(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
26 June 2014 (26.06.2014)

(10) International Publication Number
WO 2014/100269 A1

(51) International Patent Classification:
E21B 43/00 (2006.01)

(21) International Application Number:
PCT/US2013/076278

(22) International Filing Date:
18 December 2013 (18.12.2013)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
61/739,681 19 December 2012 (19.12.2012) US

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(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, 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, KZ, LA, LC, LK, LR, LS, LT, 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,

[Continued on next page]

(54) Title: APPARATUS AND METHOD FOR EVALUATING CEMENT INTEGRITY IN A WELLBORE USING ACOUSTIC TELEMETRY

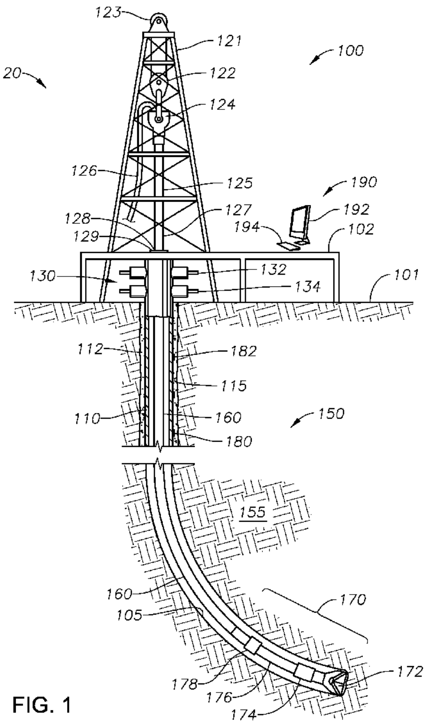

FIG. 1

(57) Abstract: An electro-acoustic system for downhole telemetry employs a series of communications nodes spaced along a string of casing within a wellbore. In one embodiment the nodes are placed within the cement sheath surrounding the joints of casing and allow wireless communication between transceivers residing within the communications nodes and a receiver at the surface. The transceivers provide node-to-node communication up a wellbore at high data transmission rates for data indicative of cement sheath integrity. A method of evaluating a cement sheath in a wellbore uses a plurality of data transmission nodes situated along the casing string which send signals to a receiver at the surface. The signals are then analyzed.

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GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, 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).

Declarations under Rule 4.17:

— *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*

— *as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))*

Published:

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

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

APPARATUS AND METHOD FOR EVALUATING CEMENT INTEGRITY IN A WELLBORE USING ACOUSTIC TELEMETRY

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of U.S. Provisional Patent Application No. 61/739,681, filed December 19, 2012, the disclosure of which is hereby incorporated by reference.

BACKGROUND OF THE INVENTION

[0002] This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

Field of the Invention

[0003] The present invention relates to the field of well drilling and completions. More specifically, the invention relates to the transmission of data along a tubular body within a wellbore. The present invention further relates to the evaluation of cement integrity behind a casing string using acoustic signals.

General Discussion of Technology

[0004] In the drilling of oil and gas wells, a wellbore is formed using a drill bit that is urged downwardly at a lower end of a drill string. The drill bit is rotated while force is applied through the drill string and against the rock face of the formation being drilled. After drilling to a predetermined depth, the drill string and bit are removed and the wellbore is lined with a string of casing. An annular area is thus formed between the string of casing and the formation penetrated by the wellbore.

[0005] A cementing operation is typically conducted in order to displace drilling fluid and fill part or all of the hollow-cylindrical annular area between the casing and the borehole wall with cement. The combination of cement and casing strengthens the wellbore and facilitates the zonal fluid isolation of certain sections of a hydrocarbon-producing formation (or “pay zones”) behind the casing.

[0006] A first string of casing is placed from the surface and down to a first drilled depth. This casing is known as a surface casing. In the case of offshore operations, this casing may be referred to as a conductor pipe. Typically, one of the main functions of the initial string(s) of casing is to isolate and protect the shallower, useable water bearing aquifers from contamination by any other wellbore fluids. Accordingly, these casing strings are almost always cemented entirely back to surface.

[0007] One or more intermediate strings of casing is also run into the wellbore. These casing strings will have progressively smaller outer diameters into the wellbore. In most current wellbore completion jobs, especially those involving so called unconventional formations where high-pressure hydraulic operations are conducted downhole, these casing strings may be entirely cemented. In some instances, an intermediate casing string may be a liner, that is, a string of casing that is not tied back to the surface.

[0008] The process of drilling and then cementing progressively smaller strings of casing is repeated several times until the well has reached total depth. In some instances, the final string of casing is also a liner. The final string of casing, referred to as a production casing, is also typically cemented into place.

[0009] Additional tubular bodies may be included in a well completion. These include one or more strings of production tubing placed within the production casing or liner. Each tubing string extends from the surface to a designated depth proximate a production interval, or "pay zone." Each tubing string may be attached to a packer. The packer serves to seal off the annular space between the production tubing string(s) and the surrounding casing.

[0010] It is important that the cement sheath surrounding the casing strings have a high degree of circumferential and axial integrity around the casing annulus against fluid channeling or flowing through the cement along the wellbore. The cement must also bond with the casing surface and borehole wall to affect a hydraulic seal against fluid migration along the wellbore. This means that the cement is fully placed into the annular region to prevent fluid communication between fluids at the level of subsurface completion and aquifers residing just below the surface. Such fluids may include fracturing fluids, aqueous acid, and formation fluids.

[0011] Heretofore, the integrity of a cement sheath has been determined through the use of a so-called cement bond long. A cement bond log (or CBL), uses an acoustic signal that is transmitted by a logging tool at the end of a wireline. The logging tool includes a transmitter, and then a receiver that "listens" for sound waves generated by the transmitter through the surrounding case strings. The logging tool includes a signal processor that takes a continuous measurement of the amplitude of sound pulses from the transmitter to the receiver.

[0012] The theory behind the CBL is that the amplitude of a sonic signal as it travels through a well cemented pipe is only a fraction of the amplitude through uncemented pipe.

Acoustic signals in free steel casing generally provide a large amplitude because the acoustic energy remains in the steel. However, for casing that is surrounded by and well bonded with cement, the amplitude is small because the acoustic energy is dispersed not only in the steel but also into the coupled cement and formation. Bond logs may also measure acoustic impedance of the cement or other material in the annulus behind the casing by resonant frequency decay.

[0013] Cement bond logs are typically conducted using an acoustic logging tool that is pulled through the wellbore using a wireline. This is done after a casing string has been cemented in placed within the wellbore. However, it is desirable to be able to evaluate the integrity of the cement sheath behind the casing string immediately after the cementing operation has been conducted and without need for a wireline or separate logging tool. Further, it is desirable to determine the progress of cement placement during the cementing operation using a series of communications nodes placed along the casing string as part of the well completion. Still further, a need exists for an acoustic telemetry system that enables the operator to receive signals at high data transmission rates, with such signals being indicative of cement sheath integrity, both at the time of cementing and later in the life of the well.

SUMMARY OF THE INVENTION

[0014] An electro-acoustic system for downhole telemetry is provided herein. The system employs a series of communications nodes spaced along a wellbore. Each node transmits a signal that represents a packet of information. The packet of information includes both a node identifier and an acoustic wave. The signals are relayed up the wellbore from node-to-node in order to provide a wireless signal to a receiver at the surface.

[0015] The system first includes a string of casing. The casing string is disposed in the wellbore. In actuality, the wellbore may have more than one casing string, including a string of surface casing, one or more intermediate casing strings, and a production casing. In any aspect, the wellbore is completed for the purpose of conducting hydrocarbon recovery operations. A cement sheath resides within an annular region formed between the casing string and a surrounding subsurface rock matrix. The cement sheath extends substantially along the exterior of the casing string.

[0016] The system further has a topside communications node. The topside communications node may be placed along the casing string proximate to surface. The surface may be an earth surface. Alternatively, in a subsea context, the surface may be an offshore platform or vessel at or below a water level. In another embodiment, the topside communications node is connected to the wellhead.

[0017] The system further includes a plurality of subsurface communications nodes. The subsurface communications nodes are attached to an outer wall of the casing string in spaced-apart relation. In one aspect, the communications nodes are spaced at between about 20 and 40 foot (6.1 to 12.2 meter) intervals. Preferably, each joint of pipe making up the casing string receives one node. The communications nodes are configured to transmit acoustic waves from node-to-node, up to the topside communications node.

[0018] Each of the subsurface communications nodes has a sealed housing. In addition, each node relies upon an independent power source. The power source may be, for example, batteries or a fuel cell. The power source resides within the housing.

[0019] In addition, each of the subsurface communications nodes has an electro-acoustic transducer. In one aspect, the communications nodes transmit data as mechanical waves at a rate exceeding about 50 bps. In one aspect, the electro-acoustic transducer is associated with a transceiver designed to receive acoustic waves at a first frequency, and then transmit or relay the acoustic waves at a second different frequency. Multiple frequency shift keying (MFSK) may be used as a modulation scheme enabling the transmission of information.

[0020] The system also includes a receiver. The receiver is positioned at the surface and is configured to receive signals from the topside communications node. The signals originate with the various subsurface communications nodes. In one aspect, the receiver is in electrical communication with the topside communications node by means of an electrical wire or through a wireless data transmission such as Wi-Fi or Blue Tooth. The receiver is configured to process the signals to identify any sections of casing that are not adequately cemented.

[0021] A method of detecting the integrity of a cement sheath along a wellbore is also provided herein. The method uses a plurality of data transmission nodes situated along a casing string to accomplish a wireless transmission of data along the wellbore. The data represents signals that indicate the presence of a cement sheath both adjacent to and between the respective communications nodes.

[0022] The method first includes running joints of pipe into the wellbore. The joints of pipe are connected together at threaded couplings. The joints of pipe are fabricated from a steel material and have a resonant frequency.

[0023] The method also provides for attaching a series of communications nodes to the joints of pipe according to a pre-designated spacing. In one aspect, each joint of pipe receives at least one communications node. Preferably, each of the communications nodes is attached to a joint of pipe by one or more clamps. In this instance, the step of attaching the communications nodes to the joints of pipe comprises clamping the communications nodes to an outer surface of the joints of pipe.

[0024] The series of communications nodes includes a topside communications node. This is the uppermost communications node along the wellbore. More specifically, the topside communications node is attached to the tubular body proximate the surface. Alternatively, the topside communications node is connected to the well head or to a tubular body immediately downstream from the wellhead. The topside communications node transmits signals from an uppermost subsurface communications node to the surface.

[0025] The communications nodes also include a series of subsurface communications nodes residing below the topside communications nodes. The subsurface communications nodes reside in spaced-apart relation along the casing string. The subsurface communications nodes are configured to transmit acoustic waves up to the topside communications node. Each subsurface communications node includes an electro-acoustic transducer and associated transceiver that receives an acoustic signal from a previous communications node, and then transmits or relays that acoustic signal to a next communications node, in node-to-node arrangement. In one aspect, the communications nodes transmit data as mechanical waves at a rate exceeding about 50 bps.

[0026] In one embodiment, one or more of the subsurface communications nodes includes a temperature sensor. The communications nodes are then designed to generate a signal that corresponds to temperature readings sensed by the respective temperature sensors. The electro-acoustic transceivers in the subsurface communications nodes then transmit acoustic signals up the wellbore representative of the temperature readings, node-to-node.

[0027] In another embodiment, selected subsurface communications nodes include a strain gauge. Alternatively or in addition, selected subsurface communications nodes include passive acoustic sensors, or microphones. Signals from the strain gauges or the microphones are sent to the surface via the subsurface communications nodes.

[0028] The method next includes providing a receiver. The receiver is placed at the surface. The receiver has a processor that processes signals received from the topside communications node, such as through the use of firmware and/or software. The receiver preferably receives electrical or optical signals via a so-called “Class I, Division I” conduit, meaning a conduit (as defined by NFPA 497 and API 500) for operation in an electrically classified area. Alternatively, data may be transferred from the topside communications node to the receiver via an electromagnetic (RF) wireless connection. The processor processes the signals to identify which signals correlate to which subsurface communications node.

[0029] The method also includes analyzing the signals to evaluate the integrity of the cement sheath in proximity to each of the communications nodes. Analyzing the signals will allow the operator to infer the quality of the cement sheath at and in between the nodes. If it is determined that cement has not been properly placed around the casing string adjacent one of the communications nodes, then appropriate decisions on subsequent drilling, completing, operating or abandonment the well can be undertaken.

BRIEF DESCRIPTION OF THE DRAWINGS

[0030] So that the present inventions can be better understood, certain drawings, charts, graphs and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[0031] Figure 1 is a side, cross-sectional view of an illustrative wellbore. The wellbore is being formed using a derrick, a drill string and a bottom hole assembly. A series of communications nodes is placed along the drill string as part of a telemetry system.

[0032] Figure 2 is a cross-sectional view of a wellbore having been completed. The illustrative wellbore has been completed as a cased hole completion. A series of communications nodes is placed along the casing string as part of a telemetry system.

[0033] Figure 3 is a perspective view of an illustrative tubular pipe joint as may be positioned in a wellbore. A communications node of the present invention, in one embodiment, is shown exploded away from the pipe joint.

[0034] Figure 4A is a perspective view of a communications node as may be used in the wireless data transmission system of the present invention, in an alternate embodiment.

[0035] Figure 4B is a cross-sectional view of the communications node of Figure 4A. The view is taken along the longitudinal axis of the node. Here, a sensor is provided within the communications node.

[0036] Figure 4C is another cross-sectional view of the communications node of Figure 4A. The view is again taken along the longitudinal axis of the node. Here, a sensor resides along the wellbore external to the communications node.

[0037] Figures 5A and 5B are perspective views of a shoe as may be used on opposing ends of the communications node of Figure 4A, in one embodiment. In Figure 5A, the leading edge, or front, of the shoe is seen. In Figure 5B, the back of the shoe is seen.

[0038] Figure 6 is a perspective view of a communications node system as may be used in the methods of the present invention, in one embodiment. The communications node system utilizes a pair of clamps for connecting a subsurface communications node onto a tubular body.

[0039] Figure 7 is a flowchart demonstrating steps of a method for detecting the integrity of a cement sheath along a wellbore in accordance with the present inventions, in one embodiment.

DETAILED DESCRIPTION OF CERTAIN EMBODIMENTS

Definitions

[0040] As used herein, the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Examples of hydrocarbons include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

[0041] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions, or at ambient conditions (about 20° C and 1 atm pressure). Hydrocarbon fluids may include, for example, oil, natural gas, gas condensates, coal bed methane, shale oil, pyrolysis oil, and other hydrocarbons that are in a gaseous or liquid state.

[0042] As used herein, the term "subsurface" refers to the region below the earth's surface.

[0043] As used herein, the term "sensor" includes any electrical sensing device or gauge. The sensor may be capable of monitoring or detecting pressure, temperature, fluid flow, vibration, or resistivity or other formation data.

[0044] As used herein, the term "formation" refers to any definable subsurface region. The formation may contain one or more hydrocarbon-containing layers, one or more non-hydrocarbon containing layers, an overburden, and/or an underburden of any geologic formation.

[0045] The terms "zone" or "zone of interest" refer to a portion of a formation containing hydrocarbons. The term "hydrocarbon-bearing formation" may alternatively be used. Zones of interest may also include formations containing brines or useable water which are to be isolated.

[0046] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shape. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

[0047] The terms "tubular member" or "tubular body" refer to any pipe, such as a joint or string of casing, a joint or string of a liner pipe, a joint or string of drill pipe, a production tubing joint or string, an injection tubing joint or string, or any other tubular tool associated with use in a wellbore.

Description of Selected Specific Embodiments

[0048] The inventions are described herein in connection with certain specific embodiments. However, to the extent that the following detailed description is specific to a particular embodiment or a particular use, such is intended to be illustrative only and is not to be construed as limiting the scope of the inventions.

[0049] **Figure 1** is a side, cross-sectional view of an illustrative well site **100**. The well site **100** includes a derrick **120** at an earth surface **101**. The well site **100** also includes a wellbore **150** extending from the earth surface **101** and down into an earth subsurface **155**. The wellbore **150** is being formed using the derrick **120**, a drill string **160** below the derrick **120**, and a bottom hole assembly **170** at a lower end of the drill string **160**.

[0050] Referring first to the derrick **120**, the derrick **120** includes a frame structure **121** that extends up from the earth surface **101**. The derrick **120** supports drilling equipment including a traveling block **122**, a crown block **123** and a swivel **124**. A so-called kelly **125** is attached to the swivel **124**. The kelly **125** has a longitudinally extending bore (not shown) in fluid communication with a kelly hose **126**. The kelly hose **126**, also known as a mud hose, is a flexible, steel-reinforced, high-pressure hose that delivers drilling fluid through the bore of the kelly **125** and down into the drill string **160**.

[0051] The kelly **125** includes a drive section **127**. The drive section **127** is non-circular in cross-section and conforms to an opening **128** longitudinally extending through a kelly drive bushing **129**. The kelly drive bushing **129** is part of a rotary table. The rotary table is a mechanically driven device that provides clockwise (as viewed from above) rotational force to the kelly **125** and connected drill string **160** to facilitate the process of drilling a borehole **105**. Both linear and rotational movement may thus be imparted from the kelly **125** to the drill string **160**.

[0052] A platform **102** is provided for the derrick **120**. The platform **102** extends above the earth surface **101**. The platform **102** generally supports rig hands along with various components of drilling equipment such as a pumps, motors, gauges, a dope bucket, tongs, pipe lifting equipment and control equipment. The platform **102** also supports the rotary table.

[0053] It is understood that the platform **102** shown in **Figure 1** is somewhat schematic. It is also understood that the platform **102** is merely illustrative and that many designs for drilling rigs and platforms, both for onshore and for offshore operations, exist. These include, for example, top drive drilling systems. The claims provided herein are not limited by the configuration and features of the drilling rig unless expressly stated in the claims.

[0054] Placed below the platform **102** and the kelly drive section **127** but above the earth surface **101** is a blow-out preventer, or BOP **130**. The BOP **130** is a large, specialized valve or set of valves used to control pressures during the drilling of oil and gas wells. Specifically, blowout preventers control the fluctuating pressures emanating from subterranean formations during a drilling process. The BOP **130** may include upper **132** and lower **134** rams used to isolate flow on the back side of the drill string **160**. Blowout preventers **130** also prevent the pipe joints making up the drill string **160** and the drilling fluid from being blown out of the wellbore **150** in the event of a sudden pressure kick.

[0055] As shown in **Figure 1**, the wellbore **150** is being formed down into the subsurface formation **155**. In addition, the wellbore **150** is being shown as a deviated wellbore. Of course, this is merely illustrative as the wellbore **150** may be a vertical well or even a horizontal well, as shown later in **Figure 2**.

[0056] In drilling the wellbore **150**, a first string of casing **110** is placed down from the surface **101**. This is known as surface casing **110** or, in some instances (particularly offshore), conductor pipe. The surface casing **110** is secured within the formation **155** by a cement sheath **112**. The cement sheath **112** resides within an annular region **115** between the surface casing **110** and the surrounding formation **155**.

[0057] During the process of drilling and completing the wellbore **150**, additional strings of casing (not shown) will be provided. These may include intermediate casing strings and a final production casing string. For an intermediate case string or the final production casing, a liner may be employed, that is, a string of casing that is not tied back to the surface **101**.

[0058] As noted, the wellbore **150** is formed by using a bottom hole assembly **170**. The bottom-hole assembly **170** allows the operator to control or “steer” the direction or orientation of the wellbore **150** as it is formed. In this instance, the bottom hole assembly **170** is known as a rotary steerable drilling system, or RSS.

[0059] The bottom hole assembly **170** will include a drill bit **172**. The drill bit **172** may be turned by rotating the drill string **160** from the platform **102**. Alternatively, the drill bit

172 may be turned by using so-called mud motors **174**. The mud motors **174** are mechanically coupled to and turn the nearby drill bit **172**. The mud motors **174** are used with stabilizers or bent subs **176** to impart an angular deviation to the drill bit **172**. This, in turn, deviates the well from its previous path in the desired azimuth and inclination.

[0060] There are several advantages to directional drilling. These primarily include the ability to complete a wellbore along a substantially horizontal axis of a subsurface formation, thereby exposing a greater formation face. These also include the ability to penetrate into subsurface formations that are not located directly below the wellhead. This is particularly beneficial where an oil reservoir is located under an urban area or under a large body of water. Another benefit of directional drilling is the ability to group multiple wellheads on a single platform, such as for offshore drilling. Finally, directional drilling enables multiple laterals and/or sidetracks to be drilled from a single wellbore in order to maximize reservoir exposure and recovery of hydrocarbons.

[0061] As the wellbore **150** is being formed, the operator may wish to evaluate the integrity of the cement sheath **112** placed around the surface casing **110** (or other casing string). To do this, the industry has relied upon so-called cement bond logs. As discussed above, a cement bond log (or CBL), uses an acoustic signal that is transmitted by a logging tool at the end of a wireline. The logging tool includes a transmitter, and one or more receivers that "listen" for sound waves generated by the transmitter through the surrounding casing string. The logging tool includes a signal processor that takes a continuous measurement of the amplitude of sound pulses from the transmitter to the receiver. Alternately, the attenuation of the sonic signal may be measured.

[0062] In some instances, a bond log will measure acoustic impedance of the material in the annulus directly behind the casing. This may be done through resonant frequency decay. Such logs include, for example, the USIT log of Schlumberger (of Sugar Land, Texas) and the CAST-V log of Halliburton (of Houston, Texas).

[0063] It is desirable to implement a downhole telemetry system that enables the operator to evaluate cement sheath integrity without need of running a CBL line. This enables the operator to check cement sheath integrity as soon as the cement has set in the annular region **115** or as soon as the wellbore **150** is completed. To do this, the well site **100** includes a plurality of communications nodes **180**, **182**. The communications nodes **180**, **182** are placed along the outer surface of the surface casing **110** according to a pre-designated spacing. The communications nodes then send acoustic signals up the wellbore **150** in node-to-node arrangement.

[0064] Acoustic telemetry systems are known in the industry. U.S. Patent No. 5,924,499 entitled "Acoustic Data Link and Formation Property Sensor for Downhole MWD System" teaches the use of acoustic signals for "short hopping" a component along a drill string. Signals are transmitted from the drill bit or from a near-bit sub and across the mud motors. This may be done by sending separate acoustic signals simultaneously -- one that is sent through the drill string, a second that is sent through the drilling mud, and optionally, a third that is sent through the formation. These signals are then processed to extract readable signals.

[0065] U.S. Patent No. 6,912,177, entitled "Transmission of Data in Boreholes," addresses the use of an acoustic transmitter that is as part of a downhole tool. Here, the transmitter is provided adjacent a downhole obstruction such as a shut-in valve along a drill stem so that an electrical signal may be sent across the drill stem. U.S. Patent No. 6,899,178, entitled "Method and System for Wireless Communications for Downhole Applications," describes the use of a "wireless tool transceiver" that utilizes acoustic signaling. Here, an acoustic transceiver is in a dedicated tubular body that is integral with a gauge and/or sensor. This is described as part of a well completion.

[0066] U.S. Patent No. 4,314,365, entitled "Acoustic Transmitter and Method to Produce Essentially Longitudinal, Acoustic Waves, teaches a "portable, electrohydraulic, acoustic transmitter" that attaches to an outer surface of a drill string. The transmitter is used to send acoustic signals down a drill string to a downhole receiver. When actuated, the downhole receiver activates a subsurface "instrument package" which performs a desired "downhole function."

[0067] None of these patents disclose an acoustic telemetry system that enables an operator to receive signals at the surface that are indicative of cement sheath integrity behind a casing string. In contrast, the well site **100** of **Figure 1** presents a telemetry system that utilizes a series of novel communications nodes **180**, **182** placed along the casing **110**. These nodes **180**, **182** allow for the high speed transmission of wireless signals based on the *in situ* generation of acoustic waves. The waves represent wave forms that may be processed and analyzed at the surface.

[0068] The nodes first include a topside communications node **182**. The topside communications node **182** is placed closest to the surface **101**. The topside communications node **182** is configured to receive acoustic signals and convert them to electrical or optical signals. The topside communications node **182** may be above grade or below grade.

[0069] In addition, the nodes include a plurality of subsurface communications nodes **180**. The subsurface communications nodes **180** are configured to receive and then relay acoustic signals along the length of the wellbore **150** up to the topside communications node **182**.

[0070] In **Figure 1**, the nodes **180**, **182** are shown schematically. However, **Figure 3** offers an enlarged perspective view of an illustrative pipe joint **300**, along with a communications node **350**. The illustrative communications node **350** is shown exploded away from the pipe joint **300**.

[0071] In **Figure 3**, the pipe joint **300** is intended to represent a joint of casing. However, the pipe joint **300** may be any other tubular body such as a joint of tubing, drill pipe, pipeline, or other jointed tubular conduit assembly. The illustrated pipe joint **300** has an elongated wall **310** defining an internal bore **315**. The bore **315** transmits drilling fluids such as an oil based mud, or OBM, during a drilling operation. The bore **315** also receives a string of tubing (such as production tubing or injection tubing, not shown), once a wellbore is completed.

[0072] The illustrated pipe joint **300** has a box end **322** having internal threads. In addition, the pipe joint **300** has a pin end **324** having external threads, such as via an integrated box end or with an internally threaded collar connector. The threads may be of any design. Tubing joints and casing joints have a slightly different general end appearance than the illustrated drill pipe joint, but these are also tubular bodies that may be equipped similar to the illustrated drill pipe joint **300**.

[0073] As noted, an illustrative communications node **350** is shown exploded away from the pipe joint **300**. The communications node **350** is designed to attach to the wall **410** of the pipe joint **300** at a selected location. In one aspect, each pipe joint **300** will have a communications node **350** between the box end **322** and the pin end **324**. In one arrangement, the communications node **350** is placed immediately adjacent the box end **322** or, alternatively, immediately adjacent the pin end **324** of every joint of pipe. In another arrangement, the communications node **350** is placed at a selected location along every second or every third pipe joint **300** in a drill string. In still another arrangement, at least some pipe joints **300** receive two communications nodes **350**.

[0074] The communications node **350** shown in **Figure 3** is designed to be pre-welded onto the wall **310** of the pipe joint **300**. Alternatively, the communications node **350** may be glued using an adhesive such as epoxy. However, it is preferred that the communications node **350** be configured to be selectively attachable to / detachable from a pipe joint **300** by mechanical means at a well site. This may be done, for example, through the use of clamps. Such a clamping system is shown at **600** in **Figure 6**, described more fully below. In any instance, the communications node **350** is an independent wireless communications device that is designed to be attached to an external surface of a well pipe.

[0075] There are benefits to the use of an externally-placed communications node that uses acoustic waves. For example, such a node will not decrease the effective inner diameter which would interfere with passing subsequent assemblies or tubulars through the internal bore **315** of the pipe joint **300**. Further, installation and mechanical attachment can be readily assessed and adjusted.

[0076] In **Figure 3**, the communications node **350** includes an elongated body **351**. The body **351** supports one or more batteries, shown schematically at **352**. The body **351** also supports an electro-acoustic transducer, shown schematically at **354**. The electro-acoustic transducer **354** is associated with a transceiver that receives acoustic signals at a first frequency, converts the received signals into a digital signal, converts the digital signal back into an acoustic signal, and transmits the acoustic signal at a second different frequency to a next communications node.

[0077] The communications node **350** is intended to represent the communications nodes **180** of **Figure 1**, in one embodiment. The electro-acoustic transducer **354** in each node **180** allows signals to be sent from node-to-node, up the wellbore **150**, as acoustic waves. The acoustic waves may be at a frequency of, for example, between about 100 kHz and 125 kHz. A last subsurface communications node **180** transmits the signals to the topside node **182**. Beneficially, the subsurface communications nodes **180** do not require a wire or cable to transmit data to the surface. Preferably, communication is routed around nodes which are not functioning properly.

[0078] The well site **100** of **Figure 1** also shows a receiver **190**. The receiver **190** comprises a processor **192** that receives signals sent from the topside communications node **182**. The signals may be received through a wire (not shown) such as a co-axial cable, a fiber optic cable, a USB cable, or other electrical or optical communications wire. Alternatively, the receiver **190** may receive the final signals from the topside node **182** wirelessly through a modem, a transceiver or other wireless communications link such as Bluetooth or Wi-Fi. The receiver **190** preferably receives electrical signals via a so-called Class I, Division I conduit, that is, a housing for wiring that is considered acceptably safe in an explosive environment. In some applications, radio, infrared or microwave signals may be utilized.

[0079] The processor **192** may include discrete logic, any of various integrated circuit logic types, or a microprocessor. In any event, the processor **192** may be incorporated into a computer having a screen. The computer may have a separate keyboard **194**, as is typical for a desk-top computer, or an integral keyboard as is typical for a laptop or a personal digital assistant. In one aspect, the processor **192** is part of a multi-purpose "smart phone" having specific "apps" and wireless connectivity.

[0080] **Figure 1** demonstrates the use of a wireless data telemetry system during a drilling operation. However, the wireless downhole telemetry system may also be employed after a well is completed. This enables the operator to confirm the viability of a cement sheath after, for example, formation fracturing operations have taken place.

[0081] **Figure 2** is a cross-sectional view of an illustrative well site **200**. The well site **200** includes a wellbore **250** that penetrates into a subsurface formation **255**. The wellbore **250** has been completed as a cased-hole completion for producing hydrocarbon fluids. The well site **200** also includes a well head **260**. The well head **260** is positioned at an earth surface **201** to control and direct the flow of formation fluids from the subsurface formation **255** to the surface **201**.

[0082] Referring first to the well head **260**, the well head **260** may be any arrangement of pipes or valves that receive reservoir fluids at the top of the well. In the arrangement of **Figure 2**, the well head **260** represents a so-called Christmas tree. A Christmas tree is typically used when the subsurface formation **255** has enough *in situ* pressure to drive production fluids from the formation **255**, up the wellbore **250**, and to the surface **201**. The illustrative well head **260** includes a top valve **262** and a bottom valve **264**.

[0083] It is understood that rather than using a Christmas tree, the well head **260** may alternatively include a motor (or prime mover) at the surface **201** that drives a pump. The pump, in turn, reciprocates a set of sucker rods and a connected positive displacement pump (not shown) downhole. The pump may be, for example, a rocking beam unit or a hydraulic piston pumping unit. Alternatively still, the well head **260** may be configured to support a string of production tubing having a downhole electric submersible pump, a gas lift valve, or other means of artificial lift (not shown). The present inventions are not limited by the configuration of operating equipment at the surface unless expressly noted in the claims.

[0084] Referring next to the wellbore **250**, the wellbore **250** has been completed with a series of pipe strings referred to as casing. First, a string of surface casing **210** has been cemented into the formation. Cement is shown in an annular bore **215** of the wellbore **250** around the casing **210**. The cement is in the form of an annular sheath **212**. The surface casing **110** has an upper end in sealed connection with the lower valve **264**.

[0085] Next, at least one intermediate string of casing **220** is cemented into the wellbore **250**. The intermediate string of casing **220** is in sealed fluid communication with the upper master valve **262**. A cement sheath **212** is again shown in a bore **215** of the wellbore **250**. The combination of the casing **210** / **220** and the cement sheath **212** in the bore **215** strengthens the wellbore **250** and facilitates the isolation of formations behind the casing **210** /**220**.

[0086] It is understood that a wellbore **250** may, and typically will, include more than one string of intermediate casing. In some instances, an intermediate string of casing may be a liner.

[0087] Finally, a production string **230** is provided. The production string **230** is hung from the intermediate casing string **230** using a liner hanger **231**. The production string **230** is a liner that is not tied back to the surface **101**. In the arrangement of **Figure 2**, a cement sheath **232** is provided around the liner **230**.

[0088] The production liner **230** has a lower end **234** that extends to an end **254** of the wellbore **250**. For this reason, the wellbore **250** is said to be completed as a cased-hole well. Those of ordinary skill in the art will understand that for production purposes, the liner **230** may be perforated after cementing to create fluid communication between a bore **235** of the liner **230** and the surrounding rock matrix making up the subsurface formation **255**. In one aspect, the production string **230** is not a liner but is a casing string that extends back to the surface.

[0089] As an alternative, end **254** of the wellbore **250** may include joints of sand screen (not shown). The use of sand screens with gravel packs allows for greater fluid communication between the bore **235** of the liner **230** and the surrounding rock matrix while still providing support for the wellbore **250**. In this instance, the wellbore **250** would include a slotted base pipe as part of the sand screen joints. Of course, the sand screen joints would not be cemented into place and would not include subsurface communications nodes.

[0090] The wellbore **250** optionally also includes a string of production tubing **240**. The production tubing **240** extends from the well head **260** down to the subsurface formation **255**. In the arrangement of **Figure 2**, the production tubing **240** terminates proximate an upper end of the subsurface formation **255**. A production packer **241** is provided at a lower end of the production tubing **240** to seal off an annular region **245** between the tubing **240** and the surrounding production liner **230**. However, the production tubing **240** may extend closer to the end **234** of the liner **230**.

[0091] In some completions a production tubing **240** is not employed. This may occur, for example, when a monobore is in place.

[0092] It is also noted that the bottom end **234** of the production string **230** is completed substantially horizontally within the subsurface formation **255**. This is a common orientation for wells that are completed in so-called "tight" or "unconventional" formations. Horizontal completions not only dramatically increase exposure of the wellbore to the producing rock face, but also enables the operator to create fractures that are substantially transverse to the direction of the wellbore. Those of ordinary skill in the art may understand that a rock matrix will generally "part" in a direction that is perpendicular to the direction of least principal stress. For deeper wells, that direction is typically substantially vertical. However, the present inventions have equal utility in vertically completed wells or in multi-lateral deviated wells.

[0093] As with the well site **100** of **Figure 1**, the well site **200** of **Figure 2** includes a telemetry system that utilizes a series of novel communications nodes. This again is for the purpose of evaluating the integrity of the cement sheath **212**, **232**. The communications nodes are placed along the outer diameter of the casing strings **210**, **220**, **230**. These nodes allow for the high speed transmission of wireless signals based on the *in situ* generation of acoustic waves.

[0094] The nodes first include a topside communications node **282**. The topside communications node **282** is placed closest to the surface **201**. The topside node **282** is configured to receive acoustic signals.

[0095] In addition, the nodes include a plurality of subsurface communications nodes **280**. Each of the subsurface communications nodes **280** is configured to receive and then relay acoustic signals along essentially the length of the wellbore **250**. Preferably, the subsurface communications nodes **280** utilize two-way electro-acoustic transducers to receive and relay mechanical waves.

[0096] The subsurface communications nodes **280** transmit signals as acoustic waves. The acoustic waves are preferably at a frequency of between about 50 kHz and 500 kHz. The signals are delivered up to the topside communications node **282** so that signals indicative of cement integrity are sent from node-to-node. A last subsurface communications node **280** transmits the signals acoustically to the topside communications node **282**. Communication may be between adjacent nodes or may skip nodes depending on node spacing or communication range. Preferably, communication is routed around nodes which are not functioning properly.

[0097] The well site **200** of **Figure 2** shows a receiver **270**. The receiver **270** comprises a processor **272** that receives signals sent from the topside communications node **284**. The processor **272** may include discrete logic, any of various integrated circuit logic types, or a microprocessor. The receiver **270** may include a screen and a keyboard **274** (either as a keypad or as part of a touch screen). The receiver **270** may also be an embedded controller with neither a screen nor a keyboard which communicates with a remote computer such as via wireless, cellular modem, or telephone lines.

[0098] The signals may be received by the processor **272** through a wire (not shown) such as a co-axial cable, a fiber optic cable, a USB cable, or other electrical or optical communications wire. Alternatively, the receiver **270** may receive the final signals from the topside node **282** wirelessly through a modem or transceiver. The receiver **270** preferably receives electrical signals via a so-called Class I, Div. 1 conduit, that is, a wiring system or circuitry that is considered acceptably safe in an explosive environment.

[0099] **Figures 1** and **2** present illustrative wellbores **150**, **250** that may receive a downhole telemetry system using acoustic transducers. In each of **Figures 1** and **2**, the top of the drawing page is intended to be toward the surface and the bottom of the drawing page toward the well bottom. While wells commonly are completed in substantially vertical orientation, it is understood that wells may also be inclined and even horizontally completed. When the descriptive terms “up” and “down” or “upper” and “lower” or similar terms are used in reference to a drawing, they are intended to indicate location on the drawing page, and not necessarily orientation in the ground, as the present inventions have utility no matter how the wellbore is orientated.

[00100] In each of **Figures 1** and **2**, the communications nodes **180**, **280** are specially designed to withstand the same corrosion and environmental conditions (high temperature, high pressure) of a wellbore **150** or **250** As the casing, drill string, or production tubing. To do so, it is preferred that the communications nodes **180**, **280** include steel housings for holding the electronics. In one aspect, the steel material is a corrosion resistant alloy.

[00101] **Figure 4A** is a perspective view of a communications node **400** as may be used in the wireless data transmission systems of **Figure 1** or **Figure 2** (or other wellbore), in one embodiment. The communications node **400** is designed to provide data communication using a transceiver within a novel downhole housing assembly. **Figure 4B** is a cross-sectional view of the communications node **400** of **Figure 4A**. The view is taken along the longitudinal axis of the node **400**. The communications node **400** will be discussed with reference to **Figures 4A** and **4B**, together.

[00102] The communications node **400** first includes a fluid-sealed housing **410**. The housing **410** is designed to be attached to an outer wall of a joint of wellbore pipe, such as the pipe joint **300** of **Figure 3**. Where the wellbore pipe is a carbon steel pipe joint such as drill pipe, casing or liner, the housing **410** is preferably fabricated from carbon steel. This metallurgical match avoids galvanic corrosion at the coupling.

[00103] The housing **410** includes an outer wall **412**. The wall **412** is dimensioned to protect internal electronics for the communications node **400** from wellbore fluids and pressure. In one aspect, the wall **412** is about 0.2 inches (0.51 cm) in thickness. The housing **410** optionally also has a protective outer layer **425**. The protective outer layer **425** resides external to the wall **412** and provides an additional thin layer of protection for the electronics.

[00104] A bore **405** is formed within the wall **412**. The bore **405** houses the electronics, shown in **Figure 4B** as a battery **430**, a power supply wire **435**, a transceiver **440**, and a circuit board **445** . The circuit board **445** will preferably include a micro-processor or electronics module that processes acoustic signals. An electro-acoustic transducer **442** is provided to convert acoustical energy to electrical energy (or vice-versa) and is coupled with outer wall **412** on the side attached to the tubular body. The transducer **442** is in electrical communication with a sensor **432**.

[00105] It is noted that in **Figure 4B**, the sensor **432** resides within the housing **410** of the communications node **400**. However, as noted, the sensor **432** may reside external to the communications node **400**, such as above or below the node **400** along the wellbore. In **Figure 4C**, a dashed line is provided showing an extended connection between the sensor **432** and the electro-acoustic transducer **442**.

[00106] The transceiver **440** will receive an acoustic telemetry signal. In one preferred embodiment, the acoustic telemetry data transfer is accomplished using multiple frequency shift keying (MFSK). Any extraneous noise in the signal is moderated by using well-known conventional analog and/or digital signal processing methods. This noise removal and signal enhancement may involve conveying the acoustic signal through a signal conditioning circuit using, for example, a bandpass filter.

[00107] The transceiver will also produce acoustic telemetry signals. In one preferred embodiment, an electrical signal is delivered to an electromechanical transducer, such as through a driver circuit. In a preferred embodiment, the transducer is the same electro-acoustic transducer that originally received the MFSK data. The signal generated by the

electro-acoustic transducer then passes through the housing **410** to the tubular body (such as production tubing **240**), and propagates along the tubular body to other communication nodes. The re-transmitted signal represents the same sensor data originally transmitted by sensor communications node **284**. In one aspect, the acoustic signal is generated and received by a magnetostrictive transducer comprising a coil wrapped around a core as the transceiver. In another aspect, the acoustic signal is generated and received by a piezo-electric ceramic transducer. In either case, the electrically encoded data are transformed into a sonic wave that is carried through the wall of the tubular body in the wellbore.

[00108] Each transceiver **440** is associated with a specific joint of pipe. That joint of pipe, in turn, has a known location or depth along the wellbore. The acoustic wave as originally transmitted from the transceiver **440** will represent a packet of information. The packet will include an identification code that tells a receiver (such as receiver **270** in **Figure 2**) where the signal originated, that is, which communications node **400** it came from. In addition, the packet will include an amplitude value originally recorded by the communications node **400** for its associated joint of pipe.

[00109] When the signal reaches the receiver at the surface, the signal is processed. This involves identifying which communications node the signal originated from, and then determining the location of that communications node along the wellbore. This further involves comparing the original amplitude value with a baseline value. The baseline value represents an anticipated value for a joint of casing having a fluid residing within its bore and a continuous cement sheath along its outer surface.

[00110] If the measured amplitude value is at or below the baseline amplitude value, then the operator can assume that a cement sheath has been placed around the joint of pipe at issue. On the other hand, if the measured amplitude value is above the baseline amplitude value, then the operator should assume that a poor cement sheath has been placed around the joint of pipe at issue. In that instance, remedial steps may be taken. Where the wellbore is presently undergoing a cementing operation, such steps may include further injecting cement through a cement shoe and up the annular region in the hopes of filling the annular region. More likely, where the wellbore has been completed, such steps may include placing perforations in the casing at the subject joint of pipe, and then conducting a so-called "cement squeeze" in order to isolate the joint of pipe and fill the annular region at the depth of that joint of pipe. Alternatively, the operator may elect to forego perforating casing at that depth or along a certain zone of interest.

[00111] The communications node **400** optionally also includes one or more sensors **432**. The sensors **432** may be, for example, pressure sensors, temperature sensors, or microphones. The sensor **432** sends signals to the transceiver **440** through a short electrical wire **435** or through the printed circuit board **435**. Signals from the sensor **432** are converted into acoustic signals using an electro-acoustic transducer, that are then sent by the transceiver **440** as part of the packet of information.

[00112] Preferably, the sensor **432** is a temperature sensor. The packet of information will then include signals representative of temperature readings taken by the temperature sensor. When the signal reaches the receiver at the surface, the signal is compared with a baseline value. The baseline value represents an anticipated temperature for a joint of casing having a fresh column of cement residing there around. Those of ordinary skill in the art of well completions will understand that cement mix undergoes an exothermic reaction which causes an increase in temperature.

[00113] If the measured temperature value is at or above the baseline temperature value, then the operator can assume that a cement sheath has been placed around the joint of pipe at issue. On the other hand, if the measured temperature value is below the baseline temperature value, then the operator should assume that a poor cement sheath has been placed around the joint of pipe at issue. Appropriate remedial steps may then be considered.

[00114] Additional methods of processing temperature data may be used. For example, the receiver may collect temperature data from a designated number of communications nodes that are in proximity to the subject communications node. Temperature readings will then be averaged to determine a moving average temperature value for a section of casing. The measured temperature reading will then be compared to the moving average temperature value to determine cement integrity at the level of a particular joint of pipe.

[00115] Ideally, the operator will review a combination of amplitude data and temperature data along the wellbore to confirm cement sheath integrity. Strain data and passive acoustic data may also be used to evaluate the integrity of the cement sheath.

[00116] The communications node **400** also optionally includes a shoe **500**. More specifically, the node **400** includes a pair of shoes **500** disposed at opposing ends of the wall **412**. Each of the shoes **500** provides a beveled face that helps prevent the node **400** from hanging up on an external tubular body or the surrounding earth formation, as the case may be, during run-in or pull-out. The shoes **500** may have a protective outer layer **422** and an optional cushioning material **424** under the outer layer **422**.

[00117] **Figures 5A** and **5B** are perspective views of an illustrative shoe **500** as may be used on an end of the communications node **400** of **Figure 4A**, in one embodiment. In **Figure 5A**, the leading edge or front of the shoe **500** is seen, while in **Figure 4B** the back of the shoe **500** is seen.

[00118] The shoe **500** first includes a body **510**. The body **510** includes a flat under-surface **512** that butts up against opposing ends of the wall **412** of the communications node **400**.

[00119] Extending from the under-surface **512** is a stem **520**. The illustrative stem **520** is circular in profile. The stem **520** is dimensioned to be received within opposing recesses **414** of the wall **412** of the node **400**.

[00120] Extending in an opposing direction from the body **510** is a beveled surface **530**. As noted, the beveled surface **530** is designed to prevent the communications node **400** from hanging up on an object during run-in into a wellbore.

[00121] Behind the beveled surface **530** is a flat (or slightly arcuate) surface **535**. The surface **535** is configured to extend along the drill string **160** (or other tubular body) when the communications node **400** is attached along the tubular body. In one aspect, the shoe **500** includes an optional shoulder **515**. The shoulder **515** creates a clearance between the flat surface **535** and the tubular body opposite the stem **520**.

[00122] In one arrangement, the communications nodes **400** with the shoes **500** are welded onto an outer surface of the tubular body, such as wall **310** of the pipe joint **300**. More specifically, the body **410** of the respective communications nodes **400** are welded onto the wall of a joint of casing. In some cases, it may not be feasible or desirable to pre-weld the communications nodes **400** onto pipe joints before delivery to a well site. Further still, welding may degrade the tubular integrity or damage electronics in the housing **410**. Therefore, it is desirable to utilize a clamping system that allows a drilling or service company to mechanically connect / disconnect the communications nodes **400** along a tubular body as the tubular body is being run into a wellbore.

[00123] **Figure 6** is a perspective view of a communications node system **600** as may be used for methods of the present invention, in one embodiment. The communications node system **600** utilizes a pair of clamps **610** for mechanically connecting a communications node **400** onto a tubular body **630** such as a joint of casing or liner.

[00124] The system **600** first includes at least one clamp **610**. In the arrangement of **Figure 6**, a pair of clamps **610** is used. Each clamp **610** abuts the shoulder **515** of a respective shoe **500**. Further, each clamp **610** receives the base **535** of a shoe **500**. In this

arrangement, the base **535** of each shoe **500** is welded onto an outer surface of the clamp **610**. In this way, the clamps **610** and the communications node **400** become an integral tool.

[00125] The illustrative clamps **610** of **Figure 6** include two arcuate sections **612**, **614**. The two sections **612**, **614** pivot relative to one another by means of a hinge. Hinges are shown in phantom at **615**. In this way, the clamps **610** may be selectively opened and closed.

[00126] Each clamp **610** also includes a fastening mechanism **620**. The fastening mechanisms **620** may be any means used for mechanically securing a ring onto a tubular body, such as a hook or a threaded connector. In the arrangement of **Figure 6**, the fastening mechanism is a threaded bolt **625**. The bolt **625** is received through a pair of rings **622**, **624**. The first ring **622** resides at an end of the first section **612** of the clamp **610**, while the second ring **624** resides at an end of the second section **614** of the clamp **610**. The threaded bolt **625** may be tightened by using, for example, one or more washers (not shown) and threaded nuts **627**.

[00127] In operation, a clamp **610** is placed onto the tubular body **630** by pivoting the first **612** and second **614** arcuate sections of the clamp **610** into an open position. The first **612** and second **614** sections are then closed around the tubular body **630**, and the bolt **625** is run through the first **622** and second **624** receiving rings. The bolt **625** is then turned relative to the nut **627** in order to tighten the clamp **610** and connected communications node **400** onto the outer surface of the tubular body **630**. Where two clamps **610** are used, this process is repeated.

[00128] The tubular body **630** may be, for example, a casing string such as the illustrative casing string **160** of **Figure 1**. Alternatively, the tubular body **630** may be a string of production tubing such as the tubing **240** of **Figure 2**. In any instance, the wall **412** of the communications node **400** is fabricated from a steel material having a resonant frequency compatible with the resonant frequency of the tubular body **630**. Stated another way, the mechanical resonance of the wall **412** is at a frequency contained within the frequency band used for telemetry.

[00129] In one aspect, the communications node **400** is about 12 to 16 inches (0.30 to 0.41 meters) in length as it resides along the tubular body **630**. Specifically, the housing **410** of the communications node may be 8 to 10 inches (0.20 to 0.25 meters) in length, and each opposing shoe **500** may be 2 to 5 inches (0.05 to 0.13 meters) in length. Further, the communications node **400** may be about 1 inch in width and inch in height. The base **410** of the communications node **400** may have a concave profile that generally matches the radius of the tubular body **630**.

[00130] A method for transmitting date in a wellbore is also provided herein. The method preferably employs the communications node **400** and the communications node system **600** of **Figure 6**.

[00131] **Figure 7** provides a flow chart for a method **700** of detecting the integrity of a cement sheath along a wellbore. The method **700** uses a plurality of data transmission nodes situated along a casing string to accomplish a wireless transmission of data along the wellbore. The data represents signals that indicate the presence of a cement sheath adjacent or in proximity to the respective communications nodes.

[00132] The method **700** first includes running a tubular body into the wellbore. This is shown at Box **710**. The tubular body is formed by connecting a series of pipe joints end-to-end, with the pipe joints being connected by threaded couplings. The joints of pipe are fabricated from a steel material suitable for conducting an acoustic signal.

[00133] The method **700** also provides for attaching a series of communications node to the joints of pipe. This is provided at Box **720**. The communications nodes are attached according to a pre-designated spacing. In one aspect, each joint of pipe receives a communications node. Preferably, each of the subsurface communications nodes is attached to a joint of pipe by one or more clamps. In this instance, the step **720** of attaching the communications nodes to the joints of pipe comprises clamping the communications nodes to an outer surface of the joints of pipe. Alternatively, an adhesive material or welding may be used for the attaching step **720**.

[00134] The method **700** further includes placing a cement sheath around the tubular body. This is indicated at Box **730**. The cement sheath is placed within an annular region formed between the casing joints and the surrounding subsurface rock matrix or previous strings of casing. The cement sheath is placed in the annular region using any known method of cementing casing into a wellbore. Typically, cement is injected down the casing string behind a bottom wiper plug and ahead of a top wiper plug, through a cement shoe, and back up the annular region. In the method **700**, the cement sheath will ideally surround the externally placed communications nodes in the annular region along areas where a cement sheath is desired.

[00135] The communications nodes include a series of subsurface communications nodes. The nodes reside along the casing string. The communications nodes also include a topside communications node. This is the uppermost communications node along the wellbore. The topside communications node may be attached to the tubular body proximate the surface. More preferably, the topside communications node is connected to the well head. The

topside communications node transmits signals from an uppermost subsurface communications node to a receiver at the surface.

[00136] The subsurface communications nodes are configured to transmit acoustic waves up to the topside communications node. Each subsurface communications node includes a transceiver that receives an acoustic signal from a previous communications node, and then transmits or relays that acoustic signal to a next communications node, in node-to-node arrangement.

[00137] The method **700** also includes providing a receiver. This is shown at Box **740**. The receiver is placed at the surface. The receiver has a processor that processes signals received from the topside communications node, such as through the use of firmware and/or software. The receiver preferably receives electrical or optical signals via a so-called "Class I, Division I" conduit or through a radio signal. The processor processes signals to identify which signals correlate to which subsurface communications node. This may involve the use of a multiplexer or a pulse-receive switch.

[00138] The method next includes transmitting signals from each of the communications nodes up the wellbore and to the receiver. This is provided at Box **750**. The signals are acoustic signals that have a resonance amplitude. These signals are sent up the wellbore, node-to-node. In one aspect, piezo wafers or other piezoelectric elements are used to receive and transmit acoustic signals. In another aspect, multiple stacks of piezoelectric crystals or other magnetostrictive devices are used. Signals are created by applying electrical signals of an appropriate frequency across one or more piezoelectric crystals, causing them to vibrate at a rate corresponding to the frequency of the desired acoustic signal.

[00139] In one aspect, the data transmitted between the nodes is represented by acoustic waves according to a multiple frequency shift keying (MFSK) modulation method. Although MFSK is well-suited for this application, its use as an example is not intended to be limiting. It is known that various alternative forms of digital data modulation are available, for example, frequency shift keying (FSK), multi-frequency signaling (MF), phase shift keying (PSK), pulse position modulation (PPM), and on-off keying (OOK). In one embodiment, every 4 bits of data are represented by selecting one out of sixteen possible tones for broadcast.

[00140] Acoustic telemetry along tubulars is characterized by multi-path or reverberation which persists for a period of milliseconds. As a result, a transmitted tone of a few milliseconds duration determines the dominant received frequency for a time period of additional milliseconds. Preferably, the communication nodes determine the transmitted frequency by receiving or "listening to" the acoustic waves for a time period corresponding to the reverberation time, which is typically much longer than the transmission time. The tone duration should be long enough that the frequency spectrum of the tone burst has negligible energy at the frequencies of neighboring tones, and the listening time must be long enough for the multipath to become substantially reduced in amplitude. In one embodiment, the tone duration is 2 ms, then the transmitter remains silent for 48 milliseconds before sending the next tone. The receiver, however, listens for 2 + 48 = 50 ms to determine each transmitted frequency, utilizing the long reverberation time to make the frequency determination more certain. Beneficially, the energy required to transmit data is reduced by transmitting for a short period of time and exploiting the multi-path to extend the listening time during which the transmitted frequency may be detected.

[00141] In one embodiment, an MFSK modulation is employed where each tone is selected from an alphabet of 16 tones, so that it represents 4 bits of information. With a listening time of 50 ms, for example, the data rate is 80 bits per second.

[00142] The tones are selected to be within a frequency band where the signal is detectable above ambient and electronic noise at least two nodes away from the transmitter node so that if one node fails, it can be bypassed by transmitting data directly between its nearest neighbors above and below. In one example the tones are evenly spaced in period within a frequency band from about 100 kHz to 125 kHz. In another example, the tones are evenly spaced in frequency within a frequency band from about 100 kHz to 125 kHz.

[00143] Preferably, the nodes employ a "frequency hopping" method where the last transmitted tone is not immediately re-used. This prevents extended reverberation from being mistaken for a second transmitted tone at the same frequency. For example, 17 tones are utilized for representing data in an MFSK modulation scheme; however, the last-used tone is excluded so that only 16 tones are actually available for selection at any time.

[00144] The communications nodes will transmit data as mechanical waves at a rate exceeding about 50 bps.

[00145] In one embodiment, each of the subsurface communications nodes also includes a temperature sensor. When the cement job is complete and the cement is setting, an exothermic reaction will take place. Changes in temperature will be indicative of the presence of cement between communications nodes. Later during production, changes in temperature may be indicative of the presence of formation fluids flowing behind the casing string. This may be indicative of flaws in the cement sheath. In any instance, the communications nodes are then designed to generate a signal that corresponds to temperature readings sensed by the respective temperature sensors along their corresponding joints of pipe.

[00146] Other sensors may also be employed in selected subsurface communications nodes. In one embodiment, strain gauges are used as sensors. Strain gauge data can be used to determine changes in stress on the casing as cement transitions from a fluid capable of transmitting hydrostatic pressure to a solid that is set. Strain gauge data can also be used to later identify volumetric changes within the set cement due to chemical reactions as cement hydration continues. Further, strain gauge data may be used to detect a pressure increase in the wellbore due to reservoir fluid influx through a flaw in the cement sheath. Data from the strain gauges may be included as part of the packet of information sent to the receiver at the surface for analysis.

[00147] In another embodiment, microphones are placed within selected subsurface communications nodes. Passive acoustic data gathered by microphones can be used to detect wellbore fluids, especially gas, that are flowing through a flaw or a mud channel in the cement sheath. As gas moves through a small gap it will produce ambient noises across a broad range of frequencies that can be detected by passive acoustic sensors in the nodes. Data from microphones may be included as part of the packet of information sent to the receiver at the surface for analysis.

[00148] As can be seen, various data can be gathered by sensors including temperature measurements, casing strain, noise caused by gas flow, and acoustic wave measurements themselves. All of this data may be considered together in evaluating a cement sheath along a wellbore.

[00149] The method **700** also includes analyzing the signals from the communications nodes. This is seen at Box **760**. The signals are analyzed to evaluate the integrity of the cement sheath adjacent or in proximity to each of the subsurface communications nodes. Preferably, the signals are analyzed after the cement has set into a solid material having a compressive strength. Analyzing the signals may mean comparing the amplitude to a baseline or to other amplitude readings.

[00150] The receiver (or a processor associated with the receiver) will compare amplitude values of the various acoustic signals, or waveforms, against a baseline amplitude value to confirm that the amplitude is not too high. The baseline amplitude value may be a specific value input into the program representative of an expected amplitude value for a joint of casing having fluids within its bore and a cement sheath around its outer surface. Alternatively, the baseline amplitude value may be a moving average amplitude value

determined by the program by averaging amplitude readings from a pre-designated number of communications nodes in proximity to the subject communications node. In one aspect, matrix equations are used to calculate a moving average, which serves as the baseline amplitude value. In any instance, an excessively high amplitude value suggests that cement has not been adequately placed around the pipe proximate to the communications node.

[00151] Where the signals correspond to temperature readings, the signals are compared to a baseline temperature value representing an expected temperature for fresh cement. Alternatively, the baseline temperature value may be a moving average temperature value determined by the program by averaging temperature readings from a pre-designated number of communications nodes in proximity to the subject communications node. In any instance, if the temperature reading from a specific communications node is too low, this will suggest that cement has not been adequately squeezed around the pipe joint at the level of that communications node.

[00152] Alternatively, analyzing the signals may mean measuring attenuation of a sonic signal. Propagation of acoustic waves between pairs of electro-acoustic transducers on neighboring subsurface communications nodes produces localized information (between two nodes) about the presence of cement and bonding. The level of acoustic wave attenuation increases from empty casing, to water-filled casing, to mud-filled casing, to casing with cement slurry (before setting), to a solidified / set cement. A plurality of pair-wise acoustic attenuation measurements provides a real-time log of the presence of cement. Optionally, this acoustic attenuation data is correlated with conventional cement bond-log data to analyze cement integrity.

[00153] A next step in the method **700** may be the identification of a subsurface communications node that is sending signals indicative of poor cement integrity within the cement sheath. This is provided at Box **770**. If it is determined that cement has not been properly placed around the casing string adjacent one of the communications nodes, various operational decisions may be made. This is indicated at Box **780**. In some embodiments (not illustrated), Boxes **770** and **780** may be replace with a single box stating "Make appropriate decision on subsequent drilling, completing, operating, or abandonment of the well."

[00154] In the method **700**, each of the communications nodes has an independent power source. The independent power source may be, for example, batteries or a fuel cell. Having a power source that resided within the housing of the communications nodes avoids the need for passing electrical connections through the housing, which could compromise fluid

isolation. In addition, each of the intermediate communications nodes has a transducer and associated transceiver.

[00155] Preferably, the electro-acoustic transducer receives acoustic signals at a first frequency, and then sends acoustic signals at a second frequency that is different from the first frequency. Each transducer then "listens" for signals at the second frequency. Preferably, each transducer "listens" for the acoustic waves sent at the first frequency until after reverberation of the acoustic waves at the first frequency has substantially attenuated. Thus, a time is selected for both transmitting and for receiving. In one aspect, the listening time may be about twice the time at which the waves at the first frequency are transmitted or pulsed. To accomplish this, the transducer will operate with and under the control of a micro-processor located on a printed circuit board, along with memory. Beneficially, the energy required to transmit signals is reduced by transmitting for a shorter period of time.

[00156] It is noted that the method **700** and the claims herein do not require that communications nodes be placed along the entire wellbore, but only along a selected section or sections. Further, the method **700** and the claims herein do not require that the cement sheath be placed along the entire annular region unless the claims expressly so state.

[00157] A separate method for determining the integrity of a cement sheath is provided herein. The cement sheath resides within an annular region along a wellbore. Preferably, the annular region is between a string of casing and a surrounding subsurface rock matrix.

[00158] The method first includes receiving signals from a wellbore. Each signal defines a packet of information having (i) an identifier for a subsurface communications node originally transmitting the signal, and (ii) an acoustic amplitude value for the subsurface communications node originally transmitting the signal.

[00159] The method also includes correlating communications nodes to their respective locations in the wellbore. In addition, the method comprises analyzing the amplitude values to determine whether any of such amplitude values are indicative of a poor cement sheath along the wellbore.

[00160] In this method, the subsurface communications nodes may be constructed in accordance with communications node **350** of **Figure 3**, communications node **400** of **Figure 4**, or other arrangement for acoustic transmission of data. Preferably, each of the subsurface communications nodes is attached to an outer wall of the casing string according to a pre-designated spacing, and resides within the annular region. The subsurface communications nodes are configured to communicate by acoustic signals transmitted through the casing string.

[00161] In one aspect, analyzing the amplitude values comprises identifying amplitude values generated by each of the subsurface communications nodes, and comparing those amplitude values to a baseline amplitude value. The baseline amplitude value may be, for example, (i) a previously stored amplitude value indicative of an amplitude value of a joint of casing having a continuous annular cement sheath, or (ii) a moving average of amplitude readings taken from a pre-designated number of communications nodes in proximity to a subject communications node.

[00162] In one aspect, each of the subsurface communications nodes further comprises a temperature sensor. The communications nodes are then designed to generate a signal that corresponds to temperature readings taken by the temperature sensors. The electro-acoustic transceivers in the subsurface communications nodes transmit acoustic signals up the wellbore representative of the temperature readings, node-to-node. In this instance, the packet of information generated by each subsurface communications node further has (iii) an acoustic waveform indicative of a temperature reading. In addition, the method further comprises analyzing the temperature readings to determine the presence of cement adjacent to the sensor.

[00163] In one aspect, analyzing the temperature readings comprises identifying temperature values generated by each of the subsurface communications nodes, and comparing those temperature values to a baseline temperature value. The baseline temperature value may be (i) a previously stored temperature value indicative of a temperature value of a joint of casing having a freshly-cemented annular region, or (ii) a moving average of temperature readings taken from a pre-designated number of communications nodes in proximity to a subject communications node in the wellbore.

[00164] As noted above, other sensors may be placed in selected subsurface communications nodes. These may include strain gauges and microphones.

[00165] As can be seen, a novel downhole telemetry system is provided, as well as a novel method for the wireless transmission of information using a plurality of data transmission nodes for detecting cement sheath integrity. In some States, new hydraulic fracturing regulations are being implemented which may require the use of cement bond logs. However, the system disclosed herein may potentially be used by an operator in lieu a cement bond log.

[00166] While it will be apparent that the inventions herein described are well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the

inventions are susceptible to modification, variation and change without departing from the spirit thereof.

Claims

What is claimed is:

1. An electro-acoustic telemetry system for evaluating a cement sheath in a wellbore, comprising:

a casing string disposed in a wellbore, with a cement sheath residing within an annular region formed between the casing string and a surrounding subsurface rock matrix along the casing string;

a topside communications node placed proximate a surface of the wellbore;

a plurality of subsurface communications nodes spaced along the wellbore and attached to an outer wall of the casing string, the subsurface communications nodes configured to transmit acoustic waves from node-to-node up the wellbore and to the topside communications node, and with at least some of the subsurface communications nodes being in contact with the cement sheath; and

a receiver at the surface configured to receive signals from the topside communications node;

wherein each of the subsurface communications nodes comprises:

a sealed housing;

an electro-acoustic transducer and associated transceiver also residing within the housing, with the transceiver being designed to relay signals from node-to-node up the wellbore, with each signal representing a packet of information that comprises an identifier for the subsurface communications node that originally transmitted the signal, and an acoustic waveform having an amplitude; and

an independent power source residing within the housing providing power to the transceiver.

2. The electro-acoustic telemetry system of claim 1, wherein the subsurface communications nodes are spaced apart such that each joint of pipe supports at least one subsurface communications node.

3. The electro-acoustic telemetry system of claim 1, wherein the subsurface communications nodes are spaced at about 20 to 40 foot (6.1 to 12.2 meter) intervals.

4. The electro-acoustic telemetry system of claim 1, wherein the subsurface communications nodes transmit data in acoustic form at a rate exceeding about 50 bps.

5. The electro-acoustic telemetry system of claim 1, wherein each of the electro-acoustic transceivers is designed to receive acoustic waves at a first frequency, and then transmit the acoustic waves at a second different frequency up the wellbore to a next subsurface communications node.

6. The electro-acoustic system of claim 1, further comprising:

one or more sensors placed along the wellbore, the sensors being any of strain gauges, temperature sensors, microphones, or combinations thereof; and

wherein the subsurface communications nodes are configured to receive and relay acoustic signals indicative of readings taken by the sensors up to the surface.

7. The electro-acoustic system of claim 6, wherein:

the one or more sensors reside within the housings of selected subsurface communications nodes; and

the electro-acoustic transducers within the selected subsurface communications nodes convert signals from the sensors into acoustic signals for the associated transceivers.

8. The electro-acoustic system of claim 6, wherein a frequency band for the acoustic wave transmission by the transceivers is about 25 KHz wide.

9. The electro-acoustic system of claim 6, wherein a frequency band for the acoustic wave transmission by the transceivers operates from about 100 kHz to 125 kHz.

10. The electro-acoustic telemetry system of claim 6, wherein the acoustic waves provide data that is modulated by (i) a multiple frequency shift keying method, (ii) a frequency shift keying method, (iii) a multi-frequency signaling method, (iv) a phase shift keying method, (v) a pulse position modulation method, or (vi) an on-off keying method.

11. The electro-acoustic telemetry system of claim 6, wherein each subsurface communications node listens for the acoustic waves generated at the first frequency for a longer time than the time for which the acoustic waves were generated at the second frequency by a previous subsurface communications node.

12. The electro-acoustic telemetry system of claim 1, wherein:

a well head is placed above the wellbore; and

the topside communications node is placed (i) on an outer surface of the well head, (ii) on an outer surface of a tubular body that is downstream of the wellhead, or (iii) on the outer surface of an uppermost joint of the casing string.

13. The electro-acoustic telemetry system of claim 12, wherein the signal from the topside communications node to the receiver is transmitted via a Class I, Division I conduit or a wireless transmission.

14. The electro-acoustic telemetry system of claim 1, wherein the subsurface communications nodes are attached to the outer wall of the casing string by (i) an adhesive material, (ii) welding, or (iii) one or more mechanical fasteners.

15. The electro-acoustic telemetry system of claim 1, wherein:

each of the subsurface communications nodes is attached to the casing string by one or more clamps; and

each of the one or more clamps comprises:

a first arcuate section;

a second arcuate section;

a hinge for pivotally connecting the first and second arcuate sections; and

a fastening mechanism for securing the first and second arcuate sections around an outer surface of the casing string.

16. The electro-acoustic telemetry system of claim 1, wherein:

the receiver comprises a processor; and

the processor is programmed to identify amplitude values generated by each subsurface communications node and compare those amplitude values to a baseline amplitude value.

17. The electro-acoustic telemetry system of claim 16, wherein the baseline amplitude value is (i) a previously stored amplitude value indicative of an amplitude value of a joint of casing having a continuous annular cement sheath, or (ii) a moving average of amplitude

readings taken from a pre-designated number of communications nodes in proximity to a subject communications node.

18. The electro-acoustic telemetry system of claim 16, wherein:

selected communications nodes further comprise a temperature sensor, with those selected communications nodes being designed to generate a signal that corresponds to temperature readings taken by the respective temperature sensors; and

the transceivers transmit acoustic signals up the wellbore representative of the temperature readings, node-to-node, as part of the packets of information.

19. The electro-acoustic telemetry system of claim 18, wherein the processor is further programmed to identify temperature values generated by the selected subsurface communications node and compare those temperature values to a baseline temperature value.

20. The electro-acoustic telemetry system of claim 19, wherein the baseline temperature value is (i) a previously stored temperature value indicative of a temperature value of a joint of casing having a freshly-cemented annular region, or (ii) is a moving average of temperature readings taken from a pre-designated number of communications nodes in proximity to a subject communications node.

21. The electro-acoustic telemetry system of claim 16, wherein:

selected communications nodes further comprise a strain gauge, with those selected communications nodes being designed to generate a signal that corresponds to strain readings taken by the respective strain gauges; and

the electro-acoustic transceivers transmit acoustic signals up the wellbore representative of the strain readings, node-to-node, as part of the packets of information.

22. The electro-acoustic telemetry system of claim 16, wherein:

selected communications nodes further comprise a passive acoustic sensor, with those selected communications nodes being designed to generate a signal that corresponds to ambient noise readings taken by the respective temperature sensors; and

the electro-acoustic transceivers transmit acoustic signals up the wellbore representative of the noise readings, node-to-node, as part of the packets of information.

23. A method of detecting the integrity of a cement sheath along a wellbore, comprising:

running joints of casing into the wellbore, the joints of casing being connected by threaded couplings to form a casing string;

attaching a series of communications nodes to the joints of casing according to a pre-designated spacing, wherein adjacent communications nodes are configured to communicate by acoustic signals transmitted through the joints of casing, and wherein each of the communications nodes comprises:

a sealed housing;

an electro-acoustic transducer and associated transceiver residing within the housing configured to relay signals, with each signal representing a packet of information that comprises an identifier for the subsurface communications node originally transmitting the signal, and an acoustic waveform; and

an independent power source also residing within the housing for providing power to the transceiver;

placing a cement sheath within an annular region formed between the casing string and a surrounding subsurface matrix substantially along the wellbore;

sending signals from the communications nodes to a receiver at a surface via the series of communications nodes; and

analyzing the signals to evaluate the integrity of the cement sheath proximate each of the communications nodes.

24. The method of claim 23, wherein the surface is an earth surface, or a drilling or production platform over a water surface.

25. The method of claim 20, wherein the housing for each of the intermediate communications nodes is fabricated from a steel material, with the steel material of the housing having a resonance frequency within a width of the resonance frequency of the acoustic waveforms transmitted through the joints of casing.

26. The method of claim 23, wherein:

the series of communications nodes comprises a topside communications node residing proximate the surface, and a series of subsurface communications nodes along the wellbore below the topside communications nodes; and the topside communications node transmits the signals from an uppermost subsurface communications node to the receiver.

27. The method of claim 26, wherein:

a well head is placed above the wellbore; and

the topside communications node is clamped (i) on an outer surface of the well head, or (ii) on the outer surface of an uppermost joint of the casing string.

28. The method of claim 27, wherein the topside communications node is in electrical communication with the receiver by means of a Class I, Division I conduit or a wireless transmission.

29. The method of claim 26, wherein each of the subsurface communications nodes is attached to an outer wall of a joint of casing by (i) an adhesive material, (ii) welding, or (iii) one or more mechanical fasteners.

30. The method of claim 26, wherein:

each of the subsurface communications nodes is attached to a joint of casing by one or more clamps; and

the step of attaching the communications nodes to the joints of casing comprises clamping the communications nodes to an outer surface of the joints of casing.

31. The method of claim 30, wherein:

the housing of each of the subsurface communications nodes comprises a first end and a second opposite end; and

each of the one or more clamps comprises a first clamp secured at the first end of the housing, and a second clamp secured at the second end of the housing.

32. The method of claim 23, wherein the subsurface communications nodes are spaced apart such that each joint of casing supports at least one subsurface communications node.

33. The method of claim 23, wherein the subsurface communications nodes are spaced at about 20 to 40 foot (6.1 to 12.2 meter) intervals.

34. The method of claim 23, wherein the subsurface communications nodes transmit data representing the waveforms at a rate exceeding about 50 bps.

35. The method of claim 23, wherein analyzing the signals to evaluate the integrity of the cement sheath comprises:

identifying amplitude values generated by each of the subsurface communications nodes; and

comparing those amplitude values to a baseline amplitude value.

36. The method of claim 35, wherein the baseline amplitude value is (i) a previously stored amplitude value indicative of an amplitude value of a joint of casing having a continuous annular cement sheath, or (ii) a moving average of amplitude readings taken from a pre-designated number of communications nodes in proximity to a subject communications node.

37. The method of claim 36, wherein:

each of the subsurface communications nodes further comprises a temperature sensor, and is designed to generate a signal that corresponds to temperature readings taken by the temperature sensor; and

the electro-acoustic transceivers in the subsurface communications nodes also transmit acoustic signals up the wellbore representative of the temperature readings, node-to-node.

38. The method of claim 35, wherein analyzing the signals to determine the integrity of the cement sheath further comprises:

identifying temperature values generated by each of the subsurface communications nodes; and

comparing those temperature values to a baseline temperature value.

39. The method of claim 38, wherein the baseline temperature value is (i) a previously stored temperature value indicative of a temperature value of a joint of casing having a freshly-cemented annular region, or (ii) a moving average of temperature readings taken from a pre-designated number of communications nodes in proximity to a subject communications node in the wellbore.

40. The method of claim 23, wherein:

selected communications nodes further comprise a strain gauge, with those selected communications nodes being designed to generate a signal that corresponds to strain readings taken by the respective strain gauges; and

the electro-acoustic transceivers transmit acoustic signals up the wellbore representative of the strain readings, node-to-node, as part of the packets of information.

41. The method of claim 23, wherein:

selected communications nodes further comprise a passive acoustic sensor, with those selected communications nodes being designed to generate a signal that corresponds to ambient noise readings taken by the respective temperature sensors; and

the electro-acoustic transceivers transmit acoustic signals up the wellbore representative of the noise readings, node-to-node, as part of the packets of information.

42. The method of claim 23, wherein a frequency band for the acoustic wave transmission by the transceivers is about 25 KHz wide.

43. The method of claim 23, wherein a frequency band for the acoustic wave transmission by the transceivers operates from about 100 kHz to 125 kHz.

44. The method of claim 23, wherein the acoustic waves provide data that is modulated by (i) a multiple frequency shift keying method, (ii) a frequency shift keying method, (iii) a multi-frequency signaling method, (iv) a phase shift keying method, (v) a pulse position modulation method, or (vi) an on-off keying method.

45. The method of claim 23, further comprising:

identifying a subsurface communications node sending signals indicative of poor cement integrity within the surrounding cement sheath.

46. The method of claim 23, further comprising:

perforating the joint of casing supporting that subsurface communications node; and

squeezing cement through the perforated joint of casing and into the annular region around the casing string.

47. The method of claim 23, wherein analyzing the signals to evaluate the integrity of the cement sheath further comprises comparing the attenuation of acoustic signals between pairs of subsurface communications nodes.

48. The method of claim 47, wherein analyzing the signals to evaluate the integrity of the cement sheath further comprises comparing the attenuation of acoustic signals with cement bond-log data.

49. A method of detecting the integrity of a cement sheath in an annular region along a wellbore, comprising:

receiving signals from a wellbore, each signal defining a packet of information having (i) an identifier for a subsurface communications node originally transmitting the signal, and (ii) an acoustic amplitude value for the subsurface communications node originally transmitting the signal;

correlating subsurface communications nodes to their respective locations in the wellbore; and

analyzing the amplitude values to determine whether any of such amplitude values are indicative of a poor cement sheath along the wellbore.

50. The method of claim 49, wherein:

the annular region resides between a casing string and a surrounding subsurface rock matrix; and

each of the subsurface communications nodes is attached to an outer wall of the casing string according to a pre-designated spacing, and resides within the annular region.

51. The method of claim 50, wherein:

the subsurface communications nodes are configured to communicate by acoustic signals transmitted through the casing string, and

each of the communications nodes comprises:

a sealed housing;

an electro-acoustic transducer and associated transceiver residing within the housing; and

an independent power source also residing within the housing for providing power to the transceiver.

52. The method of claim 51, wherein analyzing the amplitude values comprises:

identifying amplitude values generated by each of the subsurface communications nodes; and

comparing those amplitude values to a baseline amplitude value.

53. The method of claim 52, wherein the baseline amplitude value is (i) a previously stored amplitude value indicative of an amplitude value of a joint of casing having a continuous annular cement sheath, or (ii) a moving average of amplitude readings taken from a pre-designated number of communications nodes in proximity to a subject communications node.

54. The method of claim 52, wherein:

selected subsurface communications nodes further comprises a temperature sensor, and are designed to generate a signal that corresponds to temperature readings taken by the temperature sensor;

the electro-acoustic transceivers in the subsurface communications nodes transmit acoustic signals up the wellbore representative of the temperature readings, node-to-node;

the packet of information generated by each subsurface communications node further has (iii) an acoustic waveform indicative of a temperature reading; and

the method further comprises analyzing the temperature readings to determine whether any of such temperature readings are indicative of a poor cement sheath along the wellbore.

55. The method of claim 54, wherein analyzing the temperature readings comprises:

identifying temperature values generated by each of the subsurface communications nodes; and

comparing those temperature values to a baseline temperature value.

56. The method of claim 55, wherein the baseline temperature value is (i) a previously stored temperature value indicative of a temperature value of a joint of casing having a freshly-cemented annular region, or (ii) a moving average of temperature readings taken from a pre-designated number of communications nodes in proximity to a subject communications node in the wellbore.

57. The method of claim 52, wherein:

at least some of the subsurface communications nodes further comprises a passive acoustic sensor, and generate a signal that corresponds to ambient noise readings taken by the passive acoustic sensors;

the electro-acoustic transceivers in the subsurface communications nodes transmit acoustic signals up the wellbore representative of the ambient noise readings, node-to-node;

the packet of information generated by the subsurface communications nodes further has (iii) an acoustic waveform indicative of the ambient noise readings; and

the method further comprises analyzing the ambient noise readings to determine whether any of such ambient noise readings are indicative of a poor cement sheath along the wellbore.

58. The method of claim 52, wherein:

at least some of the subsurface communications nodes further comprises a strain gauge, and generate a signal that corresponds to strain readings taken by the strain gauges;

the electro-acoustic transceivers in the subsurface communications nodes transmit acoustic signals up the wellbore representative of the strain readings, node-to-node;

the packet of information generated by the subsurface communications nodes further has (iii) an acoustic waveform indicative of the strain readings; and

the method further comprises analyzing the strain readings to determine whether any of such strain readings are indicative of a poor cement sheath along the wellbore.

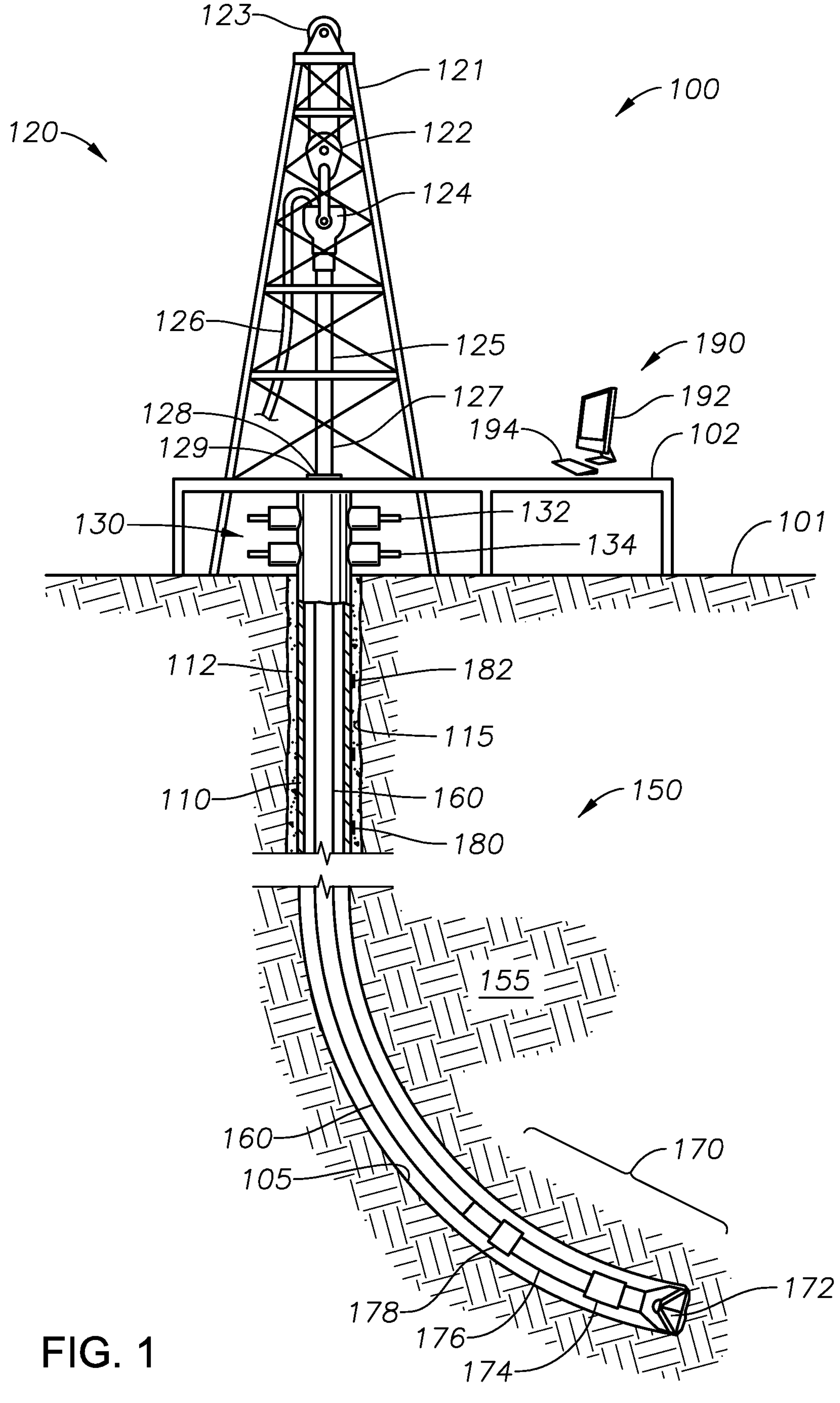
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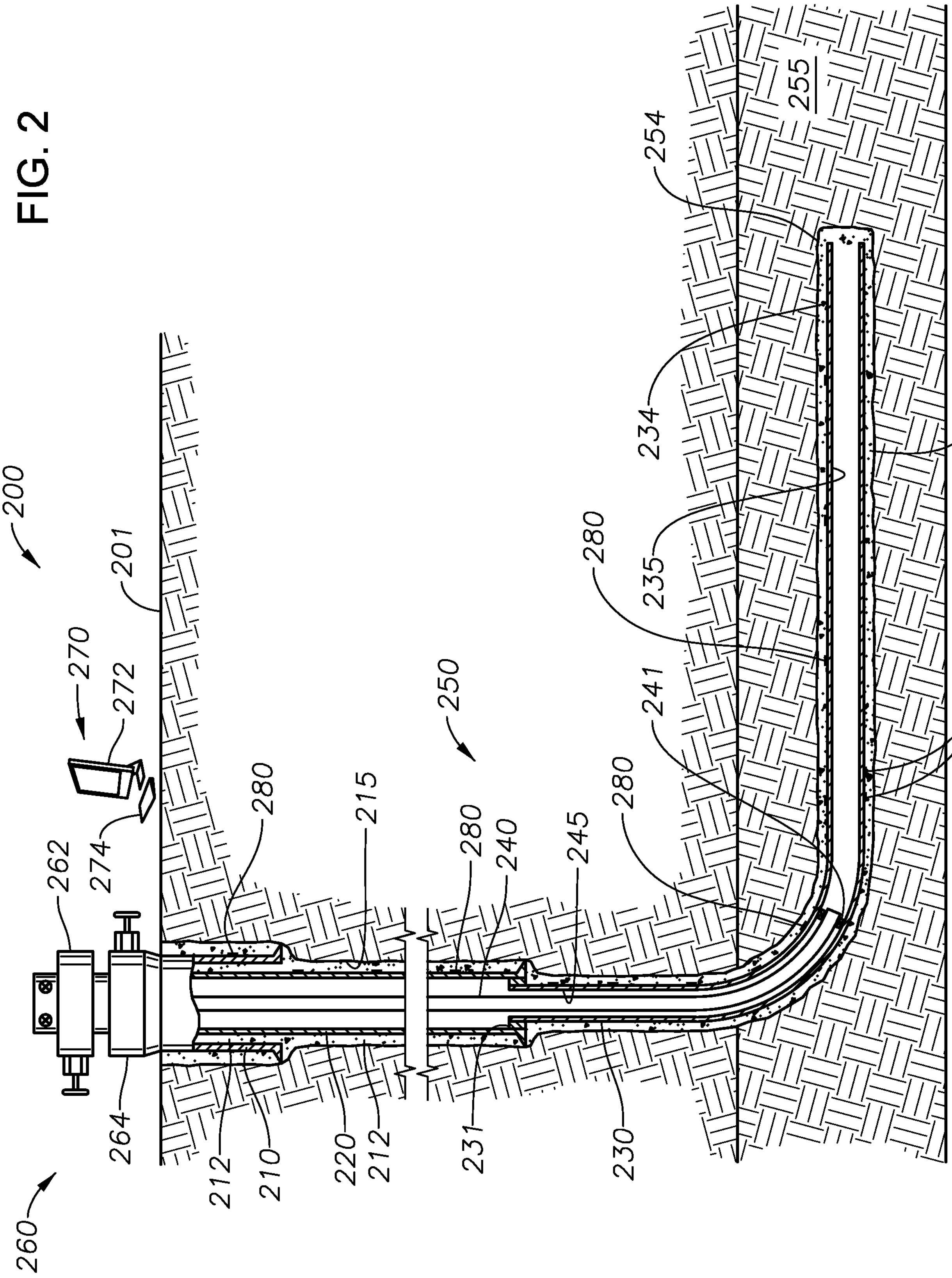
FIG. 1

FIG. 2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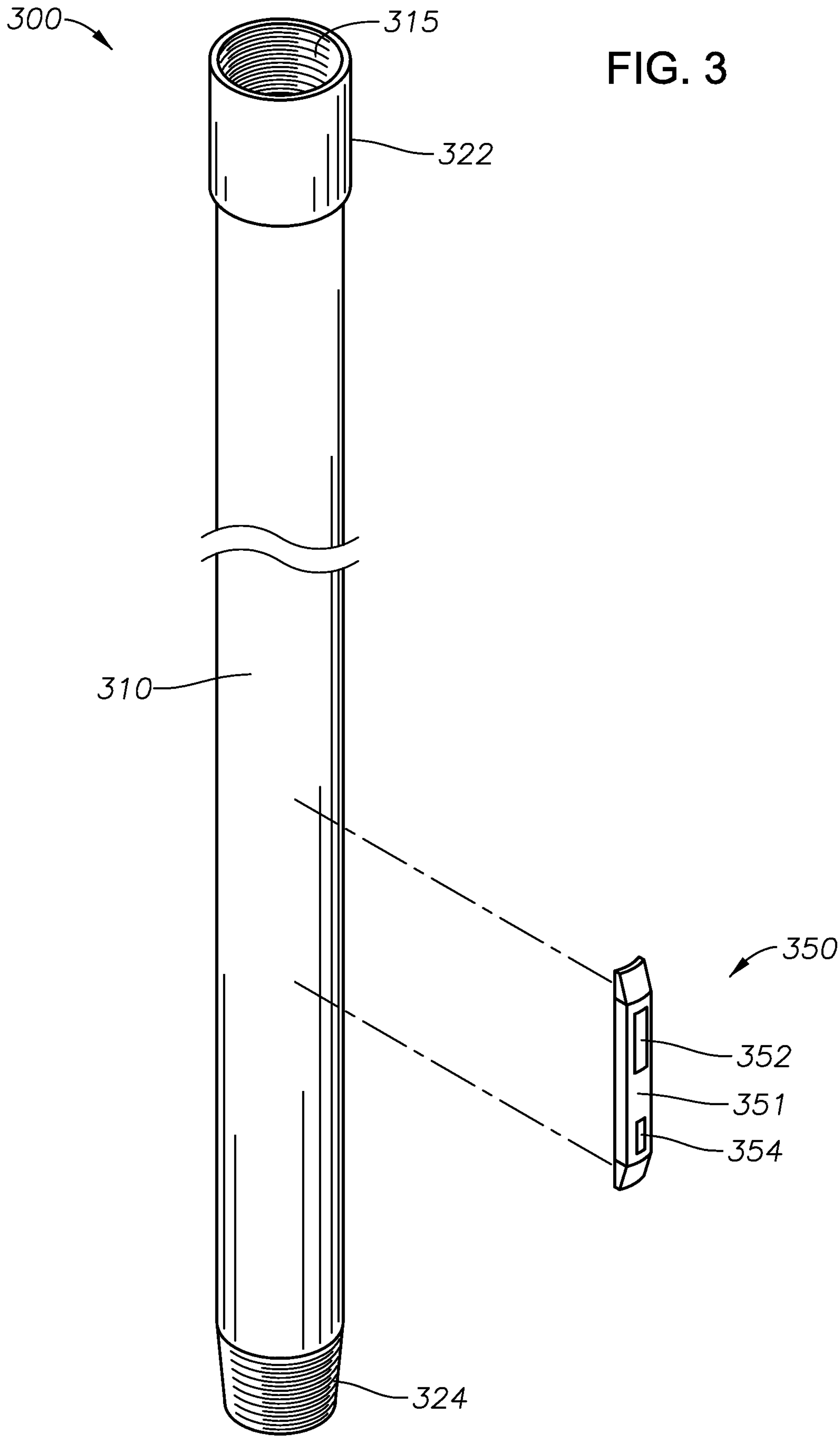

FIG. 3

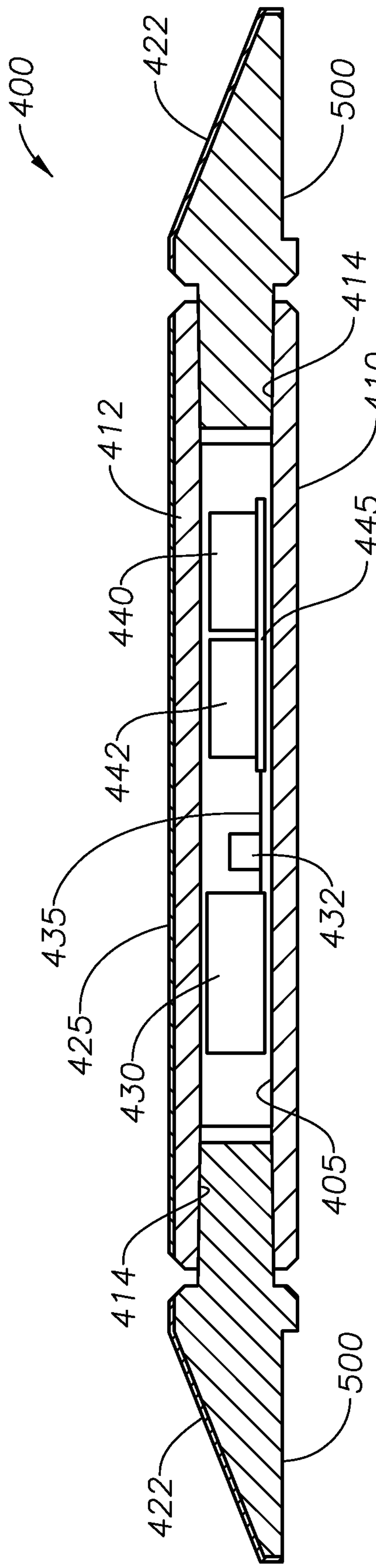
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FIG. 4B

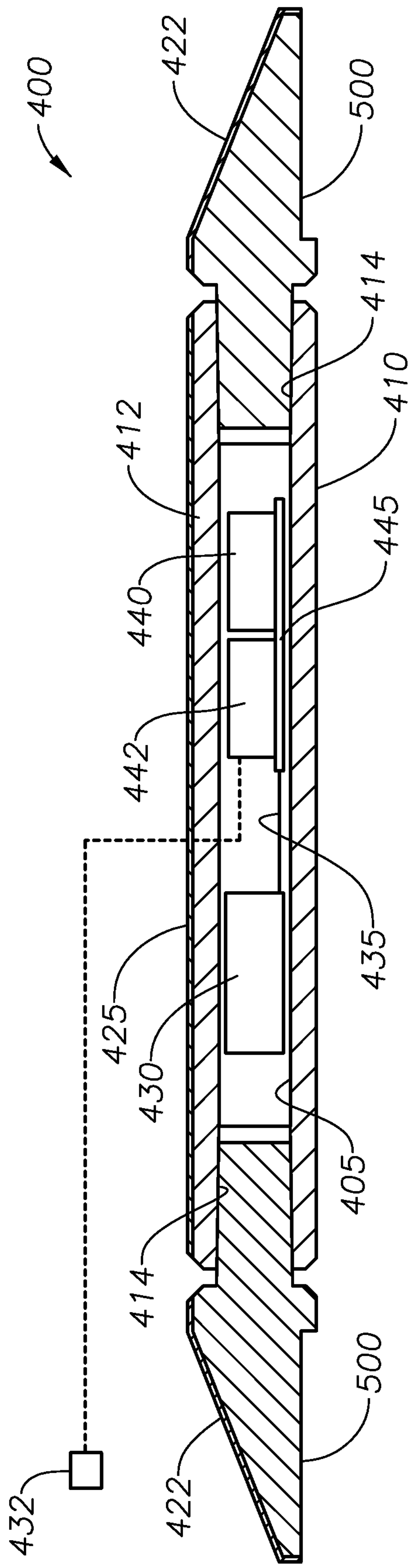
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FIG. 4C

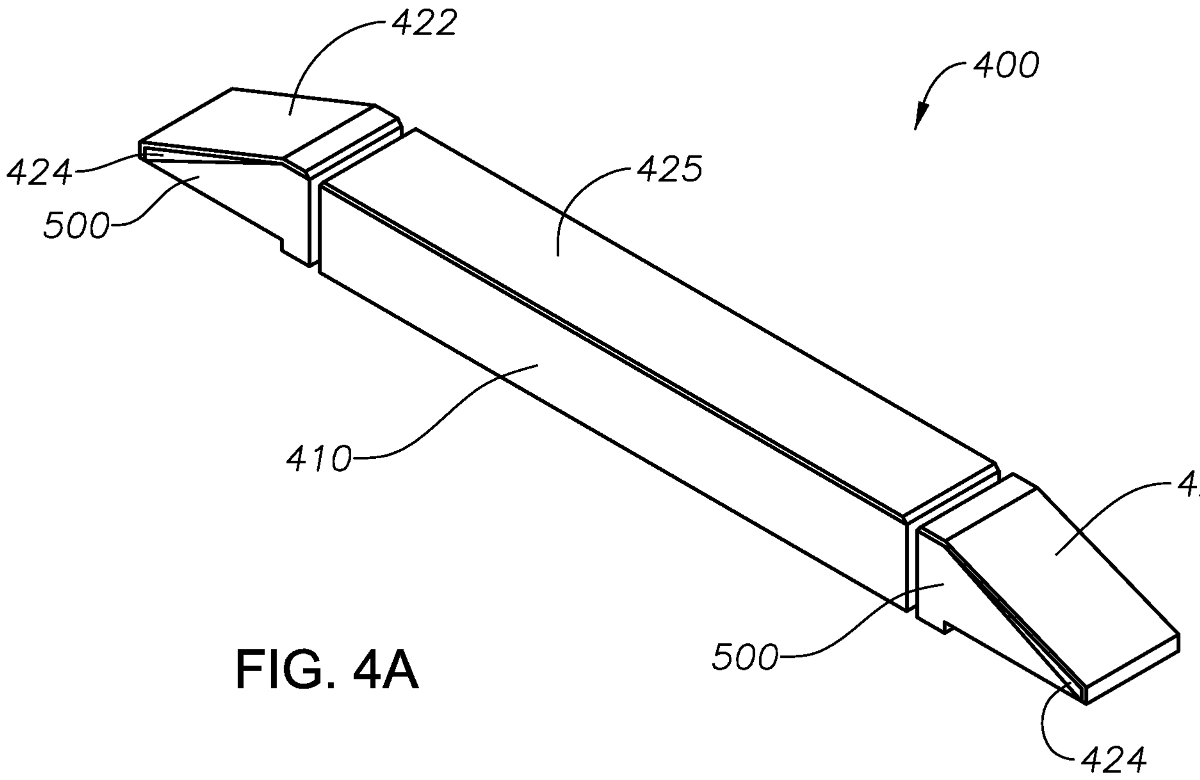


FIG. 4A

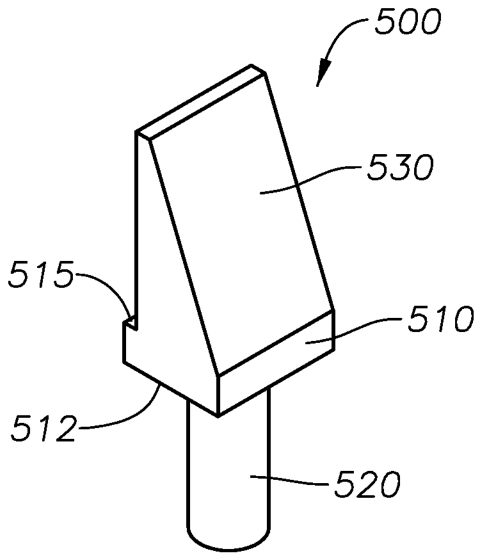


FIG. 5A

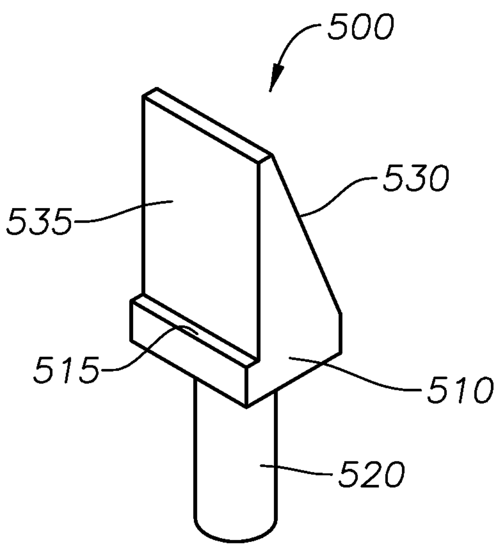
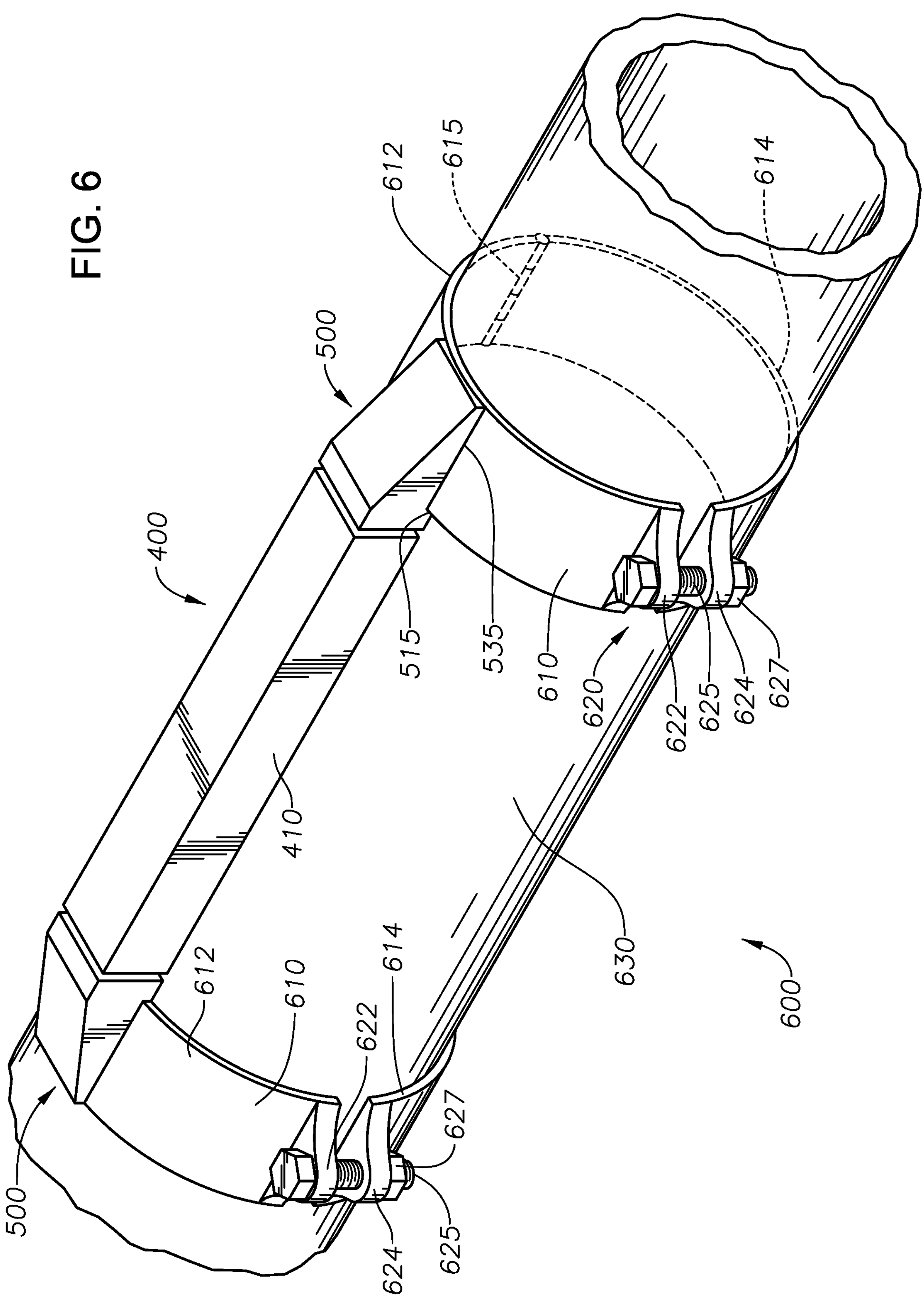


FIG. 5B

FIG. 6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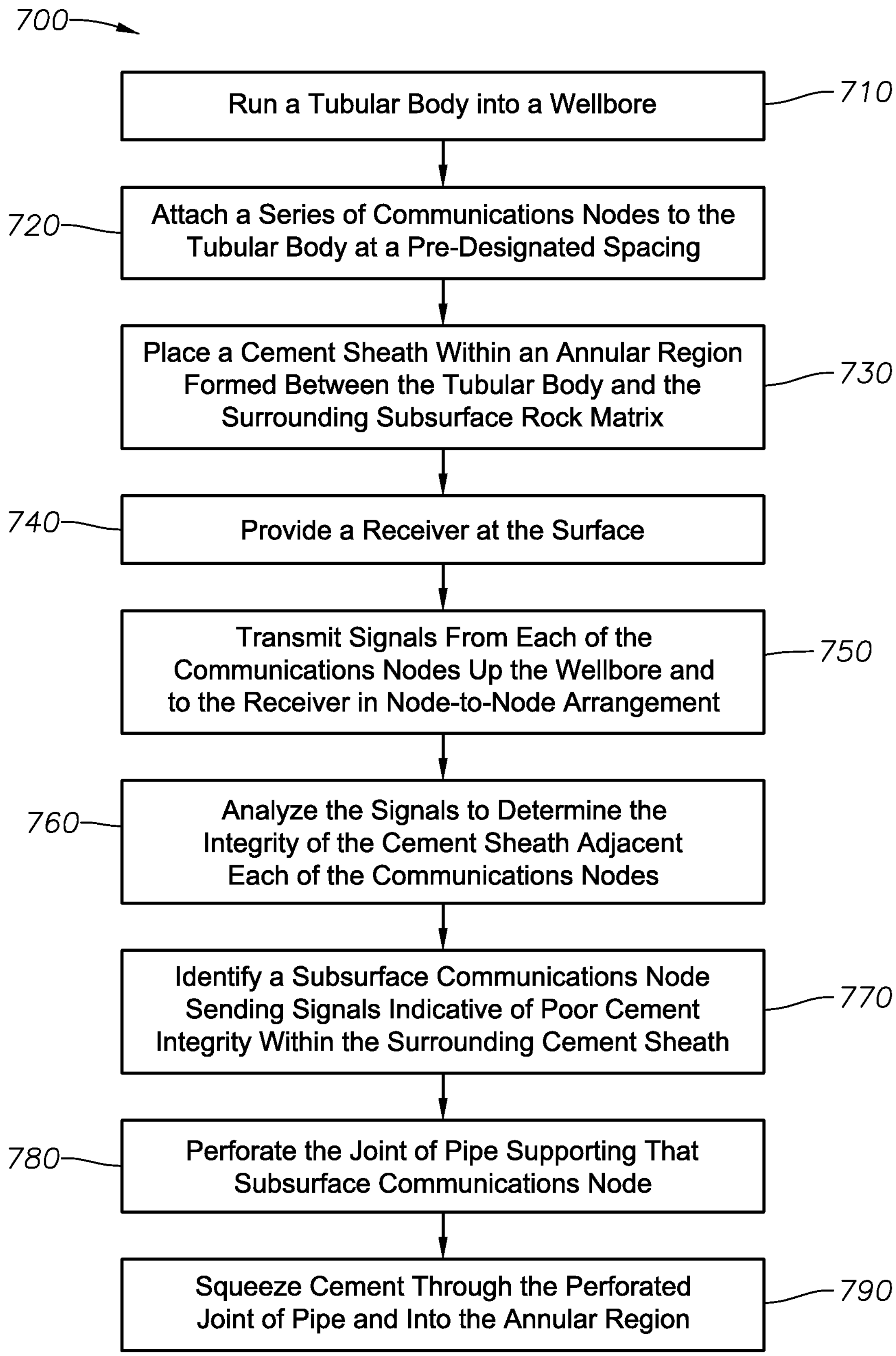
700
Run a Tubular Body into a Wellbore
710
Attach a Series of Communications Nodes to the Tubular Body at a Pre-Designated Spacing
720
Place a Cement Sheath Within an Annular Region Formed Between the Tubular Body and the Surrounding Subsurface Rock Matrix
730
Provide a Receiver at the Surface
740
Transmit Signals From Each of the Communications Nodes Up the Wellbore and to the Receiver in Node-to-Node Arrangement
750
Analyze the Signals to Determine the Integrity of the Cement Sheath Adjacent Each of the Communications Nodes
760
Identify a Subsurface Communications Node Sending Signals Indicative of Poor Cement Integrity Within the Surrounding Cement Sheath
770
Perforate the Joint of Pipe Supporting That Subsurface Communications Node
780
Squeeze Cement Through the Perforated Joint of Pipe and Into the Annular Region
790

FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2013/076278

A. CLASSIFICATION OF SUBJECT MATTER
IPC(8) - E21B 43/00 (2014.01)
USPC - 340/853.1
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)
IPC(8) - E21B 17/00, 43/00, 47/00; G01V 3/18 (2014.01)
USPC - 166/250.01, 166/253.1, 166/386; 340/853.1

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
CPC - E21B 17/00, 43/00, 47/00 (2014.02)

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

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2007/0139217 A1 (BEIQUE et al) 21 June 2007 (21.06.2007) entire document.	1-48, 50-58
Y	US 2002/0043369 A1 (VINEGAR et al) 18 April 2002 (18.04.2002) entire document.	1-48, 50-58
Y	US 2007/0024464 A1 (LEMENAGER et al) 01 February 2007 (01.02.2007) entire document.	1-58
Y	US 2010/0126718 A1 (LILLEY) 27 May 2010 (27.05.2010) entire document.	1-58
Y	US 2010/0157739 A1 (SLOCUM et al) 24 June 2010 (24.06.2010) entire document.	5, 11
Y	US 2012/0256415 A1 (DOLE) 11 October 2012 (11.10.2012) entire document.	15
Y	US 2009/0264956 A1 (RISE et al) 22 October 2009 (22.10.2009) entire document.	16-22, 35-39, 52-58
Y	US 2006/0133203 A1 (JAMES et al) 22 June 2006 (22.06.2006) entire document.	22, 41, 57
Y	US 2003/0056953 A1 (TUMLIN et al) 27 March 2003 (27.03.2003) entire document.	46
A	US 2005/0145010 A1 (VANDERVEEN et al) 07 July 2005 (07.07.2005) entire document.	1-58
A	US 2005/0024231 A1 (FINCHER et al) 03 February 2005 (03.02.2005) entire document.	1-58

☐ Further documents are listed in the continuation of Box C. ☐

* 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	Date of mailing of the international search report
14 April 2014	05 MAY 2014

Name and mailing address of the ISA/US	Authorized officer:
Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, Virginia 22313-1450 Facsimile No. 571-273-3201	Blaine R. Copenheaver PCT Helpdesk: 571-272-4300 PCT OSP: 571-272-7774