** in response to a control signal. The actuator **234** may include suitable electronics to process the control signals and initiate the desired actions. Like the annulus flow restriction device **222,** the bore flow restriction device **224** may either completely seal the bore or partially block fluid flow in the bore.

[0029] The closure member **230** may be a bypass valve that is configured to direct flow between the annulus **37** and the bore **15** of the drill string **11.** Like the flow restriction devices **222, 224,** the closure member **230** may include a signal response actuator **234** that can shift the closure member **230** between an open position, a closed position, and / or an intermediate position. The signal response actuator **234** may include suitable electronics to receive and process the control signals and to initiate the desired actions.

[0030] In embodiments, communication using mud pulses may be enabled by distributing pressure sensors at selected surface locations within the continuous circulation system **100** and / or downhole locations; e.g., at the signal relay device **60** or in the bottomhole assembly **20.** The communication may be in one direction or bidirectional. Such a system allows continuous communication while drilling and making and breaking jointed connections. Non-limiting embodiments having such functionality are described below.

[0031] Referring to **Figs. 1-2,** in one embodiment, one or more pressure transducers may be hydraulically connected to the flow lines of the continuous circulation system **100.** For instance, a first pressure transducer **251** may be in pressure communication with the line **36** supplying drilling fluid to the flow diverter **30** and a second pressure transducer **252** may be positioned along a flow line **36** (not shown) supplying drilling fluid to the top drive **24.** Thus, the first and second pressure transducer **251, 252** may detect pressure signals conveyed along the fluid column inside the drill string **11.** Additionally, a third pressure transducer **253** may be positioned to be in fluid communication with the drilling fluid in the fluid annulus **37** surrounding the drill string **11.** Thus, the third pressure transducer **253** may server as a reference pressure or may detect pressure signals conveyed along the fluid column in the annulus **37.** The hydraulic connection or pressure communication should be sufficient to allow the transfer of pressure pulses or waves.

[0032] Referring to **Fig. 3,** the signal relay device **60** may include a fourth pressure transducer **254** in pressure communication with the bore **120** and a fifth pressure transducer **256** in pressure communication with the exterior of the signal relay device **60.** Thus, the fourth pressure transducer **254** may detect pressure signals conveyed along the fluid column inside the drill string **11** and the fifth pressure transducer **256** may detect pressure signals conveyed along the fluid column in the annulus **37** surrounding the drill string **11.** Similarly, pressure transducers may be included elsewhere in the drill string **11** (e.g. in the BHA **20)** or in other downhole or surface equipment.

[0033] Referring to **Figs. 1-3,** the pressure signals or pulses detected by the transducers **251-254, 256** may be generated by a signal generator located at one or more surface and / or downhole locations. A signal generator is any device that can produce one or more discernible pressure waves having a defined characteristic such as a shape, frequency, and / or magnitude. Signal generators may use vibrating elements or change a flow parameter (*e.g.*, flow rate). Illustrative non-limiting signal generators include bypass valves, mud pulsers, sirens, vibrators, etc. The pressure pulses created by the signal generator can be considered encoded signals because the signals are transmitted in a manner that conveys information between two locations. This information may be data such as sensor readings, command signals, alarms, etc.

[0034] In one arrangement, at the surface, a pulse wave generator **260** may be used to impart pressure pulses **262** into the drilling fluid flowing in the annulus **37.** In other embodiments, the signal generator may be a valve (not shown) at the manifold **102** that imparts pressure pulses into the fluid flowing through the bore of the drill string **11.** A signal generator (not shown) could also be positioned at the top drive **24,** the pump (not shown) flowing fluid from the mud source **38,** or any location along the mud flow path. At a downhole location, pressure pulses may be generated by the upper or lower circulation valves **114, 116** of one or more signal relay devices **60,** the annulus flow restriction device **222,** and / or the bore flow restriction devices **224.** Downhole pressure pulses may also be generated using signal generators (not shown) such as bypass valves, mud pulser, or sirens in the BHA **20.**

[0035] Referring to **Figs. 1-3,** the pressure transducers **251, 252, 253** may be connected in parallel to the controller **202** of the communication system **200.** Additionally, the controller **202** may be in signal communication (not shown) with pressure transducers **254, 256** embedded in the signal relay devices **60** or may be included elsewhere in the downhole equipment. As discussed previously, the controller **202** may include suitable equipment such as electrical or fiber optic wires, or the transceiver **204** to wirelessly communicate with the signal relay devices **60** using the EM or RF waves **206.** The same RF transmitter or transceiver may be used for rig site and downhole transmission of the signals to reduce the complexity of the equipment. Signal shape and strength might be adjusted depending on operational environment.

[0036] Referring now to **FIGS. 1-4,** exemplary modes of use of the system **10** will be discussed. To begin, the non-rigid section **16** may be used to convey the BHA **20** into the wellbore **13.** It should be noted that the drill string **11** does not require the non-rigid section **16.** However, use of the non-rigid section **16** may reduce the number of pipe stands **12a** and flow diverters **30** required to reach a desired target depth. When desired, the rigid section **14** may be connected to the non-rigid section **16** with the connector **70.** Thereafter, the flow diverters **30** may be used to interconnect the sections of pipe **12a** used to form the rigid section **14.** As successive pipe joints **12a** are added to the rigid section **14,** the CCS **100** maintains a continuous flow of drilling fluid along the drill string **11.** Thus, the pressure applied to the formation remains relatively constant or can be managed within a desired range. During drilling with the BHA **20,** the drill bit **50** may be rotated by one or more of the downhole motor **28,** the rotary power device **26** positioned at the connector **70,** and the top drive **24.**

[0037] As drilling progresses, the signal generator(s) and pressure transducer(s) cooperate to form communication links that operate even when the drill string **11** is broken; *i.e.,* a pipe stand **12** is physically separated from the drill string **11.** For example, the signal generators downhole and / or at the surface may transmit pressure pulses that flow along the fluid column inside the drill string **11** and / or in the annulus **37.**

[0038] Communication uplinks, *i.e.,* transmitting information to the surface, may be accomplished by using the pressure transducers **251, 252, 253** to detect pressure pulses generated by downhole signal generators.

[0039] Communication downlinks, *i.e.,* transmitting information to a downhole location, may be accomplished by using the pressure transducers **254, 256** to detect pressure pulses generated by surface signal generators.

[0040] Communication between two downhole locations may be accomplished by using the pressure transducers **254, 256** of one signal relay device **60** and a signal generator of another signal relay device or a signal generator or pressure transducer located elsewhere along the drill string **11** *(e.g.,* a mud pulser, a bypass valve, a siren, or a pressure transducer at the BHA **20).**

[0041] It should be appreciated that the mud pulse signal communication is not interrupted when pipe **12a** is added to or removed from the drill string **11.** During such disconnections, drilling mud is still circulating even though a pipe stand is physically decoupled from the drill string **11,** which enables mud pulse signals to be conveyed between the surface and downhole. Therefore, the pressure transducers **251-254, 256,** which are in communication with the circulating mud, can detect pressure signals imparted to the flowing fluid. As a result, communication uplinks and downlinks are maintained throughout the disconnections. Stated differently, the communication links convey information between at least two locations along a flow path of the circulating drilling fluid irrespective whether the CCS **100** selects a first fluid path through the top drive the drill string or a second fluid path through the flow diverter to convey the fluid into the drill string.

[0042] In one variant, the system **10** may utilize reverse circulation. During reverse circulation, the drilling mud is pumped into the annulus **37.** The drilling mud and entrained cuttings return via a bore of the drill string **11.** In this mode of circulation also, the instrumentation described above enables uninterrupted unidirectional or bidirection communication via mud pulses. It should be understood that reverse circulation itself may have variants. For example, crossover subs may divert annulus flow into the drill string bore **15** while diverting drill string flow into the annulus. Thus, flow may be "reverse" in some sections of the well but "conventional" in other parts of the well.

[0043] One advantage of uninterrupted communication is that pressure information may be continuously transmitted by the communication system **200** or the mud pulse telemetry. Therefore, pressure adjustments may be done in real time or near-real time. Advantageously, deep drilling situations that have tight pressure windows and formations with changing formation pressure may be managed more efficiently because wellbore pressure management devices can be rapidly and accurately adjusted. Additionally, this enhanced control may enable drilling to be performed while the well is in an underbalanced pressure condition. In many instances, drilling in an underbalanced condition yields enhanced rates of penetration.

[0044] In other instances, the pressure information may indicate that corrective action may be needed to contain an undesirable condition. For example, the pressure information received may indicate that an enhanced risk for a potential "kick," or pressure spike exists. One exemplary response may include the controller **202** transmitting a control signal using the communication system **200** to the annular flow restriction device **222.** In response, the annular flow restriction device **222** may radially expand and seal against the adjacent wellbore wall. Thus, the fluid annulus **37** of the wellbore **13** downhole of the flow restriction device **222** may hydraulically isolated from the remainder of the wellbore **13.** Additionally or alternatively, the controller **202** may send a control signal to the bore flow restriction device **224.** In response, the bore flow restriction device **224** may seal the bore of the drill string **11.** Thus, the bore of the drill string **11** downhole of the flow restriction device **224** may hydraulically isolated. The actuation of either or both of the flow restriction devices **222, 224** in this manner may isolate the downhole section of the wellbore **13** and thereby reduce the risk of the pressure kick.

[0045] After the wellbore has been isolated, remedial action may be taken such as bleeding off the pressure kick, increasing mud weight, etc. In other instances, it may be desired to isolate the wellbore either temporarily or permanently. Isolating the wellbore may be done by leaving the entire drill string **11** in the wellbore **13.** Alternatively, the rigid section **14** may be disconnected from the non-rigid section **16** and pulled out the wellbore **13.** Thus, the wellbore **13** is isolated by the non-rigid section **16** and the flow restriction devices **222, 224.**

[0046] While the above modes have used surface initiated actions, it should be understood that the BHA **20** may use one or more downhole controllers that are programmed to also monitor pressure conditions, determine whether an undesirable condition exists, and transmit the necessary control signals to the flow restriction devices **222, 224,** bypass valve **250,** and / or other equipment. These actions may be taken autonomously or semi-autonomously.

[0047] The present disclosure is not limited to a particular drilling configuration. For instance, the BHA **20** may include devices that enhance drilling efficiency or allow for directional drilling. For instance, the BHA **20** may include a thruster that applies a thrust to urge the drill bit **50** against a wellbore bottom. In this instance, the thrust functions as the weight-on-bit (WOB) that would often be created by the weight of the drill string. It should be appreciated that generating the WOB using the thruster reduces the compressive forces applied to the non-rigid section 16. One or more stabilizers that may be selectively clamped to the wall may be configured to have thrust-bearing capabilities to take up the reaction forces caused by the thruster. Moreover, the thruster allows for drilling in non-vertical wellbore trajectories where there may be insufficient WOB to keep the drill bit **50** pressed against the wellbore bottom. Some embodiments of the BHA **20** may also include a steering device. Suitable steering arrangements may include, but are not limited to, bent subs, drilling motors with bent housings, selectively eccentric inflatable stabilizers, a pad-type steering devices that apply force to a wellbore wall, "point the bit" steering systems, etc. As discussed previously, stabilizers may be used to stabilize and strengthen the sections **14, 16.**

[0048] In other instances, the drill string **11** may be used for non-drilling activities such as casing installation, liner installation, casing / liner expansion, well perforation, fracturing, gravel packing, acid washing, tool installation or removal, etc. In such configurations, the drill bit **50** may not be present.

[0049] From the above, it should be appreciated from the discussion below, aspects of the present disclosure provide a system for deep drilling (*e.g.*, tight pressure windows) and drilling into formations with changing formation pressure (*e.g.*, depleted zones). Systems according to the present disclosure provide ECD control (equivalent circulating density control) for such situations. These systems may allow the exploration and production of deep high enthalpy geothermal energy due to the ability to manage tight pressure windows in deep crystalline rock.

Claims

1. A system for performing a wellbore operation while a fluid circulates in a wellbore, comprising:

- a drill string (11) comprising at least a first tubular section (14, 12a) and a second tubular section (16, 12a), each tubular section configured to be connected to and to be disconnected from the drill string (11);
- a flow diverter (30) configured to interconnect one of the first tubular section (14, 12a) and second tubular section (16, 12a) with a remainder of the drill string (11), said flow diverter (30) being connected to the top of the remainder of the drill string;
- a fluid circulating system circulating drilling fluid through at least a part of the drill string (11), the fluid circulating system comprising a continuous circulation device (100) comprising a flow diverter control device (32), an arm (34) configured, when one of the first or second tubular sections is to be added to the remainder of the drill string, to move the flow diverter control device (32) into engagement with the flow diverter (30), the continuous circulation device (100) further comprising a manifold (102) that selectively directs the drilling fluid to either a top drive (24) or the flow diverter control device (32) to form at least a first fluid path and a second fluid path, wherein only one of the first fluid path and the second fluid path circulates the drilling fluid into the drill string (11) at a specified time;

  wherein the flow diverter (30) comprises an upper end (110), a lower end (112), a bore (120) connecting the upper end (110) and the lower end (112), an upper circulation valve (114), a lower circulation valve (116) and a lateral opening (118), the upper circulation valve (114) arranged to selectively block the fluid flow along the bore (120) and the lower end (112), the lower circulation valve (116) arranged to selectively block the fluid flow between the lateral opening (118) and the bore (120);
  and wherein the flow diverter control device (32) comprises an upper valve actuator for shifting the upper circulation valve (114) between an open and a closed position and a lower valve actuator for shifting the lower circulation valve (116) between an open and a closed position, wherein, when one of the first tubular section (14, 12a) or the second tubular section (16, 12a) is to be added to the remainder of the drill string and when the flow diverter control device (32) is engaged with the flow diverter (30), the second fluid path is formed by shifting the upper circulation valve (114) into the closed position and the lower circulation valve (116) into the open position so that the drilling fluid directed to the flow diverter control device (32) can flow from the lateral opening (118) to the lower end (112) of the flow diverter (30);
  wherein, after the first tubular section (14, 12a) or the second tubular section (16, 12a) has been added to the remainder of the drill string and prior to the flow diverter control device (32) being disengaged from the flow diverter (30), the first fluid path is formed by shifting the upper circulation valve (114) into the open position and the lower circulation valve (116) into the closed position so that, during drilling after the flow diverter control device (32) is disengaged from the flow diverter (30), the drilling fluid directed to the top drive (24) can flow along the bore (120) from the upper end (110) to the lower end (112) of the flow diverter (30),

- at least one signal generator (260) in hydraulic communication with the circulating drilling fluid, the at least one signal generator (260) config-

ured to impart at least one pressure signal into the circulating drilling fluid; and
- at least one pressure transducer (254, 256) positioned in the flow diverter (30) and in pressure communication with the circulating drilling fluid and configured to detect the imparted at least one pressure signal,

wherein the at least one signal generator (260) and the at least one pressure transducer (254, 256) form a communication link, the communication link configured to convey information between at least two locations along a flow path of the circulating drilling fluid, irrespective whether the first fluid path or the second fluid path is selected by the continuous circulation device (100) to convey the drilling fluid into the drill string (11).

2. The system of claim 1, wherein the at least one signal generator (260) is positioned at a surface location.

3. The system of claim 1, wherein the communication link is bi-directional.

4. The system of claim 1, wherein the at least one signal generator (260) is positioned along the drill string (11).

5. The system of claim 4, wherein at least one pressure transducer is in hydraulic communication with an annulus surrounding the drill string (11).

6. The system of claim 1, wherein the at least one signal generator (260) includes at least a first signal generator (260) positioned near the surface and a second signal generator (260) positioned on the drill string (11).

7. A method for performing a wellbore operation while a fluid circulates in a wellbore, the method comprising:

- providing a system for performing a wellbore operation according to claim 1;

- conveying the remainder of the drill string (11) into the wellbore;
- circulating drilling fluid through at least a part of the drill string (11) using the fluid circulating system;
- selecting one of the first and second fluid path through which to convey the drilling fluid into the drill string (11);
- imparting at least one pressure signal into the circulating drilling fluid using the at least one signal generator (260) in hydraulic communication with the circulating drilling fluid; and
- detecting the imparted at least one pressure signal using the at least one pressure transducer (254, 256).

8. The method of claim 7, wherein the at least one signal generator (260) is positioned at a surface location.

9. The method of claim 7, wherein at least one pressure transducer (254, 256) is in hydraulic communication with an annulus surrounding the drill string (11).

Patentansprüche

1. System zum Durchführen eines Bohrlochbetriebs, während ein Fluid in einem Bohrloch zirkuliert, umfassend:

- einen Bohrstrang (11), umfassend mindestens einen ersten rohrförmigen Abschnitt (14, 12a) und einen zweiten rohrförmigen Abschnitt (16, 12a), wobei jeder rohrförmige Abschnitt konfiguriert ist, um mit dem Bohrstrang (11) verbunden und von diesem getrennt zu werden;
- einen Durchflussdiverter (30), der konfiguriert ist, um einen von dem ersten rohrförmigen Abschnitt (14, 12a) und dem zweiten rohrförmigen Abschnitt (16, 12a) mit einem Rest des Bohrstrangs (11) untereinander zu verbinden, wobei der Durchflussdiverter (30) mit der Oberseite des Rests des Bohrstrangs verbunden ist;
- ein fluidzirkulierendes System, das Bohrfluid durch mindestens einen Teil des Bohrstrangs (11) zirkuliert, das fluidzirkulierende System umfassend eine kontinuierliche Zirkulationsvorrichtung (100), umfassend eine Durchflussdivertersteuervorrichtung (32), einen Arm (34), der konfiguriert ist, wenn einer von dem ersten oder dem zweiten rohrförmigen Abschnitt zu dem Rest des Bohrstrangs hinzugefügt werden soll, um die Durchflussdivertersteuervorrichtung (32) in Eingriff mit dem Durchflussdiverter (30) zu bewegen, die kontinuierliche Zirkulationsvorrichtung (100) ferner umfassend ein Manifold (102), das das Bohrfluid entweder an einen oberen Antrieb (24) oder die Durchflussdivertersteuervorrichtung (32) selektiv leitet, um mindestens einen ersten Fluidweg und einen zweiten Fluidweg auszubilden, wobei nur einer von dem ersten Fluidweg und dem zweiten Fluidweg das Bohrfluid in den Bohrstrang (11) zu einer spezifizierten Zeit zirkuliert;

wobei der Durchflussdiverter (30) ein oberes Ende (110), ein unteres Ende (112), eine Bohrung (120), die das obere Ende (110) und das untere Ende (112) verbindet, ein

oberes Zirkulationsventil (114), ein unteres Zirkulationsventil (116) und eine seitliche Öffnung (118) umfasst, wobei das obere Zirkulationsventil (114) angeordnet ist, um den Fluiddurchfluss entlang der Bohrung (120) und des unteren Endes (112) selektiv zu blockieren, wobei das untere Zirkulationsventil (116) angeordnet ist, um den Fluiddurchfluss zwischen der seitlichen Öffnung (118) und der Bohrung (120) selektiv zu blockieren;
und wobei die Durchflussdiverterstеuervorrichtung (32) einen oberen Ventilaktuator zum Verschieben des oberen Zirkulationsventils (114) zwischen einer offenen und einer geschlossenen Position und einen unteren Ventilaktuator zum Verschieben des unteren Zirkulationsventils (116) zwischen einer offenen und einer geschlossenen Position umfasst, wobei, wenn einer von dem ersten rohrförmigen Abschnitt (14, 12a) oder dem zweiten rohrförmigen Abschnitt (16, 12a) zu dem Rest des Bohrstrangs hinzugefügt werden soll und wenn die Durchflussdiverterstеuervorrichtung (32) mit dem Durchflussdiverter (30) in Eingriff gebracht wird, der zweite Fluidweg durch Verschieben des oberen Zirkulationsventils (114) in die geschlossene Position und des unteren Zirkulationsventils (116) in die offene Position so ausgebildet wird, dass das Bohrfluid, das zu der Durchflussdiverterstеuervorrichtung (32) geleitet wird, von der seitlichen Öffnung (118) zu dem unteren Ende (112) des Durchflussdiverters (30) fließen kann;
wobei, nachdem der erste rohrförmige Abschnitt (14, 12a) oder der zweite rohrförmige Abschnitt (16, 12a) zu dem Rest des Bohrstrangs hinzugefügt wurde und bevor die Durchflussdiverterstеuervorrichtung (32) von dem Durchflussdiverter (30) außer Eingriff gebracht wird, der erste Fluidweg durch Verschieben des oberen Zirkulationsventils (114) in die offene Position und des unteren Zirkulationsventils (116) in die geschlossene Position so ausgebildet wird, dass während eines Bohrens, nachdem die Durchflussdiverterstеuervorrichtung (32) von dem Durchflussdiverter (30) außer Eingriff gebracht wird, das Bohrfluid, das zu dem oberen Antrieb (24) geleitet wird, entlang der Bohrung (120) von dem oberen Ende (110) zu dem unteren Ende (112) des Durchflussdiverters (30) fließen kann,

- mindestens einen Signalgenerator (260) in hydraulischer Kommunikation mit dem zirkulierenden Bohrfluid, wobei der mindestens eine Signalgenerator (260) konfiguriert ist, um mindestens ein Drucksignal in das zirkulierende Bohrfluid zu übermitteln; und
- mindestens einen Druckwandler (254, 256), der in dem Durchflussdiverter (30) positioniert ist und in Druckkommunikation mit dem zirkulierenden Bohrfluid steht und konfiguriert ist, um das übermittelte mindestens eine Drucksignal zu erfassen,
wobei der mindestens eine Signalgenerator (260) und der mindestens eine Druckwandler (254, 256) eine Kommunikationsverknüpfung ausbilden, wobei die Kommunikationsverknüpfung konfiguriert ist, um Informationen zwischen mindestens zwei Stellen entlang eines Durchflusswegs des zirkulierenden Bohrfluids zu befördern, unabhängig davon, ob der erste Fluidweg oder der zweite Fluidweg durch die kontinuierliche Zirkulationsvorrichtung (100) ausgewählt wird, um das Bohrfluid in den Bohrstrang (11) zu befördern.

2. System nach Anspruch 1, wobei der mindestens eine Signalgenerator (260) an einer Oberflächenstelle positioniert ist.

3. System nach Anspruch 1, wobei die Kommunikationsverknüpfung bidirektional ist.

4. System nach Anspruch 1, wobei der mindestens eine Signalgenerator (260) entlang des Bohrstrangs (11) positioniert ist.

5. System nach Anspruch 4, wobei mindestens ein Druckwandler in hydraulischer Kommunikation mit einem Ringraum, der den Bohrstrang (11) umgibt, steht.

6. System nach Anspruch 1, wobei der mindestens eine Signalgenerator (260) mindestens einen ersten Signalgenerator (260), der nahe der Oberfläche positioniert ist, und einen zweiten Signalgenerator (260), der an dem Bohrstrang (11) positioniert ist, einschließt.

7. Verfahren zum Durchführen eines Bohrlochbetriebs, während ein Fluid in einem Bohrloch zirkuliert, das Verfahren umfassend:

- Bereitstellen eines Systems zum Durchführen eines Bohrlochbetriebs nach Anspruch 1;

- Befördern des Rests des Bohrstrangs (11) in das Bohrloch;
- Zirkulieren von Bohrlochfluid durch mindestens einen Teil des Bohrstrangs (11) unter Verwendung des fluidzirkulierenden Systems;

- Auswählen von einem von dem ersten und dem zweiten Fluidweg, durch den das Bohrfluid in den Bohrstrang (11) befördert werden soll;
- Übermitteln von mindestens einem Drucksignal in das zirkulierende Bohrfluid unter Verwendung des mindestens einen Signalgenerators (260) in hydraulischer Kommunikation mit dem zirkulierenden Bohrfluid; und
- Erfassen des übermittelten mindestens einen Drucksignals unter Verwendung des mindestens einen Druckwandlers (254, 256).

8. Verfahren nach Anspruch 7, wobei der mindestens eine Signalgenerator (260) an einer Oberflächenstelle positioniert ist.

9. Verfahren nach Anspruch 7, wobei mindestens ein Druckwandler (254, 256) in hydraulischer Kommunikation mit einem Ringraum, der den Bohrstrang (11) umgibt, steht.

Revendications

1. Système destiné à effectuer une opération de puits de forage tandis qu'un fluide circule dans un puits de forage, comprenant :

- un train de forage (11) comprenant au moins une première section tubulaire (14, 12a) et une seconde section tubulaire (16, 12a), chaque section tubulaire étant conçue pour être reliée à et pour être détachée du train de forage (11) ;
- un déflecteur d'écoulement (30) conçu pour interrelier l'une parmi la première section tubulaire (14, 12a) et la seconde section tubulaire (16, 12a) avec un reste du train de forage (11), ledit déflecteur d'écoulement (30) étant relié au sommet du reste du train de forage ;
- un système de circulation de fluide faisant circuler le fluide de forage à travers au moins une partie du train de forage (11), le système de circulation de fluide comprenant un dispositif de circulation continue (100) comprenant un dispositif de commande du déflecteur d'écoulement (32), un bras (34) conçu, lorsque l'une des première ou seconde sections tubulaires doit être ajoutée au reste du train de forage, pour déplacer le dispositif de commande du déflecteur d'écoulement (32) en prise avec le déflecteur d'écoulement (30), le dispositif de circulation continue (100) comprenant en outre un collecteur (102) qui dirige sélectivement le fluide de forage vers soit un entraînement supérieur (24) soit le dispositif de commande du déflecteur d'écoulement (32) pour former au moins un premier trajet de fluide et un second trajet de fluide, un seul du premier trajet de fluide et du second trajet de fluide faisant circuler le fluide de forage dans le train de forage (11) à un moment spécifié ;

le déflecteur d'écoulement (30) comprenant une extrémité supérieure (110), une extrémité inférieure (112), un alésage (120) reliant l'extrémité supérieure (110) et l'extrémité inférieure (112), une vanne de circulation supérieure (114), une vanne de circulation inférieure (116) et une ouverture latérale (118), la vanne de circulation supérieure (114) étant agencée pour bloquer sélectivement l'écoulement de fluide le long de l'alésage (120) et de l'extrémité inférieure (112), la vanne de circulation inférieure (116) étant agencée pour bloquer sélectivement l'écoulement de fluide entre l'ouverture latérale (118) et l'alésage (120) ;
et le dispositif de commande du déflecteur d'écoulement (32) comprenant un actionneur de vanne supérieur pour décaler la vanne de circulation supérieure (114) entre une position ouverte et une position fermée et un actionneur de vanne inférieur pour décaler la vanne de circulation inférieure (116) entre une position ouverte et une position fermée, lorsque l'une parmi la première section tubulaire (14, 12a) ou la seconde section tubulaire (16, 12a) doit être ajoutée au reste du train de forage et lorsque le dispositif de commande du déflecteur d'écoulement (32) est mis en prise avec le déflecteur d'écoulement (30), le second trajet de fluide étant formé en décalant la vanne de circulation supérieure (114) dans la position fermée et la vanne de circulation inférieure (116) dans la position ouverte de sorte que le fluide de forage dirigé vers le dispositif de commande du déflecteur d'écoulement (32) peut s'écouler depuis l'ouverture latérale (118) vers l'extrémité inférieure (112) du déflecteur d'écoulement (30) ;
après que la première section tubulaire (14, 12a) ou la seconde section tubulaire (16, 12a) a été ajoutée au reste du train de forage et avant que le dispositif de commande du déflecteur d'écoulement (32) ne soit désolidarisé du déflecteur d'écoulement (30), le premier trajet de fluide étant formé en décalant la vanne de circulation supérieure (114) dans la position ouverte et la vanne de circulation inférieure (116) dans la position fermée de sorte que, pendant le forage, après que le dispositif de commande du dé-

flecteur d'écoulement (32) est désolidarisé du déflecteur d'écoulement (30), le fluide de forage dirigé vers l'entraînement supérieur (24) pouvant s'écouler le long de l'alésage (120) depuis l'extrémité supérieure (110) vers l'extrémité inférieure (112) du déflecteur d'écoulement (30),

- au moins un générateur de signal (260) en communication hydraulique avec le fluide de forage en circulation, l'au moins un générateur de signal (260) étant configuré pour communiquer au moins un signal de pression dans le fluide de forage en circulation ; et
- au moins un transducteur de pression (254, 256) positionné dans le déflecteur d'écoulement (30) et en communication de pression avec le fluide de forage en circulation et configuré pour détecter l'au moins un signal de pression transmis,

l'au moins un générateur de signal (260) et l'au moins un transducteur de pression (254, 256) formant une liaison de communication, la liaison de communication étant configurée pour transporter des informations entre au moins deux emplacements le long d'un trajet d'écoulement du fluide de forage en circulation, indépendamment du fait que le premier trajet de fluide ou le second trajet de fluide est sélectionné par le dispositif de circulation continue (100) pour transporter le fluide de forage dans le train de forage (11).

2. Système selon la revendication 1, dans lequel l'au moins un générateur de signal (260) est positionné à un emplacement de surface.

3. Système selon la revendication 1, dans lequel la liaison de communication est bidirectionnelle.

4. Système selon la revendication 1, dans lequel l'au moins un générateur de signal (260) est positionné le long du train de forage (11).

5. Système selon la revendication 4, dans lequel au moins un transducteur de pression est en communication hydraulique avec un espace annulaire entourant le train de forage (11).

6. Système selon la revendication 1, dans lequel l'au moins un générateur de signal (260) comporte au moins un premier générateur de signal (260) positionné près de la surface et un second générateur de signal (260) positionné sur le train de forage (11).

7. Procédé pour effectuer une opération de puits de forage tandis qu'un fluide circule dans un puits de forage, le procédé comprenant :

- la fourniture d'un système pour effectuer une opération de puits de forage selon la revendication 1 ;
- le transport du reste du train de forage (11) dans le puits de forage ;
- la circulation du fluide de forage à travers au moins une partie du train de forage (11) à l'aide du système de circulation de fluide ;
- la sélection de l'un des premier et second trajets de fluide à travers lequel le fluide de forage est transporté dans le train de forage (11);
- la fourniture d'au moins un signal de pression dans le fluide de forage en circulation à l'aide de l'au moins un générateur de signal (260) en communication hydraulique avec le fluide de forage en circulation ; et
- la détection de l'au moins un signal de pression transmis à l'aide de l'au moins un transducteur de pression (254, 256).

8. Procédé selon la revendication 7, dans lequel l'au moins un générateur de signal (260) est positionné à un emplacement de surface.

9. Procédé selon la revendication 7, dans lequel au moins un transducteur de pression (254, 256) est en communication hydraulique avec un espace annulaire entourant le train de forage (11).

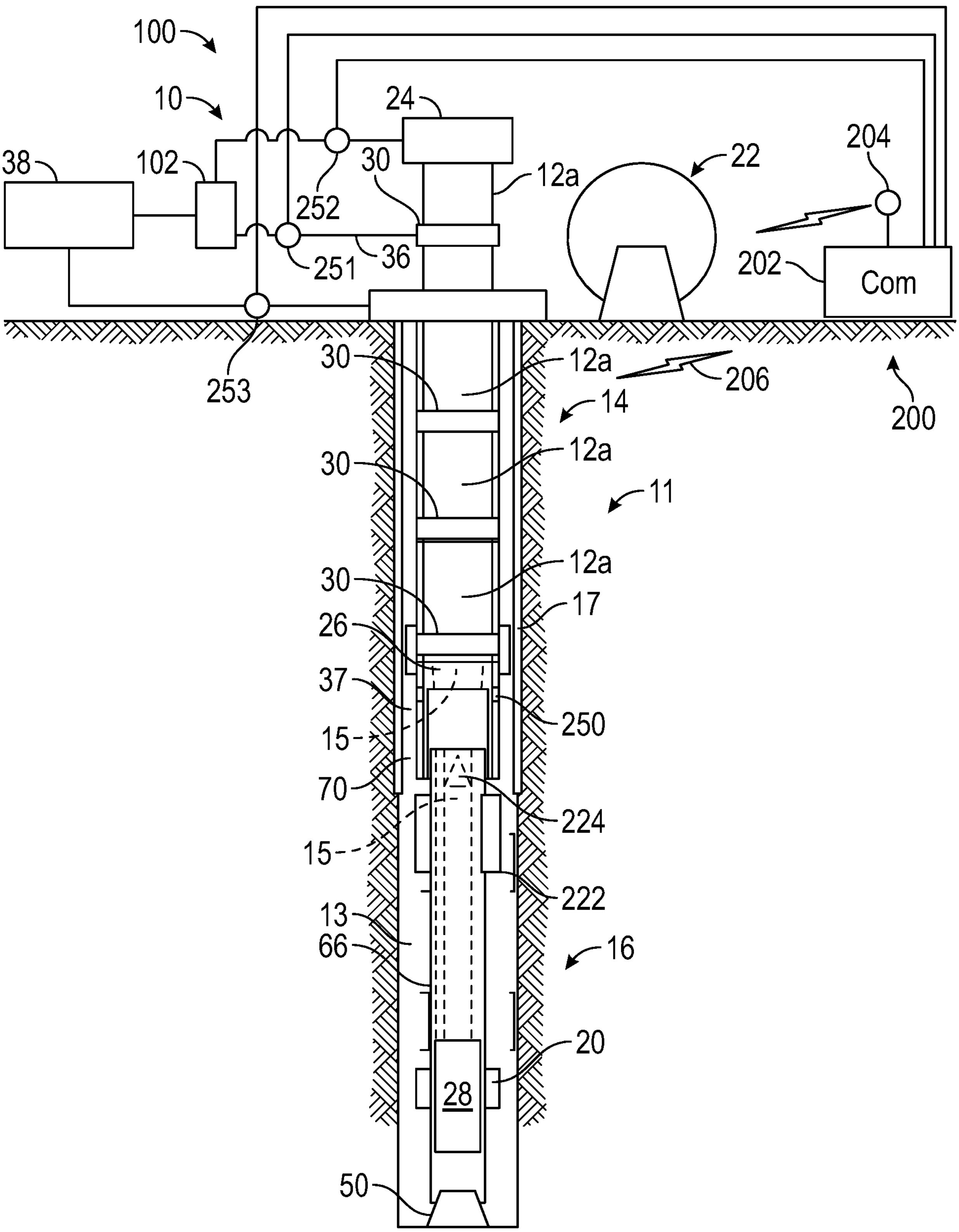
100
10
38
102
24
30
12a
22
204
252
251
36
202
Com
253
206
200
14
11
17
26
37
250
15
70
224
222
13
66
16
20
28
50

FIG. 1

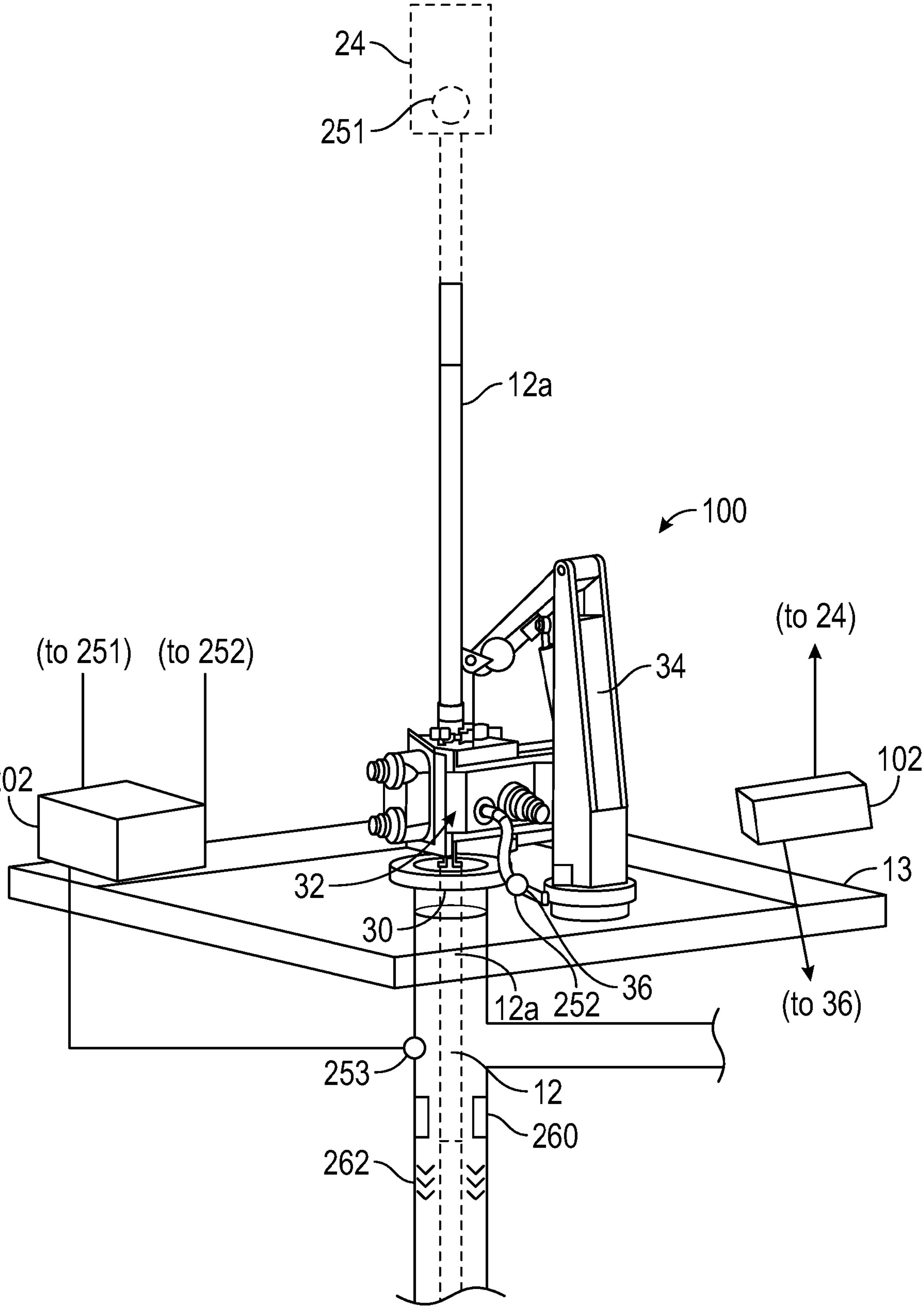
24
251
12a
100
(to 24)
(to 251)
(to 252)
34
202
102
32
13
30
36
252
12a
(to 36)
253
12
260
262

FIG. 2

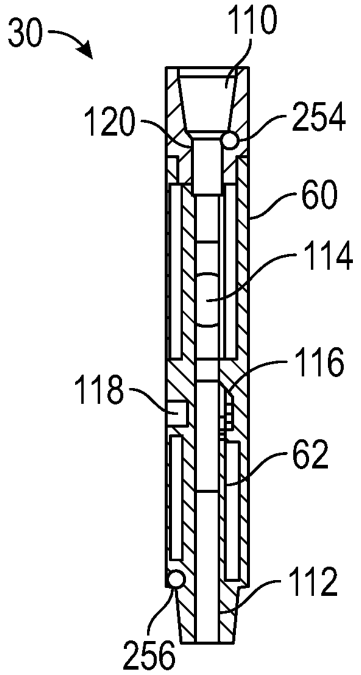
30
110
120
254
60
114
116
118
62
112
256

FIG. 3

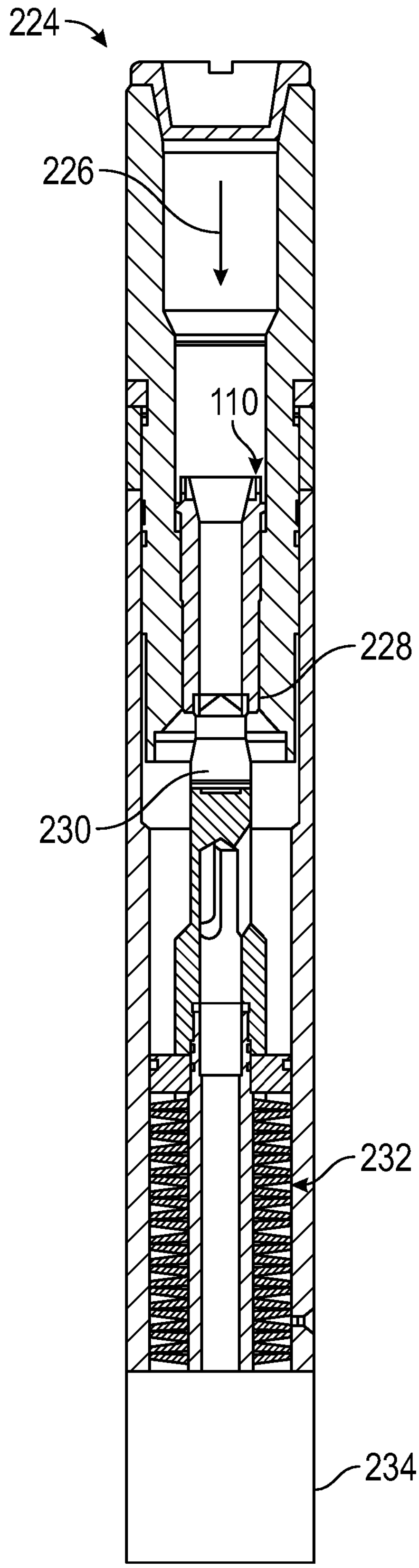
224
226
110
228
230
232
234

FIG. 4

REFERENCES CITED IN THE DESCRIPTION

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