



(51) International Patent Classification:

E21B 47/12 (2006.01) *E21B 47/14* (2006.01)

(21) International Application Number:

PCT/US2016/065415

(22) International Filing Date:

07 December 2016 (07.12.2016)

(25) Filing Language:

English

(26) Publication Language:

English

(71) Applicant: **HALLIBURTON ENERGY SERVICES, INC.** [US/US]; 3000 N. Sam Houston Pkwy E., Houston, TX 77032 (US).(72) Inventors: **GAO, Li**; 5618 Grandwood Ln, Katy, TX 77450 (US). **RAVI, Krishna**; PO Box 5622, Kingwood, TX 77325 (US). **TAWARE, Avinash**; 19 Pilot Rock Place, The Woodlands, TX 77375 (US). **STARK, Daniel, Joshua**; 8423 Hearth Dr., Apt. 3, Houston, TX 77054 (US).(74) Agent: **HILTON, Robert** et al.; McGuireWoods LLP, 1750 Tysons Blvd., Suite 1800, Tysons Corner, VA 22102 (US).(81) Designated States (*unless otherwise indicated, for every kind of national protection available*): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO,

DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (*unless otherwise indicated, for every kind of regional protection available*): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— with international search report (Art. 21(3))

(54) Title: DOWNHOLE TELEMETRY SYSTEM

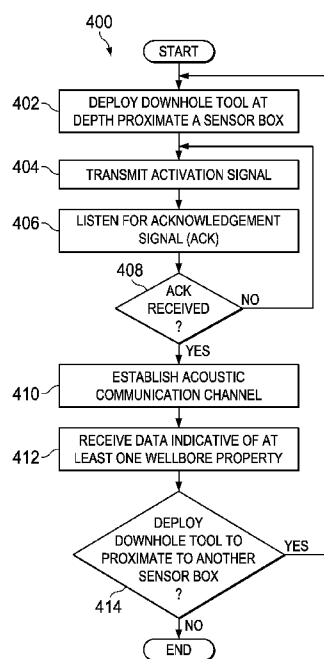


FIG. 4A

(57) Abstract: The disclosed embodiments include downhole telemetry systems and methods to obtain data indicative of wellbore properties. In one embodiment, a downhole telemetry system includes a plurality of sensor boxes, where each of the plurality of sensor boxes is deployed along a casing of a wellbore. Each sensor box is operable to obtain data indicative of at least one property of the wellbore and to transmit signals comprising data indicative of the at least one property of the wellbore. The downhole telemetry system also includes a downhole tool coupled to a conveyance and deployable in the wellbore. The downhole tool operable to transmit an activation signal to one or more sensor boxes of the plurality of sensor boxes to initiate communication with the one or more sensor boxes, and is also operable to receive signals comprising data indicative of the at least one property of the wellbore.



DOWNHOLE TELEMETRY SYSTEM

BACKGROUND

[0001] The present disclosure relates generally to downhole telemetry systems and methods to obtain data indicative of wellbore properties.

5 [0002] A wellbore is often drilled proximate to a subterranean deposit of hydrocarbon resources to facilitate exploration and production of hydrocarbon resources. Sections of casings are often coupled together and deployed in the wellbore to insulate downhole tools and strings deployed in the casing as well as hydrocarbon resources flowing through casing from the surrounding formation, to prevent cave-ins, and/or to prevent contamination of the surrounding formation. In that regard, a cement job is usually performed to fixedly secure the casing to the wellbore.

10 [0003] Wellbore properties, such as, materials present in the wellbore, a volume of cement mixture deposited in the wellbore to fixedly secure the casing to the wellbore, an approximate location of a top of the cement mixture, an approximate location of a bottom of the cement, temperature, pressure, salinity, vibration, noise threshold as well as similar properties are often periodically or continuously measured to monitor operations at or around the wellbore.

BRIEF DESCRIPTION OF THE DRAWINGS

20 [0004] The following figures are included to illustrate certain aspects of the present disclosure, and should not be viewed as exclusive embodiments. The subject matter disclosed is capable of considerable modifications, alterations, combinations, and equivalents in form and function, without departing from the scope of this disclosure.

[0005] FIG. 1A is a schematic, side view of a well environment that includes a downhole tool deployed in a casing and a plurality of sensor boxes deployed along the casing;

25 [0006] FIG. 1B illustrates a drilling environment in which the sensor boxes of FIG. 1A are deployed along a first section of the wellbore;

[0007] FIG. 1C illustrates a production environment in which the sensor boxes of FIG. 1A are deployed along the casing of FIG. 1A;

30 [0008] FIG. 2 illustrates a schematic, enlarged view of the downhole tool and the sensor boxes of FIG. 1A;

[0009] FIG. 3 illustrates a block diagram of components of the downhole tool of FIG. 1A;

[0010] FIG. 4A illustrates a flow chart of a process to obtain data indicative of at least one wellbore property of the wellbore of FIG. 1A; and

[0011] FIG. 4B illustrates another flow chart of a process to obtain data indicative of at least one wellbore property of the wellbore of FIG. 1A.

[0012] The illustrated figures are only exemplary and are not intended to assert or imply any limitation with regard to the environment, architecture, design, or process in which different embodiments may be implemented.

DETAILED DESCRIPTION OF ILLUSTRATIVE EMBODIMENTS

[0013] In the following detailed description of the illustrative embodiments, reference is made to the accompanying drawings that form a part hereof. These embodiments are described in sufficient detail to enable those skilled in the art to practice the invention, and it is understood that other embodiments may be utilized and that logical structural, mechanical, electrical, and chemical changes may be made without departing from the spirit or scope of the invention. To avoid detail not necessary to enable those skilled in the art to practice the embodiments described herein, the description may omit certain information known to those skilled in the art. The following detailed description is, therefore, not to be taken in a limiting sense, and the scope of the illustrative embodiments is defined only by the appended claims.

[0014] The present disclosure relates to downhole telemetry systems and methods to obtain data indicative of properties of a wellbore (wellbore properties). More particularly, sensor boxes are deployed along sections of a wellbore casing (casing), such as a surface casing, an intermediate casing, a production casing, or a combination thereof. Each sensor box is operable to obtain data indicative of wellbore properties, such as, materials present in the wellbore, a volume of cement mixture deposited in the wellbore to fixedly secure the casing to the wellbore, an approximate location of a top of the cement mixture, an approximate location of a bottom of the cement, temperature, pressure, salinity, pH, viscosity, vibration, noise threshold as well as similar properties disclosed herein. In some embodiments, each of the sensor boxes includes one or more sensor components operable to detect the foregoing wellbore properties. In other embodiments, the one or more of the foregoing wellbore

properties are obtained by another electronic or photonic device that is deployed in the wellbore and subsequently transmitted to one or more of the sensor boxes.

[0015] A downhole tool that is coupled to a string is deployed in the casing to retrieve the data stored in one or more of the sensor boxes. In some embodiments, the downhole tool is deployed at a location proximate to a location of a first sensor box of the one or more of sensor boxes. The downhole tool communicates with the first sensor box to establish a first communication channel with the sensor box. The first communication channel may be an acoustic communication channel, an electromagnetic communication channel, or an optical communication channel. The first sensor box then transmits data indicative of wellbore properties stored in the sensor box to the downhole tool.

[0016] In some embodiments, the downhole tool is operable to establish multiple acoustic, electronic, and/or optical communication channels with multiple sensor boxes and thereby is operable to simultaneously receive data indicative of wellbore properties from multiple sensor boxes. In other embodiments, the downhole tool retrieves data indicative of wellbore properties from one sensor box at a time. In one of such embodiments, the downhole tool is then redeployed to a location proximate to a location of a second sensor box to establish an acoustic, electronic, or optical communication channel with the second sensor box and to receive data indicative of the wellbore properties from the second sensor box. This process 400 is then repeated until the downhole tool obtains data indicative of wellbore properties from each sensor box that is deployed in the wellbore.

[0017] In some embodiments, the downhole tool, upon receipt of data indicative of wellbore properties, directly transmits said data up-hole to a controller, where the data is assessed by an operator. In other embodiments, the downhole tool, stores the data in a storage medium component of the downhole tool and periodically transmits data stored in the storage medium to the controller. In further embodiments, the downhole tool transmits data indicative of wellbore properties to another electronic device that is assessable by the operator. Additional descriptions of the foregoing telemetry system and methods to obtain data indicative of wellbore properties are provided in the paragraphs below and are illustrated in at least FIGS. 1-4.

[0018] Now turning to the figures, FIG. 1A illustrates a schematic, side view of a well environment 100 that includes a downhole tool 124 deployed in a casing 116 of a wellbore 106 and a plurality of sensor boxes 122A-122D deployed along the casing 116 of the wellbore 106. In the embodiment of FIG. 1A, a well 102 having the wellbore 106 extends from a

surface 108 of the well 102 to or through the subterranean formation 112. The casing 116 is deployed along the wellbore 106 to insulate downhole tools and devices deployed in the casing 116, to provide a path for hydrocarbon resources flowing from the subterranean formation 112, to prevent cave-ins, and/or to prevent contamination of the subterranean formation 112. The casing 116 is normally surrounded by a cement sheath 128 formed from cement slush, and deposited in an annulus between the casing 116 and the wellbore 106 to fixedly secure the casing 116 to the wellbore 106 and to form a barrier that isolates the casing 116. Although not depicted, there may be layers of casing concentrically placed in the wellbore 106, each having a layer of cement or the like deposited thereabout.

[0019] A hook 138, cable 142, traveling block (not shown), hoist (not shown), and conveyance 120 are provided to lower a downhole tool 124 down the wellbore 106 or to lift the downhole tool 124 up from the wellbore 106. The conveyance 120 may be wireline, slickline, coiled tubing, drill pipe, production tubing, downhole tractor, or another type of conveyance operable to deploy the downhole tool 124 at various depths of the wellbore 106. In some embodiments, the conveyance 120 includes an optical fiber, an electrical string, or another telecommunication cable that is operable to transmit data from the downhole tool 124 to a surface based electronic device.

[0020] At wellhead 136, an inlet conduit 152 is coupled to a fluid source (not shown) to provide fluids, such as cement mixtures, drilling fluids, displacement fluids or other fluids downhole. The conveyance 120 has an internal cavity that provides a fluid flow path from the surface 108 downhole. The fluids travel down the conveyance 120, and exit the conveyance 120. The fluids flow through an annulus 148 between the casing 116 and the surrounding formation 112 to an outlet conduit 164, and eventually into a container 140. A pump (not shown) may also facilitate fluid flow through the annulus 148 and the outlet conduit 164.

[0021] First, second, third, and fourth sensor boxes 122A-122D are deployed at various locations along the casing 116. Each of the first, second, third, and fourth sensor boxes 122A-122D is operable to obtain data indicative of wellbore properties. In some embodiments, each of the sensor boxes 122A-122D includes at least one sensor component operable to determine wellbore properties. In one of such embodiments, the at least one sensor component includes a sensor component operable to determine boundary properties of the wellbore 106 or materials deposited in the wellbore 106. For example, each of the sensor boxes 122A-122D includes a sensor component operable to determine a relative distance from said sensor to a

boundary of the wellbore, a relative distance from said sensor to a boundary of a cement mixture deposited in the wellbore, a relative distance from said sensor to a boundary of a mud mixture, or a relative distance from said sensor to the boundary of another material that is deposited in the wellbore 116. In another one of such embodiments, the at least one sensor includes a sensor operable to determine presence of leaks in the wellbore. In a further one of such embodiments, the at least one sensor includes a thermometer that senses a temperature of the wellbore 106 at a location proximate to said sensor. The at least one sensor may also include a pressure sensor that senses a pressure level of the wellbore 106 at the location proximate to said sensor. The at least one sensor may also include additional sensors operable to determine salinity, pH, viscosity, vibration, displacement, velocity, torque, acceleration, and other properties of the wellbore at the location proximate to said sensor.

[0022] In some embodiments, the at least one sensor also includes sensors that are operable to detect presence of nearby hydrocarbon resources. In one of such embodiments, the at least one sensor also includes sensors that are operable to determine a distance from the nearby hydrocarbon resources to the said sensors. In further embodiments, the at least one sensor may further determine the concentration of the nearby hydrocarbon resources. In further embodiments, the at least one sensor may further determine the extraction rate of the nearby hydrocarbon resources.

[0023] In some embodiments, electronic and/or photonic devices operable to detect wellbore properties described herein are deposited in the wellbore, or mixed with other materials such as cement, mud, displacement fluids. In such embodiments, the first, second, third, and fourth sensor boxes 122A-122D contain sub-components such as RFID detectors, acoustic detectors, photonics, as well as other sensor or detector components that are operable to communicatively connect to one or more of said electronic and/or photonic devices and to receive data indicative of wellbore properties from said devices.

[0024] The first, second, third, and fourth sensor boxes 122A-122D are each operable to communicative connect to the downhole tool 124 to transmit data indicative of wellbore properties to the downhole tool 124. Further, the first, second, third, and fourth sensor boxes 122A-122D each includes a transmitter operable to transmit signals, such as acoustic signals, electromagnetic signals, and optical signals that containing data indicative of wellbore properties to the downhole tool 124.

[0025] The downhole tool 124 includes any electronic device operable to receive acoustic, electromagnetic, or optical signals from the first, second, third and fourth sensor boxes 122A-

122D. Additional descriptions of establishing communication channels between the downhole tool 124 and sensor boxes are provided in more detail in the paragraphs below and are at least illustrated in FIGS. 2-4. In some embodiments, the downhole tool 124 transmits data obtained from the sensors via the conveyance 120 or via a telecommunication cable (e.g., an optical fiber, an electrical cable, or similar cable) coupled to the conveyance 120 to a surface based controller 184. In other embodiments, the downhole tool 124 stores data received from the sensor boxes in a storage medium component of the downhole tool 124 and periodically transmits the stored data. In a further embodiment, data stored in the storage medium of the downhole tool 124 are retrieved once the downhole tool 124 is retrieved from the wellbore 106. Although FIG. 1A illustrates one downhole tool 124 and four sensor boxes 122A-122D deployed in the wellbore 106, a different number of downhole tools and sensor boxes may be deployed.

[0026] In some embodiments, the wellbore 106 is subdivided into multiple sections that are drilled and completed at different times. For example, the wellbore 106 may include a main borehole and multiple lateral boreholes (not shown), each having one end adjacent to a side of the main borehole. In one of such embodiments, the drilling and completion of the main borehole are completed, and sensor boxes, such as the first, second, third, and fourth sensor boxes 122A-122D are deployed in along the main borehole prior to the drilling and completion of one or more of the lateral boreholes. In such embodiment, the sensor boxes 122A-122D are operable to obtain data indicative of one or more wellbore properties of the main borehole and initiate communication with one or more downhole tools that traverse the main borehole during drilling and completion of one or more of the lateral boreholes.

[0027] FIG. 1B illustrates a drilling environment 150 in which the sensor boxes 122A-122D are deployed along a first section of the wellbore 106. In one embodiment, the first section of the wellbore 106 represents the main borehole of the wellbore 106. In this embodiment, drill bit 126 and the downhole tool 124 are coupled to the conveyance 120. The drill bit 126 is lowered down the wellbore 106 to perform drilling operations on a lateral borehole (second section) of the wellbore 106, which extends from a side of the first section of the wellbore 106. As the downhole tool 124 travels to a location proximate one of the sensor boxes 122A-122D, the downhole tool 124 is operable to transmit an activation signal to the sensor box to initiate communication with the sensor box. The downhole tool 124 is further operable to receive signals indicative of data of at least one property of the wellbore 106. In some embodiments, the downhole tool 124 transmits data obtained from the sensors

via the conveyance 120 or via a telecommunication coupled to the conveyance 120 to a surface based controller 184. In other embodiments, the downhole tool 124 stores data received from the sensor boxes in a storage medium component of the downhole tool 124 and periodically transmits the stored data. In a further embodiment, data stored in the storage medium of the downhole tool 124 are retrieved once the downhole tool 124 is retrieved from the wellbore 106.

[0028] FIG. 1C illustrates a production environment 180 in which the sensor boxes 122A-122D of FIG. 1A are deployed along the casing 116. Once the well 102 has been prepared and completed, and sensor boxes 122A-122D have been deployed along the wellbore 106, the sensor boxes 122A-122D may operate during the production stage of the well 102 to obtain measurements of one or more wellbore properties of the wellbore 106. For example, the first sensor box 122A is deployed proximate perforations 141 and is operable to measure the flow rate of hydrocarbon resources flowing out of the perforations 141, the type of hydrocarbon resources flowing out of the perforations 141, the temperature of the hydrocarbon resources flowing out of the perforations 141, as well as other quantifiable properties of the hydrocarbon resources flowing out of the perforations 141. The first sensor box 122A is further operable to store data indicative of the measurements of the hydrocarbon resources in a storage medium of the first sensor box 122A. In some embodiments, the first sensor box 122A, upon receipt of an activation signal from a downhole device, such as the downhole tool 124, is further operable to transmit data indicative of the measurements of the hydrocarbon resources to the downhole device.

[0029] FIG. 2 illustrates a schematic, enlarged view of the downhole tool 124 and the sensor boxes 122A-122D of FIG. 1A. A cement mixture (not shown) is deposited in a section of the annulus 148 to fixedly secure the casing 116. The first and second sensor boxes 122A and 122B are deployed at locations proximate to a bottom of the cement mixture, where the bottom of the cement mixture is defined by a bottom boundary 146. The third and fourth sensor boxes 122C and 122D are deployed at locations proximate to a top of the cement mixture, where the top of the cement mixture is defined by a top boundary 144.

[0030] The downhole tool 124 is coupled to the conveyance 120 and may be raised or lowered to depths proximate to the locations of the first, second, third, and fourth sensor boxes 122A-122D. In the embodiment of FIG. 2, the downhole tool 124 is lowered to a depth that is proximate the locations of the first and the second sensor boxes 122A and 122B. The downhole tool 124 broadcasts a signal indicative (activation signal) of the presence of the

downhole tool 124. In some embodiments, the activation signal includes an identification of the downhole tool 124. In other embodiments, the activation signal is transmitted within a predetermined frequency. In one of such embodiments, the first sensor box 122A is operable to determine the frequency of the activation signal and is operable to transmit acoustic signals containing data indicative of wellbore properties upon determining that the activation signal is transmitted within a predetermined frequency (first frequency).

[0031] In some embodiments, the downhole tool 124 transmits the activation signal together with instructions on how to establish a communication channel with the downhole tool 124 as well as other pilot signals used to establish the acoustic communication channel to the first sensor box 122A. As stated herein, the communication channel may be an acoustic communication channel, an optical communication channel, or an electromagnetic communication channel. In some embodiments, the instructions identify compatible protocols for establishing the acoustic communication channel. In one of such embodiments, the instructions identify a frequency division multiple access (FDMA) protocol for establishing the acoustic communication channel. The instructions may also require the first sensor box 122A to transmit data within a frequency range that is different from the frequency range of data transmissions from other sensor boxes 122B-122D. For example, the downhole tool may specify that the first sensor box 122A should transmit data within a first frequency range, and that the second sensor box 122B should transmit data within a second frequency range. In another one of such embodiments, the instructions identify a code division multiple access (CDMA) protocol for establishing the acoustic communication channel. For example, the instructions may request the first sensor box 122A to transmit data using a first coding scheme, and may request the second sensor box 122B to transmit data using a second and different coding scheme.

[0032] In a further one of such embodiments, the instructions identify a time division multiple access (TDMA) protocol for establishing the acoustic communication channel. For example, the instructions may request the first sensor box 122A to transmit data within a first period of time and may request the second sensor box 122B to transmit data within a second and different period of time. In a further embodiment, the instructions identify an orthogonal frequency divisional multiple access (OFDMA) protocol, or a protocol similar to one of the communication protocols disclosed herein for establishing the acoustic communication channel.

[0033] The first sensor box 122A includes a sensor operable to detect the activation signal. In some embodiments, where the activation signal is transmitted as an acoustic signal, the first sensor box 122A includes an acoustic sensor operable to detect acoustic signals. In other embodiments, the first sensor box 122A includes an electromagnetic sensor, a RFID sensor, a NFC sensor, a magnetic sensor, a conductive sensor, an acoustic impedance sensor or a different type of sensor that is operable to detect different types of signals that are used as the activation signal. In some embodiments, the first sensor box 122A, upon receipt of signals from the downhole tool 124, determines if the received signals include the activation signal. The first sensor box 122A then transmits an acknowledgement signal acknowledging the presence of the first sensor box 122A to the downhole tool 124.

[0034] In some embodiments, the first sensor box 122A is operable to detect the presence of the downhole tool 124 without the activation signal. In one of such embodiments, the first sensor box 122A contains at least of a magnetic field sensor, a conductive sensor, an electromagnetic sensor, and an acoustic impedance sensor, where each sensor is operable to detect a disturbance in a magnetic field caused by the presence of the downhole tool 124. In another one of such embodiments, the first sensor box 122A is operable to utilized at least one of the magnetic field sensor a conductive sensor, an electromagnetic sensor, and an acoustic impedance sensor to identify variations in the conductivity or acoustic impedance due to the proximity of the downhole tool 124. The first sensor box 122A then transmits the acknowledgement signal upon determining that the downhole tool 124 is within a proximately due to the disturbance in the magnetic field. The first sensor box 122A then transmits data indicative of wellbore properties via the established acoustic communication channel to the downhole tool 124. In some embodiments, data indicative of wellbore properties includes a distance from the first downhole tool 124 to the bottom boundary 146, the top boundary 144 and/or other wellbore properties disclosed herein.

[0035] The downhole tool 124 may utilize the procedures described in the foregoing paragraphs to establish an acoustic communication channel with the second sensor box 122B. In some embodiments, the downhole tool 124 may utilize a CDMA, TDMA, FDMA, OFDMA or another protocol to establish acoustic communication channels with both the first and the second sensor boxes 122A and 122B and to simultaneously receive data from both sensor boxes 122A and 122B.

[0036] The downhole tool 124, upon receiving data from both the first and the second sensor boxes 122A and 122B, may be re-deployed to a depth proximate the third and fourth

sensor boxes 122C and 122D. The downhole tool 124 may utilize the procedures described in the foregoing paragraphs to establish communication channels with the third and the fourth sensor boxes 122C and 122D to obtain data indicative of wellbore properties from the third and the fourth sensor boxes 122C and 122D. The established communication channels may be acoustic communication channels, electromagnetic communication channels, optical communication channels, or a combination of the foregoing channels. Although FIG. 2 illustrates four sensor boxes, the downhole tool 124 may be redeployed to other depths proximate to additional sensor boxes to obtain data indicative of wellbore properties from said sensor boxes.

[0037] FIG. 3 illustrates a block diagram of components of the downhole tool 124 of FIG. 1A. The downhole tool 124 includes a transmitter 302 that is operable to transmit activation signals and signals indicative of instructions to establish an acoustic communication channel with one or more sensor boxes. The downhole tool 124 also includes a receiver 304 operable to receive acknowledgement signals, signals indicative of instructions to establish an acoustic communication channel as well as acoustic signals containing data indicative of wellbore properties. In some embodiments, the transmitter 302 and the receiver 304 are components of a transceiver (not shown) that is also operable to transmit and to receive acoustic signals used to establish the acoustic communication channel and to receive data indicative of wellbore properties. In other embodiments, where signals (such as activation signals and acknowledge signals) used to establish acoustic communication signals are electrical signals, magnetic signals, optical signals, electromagnetic signals, or other types of signals discussed herein, the transmitter 302 and the receiver 304 are also operable to transmit and to receive said types of signals.

[0038] The downhole tool 124 also includes a storage medium 306. The storage medium 206 may be formed from data storage components such as, but not limited to, read-only memory (ROM), random access memory (RAM), flash memory, magnetic hard drives, solid state hard drives, as well as other types of data storage components and devices. In some embodiments, the storage medium 306 includes multiple data storage devices. Data received from the sensor boxes 122A-122D are stored on the storage medium 306. The storage medium 306 also includes instructions for operating the downhole tool 124, instructions for establishing acoustic communication channels with sensor boxes, as well as instructions on for providing data stored indicative of wellbore properties to the controller 184 or to another surface based electronic device that is accessible by an operator. In some embodiments, the

storage medium 206 also includes an identification of the downhole tool 124, identifications of the sensor boxes 122A-122D that are deployed in the wellbore 106, and approximate locations of the sensor boxes 122A-122D.

[0039] The downhole tool 124 also includes a processor 308 that is operable to execute the instructions stored in the storage medium 306 to transmit activation signals to the sensor boxes 122A-122D, to detect acknowledge signals from the sensor boxes 122A-122D, establish acoustic communication channels with the sensor boxes 122A-122D, receive acoustic signals containing data indicative of wellbore properties, store said data on the storage medium 306, and to perform other operations described herein. In some embodiments, the processor 308 is a sub-component of the transmitter 302 or the receiver 304. In further embodiments, the processor 308 is a separate component that utilizes the transmitter 302, the receiver 304, and the other components of the downhole tool 124 to perform the operations described herein.

[0040] The downhole tool 124 further includes a power source 310 that provides power to the downhole tool 124. In some embodiments, the power source 310 is a rechargeable power source. In one of such embodiments, the power source 310 is electrically coupled to a power supply (not shown). In another one of such embodiments, the power source 310 is operable to convert kinetic energy, such as vibrations generated during hydrocarbon production to electrical energy to recharge the power source 310. In further embodiments, the power source 310 is operable to convert thermal energy, such as through the use of thermoelectric devices, or chemical energy, such as through a reaction with substances found in the surrounding environment, to recharge the power source 310. In further embodiments, the power source 310 is operable to convert chemical energy to recharge the power source 310. As such, the power source 310 may be recharged at the downhole location where the downhole tool 124 is deployed. Although the foregoing paragraphs describe establishing acoustic communication channels and transmitting/receiving acoustic signals, the downhole tool 124 is also operable to establish electromagnetic communication channels, to transmit/receive electromagnetic signals, to establish optical communication channels, to transmit/receive optical signals, to establish other types of communication channels, and to transmit/receive other types of signals disclosed herein.

[0041] In some embodiments, the downhole tool 124 includes one or more sensors operable to detect wellbore properties disclosed herein. In one or such embodiments, the sensors include a sensor operable to determine presence of leaks in the wellbore.

[0042] FIG. 4 illustrates a flow chart of a process 400 to obtain data indicative of at least one wellbore property of the wellbore 106 of FIG. 1A. Although the operations in the process 400 are shown in a particular sequence, certain operations may be performed in different sequences or at the same time where feasible.

5 [0043] At step 402, the downhole tool 124 is deployed at a depth proximate the first sensor box 122A. At step 404, the downhole tool 124 transmits an activation signal indicative of the presence of the downhole tool 124. The process 400 then proceeds to step 406 and the downhole tool 124 listens for an acknowledgement signal indicative of the presence of the first sensor box 122A. At step 408, the downhole tool 124 determines if an acknowledgement signal has been received within a predetermined operational duration (e.g., one second after transmission of the activation signal, ten seconds after the transmission of the activation signal, or another operational duration). If the downhole tool 124 does not receive the acknowledgement signal within the operational duration, then the process 400 returns to step 404 and the downhole tool 124 transmits another activation signal. Alternatively, if the downhole tool 124 receives the acknowledgement signal within the operational duration, then the process 400 proceeds to step 410 and the downhole tool 124 establishes an acoustic communication channel with the first sensor box 122A.

10 [0044] At step 412, the downhole tool 124 receives data indicative of wellbore properties from the first sensor box 122A. In some embodiments, the downhole tool is coupled to or communicatively connected to a telecommunication cable, such as a wireline, an optical fiber, or another type of telecommunication cable disclosed herein that is operable to transmit data obtained from the first sensor box 122A to the controller 184. In such embodiments, the downhole tool 124 transmits data obtained from the first sensor box 122A via the telecommunication cable to the controller 184. In some embodiments, data received from the first sensor box 122A are stored in the storage medium 306 of the downhole tool 124. In some embodiments, another sensor box, such as the second sensor box 122B, or an electromagnetic or acoustic device, such as an electromagnetic tag or an acoustic tag, is also deployed at or proximate the depth of the first sensor box 122A. In such embodiments, the downhole tool 124 also performed steps 404, 406, 408, 410, and 412 to establish an acoustic communication channel with the second sensor box 122B and to receive data indicative of wellbore properties from the second sensor box 122B. The process 400 proceeds to step 414 once the downhole tool 124 receives data from the first sensor box 122, as well as from other sensor boxes that are deployed at or proximate the depth of the first sensor box 122A. At step

414, the downhole tool 124 determines if said tool 124 should be deployed proximate to another sensor box at a different location. If the downhole tool 124 determines that said tool 124 should be deployed to another location, then the process 400 proceeds to step 402 and the downhole tool 124 is re-deployed to another depth that is proximate to another sensor box. Alternatively, if the downhole tool 124 determines that said tool should not be redeployed, then the process ends.

[0045] FIG. 4B illustrates a flow chart of a process 450 to obtain data indicative of at least one wellbore property of the wellbore 106 of FIG. 1A. Although the operations in the process 450 are performed by the first sensor box 122A, the operations may also be performed by another sensor box disclosed herein and deployed in the wellbore 106. Although the operations in the process 450 are shown in a particular sequence, certain operations may be performed in different sequences or at the same time where feasible.

[0046] At step 452, the first sensor box 122A obtains data indicative of wellbore properties. In some embodiments, step 452 is performed continuously for the operational duration of the first sensor box 122A. In other embodiments, the step 452 is performed periodically. The process 450 proceeds to step 454 if the first sensor box 122 receives signals from the downhole tool 124. In some embodiments, the signals include instructions to establish an acoustic communication channel with the downhole tool 124. At step 454, the first sensor box 122A compares a signal profile of the received signals with a signal profile of the activation signal and determines if the received signals match the activation signal, respectively. In some embodiments, the received signals contain the activation signal together with other instructions to set up a communication channel with the downhole tool 124. In further embodiments, the first sensor box 122A determines the signal intensity of the received signals. In such embodiments, the first sensor box 122A determines that the received signals match the activation signal if the signal intensity of the received signals is greater than a first threshold value. The process 450 then proceeds to step 458 upon such determination. In further embodiments, the first sensor box 122A scans for signals within a first frequency range and having a signal intensity greater than the first threshold value. In such embodiments, the first sensor box 122A determines that the received signals match the activation signal if the frequency of the received signals is within the first frequency range and if the signal intensity of the received signals is greater than the first threshold value. The process 450 then proceeds to step 458.

[0047] At step 456, if the received signals do not include the activation signal, then the process 450 proceeds to step 452. Alternatively, if the received signals do include the activation signal then the process 450 proceeds to step 458. At step 458, the first sensor box 122A transmits the acknowledgement signal to notify the presence of the first sensor box 122A and to notify downhole tool 124 that the first sensor box 122A is operable to communicatively connect to the downhole tool 124. At step 460, the first sensor box 122A transmits acoustic signals containing data indicative of wellbore properties to the downhole tool 124. The process 450 then returns to step 452. Although the processes 400 and 450 describe establishing acoustic communication channels and transmitting acoustic signals, the foregoing processes 400 and 450 may also be utilized to establish electromagnetic communication channels, to transmit/receive electromagnetic signals, to establish optical communication channels, to transmit/receive optical signals, to establish other types of communication channels, and to transmit/receive other types of signals disclosed herein.

[0048] The above-disclosed embodiments have been presented for purposes of illustration and to enable one of ordinary skill in the art to practice the disclosure, but the disclosure is not intended to be exhaustive or limited to the forms disclosed. Many insubstantial modifications and variations will be apparent to those of ordinary skill in the art without departing from the scope and spirit of the disclosure. The scope of the claims is intended to broadly cover the disclosed embodiments and any such modification. Further, the following clauses represent additional embodiments of the disclosure and should be considered within the scope of the disclosure:

[0049] Clause 1, a downhole telemetry system comprising a plurality of sensor boxes, each of the plurality of sensor boxes deployed along a casing of a wellbore, each sensor box of the plurality of sensor boxes operable to obtain data indicative of at least one property of the wellbore; and transmit signals comprising data indicative of the at least one property of the wellbore; and a downhole tool coupled to a conveyance and deployable in the wellbore, the downhole tool operable to transmit an activation signal to one or more sensor boxes of the plurality of sensor boxes to initiate communication with the sensor box; and receive signals comprising data indicative of the at least one property of the wellbore.

[0050] Clause 2, the downhole telemetry system of clause 1, wherein each sensor box of the plurality of sensor boxes is further operable to: detect signals transmitted from the downhole tool; determine if the signals transmitted from the downhole tool comprise the activation signal; and transmit an acknowledgement signal to the downhole tool upon

determining that the signals transmitted from the downhole tool comprise the activation signal.

[0051] Clause 3, the downhole telemetry system of clause 1 or 2, wherein the acknowledgement signal comprises instructions to establish at least one of an acoustic communication channel, an optical communication channel, and an electromagnetic communication channel with the one or more sensor boxes of the plurality of sensor boxes, and wherein the downhole tool is further operable to establish at least one of the acoustic communication channel, the optical communication channel, and the electromagnetic communication channel with the one or more sensor boxes based on the instructions of the acknowledgement signal.

[0052] Clause 4, the downhole telemetry system of any of clauses 1-3, wherein the downhole tool is further operable to utilize at least one of a frequency division multiple access (FDMA) protocol, a time division multiple access (TDMA) protocol, and a code division multiple access (CDMA) protocol to establish the at least one of the acoustic communication channel, the optical communication channel, and the electromagnetic communication channel with the one or more sensor boxes.

[0053] Clause 5, the downhole telemetry system of any of clauses 1-4, wherein each sensor box of the one or more sensor boxes is operable to transmit the signals comprising data indicative of the at least one property of the wellbore within a different frequency range.

[0054] Clause 6, the downhole telemetry system of any of clauses 1-5, wherein the signals comprise at least one of acoustic signals, electromagnetic signals, optical signals, and photonic signals.

[0055] Clause 7, the downhole telemetry system of any of clauses 1-6, wherein the activation signal is a signal transmitted within a first frequency range, and wherein each sensor box of the plurality of sensor boxes is further operable to determine a frequency of signals transmitted by the downhole tool; and transmit signals comprising data indicative of the at least one property of the wellbore upon determining that the frequency of the signals transmitted by the downhole tool is within the first frequency range.

[0056] Clause 8, the downhole telemetry system of any of clauses 1-7, wherein each sensor box of the plurality of sensor boxes is further operable to determine a signal intensity of the signals transmitted by the downhole tool; and transmit signals comprising data indicative of the at least one property of the wellbore upon determining that the signal intensity of the signals transmitted by the downhole tool is greater than a first threshold value.

[0057] Clause 9, the downhole telemetry system of any of clauses 1-8, wherein each sensor box of the plurality of sensor boxes comprises at least one of a magnetic field sensor, a conductive sensor, an electromagnetic sensor, and an acoustic impedance sensor, each of said sensors being operable to detect a presence of the downhole tool, and wherein each sensor box of the plurality of sensor boxes is further operable to transmit signals comprising data indicative of the at least one property of the wellbore upon detecting the presence of the downhole tool.

[0058] Clause 10, the downhole telemetry system of any of clauses 1-9, wherein the conveyance comprises at least one of a wireline, an electronic line, an optical fiber, and a coiled tubing, and wherein downhole tool is further operable to transmit data indicative of the at least one property of the wellbore via the wireline to a surface based electronic device.

[0059] Clause 11, the downhole telemetry system of any of clauses 1-10, wherein the downhole tool comprises a machine readable medium operable to store data indicative of the at least one property of the wellbore.

[0060] Clause 12, the downhole telemetry system of any of clauses 1-11, wherein the at least one property of the wellbore comprises a location of a top of a cement mixture deposited along an annulus between the casing and the wellbore.

[0061] Clause 13, the downhole telemetry system of any of clauses 1-12, further comprising a plurality of sensors deployed along the annulus, wherein each sensor of the plurality of sensors is operable to detect the at least one property of the wellbore; and transmit the at least one property of the wellbore to the one or more sensor boxes.

[0062] Clause 14, the downhole telemetry system of any of clauses 1-13, wherein the downhole tool is further operable to determine a presence of one or more leaks in the wellbore.

[0063] Clause 15, a method to obtain data indicative of at least one wellbore property, the method comprising deploying a downhole tool to a first location proximate to a first sensor box of a plurality of sensor boxes deployed along a casing of a wellbore; periodically transmitting an activation signal to the first sensor box to initiate acoustic communication with the first sensor box; detecting a first acknowledgement signal from the first sensor box of the plurality of sensor boxes; establishing a first acoustic communication channel with the first sensor box of the plurality of sensor boxes upon detecting the first acknowledgement signal; and receiving acoustic signals comprising data indicative of the at least one property of the wellbore via the first acoustic channel.

[0064] Clause 16, the method of clause 15, further comprising deploying a downhole tool to a second location proximate to a second sensor box of a plurality of sensor boxes deployed along a casing of a wellbore; periodically transmitting an activation signal to the second sensor box to initiate acoustic communication with the second sensor box; detecting a second acknowledgement signal from the second sensor box of the plurality of sensor boxes; establishing a second acoustic communication channel with the second sensor box of the plurality of sensor boxes upon detecting the second acknowledgement signal; and receiving acoustic signals comprising data indicative of the at least one property of the wellbore via the second acoustic communication channel.

[0065] Clause 17, the method of clause 15 or 16, further comprising transmitting the acoustic signals comprising data indicative of the at least one property of the wellbore to a surface based electronic device.

[0066] Clause 18, the method of any of clauses 15-17, wherein establishing the first acoustic communication channel comprises utilizing at least one of a FDMA, TDMA, CDMA protocol to establish the first acoustic communication channel with the first sensor box.

[0067] Clause 19, a non-transitory machine-readable medium comprising instructions stored therein, which when executed by one or more processors, causes the one or more processors to perform operations comprising periodically transmitting activations signals to a plurality of sensor boxes that are deployed along a casing of a wellbore to initiate acoustic communication with the plurality of sensor boxes; detecting acknowledgement signals from one or more of the plurality of sensor boxes; establishing an acoustic communication channel with the one or more of the plurality of sensor boxes; receiving acoustic signals comprising data indicative of the at least one property of the wellbore; and storing data indicative of the at least one property of the wellbore in a storage component.

[0068] Clause 20, the non-transitory machine-readable medium of claim 19, further comprising instructions stored therein, which when executed by one or more processors, causes the one or more processors to perform operations comprising utilizing at least one of a FDMA, TDMA, CDMA protocol to establish the acoustic communication channel with the one or more of the plurality of sensor boxes.

[0069] Unless otherwise specified, any use of any form of the terms "connect," "engage," "couple," "attach," or any other term describing an interaction between elements in the foregoing disclosure is not meant to limit the interaction to direct interaction between the elements and may also include indirect interaction between the elements described. As used

herein, the singular forms “a”, “an” and “the” are intended to include the plural forms as well, unless the context clearly indicates otherwise. Unless otherwise indicated, as used throughout this document, “or” does not require mutual exclusivity. It will be further understood that the terms “comprise” and/or “comprising,” when used in this specification and/or the claims, specify the presence of stated features, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, steps, operations, elements, components, and/or groups thereof. In addition, the steps and components described in the above embodiments and figures are merely illustrative and do not imply that any particular step or component is a requirement of a claimed embodiment.

[0070] It should be apparent from the foregoing that embodiments of an invention having significant advantages have been provided. While the embodiments are shown in only a few forms, the embodiments are not limited but are susceptible to various changes and modifications without departing from the spirit thereof.

We claim:

CLAIMS

1. A downhole telemetry system comprising:

a plurality of sensor boxes, each of the plurality of sensor boxes deployed along a casing of a wellbore, each sensor box of the plurality of sensor boxes operable to:
obtain data indicative of at least one property of the wellbore; and
transmit signals comprising data indicative of the at least one property of the wellbore; and

a downhole tool coupled to a conveyance and deployable in the wellbore, the downhole tool operable to:

transmit an activation signal to one or more sensor boxes of the plurality of sensor boxes to initiate communication with the sensor box; and
receive signals comprising data indicative of the at least one property of the wellbore.

2. The downhole telemetry system of claim 1, wherein each sensor box of the plurality of sensor boxes is further operable to:

detect signals transmitted from the downhole tool;
determine if the signals transmitted from the downhole tool comprise the activation signal; and
transmit an acknowledgement signal to the downhole tool upon determining that the signals transmitted from the downhole tool comprise the activation signal.

3. The downhole telemetry system of claim 2, wherein the acknowledgement signal comprises instructions to establish at least one of an acoustic communication channel, an optical communication channel, and an electromagnetic communication channel with the one or more sensor boxes of the plurality of sensor boxes, and wherein the downhole tool is further operable to establish at least one of the acoustic communication channel, the optical communication channel, the electromagnetic communication channel with the one or more sensor boxes based on the instructions of the acknowledgement signal.

4. The downhole telemetry system of claim 3, wherein the downhole tool is further operable to utilize at least one of a frequency division multiple access (FDMA) protocol, a code division multiple access (CDMA) protocol, and a time division multiple access (TDMA) protocol to establish the at least one of the acoustic communication channel, the optical communication channel, and the electromagnetic communication channel with the one or more sensor boxes.
5. The downhole telemetry system of claim 4, wherein each sensor box of the one or more sensor boxes is operable to transmit the signals comprising data indicative of the at least one property of the wellbore within a different frequency range.
6. The downhole telemetry system of claim 1, wherein the signals comprise at least one of acoustic signals, electromagnetic signals, optical signals, and photonic signals.
7. The downhole telemetry system of claim 1, wherein the activation signal is a signal transmitted within a first frequency range, and wherein each sensor box of the plurality of sensor boxes is further operable to:
- determine a frequency of signals transmitted by the downhole tool; and
- transmit signals comprising data indicative of the at least one property of the wellbore upon determining that the frequency of the signals transmitted by the downhole tool is within the first frequency range.
8. The downhole telemetry system of claim 1, wherein each sensor box of the plurality of sensor boxes is further operable to:
- determine a signal intensity of the signals transmitted by the downhole tool; and
- transmit signals comprising data indicative of the at least one property of the wellbore upon determining that the signal intensity of the signals transmitted by the downhole tool is greater than a first threshold value.
9. The downhole telemetry system of claim 1, wherein each sensor box of the plurality of sensor boxes comprises at least one of a magnetic field sensor, a conductive sensor, an electromagnetic sensor, and an acoustic impedance sensor, each of said sensors being operable to detect a presence of the downhole tool, and wherein each sensor box of the

plurality of sensor boxes is further operable to transmit signals comprising data indicative of the at least one property of the wellbore upon detecting the presence of the downhole tool.

- 5 10. The downhole telemetry system of claim 1, wherein the conveyance comprises at least one of a wireline, an electronic line, an optical fiber, and a coiled tubing, and wherein downhole tool is further operable to transmit data indicative of the at least one property of the wellbore via the wireline to a surface based electronic device.
- 10 11. The downhole telemetry system of claim 1, wherein the downhole tool comprises a machine readable medium operable to store data indicative of the at least one property of the wellbore.
- 15 12. The downhole telemetry system of claim 1, wherein the at least one property of the wellbore comprises a location of a top of a cement mixture deposited along an annulus between the casing and the wellbore.
- 20 13. The downhole telemetry system of claim 12, further comprising a plurality of sensors deployed along the annulus, wherein each sensor of the plurality of sensors is operable to:
detect the at least one property of the wellbore; and
transmit the at least one property of the wellbore to the one or more sensor boxes.
- 25 14. The downhole telemetry system of claim 1, wherein the downhole tool is further operable to determine a presence of one or more leaks in the wellbore.
- 30 15. A method to obtain data indicative of at least one wellbore property, the method comprising:
deploying a downhole tool to a first location proximate a first sensor box of a plurality of sensor boxes deployed along a casing of a wellbore;
periodically transmitting an activation signal to the first sensor box to initiate acoustic communication with the first sensor box;
detecting a first acknowledgement signal from the first sensor box of the plurality of sensor boxes;

establishing a first acoustic communication channel with the first sensor box of the plurality of sensor boxes upon detecting the first acknowledgement signal; and receiving acoustic signals comprising data indicative of the at least one property of the wellbore via the first acoustic channel.

5

16. The method of claim 15, further comprising:

deploying a downhole tool to a second location proximate a second sensor box of a plurality of sensor boxes deployed along a casing of a wellbore;

periodically transmitting an activation signal to the second sensor box to initiate acoustic communication with the second sensor box;

10

detecting a second acknowledgement signal from the second sensor box of the plurality of sensor boxes;

establishing a second acoustic communication channel with the second sensor box of the plurality of sensor boxes upon detecting the second acknowledgement signal;

15

and receiving acoustic signals comprising data indicative of the at least one property of the wellbore via the second acoustic communication channel.

17. The method of claim 16, further comprising transmitting the acoustic signals comprising data indicative of the at least one property of the wellbore to a surface based electronic device.

20

18. The method of claim 15, wherein establishing the first acoustic communication channel comprises utilizing at least one of a FDMA, TDMA, CDMA protocol to establish the first acoustic communication channel with the first sensor box.

25

19. A non-transitory machine-readable medium comprising instructions stored therein, which when executed by one or more processors, causes the one or more processors to perform operations comprising:

periodically transmitting activations signals to a plurality of sensor boxes that are deployed along a casing of a wellbore to initiate acoustic communication with the plurality of sensor boxes;

detecting acknowledgement signals from one or more of the plurality of sensor boxes;

30

establishing an acoustic communication channel with the one or more of the plurality of sensor boxes;

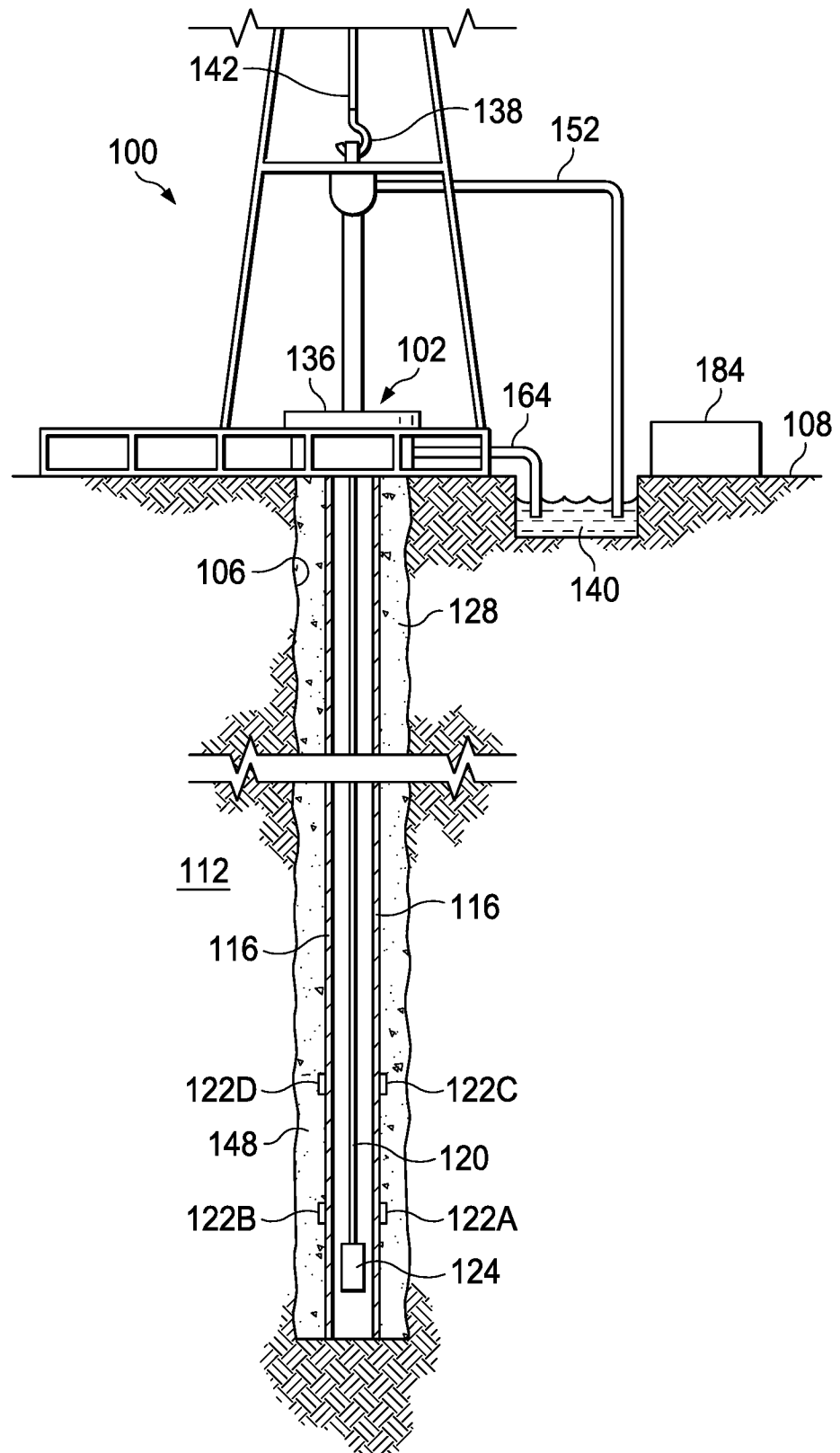
receiving acoustic signals comprising data indicative of the at least one property of the wellbore; and

5 storing data indicative of the at least one property of the wellbore in a storage component.

20. The non-transitory machine-readable medium of claim 19, further comprising instructions stored therein, which when executed by one or more processors, causes the one or more
10 processors to perform operations comprising utilizing at least one of a FDMA, TDMA, CDMA protocol to establish the acoustic communication channel with the one or more of the plurality of sensor boxes.

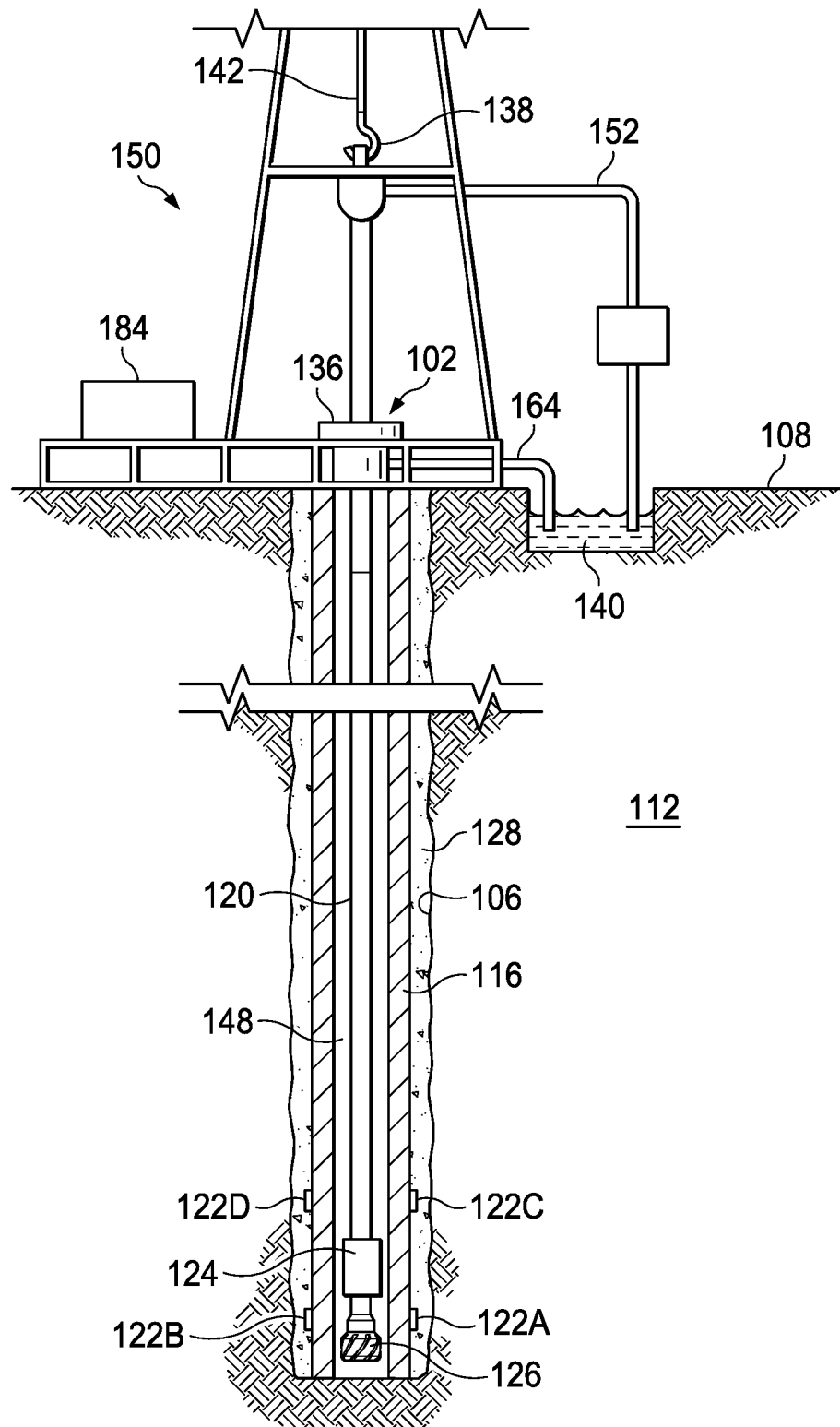
1/6

FIG. 1A

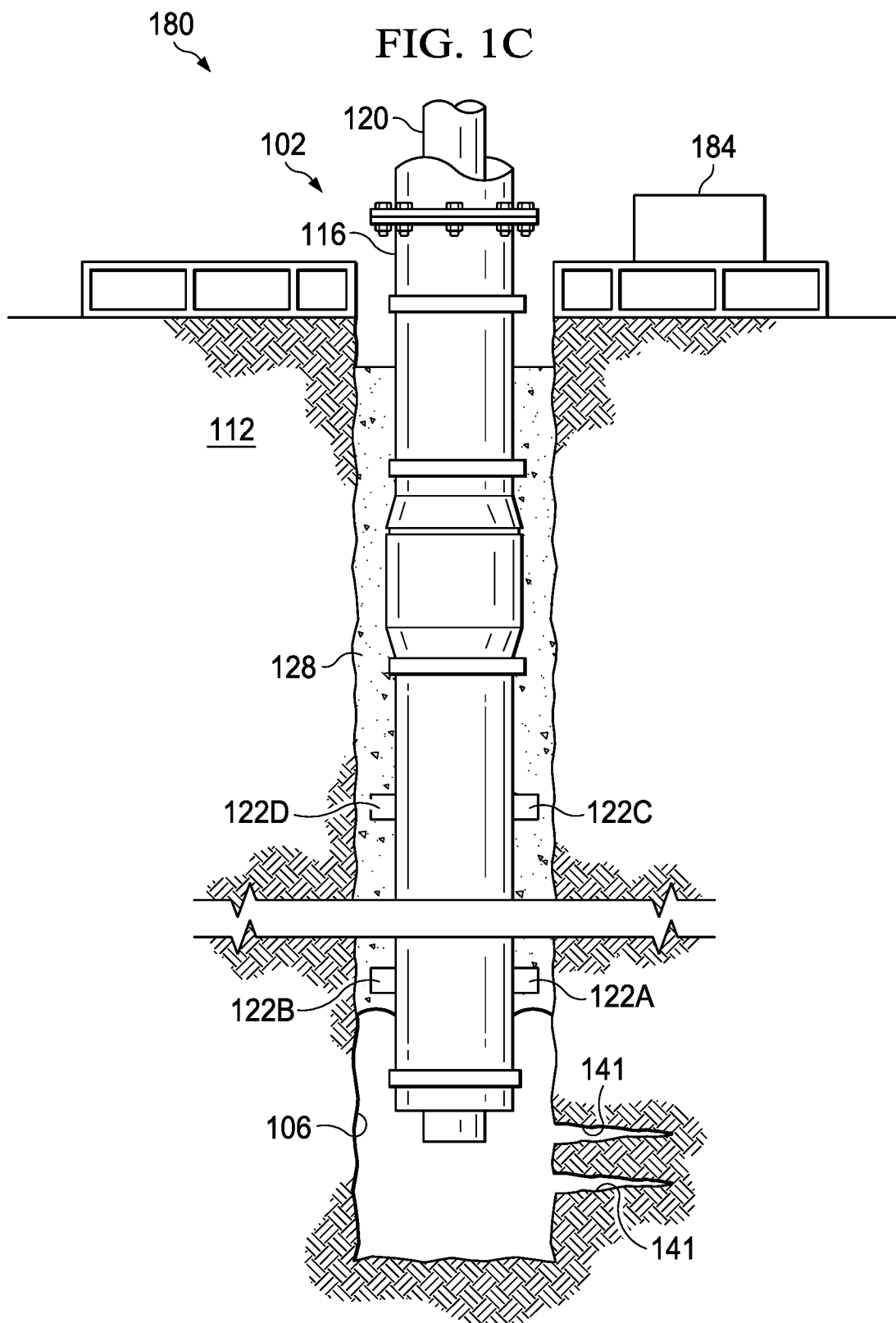


2/6

FIG. 1B



3/6



4/6

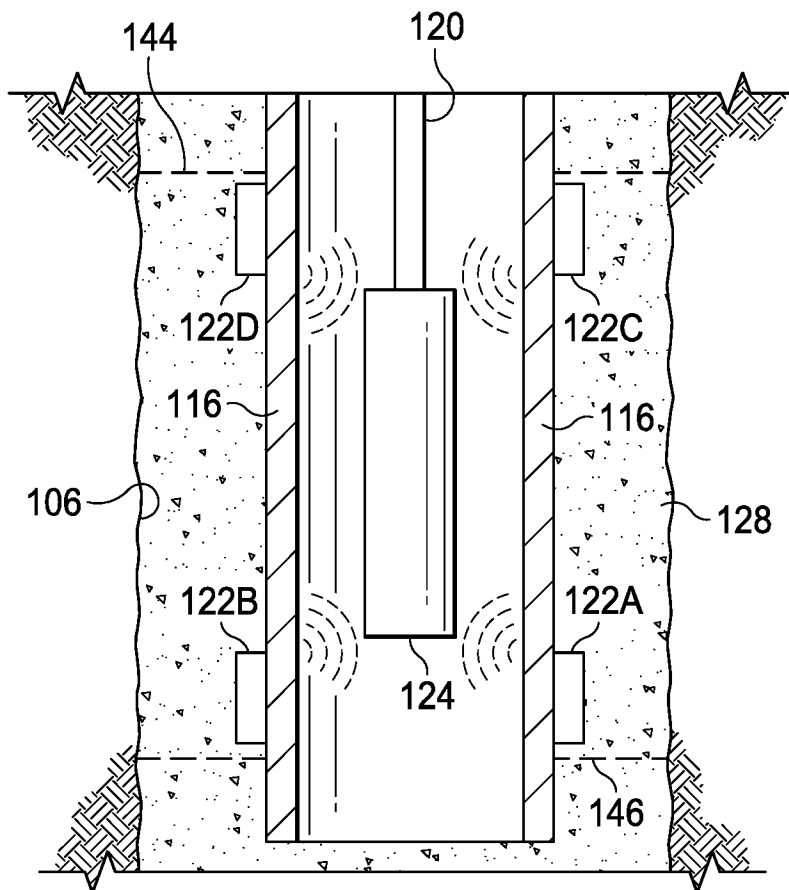


FIG. 2

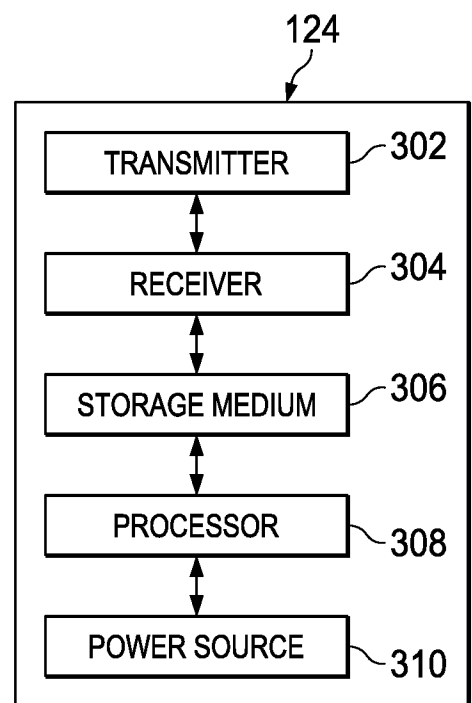


FIG. 3

5/6

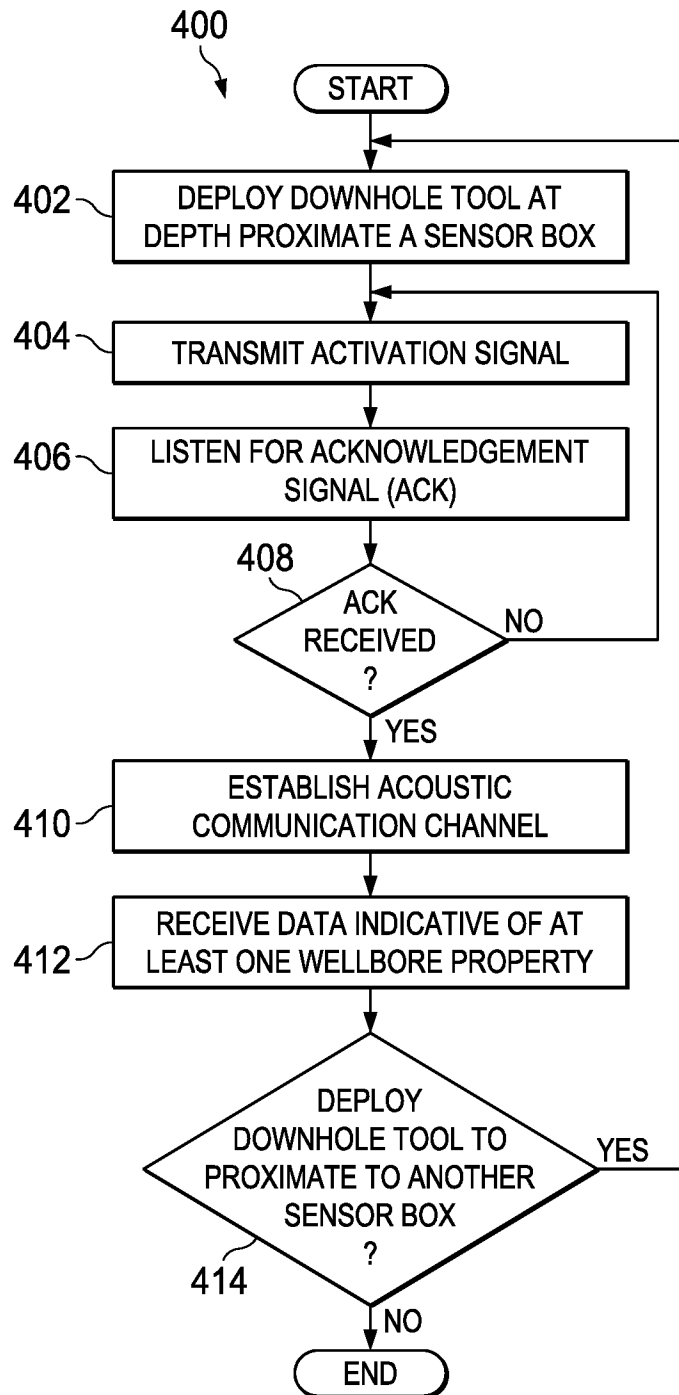


FIG. 4A

6/6

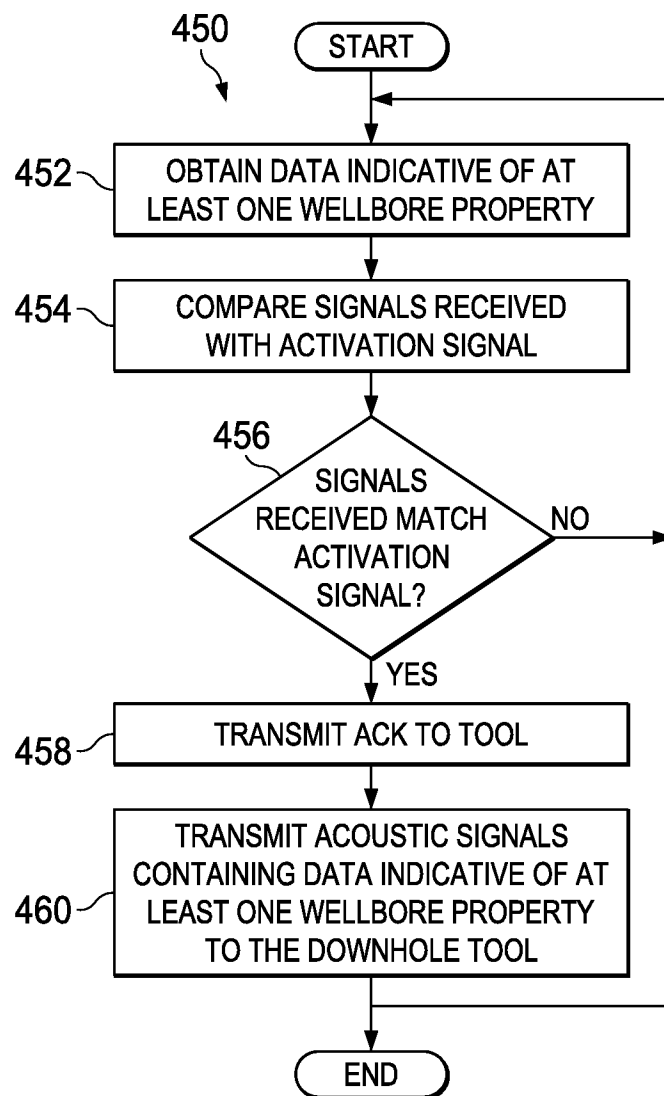


FIG. 4B

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/065415**A. CLASSIFICATION OF SUBJECT MATTER****E21B 47/12(2006.01)i, E21B 47/14(2006.01)i**

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHEDMinimum documentation searched (classification system followed by classification symbols)
E21B 47/12; G01V 1/46; E21B 47/00; G06K 19/077; E21B 47/14; E21B 33/13; G01V 1/40Documentation 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 modelsElectronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & keywords: downhole telemetry system, sensor box, downhole tool, activation signal, acknowledgement signal, communication channel, and wellbore property**C. DOCUMENTS CONSIDERED TO BE RELEVANT**

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2015-153537 A1 (SCHLUMBERGER CANADA LIMITED et al.) 08 October 2015 See paragraphs [0016]-[0022], [0027], [0032]-[0036], claims 1, 9, and figures 1-4.	1, 6-10, 14
Y		2-5, 11-13, 15-20
Y	US 2012-0250461 A1 (MILLOT et al.) 04 October 2012 See paragraphs [0058]-[0059], [0067]-[0068] and figures 1, 4A-4B.	2-5, 15-20
Y	US 2008-0106972 A1 (LIANG et al.) 08 May 2008 See paragraphs [0019]-[0020], [0023]-[0024], [0030] and figures 1-3, 7.	11-13, 19-20
A	US 2014-0111349 A1 (ROBERSON et al.) 24 April 2014 See paragraphs [0052]-[0054] and figure 2.	1-20
A	US 6408943 B1 (SCHULTZ et al.) 25 June 2002 See claim 1 and figures 1-2.	1-20

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

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

24 August 2017 (24.08.2017)

Date of mailing of the international search report

25 August 2017 (25.08.2017)

Name and mailing address of the ISA/KR

International Application Division

Korean Intellectual Property Office

189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea



Facsimile No. +82-42-481-8578

Authorized officer

LEE, Jong Kyung

Telephone No. +82-42-481-3360



INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/065415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
WO 2015-153537 A1	08/10/2015	US 2017-022806 A1	26/01/2017
US 2012-0250461 A1	04/10/2012	AU 2012-235718 A1	10/10/2013
		AU 2016-204117 A1	07/07/2016
		BR 112013024846 A2	27/12/2016
		EP 2691606 A2	05/02/2014
		WO 2012-131600 A2	04/10/2012
		WO 2012-131600 A3	21/11/2013
US 2008-0106972 A1	08/05/2008	GB 2456704 A	29/07/2009
		GB 2456704 B	16/11/2011
		US 7602668 B2	13/10/2009
		WO 2008-058076 A1	15/05/2008
US 2014-0111349 A1	24/04/2014	AU 2012-220382 A1	30/08/2012
		AU 2012-220382 B2	31/03/2016
		CA 2771626 A1	03/03/2011
		CA 2771626 C	25/02/2014
		CA 2771698 A1	03/03/2011
		CA 2771698 C	08/04/2014
		CA 2827763 A1	30/08/2012
		CA 2827763 C	21/06/2016
		CA 2929374 A1	09/07/2015
		CA 2929566 A1	09/07/2015
		CA 2929578 A1	09/07/2015
		CA 2929581 A1	09/07/2015
		EP 2129867 A1	09/12/2009
		EP 2129867 B1	21/08/2013
		EP 2336487 A1	22/06/2011
		EP 2336487 B1	30/10/2013
		EP 2343434 A1	13/07/2011
		EP 2343434 B1	29/06/2016
		EP 2489828 A1	22/08/2012
		EP 2489829 A1	22/08/2012
		EP 2489829 B1	16/04/2014
		GB 2486138 A	06/06/2012
		GB 2487856 A	08/08/2012
		GB 2505085 A	19/02/2014
		GB 2535079 A	10/08/2016
		GB 2535908 A	31/08/2016
		GB 2536819 A	28/09/2016
		GB 2538628 A	23/11/2016
		US 2008-0236814 A1	02/10/2008
		US 2010-0050905 A1	04/03/2010
		US 2010-0051266 A1	04/03/2010
		US 2010-0051275 A1	04/03/2010
		US 2011-0186290 A1	04/08/2011
		US 2011-0187556 A1	04/08/2011
		US 2011-0192592 A1	11/08/2011

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/065415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 6408943 B1	25/06/2002	US 2011-0192593 A1	11/08/2011
		US 2011-0192594 A1	11/08/2011
		US 2011-0192597 A1	11/08/2011
		US 2011-0192598 A1	11/08/2011
		US 2011-0199228 A1	18/08/2011
		US 2014-0174732 A1	26/06/2014
		US 2014-0182845 A1	03/07/2014
		US 2014-0182848 A1	03/07/2014
		US 7712527 B2	11/05/2010
		US 8083849 B2	27/12/2011
		US 8162050 B2	24/04/2012
		US 8162055 B2	24/04/2012
		US 8291975 B2	23/10/2012
		US 8297352 B2	30/10/2012
		US 8297353 B2	30/10/2012
		US 8302686 B2	06/11/2012
		US 8316936 B2	27/11/2012
		US 8342242 B2	01/01/2013
		US 9394756 B2	19/07/2016
		US 9394784 B2	19/07/2016
		US 9394785 B2	19/07/2016
		US 9494032 B2	15/11/2016
		WO 2008-119963 A1	09/10/2008
		WO 2011-023938 A1	03/03/2011
		WO 2011-023938 A9	16/06/2011
		WO 2011-023942 A2	03/03/2011
		WO 2011-023942 A3	16/06/2011
		WO 2011-058324 A1	19/05/2011
		WO 2012-114068 A2	30/08/2012
		WO 2012-114068 A3	15/08/2013
		WO 2015-102838 A1	09/07/2015
		WO 2015-102897 A1	09/07/2015
		WO 2015-103111 A1	09/07/2015
		WO 2015-103112 A1	09/07/2015
		AU 2295002 A	30/01/2002
		CA 2416111 A1	24/01/2002
		EP 1305499 A1	02/05/2003
		NO 20030200 A	05/03/2003
		US 2002-0179301 A1	05/12/2002
		WO 02-06628 A1	24/01/2002