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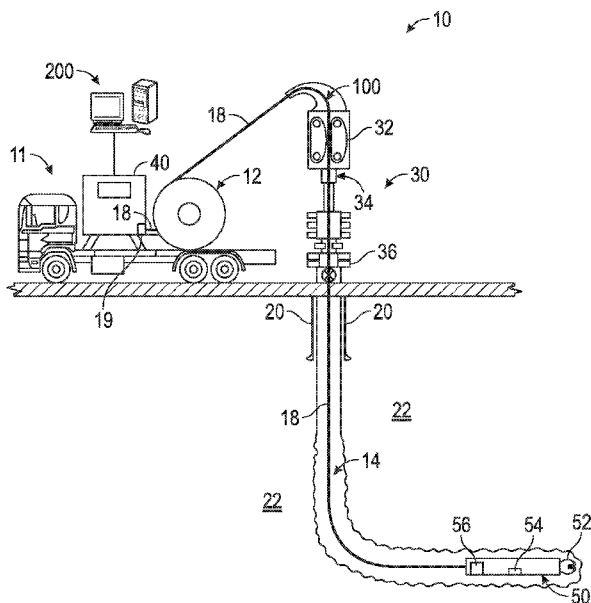


FIG. 1

(57) Abstract: A system is provided which includes a bottomhole assembly, a cable assembly, and a controller. The bottomhole assembly is disposed in a wellbore traversing a subterranean formation from a surface of the earth, and includes a drill tool. The cable assembly includes a fiber optic line coupled with the bottomhole assembly. The fiber optic line has a length that traverses a length of the wellbore from the bottomhole assembly to the surface. The fiber optic line is a distributed sensor and measures one or more downhole parameters along the length of the fiber optic line during the drilling of the wellbore. The controller is coupled with the cable assembly, and receives data from the fiber optic line during the drilling of the wellbore by the drill tool.



## DRILLING SYSTEM

### FIELD

[0001] The present disclosure relates generally to drilling systems. In at least one example, the present disclosure relates to drilling systems including a cable assembly to measure drilling parameters during drilling.

### BACKGROUND

[0002] Wellbores are drilled into the earth for a variety of purposes including accessing hydrocarbon bearing formations. A variety of bottomhole assemblies may be used within a wellbore in connection with accessing and extracting such hydrocarbons. To access the hydrocarbon bearing formations, the wellbore is drilled to a desired depth and location.

### BRIEF DESCRIPTION OF THE DRAWINGS

[0003] Implementations of the present technology will now be described, by way of example only, with reference to the attached figures, wherein:

[0004] FIG. 1 is a diagram illustrating an exemplary environment for a drilling system according to the present disclosure;

[0005] FIG. 2 is a diagram of a processing system which may be employed as shown in FIG. 1;

[0006] FIG. 3A is a diagram illustrating a cross-sectional view of an exemplary cable;

[0007] FIG. 3B is a diagram illustrating a cross-sectional view of another exemplary cable;

[0008] FIG. 3C is a diagram illustrating a cross-sectional view of another exemplary cable;

[0009] FIG. 4 is a diagram illustrating an exemplary drilling operation;

[0010] FIG. 5 is a diagram illustrating an exemplary drilling operation;

[0011] FIG. 6 is a diagram illustrating an exemplary drilling operation;

[0012] FIG. 7 is a diagram illustrating an exemplary drilling operation; and

[0013] FIG. 8 is a flow chart of a method for utilizing an acoustic telemetry system.

## DETAILED DESCRIPTION

[0014] It will be appreciated that for simplicity and clarity of illustration, where appropriate, reference numerals have been repeated among the different figures to indicate corresponding or analogous elements. In addition, numerous specific details are set forth in order to provide a thorough understanding of the embodiments described herein. However, it will be understood by those of ordinary skill in the art that the embodiments described herein can be practiced without these specific details. In other instances, methods, procedures and components have not been described in detail so as not to obscure the related relevant feature being described. Also, the description is not to be considered as limiting the scope of the embodiments described herein. The drawings are not necessarily to scale and the proportions of certain parts may be exaggerated to better illustrate details and features of the present disclosure.

[0015] Disclosed herein is a system to measure downhole parameters along a length of the wellbore during drilling of the wellbore. The system includes a bottomhole assembly which drills a wellbore in a formation. A cable assembly is coupled with the bottomhole assembly and includes a fiber optic line. The fiber optic line traverses a length of the wellbore from the bottomhole assembly to the surface. As the fiber optic line is a distributed sensor, the fiber optic line can measure downhole parameters along the length of the wellbore during drilling of the wellbore by the bottomhole assembly. A controller is coupled with the cable assembly 100 and receives data from the fiber optic line during the drilling of the wellbore.

[0016] Conventionally, to make measurements of downhole parameters during the process of drilling a wellbore, drilling is stopped and the drill string is removed from the wellbore. Then, a logging string is inserted into the wellbore, measurements are taken, and after removal, the drill string is re-inserted into the wellbore again to continue drilling. As a result, there is no true understanding of whether there is a problematic issue present, what the issue may be, and where the issue is located. The process is very time consuming, and if occurring too late in the process, excessive resources may be wasted. However, with the fiber optic line measuring downhole parameters during drilling, a determination may be made whether there are any issues during drilling and make corresponding adjustments as needed without removing the drill string, thereby avoiding substantial delay or further drilling. For example, if fluid is being lost into the formation, the data from the fiber optic line can inform that the issue is present as well as inform of the location and depth of the issue. Accordingly, the drilling can be paused or adjusted,

without removal of the drill string, to correct the issue such that the damage is mitigated. Additionally, in some examples, the data from the fiber optic line can inform of the type of issue that is present.

[0017] The system can be employed in an exemplary wellbore system 10 shown, for example, in FIG. 1. The wellbore system 10 can include a wellhead 30 extending over and around a wellbore 14. The wellbore 14 is within an earth formation 22 and, in at least one example, can have a casing 20 at least partially lining the wellbore 14. In at least one example, the casing 20 can be held into place by cement. In at least one example, the casing 20 can be at least partially made of an electrically conductive material, for example steel. In another example, the casing 20 can be at least partially made of a non-electrically conductive material, for example fiberglass or PEEK, or of a low-conductivity material, for example carbon composite, or a combination of such materials. A bottomhole assembly 50 coupled with a conduit 18 can be disposed within the wellbore 14 and moved down the wellbore 14 via the conduit 18 to a desired location. As illustrated in FIG. 1, the conduit 18 is coiled tubing. In other examples, the conduit 18 can be, for example, tubing-conveyed, wireline, slickline, work string, joint tubing, jointed pipe, pipeline, and/or any other suitable means.

[0018] The bottomhole assembly 50 can include, for example, downhole sensors, chokes, and valves. The chokes and valves may include actuatable flow regulation devices, such as variable chokes and valves, and may be used to regulate the flow of the fluids into and/or out of the conduit 18. The bottomhole assembly 50 also includes a drill tool 52 to drill the wellbore 14 in the formation 22. For example, the drill tool 52 can include a drill bit, a mill, and/or an auger. One or more assembly sensors 54 can be disposed in the bottomhole assembly 50 and provide measurements and data of the wellbore 14, the formation 22, and/or the bottomhole assembly 50. For example, the assembly sensors 54 can include a directional sensor which can determine the direction that the bottomhole assembly 50 is drilling in the formation 22. In some examples, as illustrated in FIG. 1, the bottomhole assembly 50 can include a power source 56. The power source 56 can provide power to the components of the bottomhole assembly 50, for example the assembly sensors 54 and/or a motor to actuate the drill tool 52.

[0019] A cable assembly 100 can be coupled with the bottomhole assembly 50. The cable assembly 100 traverses a length of the wellbore 14 from the bottomhole assembly 50 to the surface. In at least one example, the cable assembly 100 can be disposed within an annulus of the

conduit 18. In some examples, the cable assembly 100 can be coupled with the conduit 18, for example by fasteners and/or adhesives. In some examples, the cable assembly 100 can be external to the conduit 18 within the wellbore 14. As will be discussed in further detail in FIGS. 3A-3C, the cable assembly 100 can include a fiber optic line 310. The fiber optic line 310, along with the cable assembly 100, can traverse the length of the wellbore 14 from the bottomhole assembly 50 to the surface. The fiber optic line 310 can be a distributed sensor such that the fiber optic line 310 can measure one or more downhole parameters along the length of the fiber optic line 310 traversing the length of the wellbore 14 during drilling of the wellbore 14 by the bottomhole assembly 50. For example, the fiber optic line 310, as a distributed sensor, can measure one or more downhole parameters along the entire length of the fiber optic line 310, such as any distance from an optical source 19 along the fiber optic line 310. The fiber optic line 310 can be a distributed temperature sensor, a distributed acoustic sensor, and/or a distributed pressure sensor, and the one or more downhole parameters can include temperature, acoustic signals, and/or pressure. Additionally or alternately, the fiber optic line 310 has the ability to transmit large amounts of information quickly without electric power.

[0020] The wellhead 30 can include a blowout preventer 36, a stripper 34, and/or an injector 32. The injector 32 can inject the conduit 18 into the wellbore 14. For example, the conduit 18 can be stored in a reel 12, and the conduit 18 passes from the reel 12 through the injector 32 into the wellbore 14. In other examples, the injector 32 can pull the conduit 18 to retrieve the conduit 18 from the wellbore 14. The stripper 34 can provide a pressure seal around the conduit 18 as the conduit 18 is being run into and/or pulled out of the wellbore 14. The blowout preventer 36 can seal, control, and/or monitor the wellbore 14 to prevent blowouts, or uncontrolled and/or undesired release of fluids from the wellbore 14. In other examples, different systems can be utilized based on the type of conduit 18 and/or the environment such as subsea or surface operations.

[0021] An optical source 19 can be optically coupled with the fiber optic line 310 in the cable assembly 100. In at least one example, the optical source 19 can be disposed in a surface unit 40 which can be equipped with data analysis capability and communicatively coupled with a controller 200. As illustrated in FIG. 1, the surface unit 40 and the controller 200 are located adjacent to the wellbore 14. In some examples, the surface unit 40 and/or the controller 200 can be located at a separate location and the data can be transferred by either wired or wireless

transmission. The surface unit 40 can include a vehicle 11, as illustrated in FIG. 1. In some examples, the surface unit 40 can include a derrick, a building structure, and/or any other suitable structure. The optical source 19 can emit light signals through the fiber optic line 310, and the light signals can reflect back to the optical source 19 and provide data such as the measurements of the one or more downhole parameters at any and/or all lengths along the fiber optic line 310. The modulation of the intensity, phase, polarization, wavelength, and/or transit time of the light signals in the fiber optic line 310 can communicate the data in the wellbore 14.

[0022] The optical source 19 can be coupled with the controller 200 which can receive the data from the fiber optic line 310 during the drilling of the wellbore 14. The controller 200, as discussed in further detail in FIG. 2, can adjust the drilling of the wellbore 14 based on the data from the fiber optic line 310. For example, the data can include the measurements of the one or more downhole parameters. In some examples, the data can also include signals from the assembly sensors 54 from the bottomhole assembly 50. The controller 200 can receive the data in substantially real time and make adjustments automatically and/or indicate the need for adjustments of the drilling process based on such data without substantial delay. Accordingly, any issues may be handled without excessive loss in time and/or resources. As the fiber optic line 310 can indicate the distance of any measurements along the fiber optic line 310 from the optical source 19, the depth and location of the issues in the wellbore 14 can also be known. Accordingly, time and resources can be saved by not needing to search for the issues in the wellbore 14.

[0023] It should be noted that while FIG. 1 generally depicts a land-based operation, those skilled in the art would readily recognize that the principles described herein are equally applicable to operations that employ floating or sea-based platforms and rigs, without departing from the scope of the disclosure. Also, even though FIG. 1 depicts an L-shaped wellbore, the present disclosure is equally well-suited for use in wellbores having other orientations, including horizontal wellbores, slanted wellbores, multilateral wellbores or the like.

[0024] FIG. 2 is a block diagram of an exemplary controller 200. Controller 200 is configured to perform processing of data and communicate with the cable assembly 100, for example as illustrated in FIG. 1. In operation, controller 200 communicates with one or more of the above-discussed components, and may also be configured to communication with remote devices/systems.

[0025] As shown, controller 200 includes hardware and software components such as network interfaces 210, at least one processor 220, sensors 260 and a memory 240 interconnected by a system bus 250. Network interface(s) 210 can include mechanical, electrical, and signaling circuitry for communicating data over communication links, which may include wired or wireless communication links. Network interfaces 210 are configured to transmit and/or receive data using a variety of different communication protocols, as will be understood by those skilled in the art.

[0026] Processor 220 represents a digital signal processor (e.g., a microprocessor, a microcontroller, or a fixed-logic processor, etc.) configured to execute instructions or logic to perform tasks in a wellbore environment. Processor 220 may include a general purpose processor, special-purpose processor (where software instructions are incorporated into the processor), a state machine, application specific integrated circuit (ASIC), a programmable gate array (PGA) including a field PGA, an individual component, a distributed group of processors, and the like. Processor 220 typically operates in conjunction with shared or dedicated hardware, including but not limited to, hardware capable of executing software and hardware. For example, processor 220 may include elements or logic adapted to execute software programs and manipulate data structures 245, which may reside in memory 240.

[0027] Sensors 260 typically operate in conjunction with processor 220 to perform measurements, and can include special-purpose processors, detectors, transmitters, receivers, and the like. In this fashion, sensors 260 may include hardware/software for generating, transmitting, receiving, detection, logging, and/or sampling magnetic fields, seismic activity, and/or acoustic waves, temperature, pressure, or other parameters. Additionally, sensors 260 may include the fiber optic line 310 and/or the assembly sensors 54 as disclosed herein.

[0028] Memory 240 comprises a plurality of storage locations that are addressable by processor 220 for storing software programs and data structures 245 associated with the embodiments described herein. An operating system 242, portions of which may be typically resident in memory 240 and executed by processor 220, functionally organizes the device by, inter alia, invoking operations in support of software processes and/or services 244 executing on controller 200. These software processes and/or services 244 may perform processing of data and communication with controller 200, as described herein. Note that while process/service 244 is

shown in centralized memory 240, some examples provide for these processes/services to be operated in a distributed computing network.

[0029] It will be apparent to those skilled in the art that other processor and memory types, including various computer-readable media, may be used to store and execute program instructions pertaining to the fluidic channel evaluation techniques described herein. Also, while the description illustrates various processes, it is expressly contemplated that various processes may be embodied as modules having portions of the process/service 244 encoded thereon. In this fashion, the program modules may be encoded in one or more tangible (non-transitory) computer readable storage media for execution, such as with fixed logic or programmable logic (e.g., software/computer instructions executed by a processor, and any processor may be a programmable processor, programmable digital logic such as field programmable gate arrays or an ASIC that comprises fixed digital logic. In general, any process logic may be embodied in processor 220 or computer readable medium encoded with instructions for execution by processor 220 that, when executed by the processor, are operable to cause the processor to perform the functions described herein. Data may also be transmitted or streamed for viewing from a remote location via network interfaces 210.

[0030] FIGS. 3A-3C are cross-sectional views of exemplary cables 100 in a plane perpendicular to a central axis. Any of the components discussed in FIGS. 3A-3C can be interchanged amongst the exemplary cables 100 without departing from the scope of the present disclosure.

[0031] FIG. 3A illustrates a cable assembly 100 that may have separate optical and electrically conductive pathways that are used for separate optical and electrical signal communication as further described below. The cable assembly 100, as illustrated in FIG. 3A can include an outer tube 350 forming an inner core 315 of the cable assembly 100. At least one fiber optic line 310 and at least one conductor line 330 are disposed within the inner core 315 of the cable assembly 100. The conductor line 330 can be operable to transmit power to the bottomhole assembly 50. The fiber optic line 310 can have a polymer coating such as an acrylate based polymer. The fiber optic line 310 may be bend insensitive, and may be single mode or multi-mode. Multi-mode optical fibers permit the optical fibers to carry out more than one function, such as carrying out two or more of communication, temperature or pressure sensing whereas single mode may be limited to one of such functions. Although FIG. 3A illustrates the

cable assembly 100 having a fiber optic line 310 with a single optical fiber, the cable assembly 100 may alternatively have a plurality of optical fibers, such as two to ten, or alternatively two to five optical fibers. The use of a plurality of optical fibers may permit separate control or redundancy. For instance, some optical fibers may be used for communicating control to the bottomhole assembly 50 whereas others are used for communicating or taking measurements of pressure or temperature. Further, by use a plurality of optical fibers, if one or more optical fibers become damaged or inoperable, the remaining optical fibers may still be used.

[0032] FIG. 3B illustrates another exemplary cable assembly 100. The cable assembly 100 as illustrated in FIG. 3B includes a fiber optic line 310 disposed within an inner core 315 of the cable assembly 100. An inner tube 320 can be positioned around the inner core 315 so as to surround and contain the contents of the inner core 315. The inner tube 320 may be a metal tube, such as steel, in which case together with the fiber optic line 310 it may be referred to in the field as fiber in metal tube (FIMT). The inner core 315 can be filled with a viscous substance 316 to provide protection for the fiber optic line 310. The viscous substance 316 can be liquids, gels, foams, or any other material capable of limiting quick or sudden movement within the tube which may damage the optical fibers. The fiber optic line 310 provides optical communication between the bottomhole assembly 50 and surface equipment, for example the controller 200. For instance, the fiber optic line 310 can be used to transmit information gathered downhole to the surface equipment. For example, the fiber optic line 310 can measure one or more downhole parameters along the length of the wellbore 14 during drilling of the wellbore 14. In some examples, the fiber optic line 310 can transmit data from assembly sensors 54 to the surface equipment. Additionally, the fiber optic line 310 can be used to transmit commands from surface equipment to components in the bottomhole assembly 50. A conductor line 330, as illustrated in FIG. 3B, can be an electrical conducting material. The conductor line 330 can be positioned circumferentially around the inner tube 320, such that the entire external surface of the inner tube 320 is covered and surrounded by the conductor line 330. The conductor line 330 may be positioned such that no portion of the conductor line 330 overlaps itself as it wraps around the inner tube 320. The conductor line 330 can function as a conductor line and provide a pathway for electrical communication between the bottomhole assembly 50 and the surface equipment. The conductor line 330 can be any conductive material suitable for transferring electrical signals and capable of withstanding temperatures downhole, including conductive metals such as

copper. The conductor line 330 may be a thin conductive layer which may be wrapped about the inner tube 320, and may be a conductive tape, including copper tape. For example, the copper tape can provide power from the surface to the bottomhole assembly 50. Accordingly, the conductor line 330 may be provided along the entire length of the inner tube 220.

[0033] The conductor line 330 can be enclosed by an insulation material 340. Positioned around the insulation material 340 is an outer tube 350. The insulation material 340 can be any suitable temperature resistant material capable of withstanding temperatures downhole and may be corrosion resistant. In at least one example, the insulation material 340 can be a polymer such as fluorinated ethylene propylene (FEP) and formed in the shape of tubing. The insulation material 340 can provide protection and spacing between the outer tube 350 and the conductor line 330 to prevent contact which may cause a short. The outer tube 350 can be any suitable metal or metal alloy which is capable of grounding electricity and serves as a protective outer layer for the entire cable assembly 100. A particular metal alloy may include iron or steel, and may be nickel-iron-chromium alloy such as Alloy 825 (UNS designation N08825).

[0034] FIG. 3C illustrates an exemplary cable assembly 100 which does not include a conductor line 330. The cable assembly 100 can include an outer tube 350 forming an inner core 315 of the cable assembly 100. The cable assembly 100, as illustrated in FIG. 3C, includes a fiber optic line 310 disposed within an inner core 315 of the cable assembly 100. In such an example, the power source 56 of the bottomhole assembly 50 may include a battery such that the bottomhole assembly 50 does not require power to be transmitted from the surface.

[0035] FIG. 4 illustrates an exemplary drilling operation. As illustrated in FIG. 4, four formations 400, 402, 404, 406 may be present. The system 10, similar to the system as illustrated in FIG. 1, is in operation drilling a wellbore 14. In the exemplary scenario as illustrated in FIG. 4, the drilling plan is to drill into formation 404. However, as shown, the bottomhole assembly 50 has drilled the wellbore 14 into formation 406. As the cable assembly 100 includes the fiber optic line 310, for example as discussed above, the fiber optic line 310 measures one or more downhole parameters during drilling. The controller 200 can receive the data from the fiber optic line 310 and characterize the formation 406 to help evaluate if the wellbore 14 is drilled on target. The controller 200 can determine that the bottomhole assembly 50 has drilled into the wrong formation 406. Then, without removing the bottomhole assembly 50 and the conduit 18 and inserting a logging tool, the system 10 can determine that there is an issue and address that

issue by adjusting the drilling, for example adjusting the direction of the bottomhole assembly 50 to drill into the desired formation 404. In at least one example, for example as illustrated in FIG. 7, the assembly sensors 54 can include a camera 700 such that formation boundaries may be physically viewed.

[0036] FIG. 5 illustrates another exemplary drilling operation. As illustrated in FIG. 5, fluid, as denoted by the arrows, is flowing out of the wellbore 14 into the formation 22. The system 10, similar to the system as illustrated in FIG. 1, is in operation drilling a wellbore 14. In the exemplary scenario as illustrated in FIG. 5, it is intended for the fluid to flow to the surface through the wellbore 14. However, as shown, losses are experienced as fluid flows out of the wellbore 14 through one or more loss zones 500. As the cable assembly 100 includes the fiber optic line 310, for example as discussed above, the fiber optic line 310 measures one or more downhole parameters during drilling, and the controller 200 can determine that losses are occurring. For example, the fiber optic line 310 may measure temperature, pressure, and/or acoustics (which may be indicative of flow characteristics), and determine that the temperature becomes warmer due to lack of fluid cooling the annulus past a certain point and/or the flow parameters change at a specific location in the wellbore 14. Additionally, sensors in the bottomhole assembly 50 may detect a drop in pressure at a specific location if a loss zone is encountered. Accordingly, without removing the bottomhole assembly 50 and the conduit 18 and inserting a logging tool, the system 10 can determine that there is an issue and address that issue by adjusting the drilling, for example blocking the loss zones 500 such that the fluid loss is reduced and/or eliminated. In at least one example, for example as illustrated in FIG. 7, the assembly sensors 54 can include a camera 700 such that the nature of the loss zones 500 can be physically viewed and the nature of the loss zones 500 can be characterized to plan an appropriate remediation.

[0037] FIG. 6 illustrates another exemplary drilling operation. As illustrated in FIG. 6, undesired and/or unplanned fluid, as denoted by the arrows, is flowing from the formation 22 into the wellbore 14. In some examples, influx solids can be brought into the wellbore 14. In some examples, influx fluid mixed with influx solids can be brought into the wellbore 14. The system 10, similar to the system as illustrated in FIG. 1, is in operation drilling a wellbore 14. In the exemplary scenario as illustrated in FIG. 6, fluid should not be flowing into the wellbore 14 at one or more influx locations 600. As the cable assembly 100 includes the fiber optic line 310,

for example as discussed above, the fiber optic line 310 measures one or more downhole parameters during drilling, and the controller 200 can determine that influxes are occurring. For example, the fiber optic line 310 may measure temperature, pressure, and/or acoustics, and determine that the temperature becomes warmer at a specific point from fluid influx, or cooler at a specific point from gas influx and/or the flow characteristics change at a specific location in the wellbore 14. Additionally, sensors in the bottomhole assembly 50 may detect an increase in pressure at a specific location if an influx zone is encountered. The exact location of the influx locations 600 can be pinpointed without wasting resources searching for the influx locations 600. Accordingly, without removing the bottomhole assembly 50 and the conduit 18 and inserting a logging tool, the system 10 can determine that there is an issue and address that issue by adjusting the drilling, for example blocking the influx locations 600 to reduce and/or eliminate the influx fluid. In at least one example, for example as illustrated in FIG. 7, the assembly sensors 54 can include a camera 700 such that the nature of the influx locations 600 can be physically viewed and the nature of the influx locations 600 can be characterized to plan an appropriate remediation.

[0038] Referring to FIG. 8, a flowchart is presented in accordance with an example embodiment. The method 800 is provided by way of example, as there are a variety of ways to carry out the method. The method 800 described below can be carried out using the configurations illustrated in FIGS. 1-7, for example, and various elements of these figures are referenced in explaining example method 800. Each block shown in FIG. 8 represents one or more processes, methods or subroutines, carried out in the example method 800. Furthermore, the illustrated order of blocks is illustrative only and the order of the blocks can change according to the present disclosure. Additional blocks may be added or fewer blocks may be utilized, without departing from this disclosure. The example method 800 can begin at block 802.

[0039] At block 802, a wellbore is drilled in a formation by a bottomhole assembly. The bottomhole assembly can be coupled with a cable. The cable assembly can include a fiber optic line. The fiber optic line can be a distributed sensor and traverse the length of the wellbore from the bottomhole assembly to the surface. For example, the fiber optic line can be a distributed temperature sensor, a distributed acoustic sensor, and/or a distributed pressure sensor, and measure one or more downhole parameters which can include temperature, acoustic signals,

and/or pressure. The bottomhole assembly can include one or more assembly sensors which can measure parameters of the wellbore, the formation, and/or the bottomhole assembly. For example, the assembly sensors can include a camera which can provide images of the wellbore and/or the formation. In some examples, the cable assembly can include a conductor line which can provide electric signals and/or power to the bottomhole assembly from the surface. In some examples, the cable assembly may not include a conductor line, and the bottomhole assembly may include a battery to provide power.

[0040] At block 804, the fiber optic line, during the drilling, can measure the one or more downhole parameters along a length of the wellbore. As the fiber optic line can be a distributed sensor, the fiber optic line can obtain measurements of the one or more downhole parameters at any location along the length of the wellbore. Accordingly, any issues can be pinpointed in the wellbore during drilling.

[0041] At block 806, data from the fiber optic line can be transmitted to a controller during the drilling. The data can include the measurements of the one or more downhole parameters by the fiber optic line. In some examples, the data can include measurements or data from the bottomhole assembly, for example the assembly sensors, as the fiber optic line can provide telemetry between the bottomhole assembly and the surface.

[0042] The controller can adjust the drilling of the wellbore based on the data from the fiber optic line. For example, the direction of the drilling may be adjusted. In some examples, the drilling may be paused to address any influx to the wellbore and/or outflow from the wellbore of fluid and/or solids. In some examples, the controller can adjust the drilling of the wellbore automatically, for example without any human assistance or input.

[0043] Numerous examples are provided herein to enhance understanding of the present disclosure. A specific set of statements are provided as follows.

[0044] Statement 1: A system is disclosed comprising: a bottomhole assembly disposed in a wellbore traversing a subterranean formation from a surface of the earth, the bottomhole assembly having a drill tool; a cable assembly including a fiber optic line coupled with the bottomhole assembly, the fiber optic line having a length that traverses a length of the wellbore from the bottomhole assembly to the surface, the fiber optic line being a distributed sensor and measuring one or more downhole parameters along the length of the fiber optic line during the

drilling of the wellbore; and a controller coupled with the cable assembly, the controller receiving data from the fiber optic line during the drilling of the wellbore by the drill tool.

[0045] Statement 2: A system is disclosed according to Statement 1, wherein the cable assembly includes a conduct line transmitting power to the bottomhole assembly.

[0046] Statement 3: A system is disclosed according to Statements 1 or 2, wherein the bottomhole assembly includes a battery providing power to the bottomhole assembly.

[0047] Statement 4: A system is disclosed according to any of preceding Statements 1-3, further comprising a conduit coupled with the bottomhole assembly.

[0048] Statement 5: A system is disclosed according to Statement 4, wherein the cable assembly is disposed within an annulus of the conduit.

[0049] Statement 6: A system is disclosed according to Statements 4 or 5, wherein the cable assembly is coupled with the conduit.

[0050] Statement 7: A system is disclosed according to any of preceding Statements 4-6, wherein the cable assembly is external to the conduit.

[0051] Statement 8: A system is disclosed according to any of preceding Statements 1-7, wherein the fiber optic line is one or more of the following: a distributed temperature sensor, a distributed acoustic sensor, and a distributed pressure sensor; and wherein the one or more downhole parameters includes temperature, acoustic signals, and/or pressure.

[0052] Statement 9: A system is disclosed according to any of preceding Statements 1-8, wherein the controller receives the data from the fiber optic line and adjusts the drilling of the wellbore based on the data.

[0053] Statement 10: A system is disclosed according to any of preceding Statements 1-9, wherein the bottomhole assembly includes one or more sensors, and the data includes measurements from the one or more sensors.

[0054] Statement 11: A drilling device is disclosed comprising: a bottomhole assembly having a drill tool operable to drill a wellbore; a cable assembly including a fiber optic line coupled with the bottomhole assembly, the fiber optic line having a length and being a distributed sensor and operable to measure one or more downhole parameters along the length of the fiber optic line during drilling of the wellbore; and a controller coupled with the cable assembly, the controller operable to receive data from the fiber optic line during the drilling of the wellbore.

[0055] Statement 12: A drilling device is disclosed according to Statement 11, wherein the cable assembly includes a conductor line operable to transmit power to the bottomhole assembly.

[0056] Statement 13: A drilling device is disclosed according to Statements 11 or 12, wherein the bottomhole assembly includes a battery operable to provide power to the bottomhole assembly.

[0057] Statement 14: A drilling device is disclosed according to any of preceding Statements 11-13, wherein the fiber optic line is one or more of the following: a distributed temperature sensor, a distributed acoustic sensor, and a distributed pressure sensor; and wherein the one or more downhole parameters includes temperature, acoustic signals, and/or pressure.

[0058] Statement 15: A drilling device is disclosed according to any of preceding Statements 11-14, wherein the controller receives the data from the fiber optic line and is operable to adjust the drilling of the wellbore based on the data.

[0059] Statement 16: A drilling device is disclosed according to any of preceding Statements 11-15, wherein the bottomhole assembly includes one or more sensors, and the data includes measurements from the one or more sensors.

[0060] Statement 17: A method is disclosed comprising: drilling, by a bottomhole assembly having a drill tool, a wellbore in a formation; measuring, by a fiber optic line having a length and coupled with the bottomhole assembly during the drilling, one or more downhole parameters along the length of the fiber optic line; and transmitting, to a controller during the drilling, data from the fiber optic line, wherein the fiber optic line is a distributed sensor and the length of the fiber optic line traverses the length of the wellbore from the bottomhole assembly to the surface.

[0061] Statement 18: A method is disclosed according to Statement 17, further comprising: adjusting, by the controller, the drilling of the wellbore based on the data from the fiber optic line.

[0062] Statement 19: A method is disclosed according to Statements 17 or 18, wherein the fiber optic line is one or more of the following: a distributed temperature sensor, a distributed acoustic sensor, and a distributed pressure sensor; and wherein the one or more downhole parameters includes temperature, acoustic signals, and/or pressure.

[0063] Statement 20: A method is disclosed according to any of preceding Statements 17-19, wherein the bottomhole assembly includes one or more sensors, and the data includes measurements from the one or more sensors.

[0064] The disclosures shown and described above are only examples. Even though numerous characteristics and advantages of the present technology have been set forth in the foregoing description, together with details of the structure and function of the present disclosure, the disclosure is illustrative only, and changes may be made in the detail, especially in matters of shape, size and arrangement of the parts within the principles of the present disclosure to the full extent indicated by the broad general meaning of the terms used in the attached claims. It will therefore be appreciated that the embodiments described above may be modified within the scope of the appended claims.

## CLAIMS

What is claimed is:

1. A system comprising:
  - a bottomhole assembly disposed in a wellbore traversing a subterranean formation from a surface of the earth, the bottomhole assembly having a drill tool;
  - a cable assembly including a fiber optic line coupled with the bottomhole assembly, the fiber optic line having a length that traverses a length of the wellbore from the bottomhole assembly to the surface, the fiber optic line being a distributed sensor and measuring one or more downhole parameters along the length of the fiber optic line during the drilling of the wellbore; and
  - a controller coupled with the cable assembly, the controller receiving data from the fiber optic line during the drilling of the wellbore by the drill tool.
2. The system of claim 1, wherein the cable assembly includes a conductor line transmitting power to the bottomhole assembly.
3. The system of claim 1, wherein the bottomhole assembly includes a battery providing power to the bottomhole assembly.
4. The system of claim 1, further comprising a conduit coupled with the bottomhole assembly.
5. The system of claim 4, wherein the cable assembly is disposed within an annulus of the conduit.
6. The system of claim 4, wherein the cable assembly is coupled with the conduit.
7. The system of claim 4, wherein the cable assembly is external to the conduit.

8. The system of claim 1, wherein the fiber optic line is one or more of the following: a distributed temperature sensor, a distributed acoustic sensor, and a distributed pressure sensor; and wherein the one or more downhole parameters includes temperature, acoustic signals, and/or pressure.
9. The system of claim 1, wherein the controller receives the data from the fiber optic line and adjusts the drilling of the wellbore based on the data.
10. The system of claim 1, wherein the bottomhole assembly includes one or more sensors, and the data includes measurements from the one or more sensors.
11. A drilling device comprising:
  - a bottomhole assembly having a drill tool operable to drill a wellbore;
  - a cable assembly including a fiber optic line coupled with the bottomhole assembly, the fiber optic line having a length and being a distributed sensor and operable to measure one or more downhole parameters along the length of the fiber optic line during drilling of the wellbore; and
  - a controller coupled with the cable assembly, the controller operable to receive data from the fiber optic line during the drilling of the wellbore.
12. The drilling device of claim 11, wherein the cable assembly includes a conductor line operable to transmit power to the bottomhole assembly.
13. The drilling device of claim 11, wherein the bottomhole assembly includes a battery operable to provide power to the bottomhole assembly.
14. The drilling device of claim 11, wherein the fiber optic line is one or more of the following: a distributed temperature sensor, a distributed acoustic sensor, and a distributed pressure sensor; and wherein the one or more downhole parameters includes temperature, acoustic signals, and/or pressure.

15. The drilling device of claim 11, wherein the controller receives the data from the fiber optic line and is operable to adjust the drilling of the wellbore based on the data.
16. The drilling device of claim 11, wherein the bottomhole assembly includes one or more sensors, and the data includes measurements from the one or more sensors.
17. A method comprising:  
drilling, by a bottomhole assembly having a drill tool, a wellbore in a formation;  
measuring, by a fiber optic line having a length and coupled with the bottomhole assembly during the drilling, one or more downhole parameters along the length of the fiber optic line; and  
transmitting, to a controller during the drilling, data from the fiber optic line,  
wherein the fiber optic line is a distributed sensor and the length of the fiber optic line traverses the length of the wellbore from the bottomhole assembly to the surface.
18. The method of claim 17, further comprising:  
adjusting, by the controller, the drilling of the wellbore based on the data from the fiber optic line.
19. The method of claim 17, wherein the fiber optic line is one or more of the following: a distributed temperature sensor, a distributed acoustic sensor, and a distributed pressure sensor; and wherein the one or more downhole parameters includes temperature, acoustic signals, and/or pressure.
20. The method of claim 17, wherein the bottomhole assembly includes one or more sensors, and the data includes measurements from the one or more sensors.

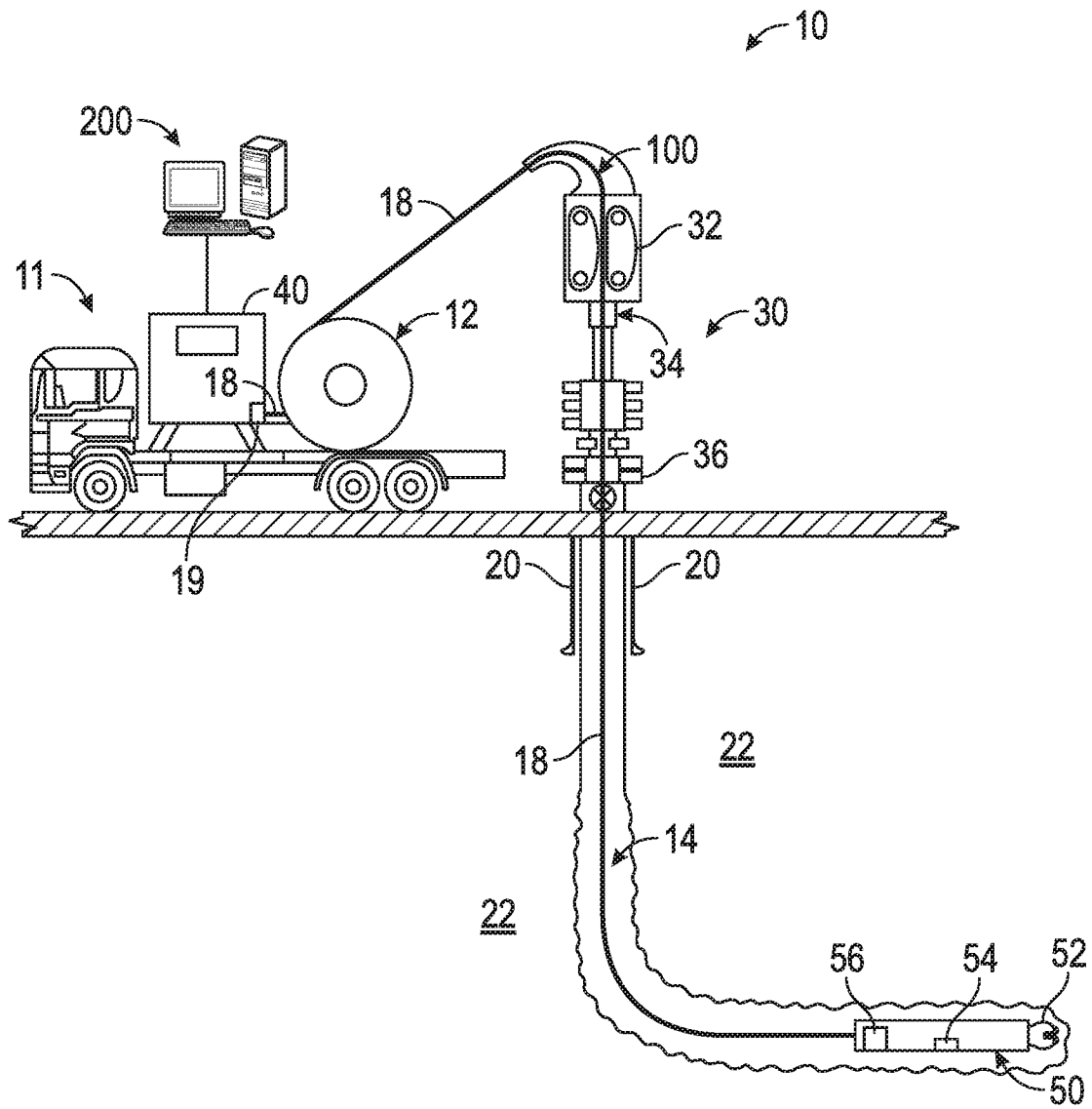


FIG. 1

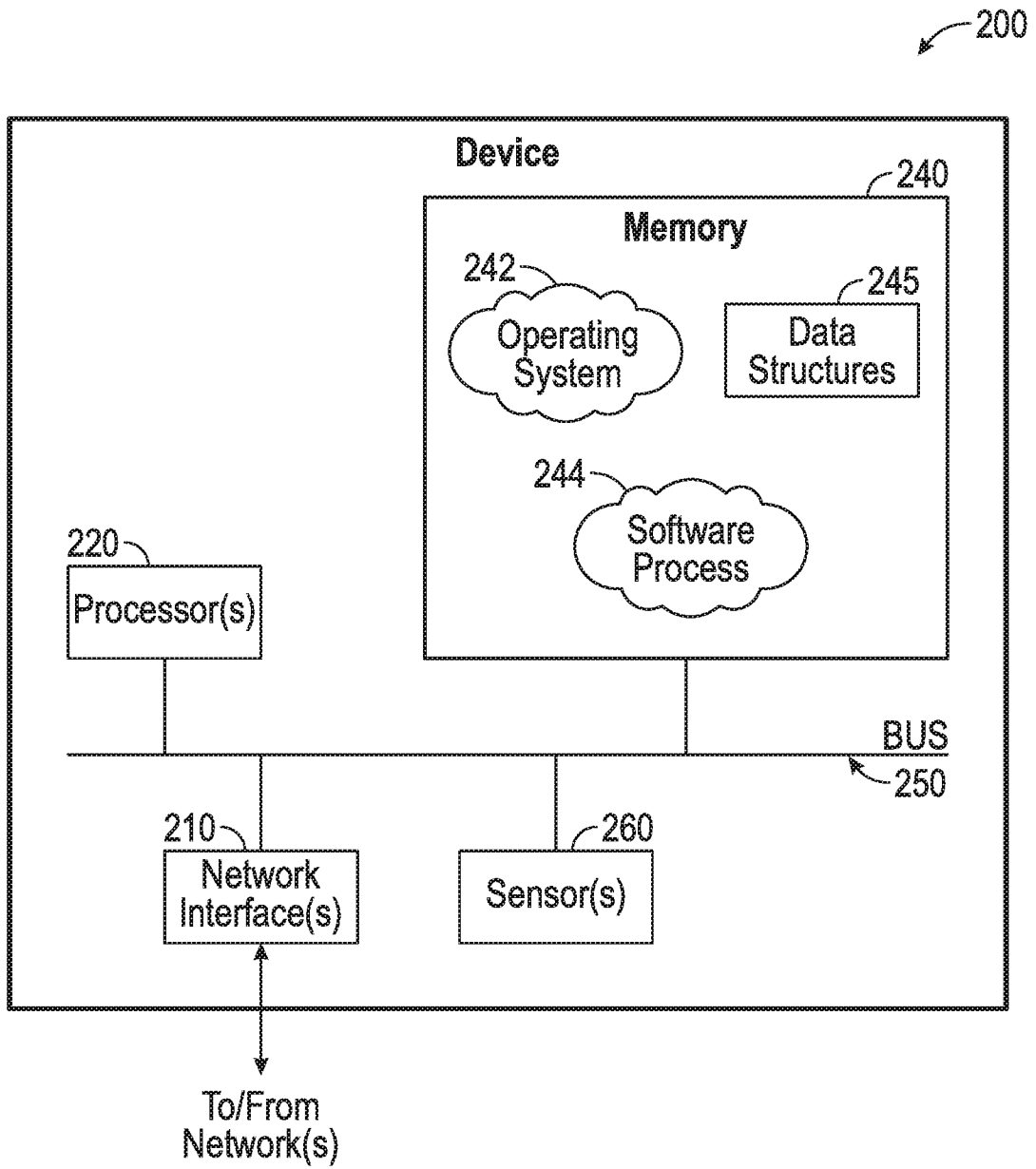


FIG. 2

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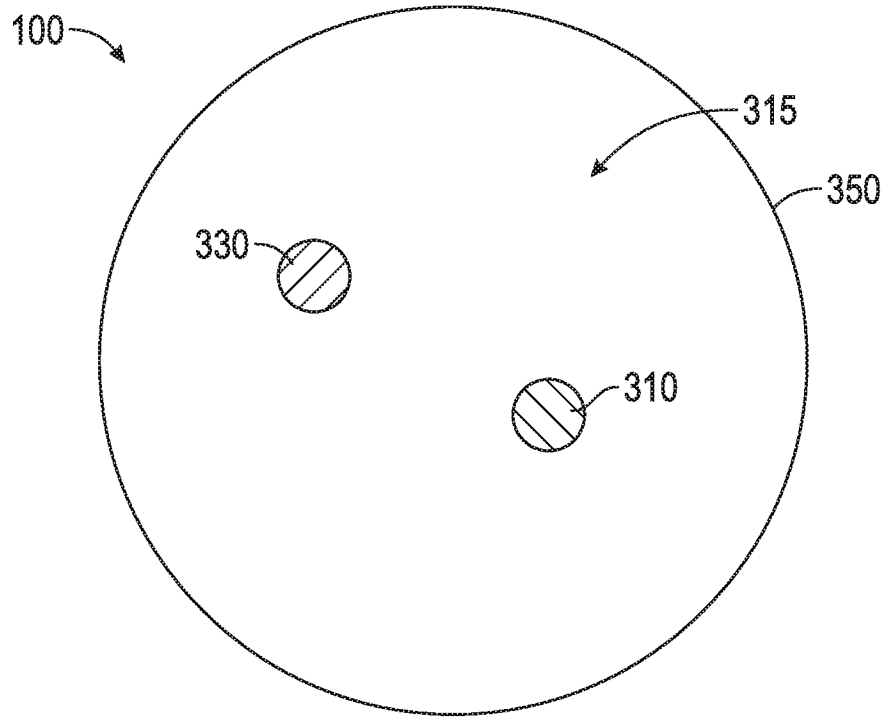
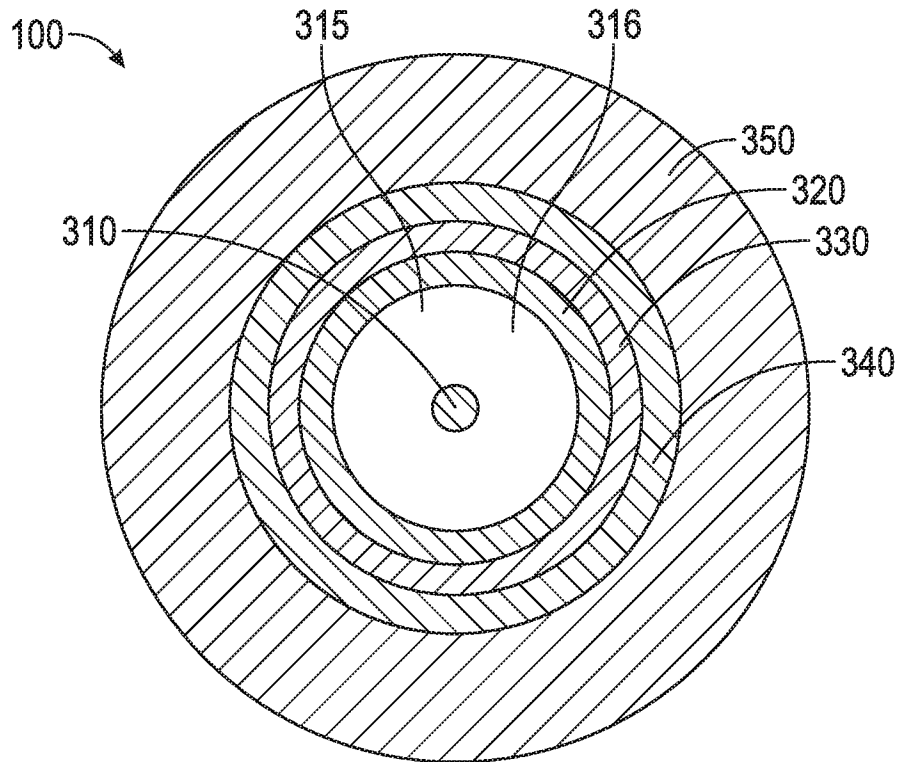


FIG. 3A



B

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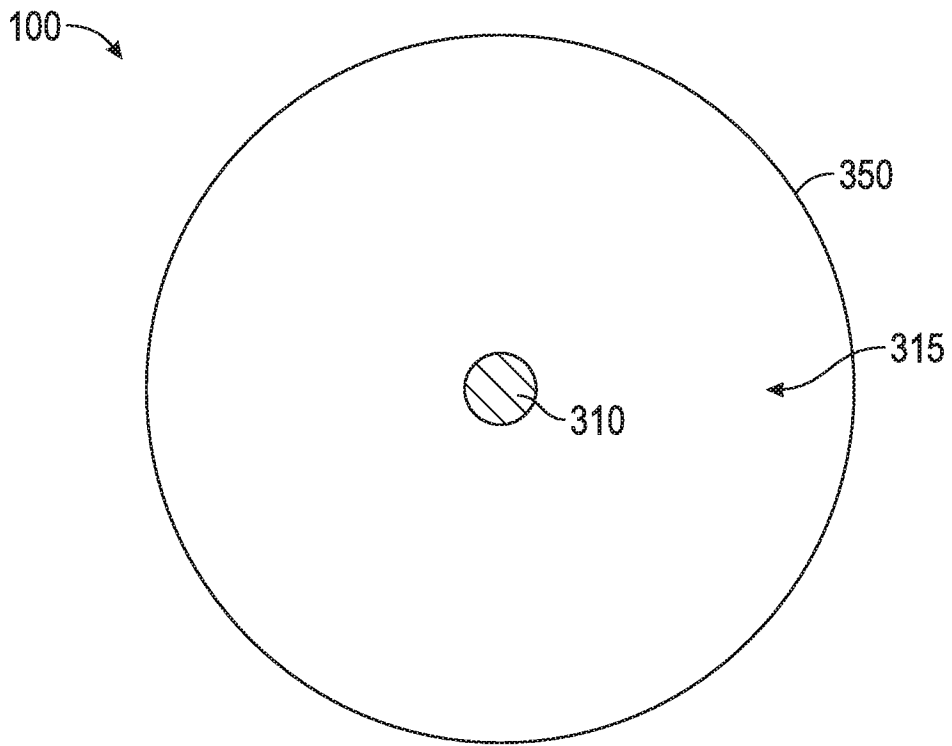


FIG. 3C



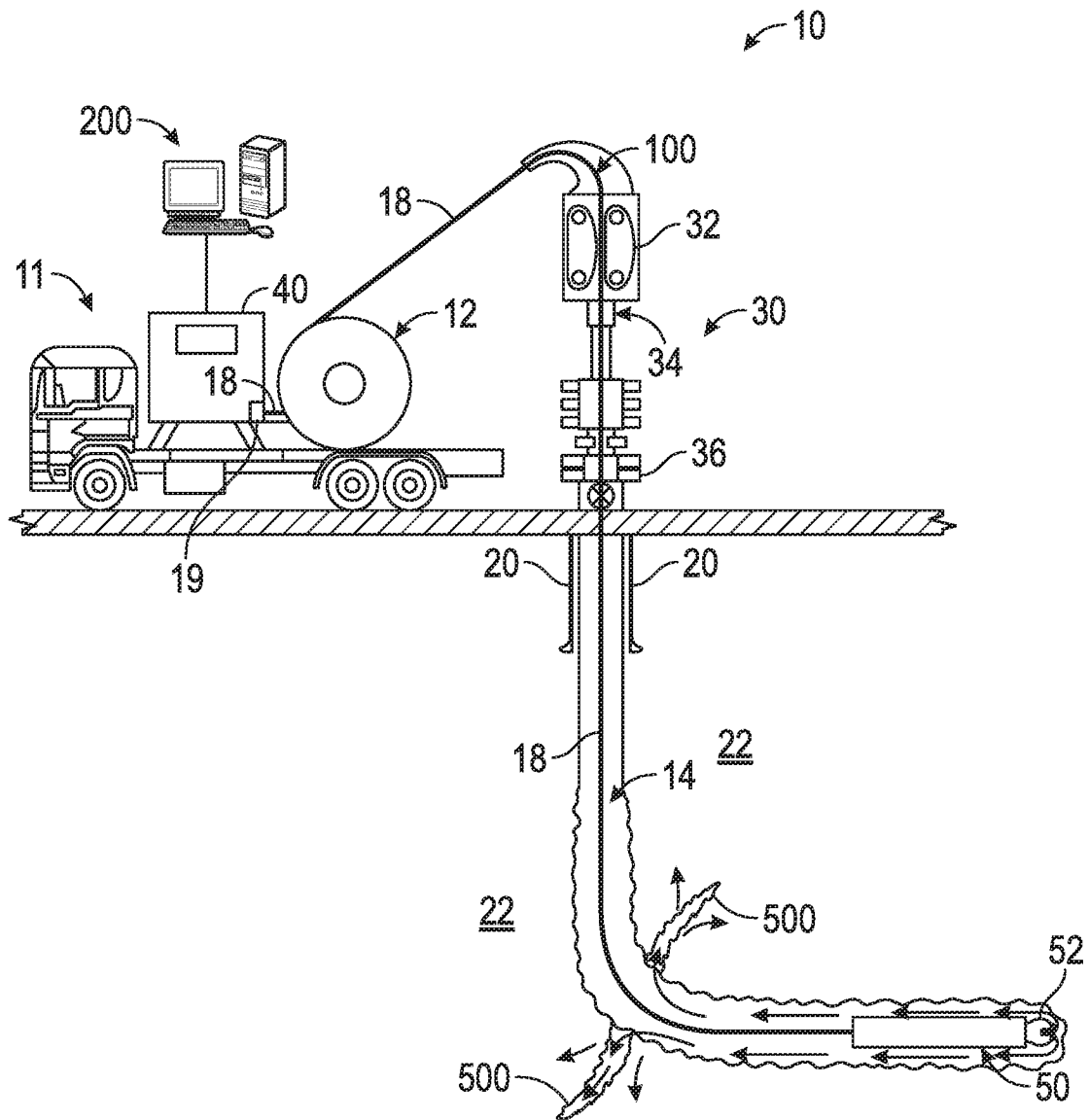


FIG. 5

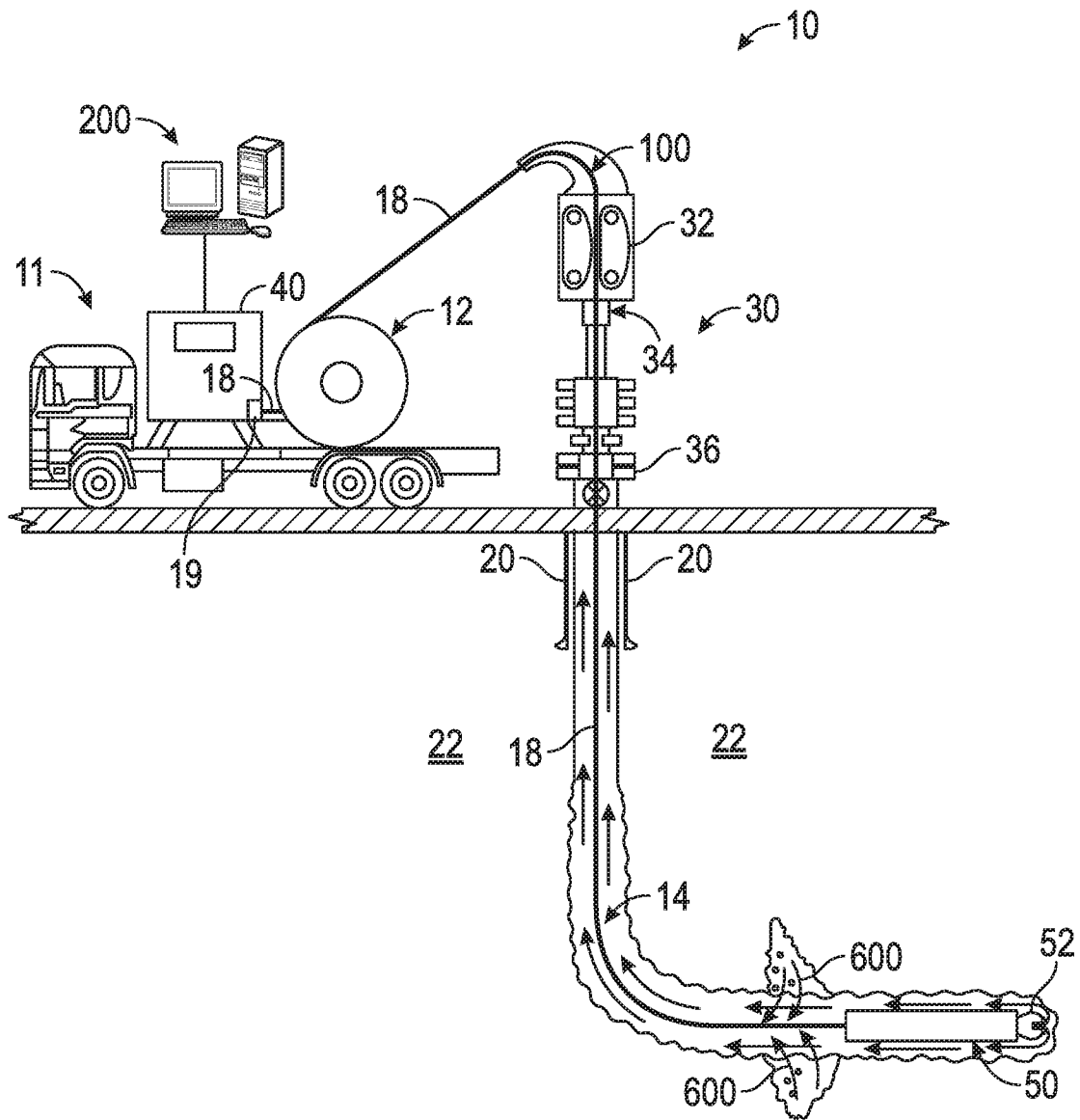


FIG. 6

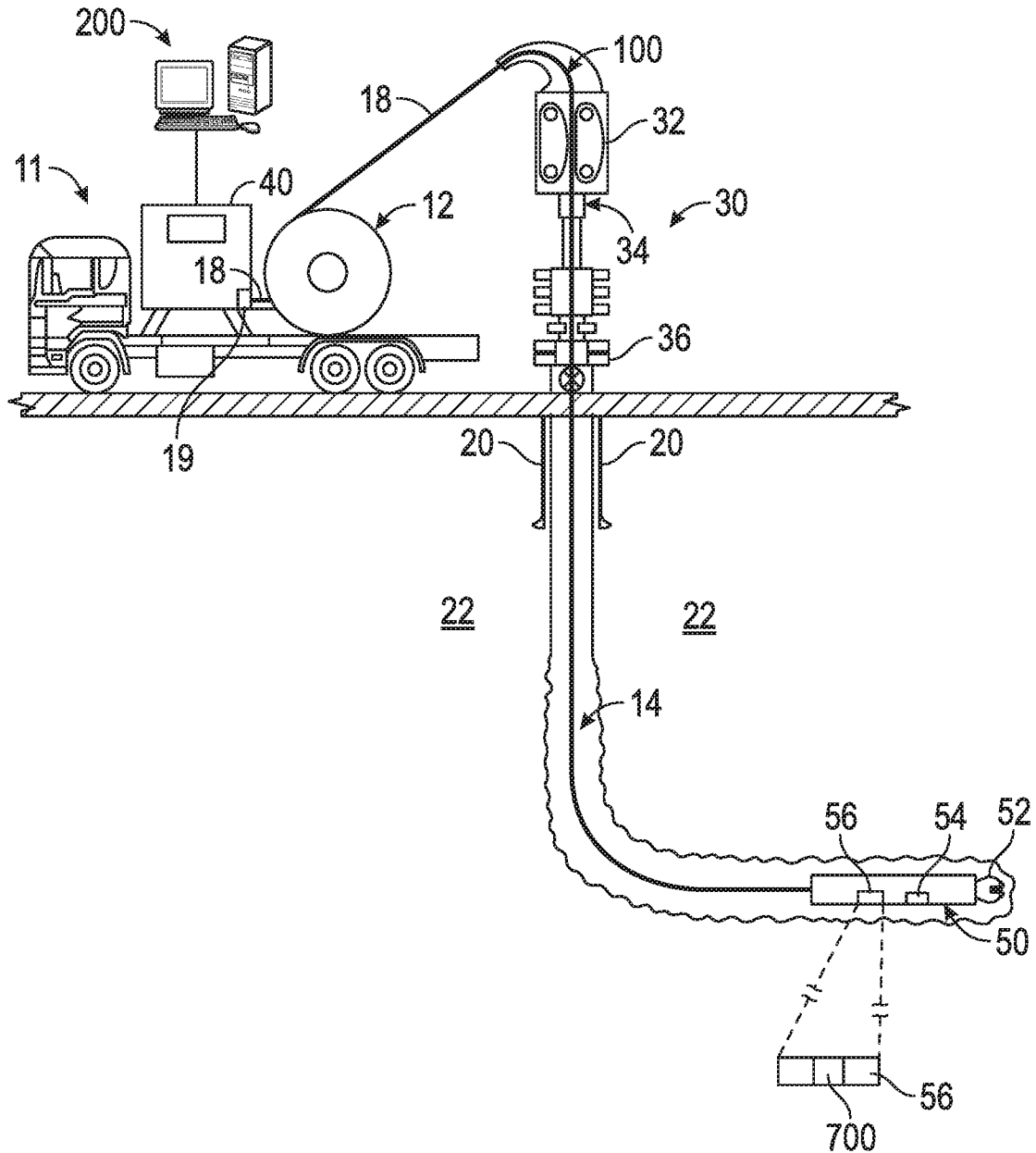


FIG. 7

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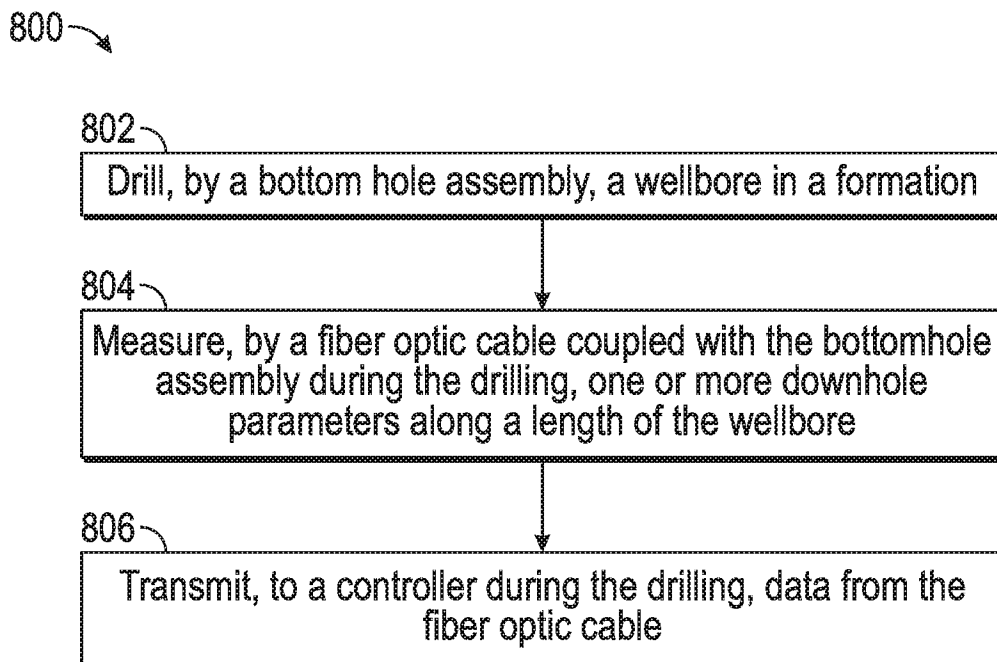


FIG. 8

**A. CLASSIFICATION OF SUBJECT MATTER****E21B 44/00(2006.01)i, E21B 47/12(2006.01)i**

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 44/00; E21B 007/04; E21B 21/00; E21B 23/14; E21B 47/01; E21B 47/02; E21B 7/00; E21B 7/04; E21B 47/12

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKOMPASS(KIPO internal) &amp; Keywords: drilling, bottomhole assembly, wellbore, cable, fiber optic line, sensor

**C. DOCUMENTS CONSIDERED TO BE RELEVANT**

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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A	US 4463814 A (HORSTMAYER et al.) 07 August 1984 claim 1 and figures 1-2	1-20

 Further documents are listed in the continuation of Box C. See patent family annex.

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"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

"&amp;" document member of the same patent family

Date of the actual completion of the international search

17 March 2020 (17.03.2020)

Date of mailing of the international search report

**18 March 2020 (18.03.2020)**

Name and mailing address of the ISA/KR

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Information on patent family members

International application No.

PCT/US2019/037976

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