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(54) Title: ACOUSTIC MEASUREMENTS WITH DOWNHOLE SAMPLING AND TESTING TOOLS

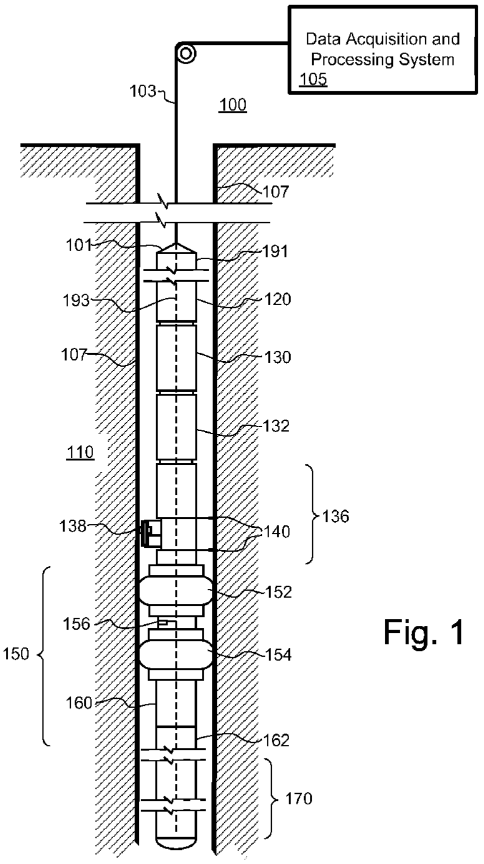

Fig. 1

(57) Abstract: Methods and related systems are described for measuring acoustic signals in an annular region. The system includes a tool housed in a tool housing for deployment downhole in a borehole, a downhole pumping system mounted within the tool housing and adapted to pump fluid between the tool and an annular region defined by at least the tool housing and a wall of the borehole, and an acoustic transducer mounted on the tool adapted to be in acoustic communication primarily with the annular region. Methods and related systems are also described for measuring acoustic signals on a borehole wall, and for measuring acoustic signals within a downhole tool.

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Acoustic Measurements with Downhole Sampling and Testing Tools

BACKGROUND OF THE INVENTION

1. Field of the Invention

[0001] This patent specification relates to downhole fluid sampling and testing. More particularly, this patent specification relates to systems and methods for making and analyzing acoustic measurements with downhole fluid sampling and/or testing tool.

2. Background of the Invention

[0002] In the oilfield service industry, characterizing commercially viable reservoirs of hydrocarbons is a main objective of well logging services. Downhole sampling and testing tools such as the Modular Dynamic Formation Tester (MDT) from Schlumberger are used during the well logging phase to gain a more direct assessment of the production characteristics of the accumulation. In one common configuration, the MDT is arranged with dual packers set against the borehole wall, thereby creating an isolated fluid interval in the annulus bounded by the tool outer surface, the borehole wall, and the two inflatable packers. Additional modules within the MDT enable controlled changes in pressure and flow in the interval. According to this conventional configuration, the pressure is monitored by pressure gauges designed to record the average pressure approximately once per second. During some types of operations, for example fluid sampling operations, fluid is drawn from the annular packed-off region into the tool. Although the onset of a change in the fluid properties of the annular region is often eventually detected by sensors within the tool body, it is often desirable to improve evaluation of the such changes and to obtain the information more quickly.

[0003] In some types of testing operations, rapid changes in pressure sometimes occur. For example, in a microhydraulic fracturing test, the interval is pressurized by pumping fluid into the annulus until a tensile fracture begins. The initiation is recorded by a breakdown on a pressure-vs-time record sampled at about one sample per second. It is desirable to evaluate these rapid changes in greater detail. During other types of testing operations, pressure transient responses are measured downhole using tools such as the MDT that amount to a small-scale drill stem test. It is desirable to improve the evaluations of the formation when performing such types of operations. Additionally since the sampling and testing tools have pumps, valves and many other moving parts, it is desirable to more effectively monitor the operation of these moving parts.

SUMMARY OF THE INVENTION

[0004] According to embodiments, a system for measuring acoustic signals in an annular region is provided. The system includes a tool housed in a tool housing for deployment downhole in a borehole, a downhole pumping system mounted within the tool housing and adapted to pump fluid between the tool and an annular region defined by at least the tool housing and a wall of the borehole, and an acoustic transducer mounted on the tool adapted to be in acoustic communication primarily with the annular region. Expandable packers are preferably positioned to seal the region between the tool housing and the borehole wall such that the annular region is defined by the tool housing, the borehole wall, and the packers.

[0005] According to embodiments, a method for measuring acoustic signals in an annular region is provided. The method includes positioning a downhole tool housing in a borehole; pumping fluid between the tool housing and the annular region defined by at least an outer surface of the tool housing and a borehole wall; and measuring acoustic energy propagating within the annular region. Properties of the fluid flowing into the annulus from the formation are preferably evaluated using the measured acoustic energy propagating within the annulus. Examples of evaluated properties include detecting an onset of gas flowing into the annulus, an onset of liquid flowing into the annulus, an onset of water flowing into the annulus, and an onset of sand flowing into the annulus.

[0006] According to further embodiments, a system for measuring acoustic signals on a borehole wall is provided. The system includes a downhole tool housed in a tool housing for deployment downhole in a borehole; a downhole pumping system mounted within the tool housing; and an acoustic transducer deployable to be in acoustic communication primarily with the rock formation. The pumping system is preferably adapted to pump fluid between the tool and a subterranean rock formation near the tool when deployed in a borehole.

[0007] According further embodiments, a method for measuring acoustic signals on a borehole wall is provided. The method includes positioning a downhole tool in a borehole; pumping fluid with a pumping system housed within the tool; positioning an acoustic transducer such that it is acoustic communication primarily with the borehole wall; and measuring acoustic energy propagating within the rock formation using the acoustic transducer.

[0008] According to yet further embodiments a system for measuring acoustic signals within a downhole tool is provided. The system includes a downhole tool housed in a tool housing for deployment downhole in a borehole; a downhole pumping system mounted within the tool housing and adapted to pump fluid between the tool and a subterranean rock formation near the tool when deployed in a borehole; and an acoustic transducer mounted within the tool housing.

[0009] According to yet further embodiments a method for measuring acoustic energy propagating within a downhole tool is provided. The method includes positioning a downhole tool in a borehole; pumping fluid between the tool housing and a subterranean rock formation through which the borehole passes; and measuring acoustic energy propagating within the rock formation.

[0010] Further features and advantages of the invention will become more readily apparent from the following detailed description when taken in conjunction with the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] The present invention is further described in the detailed description which follows, in reference to the noted plurality of drawings by way of non-limiting examples of exemplary embodiments of the present invention, in which like reference numerals represent similar parts throughout the several views of the drawings, and wherein:

[0012] FIG. 1 shows a downhole system for making acoustic measurements with a downhole fluid sampling tool, according to embodiments;

[0013] FIG. 2 shows further detail of a dual-packer module with an acoustic transducer, according to embodiments;

[0014] FIGs. 3a-3c show an acoustic sensor module forming part of a tool string, according to embodiments;

[0015] FIG. 4 show two acoustic sensor modules near a pump out module, according to embodiments;

[0016] FIG. 5 shows a pump out module including acoustic transducers, according to embodiments;

[0017] FIG. 6 is a schematic diagram of a dual-packer module according to embodiments;

[0018] FIG. 7 shows a dual-packer module with acoustic transducers mounted for contact with the borehole wall, according to embodiments;

[0019] FIG. 8 shows an acoustic transducer module for coupling acoustic sensors to a borehole wall, according to embodiments;

[0020] FIG. 9 shows an acoustic transducer module for coupling acoustic sensors to a borehole wall, according to further embodiments;

[0021] FIG. 10 shows a fluid sampling module having acoustic transducers coupled to a borehole wall, according to further embodiments;

[0022] FIG. 11 is a block diagram showing a general workflow for interpreting acoustic data from a wellbore, according to embodiments;

[0023] FIGs. 12a and 12b are flow charts showing steps of interpreting acoustic data, according to embodiments; and

[0024] FIG. 13 shows steps involved in interpreting ultrasonic data, according to embodiments.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0025] The particulars shown herein are by way of example and for purposes of illustrative discussion of the embodiments of the present invention only and are presented in the cause of providing what is believed to be the most useful and readily understood description of the principles and conceptual aspects of the present invention. In this regard, no attempt is made to show structural details of the present invention in more detail than is necessary for the fundamental understanding of the present invention, the description taken with the drawings making apparent to those skilled in the art how the several forms of the present invention may be embodied in practice. Further, like reference numbers and designations in the various drawings indicated like elements.

[0026] It has been found that by making and properly recording acoustic and/or micro-acoustic frequency measurements, additional information about the fluids, reservoir rocks and their state of stress can be learned. For example, the resonant period for acoustic pulses reverberating in the annulus interval will be sensitive to the bulk modulus of the fluid(s) in the interval, the compliance of the packers, and to the hoop strength of the borehole wall. Changes in fluid property (e.g. by influx of gas) or rock strength (e.g. due to tensile failure) are associated with observable changes in this period. Similarly, changes in viscosity of the fluid(s) or permeability of the borehole wall are associated with observable changes in attenuation of acoustic pulses.

[0027] FIG. 1 shows a downhole system for making acoustic measurements with a downhole fluid sampling tool, according to embodiments. Wireline logging system 100 is shown including multiple tools containing sensors for taking geophysical measurements. Wireline 103 is a power and data transmission cable that connects the tools to a data acquisition and processing system 105 on the surface. The tools connected to the wireline 103 are lowered into a well borehole 107 to obtain measurements of geophysical properties for the surrounding subterranean rock formation 110. The wireline 103 supports tools by supplying power to the tool string

101. Furthermore, the wireline 103 provides a communication medium to send signals to the tools and to receive data from the tools.

[0028] The tools, sometimes referred to as modules are typically connected via a tool bus 193 to telemetry unit 191 which is turn is connects to the wireline 103 for receiving and transmitting data and control signals between the tools and the surface data acquisition and processing system 105. Commonly, the tools are lowered to a particular depth of interest in the borehole and are then retrieved by reeling-in by the data acquisition and processing system 105. For sampling and testing operations, such as Schlumberger's MDT tool, the tool is positioned at location and data is collected while the tool is stationary and sent via wireline 103 to data acquisition and processing system 105 at the surface, usually contained inside a logging truck or logging unit (not shown).

[0029] Electronic power module 120 converts AC power from the surface to provide DC power for all modules in the tool string 101. Pump out module 130 is used to pump unwanted fluid, for example mud filtrate, from the formation to the borehole, so that representative samples can be taken from formation 110. Pump out module 130 can also be used to pump fluid from the borehole into the flowline for inflating packers in module containing inflatable packers. Pump out module 130 can also be configured to transfer fluid from one part element of the tool string to another. Hydraulic module 132 contains an electric motor and hydraulic pump to provide hydraulic power as may be needed by certain modules. Single-probe module 136 contains probe assembly 138 having a packer and telescoping backup pistons 140. Single-probe module 136 may also contain pressure gauges, fluid resistivity, and temperature sensors, and a pretest chamber (now shown). The probe module 136 also includes strain gauge and a high resolution CQG gauge. Examples of a fluid sampling system using probes and packers are depicted in U.S. Patent Nos. 4,936,139 and 4,860,581 where are incorporated by reference herein.

[0030] According to embodiments, dual-packer module 150 is provided with one ore more acoustic transducers for making acoustic measurements in connection with downhole fluid sampling and or testing. Dual-packer module 150 includes an upper inflatable packer element 152, lower packer element 154, valve body 160 and electronics 162. Inflatable packer elements 152 and 154 seal against the borehole wall 107 to isolate an interval of the borehole. Pumpout Module 130 inflates the packers with wellbore fluid. The length of the test interval (i.e., the distance between the packers) about 3.2 ft (0.98 m) and can be extended by inserting spacers between the packer elements. The area of the isolated interval of the borehole is about many orders of magnitude larger than the area of the borehole wall isolated by a probe such as probe 138. For fluid sampling, the large area results in flowing pressures that are only slightly below the reservoir pressure, which avoids or reduces phase separation for pressure-sensitive fluids such as gas condensates or volatile oils. In low-permeability formations, high drawdown usually occurs with the probe, whereas the fluid can be withdrawn from the formation using the dual-packer module 150 with minimum pressure drop through the larger flowing area. Dual-packer module 150 can be used for pressure transient testing, following a large-volume flow from the formation, the resulting pressure buildup has a radius of investigation of 50 to 80 ft (15 to 24 m). Similar to a small-scale drillstem test (DST), this type of testing offers advantages over conventional DST tests. It is environmentally friendly because no fluids flow to the surface, and it is cost effective because many zones can be tested in a short time. Dual-packer module 150 can also be used to create a micro-hydraulic fracture that can be pressure tested to determine the minimum in situ stress magnitude. The fracture

is created by pumping wellbore fluid into the interval between the inflatable packer elements. According to embodiments, acoustic transducer 156 is mounted on dual-packer module 150 are used to monitor the sampling and testing carried out with dual-packer module 150. Below dual-packer module 150 are one or more sample chamber units 170 for holding fluid samples collected downhole.

[0031] FIG. 2 shows further detail of a dual-packer module with an acoustic transducer, according to embodiments. Dual-packer module 150 includes upper inflatable packer element 152 and lower inflatable packer element 154. The upper packer element 152 includes inflatable member 242 which is securely mounted on rigid or semi-rigid mandrel section 240. The lower packer element 154 includes inflatable member 244 which is securely mounted on rigid or semi-rigid mandrel section 248. Between the two packer elements is an acoustic sensor element 210. Sensor element 210 includes an acoustic transducer 220 which is shown mounted on the exterior of mandrel section 246. Mandrel sections 240, 248 and 246 are centered in the borehole and parallel to the borehole axis when the packer elements are inflated. In this way, acoustic transducer can make measurements of acoustic energy in the annulus formed by the borehole wall, upper and lower packer elements and the mandrel. Acoustic transducer can also be used to actively produce acoustic energy for use in analysis as describe elsewhere herein. Acoustic transducer 220 is controlled by electronics 212 via electrical interconnect 214. The electronics 212 are used to activate transducer 220 to produce acoustic energy and/or make measurements of acoustic energy. Electronics 212 is controlled by and feeds data to other components and the surface via connection to tool bus 193. The combination of electronics 212 and aoustic transducer 220 is capable of forming a dynamic acoustic sensor and making pressure measurements at 1Hz sample rate recording continuously at an acoustic sample rate of at least 44.1kHz. According to certain embodiments, the acoustic transducer is capable of generating and measuring ultrasonic energy in addition to or instead of sonic energy. FIG. 2b is a cross-section view along the line X-X' of FIG. 2a. As shown there are multiple acoustic transducers 220, 222, 224 and 226 mounted around the exterior of mandrel section 246. By arranging the acoustic transducers in an array as shown, azimuthal information can be analyzed as is described in further detail herein. Also shown in FIG. 2b are toolbus 193 and fluid flowline 230. By providing an array of transducers azimuthally spaced apart transducers, multi directional data can be gathered. According to certain embodiments a directional sensor 250 is also provided as part of sensor element 210 so that the azimuthal position of the acoustic transducers is known in the well during measurement. Note that the directional sensor 250 could be located in a different module within the toolstring.

[0032] According to an embodiment, a simple measurement using acoustic transducer 220 is made in the annulus defined by the packer elements 242 and 244, mandrel section 246 and the borehole wall (not shown). The pressure is measured at 1Hz sample rate continuously upto 44.1kHz. For some applications it is sufficient to listen passively. However, additional measurements, for example, changes in the system response due to changes in interval pressure are improved by repeatedly generate broadband pressure pulses. The pressure pulses can be generated either with pressure relief valves, or with a piezoelectric source 252.

[0033] FIGs. 3a-3c show an acoustic sensor module forming part of a tool string, according to embodiments. Acoustic sensor module 310 shown in FIG. 3a has a plurality of acoustic transducers including acoustic transducers 320, 324 and 330 that are controlled by electronics 312 via electrical interconnections. The acoustic transducers 320 and 324 are positioned and designed for providing measurements of acoustic energy propagating in the fluid outside the tool body. Therefore, acoustic isolation is provided in the form of a floating mechanical connection with the tool, thereby greatly decoupling the tool vibrations form the transducers. In particular, the sensor housing is spring loaded (not shown). For transducers operating in ultrasonic frequencies, the sensors are mounted in a tungsten-rubber composite isolation material.

[0034] Electronics 312 is used to activate the acoustic transducers to produce acoustic energy and/or make measurements of acoustic energy. Electronics 312 is controlled by and feeds data to other components and the surface via connection to tool bus 193. Toolbus 193 is shown housed in electrical conduit 358. Tool joint 350 is shown between sensor module 310 and the module immediately above sensor module 310. At tool joint 350 the electrical conduit 358 connects to electrical conduit 356 from the module above. Also housed within conduits 356 and 358 are one or more power lines (not shown). Fluid flowline conduit 354 connected to fluid flowline conduit 352 also at tool joint 350. The tool fluid flow line allows the communication of fluid between the modules. For specific applications, for example, fluid connection is made to the formation, and the sample chambers have valves that connect the sample cylinder to the flowline. According to embodiments, acoustic transducer 330 is provided in acoustic and preferably fluid communication with fluid flowline conduit 354, such that measurements and analysis of the fluids flowing in the flowline can be made as described in further detail herein. Depending on the placement of the sensor module 310 within the tool string, different aspects of the tool, annular region, formation, and/or formation fluid can be analyzed acoustically.

[0035] FIG. 3b is a cross-section along the line X-X' shown in FIG. 3a. As shown, acoustic transducers 320 and 324 are mounted on mandrel section 342. The acoustic transducers are positioned in a recessed manner for protection. Also shown in FIG. 3b is fluid flowline conduit 354, electrical conduit 358 and tool bus 193. According to embodiments, FIG. 3c shows two further acoustic transducers 322 and 326 mounted at a different longitudinal position on mandrel section 324. Note that the transducers 322 and 326 are also in position perpendicular to the transducers 320 and 324 shown in FIG. 3b, thus forming an array of acoustic transducers. Also shown in FIG. 3c is fluid flowline conduit 354, electrical conduit 358 and tool bus 193.

[0036] According to embodiments, acoustic transducers 320, 322, 324 and 326 are excited by a continuous-wave voltage to probe annular region bounded by the annulus when acoustic sensor module 310 is positioned between two packers as in the arrangement shown in FIG. 2. The current response is recorded and the voltage-to-current ratio gives an electrical impedance measurement reflective of the acoustic properties of the enclosed fluid and the elasto-dynamic properties of the surrounding formation. The frequency is preferably swept through an appropriate bandwidth to capture a sufficient amount of data to determine material parameters such as acoustic velocity, acoustic attenuation, formation acoustic impedance, formation permeability.

[0037] According to further embodiments, a full-azimuthal-coverage ultrasonic array is provided in the packed-off section of tool such as Schlumberger's Modular Dynamics Tester tool (MDT) such that an image of the mechanical behaviour of the borehole can be made during a mini-frac job. Acoustic transducers 320, 322, 324 and 326 could be used for such an application alone, or additional spaced apart transducers can be provided to further improve azimuthal resolution. With a real-time image at 30 frames per second, quantitative observations of the deformation of the borehole wall during pump-up and the initiation of the fracture are made. Additionally, the location and orientation of the induced fracture is precisely determined.

[0038] FIG. 4 show two acoustic sensor modules near a pump out module, according to embodiments. Sensor module 410 is mounted above pump out module 440, and sensor module 460 is mounted below pump out module 440. Sensor module 410 includes an acoustic transducer 420 which is positioned to measure acoustic energy within fluid flowline 430. Electronics 412 is used to activate acoustic transducer 420 to produce acoustic energy and/or make measurements of acoustic energy within fluid flowing 430. Electronics 412 is controlled by and feeds data to other components and the surface via connection to a tool bus (not shown) housed within electrical conduit 432. Similarly, sensor module 460 includes an acoustic transducer 470 which is positioned to measure acoustic energy within fluid flowline 480. Electronics 462 is used to activate acoustic transducer 470 to produce acoustic energy and/or make measurements of acoustic energy within fluid flowing 480. Electronics 462 is controlled by and feeds data to other components and the surface via connection to a tool bus (not shown) housed within electrical conduit 482. Pump out module 440 includes check valve unit 442 and displacement unit 446. Displacement unit 446 in turn, includes an upper piston 448 and a lower piston 454. The pistons are rigidly attached to each other and are actuated up and down within displacement unit 446 by action of hydraulic fluid being alternatingly pumped into the upper and lower portions of the displacement unit. Fluid in fluid flowline 444 can be pumped in either direction by control of four check valves (not shown) within check valve unit 442 and upper conduit 450 and lower conduit 452.

[0039] In the arrangement shown in FIG. 4, the acoustic sensors modules 410 and 460 can be used to monitor tool performance. Specifically the sensor modules are in position to accurately monitor performance of pump out module 440. According to other embodiments, sensor modules 410 and 460 are used to detect phase change within the tool. By positioning two sensor modules, one on either side of the pump out module, phase breakout can be detected on the low pressure side of the pump out module and phase recombination can be detected at the high pressure side of the pump out module.

[0040] FIG. 5 shows a pump out module including acoustic transducers, according to embodiments. Pump out module 540 includes check valve unit 542 and displacement unit 546. Displacement unit 546 in turn, includes an upper piston 548 and a lower piston 554. The pistons are rigidly attached to each other and are actuated up and down within displacement unit 546 by action of hydraulic fluid being alternatingly pumped into the upper and lower portions of the displacement unit. Fluid in fluid flowline 544 can be pumped in either direction by control of four check valves (not shown) within check valve unit 542 and upper conduit 550 and lower conduit 552. Acoustic transducer 520 is positioned to measure acoustic energy within upper conduit 550, and acoustic transducer 522 is positioned to measure acoustic energy within lower conduit 552. Electronics 512 is used to activate acoustic transducers 520 and 522 to produce acoustic energy and/or make measurements of acoustic energy within conduits 550 and 552. Electronics 512 is controlled by and feeds data to other components and the surface via connection to a tool bus 193 housed within a electrical conduit (not shown).

[0041] In the arrangement shown in FIG. 5, the acoustic transducers 520 and 522 can be used to monitor tool performance just as the sensor modules in FIG. 4. The acoustic transducers 520 and 522 in an ideal position to monitor performance of pump out module 540. According to other embodiments, acoustic transducers 520 and 522 are used to detect phase change within the tool. Phase breakout can be detected on the low pressure side of the pump out module and phase recombination can be detected at the high pressure side of the pump out module.

[0042] FIG. 6 is a schematic diagram of a dual-packer module according to embodiments. Dual-packer module 610 includes upper packer element 152, lower inflatable packer element 154, valve body 650 and electronics body 680. Upper packer element 152 includes inflatable member 242 securely mounted to mandrel section 240. Also shown is tool fluid flowline section 630. Lower packer element 154 includes inflatable member 244 securely mounted to mandrel section 248, and tool fluid flowline section 632. Valve body 650 includes tool fluid flowline section 634. Inflate valve 654 controls fluid in inflate line 662 which inflates and deflates inflatable elements 242 and 244. Inflate pressure transducer 660 measures the pressure on inflate line 662. Interval valve 656 controls flow between the tool fluid flow line and interval flowline 664 which leads to interval inlet 666. Interval check valve 652 is provided between interval flowline and the exterior of valve body 650 in a location outside the interval. Pressure transducer 658 monitors fluid pressure in interval flow line 664. Acoustic transducer 620 is positioned as shown to make acoustic measurements on interval flow line 664. Also shown is electrical conduit 640 which houses both power lines and the tool bus (not shown). Bypass line 668 connects annular fluid above the upper packer with annular fluid below the lower packer.

[0043] FIG. 7 shows a dual-packer module with acoustic transducers mounted for contact with the borehole wall, according to embodiments. Packer element 752 includes inflatable packer member 742 attached to rigid mandrel 740. Two acoustic transducers 720 and 722 are mounted on the exterior of packer member 742 such that when packer member 742 is inflated, transducers 720 and 722 make firm contact with the borehole wall. Electronics 712 is used to activate acoustic transducers 720 and 722 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Electronics 712 is controlled by and feeds data to other components and the surface via connection to a tool bus 193. According to further embodiments, a directional sensor 750 is provided as part of packer element 752 so that the azimuthal position of the acoustic transducers is known in the well during measurement. According to yet further embodiments, additional acoustic transducers are positioned in a spaced apart manner about the outer most portion of inflatable member 742, such that the transducers contact the borehole wall upon inflation of member 742. Providing arrays of 4, 6, 8, 16 or greater numbers of spaced-apart transducers can be provided to increase azimuthal resolution. Note that this arrangement does not require the presence of the second packer (although a second packer is shown in FIG. 7), or a pressurized interval in order to perform tests on the formation. According to an embodiment, a single-packer system is designed to change the effective stress on the formation wall outside the packer by exerting force on the borehole wall. The spaced apart acoustic transducers are used to monitor changes in acoustic properties as a function of azimuth and effective stress.

[0044] According to other embodiments a second packer element 754 is provided which includes inflatable packer member 792 attached to rigid mandrel 740. Two acoustic transducers 770 and 772 are mounted on the exterior of packer member 792 such that when packer member 792 is inflated, transducers 770 and 772 make firm contact with the borehole wall. Electronics 762 is used to activate acoustic transducers 770 and 772 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Electronics 762 is controlled by and feeds data to other components and the surface via connection to a tool bus 193. According to embodiments, the acoustic transducers on one of the packers, for example at least one of the transducers 770 and 772 on packer element 675 is designed and controlled to act as an acoustic source, including an ultrasonic source, and the transducers in the other packer, for example transducers 720 and 722 on packer element 752 are designed and controlled to act as acoustic receivers. In this way, transmitted or “pitch-catch” type acoustic analysis is provided.

[0045] FIG. 8 shows an acoustic transducer module for coupling acoustic sensors to a borehole wall, according to embodiments. Acoustic transducer module 810 forms part of a wireline toolstring such as toolstring 101 in wireline system 100 as shown in FIG. 1. Acoustic module 810 includes extending arm member 836 and sensor pad 830 which makes firm contact with the borehole wall 107. Sensor pad 830 is actuated and held in place using cross link member 832. Mounted on pad 830 are two acoustic transducers 820 and 822. Electronics 812, via electrical lines 838, activates acoustic transducers 820 and 822 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Electronics 812 is controlled by and feeds data to other components and the surface via connection to a tool bus 193. Acoustic module 810 includes second extending arm member 846 and sensor pad 840 which makes firm contact with the borehole wall 107. Sensor pad 840 is actuated and held in place using cross link member 842. Mounted on pad 840 are two acoustic transducers 824 and 826. Electronics 812, via electrical lines 848, activates acoustic transducers 824 and 826 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Two further arms are included for a total of four arms. Sensor pad 884 is shown on which two acoustic transducers 880 and 882 are mounted. Note that transducers 820 and 822 are axially spaced apart along pad 830, and transducers 824 and 826 are axially spaced apart on pad 840. Providing an axial spacing can be useful in evaluating rock stress related information as is describe in further detail below.

[0046] FIG. 9 shows an acoustic transducer module for coupling acoustic sensors to a borehole wall, according to further embodiments. Acoustic transducer module 910 forms part of a wireline toolstring such as toolstring 101 in wireline system 100 as shown in FIG. 1. Acoustic module 910 is similar to module 810 shown in FIG. 8, except that there are extending arms on both top and bottom sides of the sensor pad. This arrangement allows the tool to move downward in the borehole without the need of closing the arms. Additionally, the pads are spring loaded to keep them extended and in contact with the formation. As shown, acoustic module 910 includes extending arm members 936 and 932, and sensor pad 930 which makes firm contact with the borehole wall 107. Sensor pad 930 is actuated and held in place using springs (not shown). Mounted on pad 930 are two acoustic transducers 920 and 922. Electronics 912, via electrical lines 938, activates acoustic transducers 920 and 922 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Electronics 912 is controlled by and feeds data to other components and the surface via connection to a tool bus 193. Acoustic module 910 also includes extending arm members 946 and 942, and sensor pad 940 which makes firm contact with the borehole wall 107. Pad 940 is actuated and held in place using springs (not shown). Mounted on pad 940 are two acoustic transducers 924 and 926. Electronics

912, via electrical lines 948, activates acoustic transducers 924 and 926 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Two further sensor pads are included for a total of four sensor pads, azimuthally spaced about the axis of the tool and the borehole. Pad 984 is shown on which two acoustic transducers 980 and 982 are mounted. Lower arm 972 is used in combination and upper arm (not shown) to position pad 984 against the borehole wall 107.

[0047] FIG. 10 shows a fluid sampling module having acoustic transducers coupled to a borehole wall, according to further embodiments. Fluid sampling module 1010 forms part of a wireline toolstring such as toolstring 101 in wireline system 100 as shown in FIG. 1. Sampling module 1010 is a dual-probe type, although the acoustic transducer could also be adapted to a single probe module. As shown, sensor module 1010 includes extending probe members 1030 and 1040. Probe member 1030 has a packer 1036 and probe member 1040 has a packer 1046. Each packer makes firm contact with the borehole wall when the probe members are extended. Each packer has a hollow center section for sampling fluid via a tube connected to the central section. Packer 1036 has mounted thereon acoustic transducer 1020, and packer 1022 has mounted thereon acoustic transducer 1022. When the probe members extend, the acoustic transducers thus make firm contact with the borehole wall 107. Electronics 1012 activates acoustic transducers 1020 and 1022 to produce acoustic energy and/or make measurements of acoustic energy transmitted through the formation rock. Electronics 1012 is controlled by and feeds data to other components and the surface via connection to a tool bus 193. Thus the arrangements shown in FIG. 10 allow for acoustic measurements to be made directly on the borehole wall during a fluid sampling operation. By providing acoustic transducers that are in contact with the borehole wall, as shown in and described with respect to FIGs. 7-10, improved shear wave acoustic energy can be both imparted into the formation and detected from the formation.

[0048] According to further embodiments, acoustic transducers (operating in the sonic and/or ultrasonic range) are used to make multi-channel measurements sensitive to variations in the acoustic response as a function of azimuthal orientation relative to the borehole axis. The transducers can be mounted directly on the packers, such as shown in FIG. 7, or on arms such as shown in FIGs. 8 and 9, in order to press the transducers into contact with the formation. Making firm contact with the formation significantly improves coupling, as well as providing for direct measurement of formation shear slowness.

[0049] According to embodiments, arrays of axially spaced apart receivers, placed in contact with the borehole wall, as shown in FIG. 7-10, at multiple azimuths are used to determine propagation speed and attenuation for signals passing across the array, without a strict requirement for control or synchronization of the sources of the signals.

[0050] According to various embodiments, methods and techniques of analyzing acoustic measurements will now be described in further detail. Acoustic measurements made with the transducers described are useful in a wide variety of ways. A simple method for obtaining useful information is passively listening for sounds or changes in sound properties indicative of conditions of interest. For example, sounds or changes in sound properties associated with rock breaking or deforming are detected. The analysis includes detecting sounds or changes in sound properties associated with changes in fluid flow dynamics, such as changes from multiphase to single phase, or the reverse. Other detectable changes include changes from gas to liquid, or the reverse; influx of sand; and presence or absence of fluid flowing, which is a common question when pumping compressible fluids. Sounds or changes in sound properties are also used as a diagnostic of the quality of tool performance, such as the sound of pumps running, valves opening and closing, packers slipping or failing to seal, the opening and closing of sample bottles.

[0051] According to certain embodiments, timely detection of failure conditions enables the development of methods to remediate the conditions as they occur. For example, the detection of sand entering the flow lines might enable remediation by various means such as reducing the pump rate, reversing the flow, or releasing a burst of cleansing flow.

[0052] The addition of sonic and/or ultrasonic sensors to a dual-packer module such as shown in FIGs. 1, 2, 6 and 7, significantly increases the tools ability to determine properties of the rock formations and formation fluids. In particular, the transducer measurements provide for a determination of how the properties of this system vary when changes are made in the state of one or more conditions subject to active control. Such conditions include, for example, borehole pressure and/or the presence and concentration of treatment fluids. The resonant period for acoustic pulses reverberating in the interval are sensitive to the bulk modulus of the fluid(s) in the interval, to the compliance of the packers, and to the hoop strength and permeability of the borehole wall. Changes in fluid property (e.g. by influx of gas) or rock strength (e.g. due to tensile failure) can be associated with observable changes in this period. Similarly, changes in viscosity of the fluid(s) or permeability of the borehole wall can be associated with observable changes in attenuation of acoustic pulses. Measured changes in sound velocity or attenuation depend upon average properties throughout the packed-off interval thereby complementing and constraining measurements made by other, more local sensors.

[0053] Changes in properties of the borehole wall are induced, for example, by changes in hydrostatic pressure and/or the introduction of acid or other active chemicals into the packed-off interval. According to embodiments, such changes are monitored by monitoring speed and attenuation of the reverberant pressure transients.

[0054] According to certain embodiments, measurements made at various known or well understood conditions are used to calibrate acoustic logs made at other times under conditions that are not well-matched to production conditions or which require estimation of one or more auxiliary parameters. For example, estimates of fracture permeability for natural fracture systems can be estimated from sonic logs by measuring attenuation of Stoneley waves as in the Schlumberger STPerm service performed using a sonic tool such Schlumberger's Sonic Scanner. It is known that this permeability changes when borehole pressure (and therefore effective stress on the formation) changes. Since logs are normally run when borehole pressures are higher than formation pressures (i.e. overbalanced) while production occurs with borehole pressures lower than formation pressures (i.e. underbalanced) the log-based estimates of permeability can be adjusted to account for the change in effective stress. The amount of change depends upon local properties of the formation. By measuring the Stoneley attenuation in the packed interval at a range of fluid pressures, according to embodiments, an improved calibration of the relationship between the log-based values and the values during actual production is provided. Similarly, an adjustment for the presence of mudcake must be made in calculating the log-based values. By recording the changes in Stoneley attenuation as flow from the formation into the tool reduces the mudcake, an improved ability to compensate for this effect in the entire logged zone is provided.

[0055] It is known that fractures in the rock matrix near the wellbore are associated with anisotropy in the elastic tensors governing sound propagation through that rock matrix. According to embodiments, providing acoustic transducers in the packers such as shown in FIG. 7, monitoring of the development of that anisotropy as a function of time and borehole pressure is provided.

[0056] In a single-packer system designed to change the effective stress on the formation wall outside the packer and to monitor changes in acoustic properties as a function of azimuth and effective stress, the system response tends to have the symmetries of the local stress field. In particular, in a vertical well, the system has mirror symmetry about the vertical planes containing the minimum and maximum horizontal stresses. Supposing that we make a tool with sufficient rotational symmetry, these principal directions will therefore be observable whenever the two principal horizontal stresses are unequal. For example, in the arrangement shown in FIG. 7, the upper packer can include four azimuthally equal spaced receivers, and the lower packer can include four azimuthally equal spaced transmitters. According to further embodiments, 8 equally spaced transmitters and 8 equally spaced receivers are provided so as to enable an evaluation of quadrapole modes. By observation the changes in acoustic behavior that result from changes in packer pressure (hence, in effective stress) analysis of rock strength parameters is provided. See, e.g., T. Bratton, V. Bricout, R. Lam, T. Plona, B. Sinha, K. Tagbor, and A. Venkitaraman, and T. Borbas, "Rock Strength Parameters From Annular Pressure While Drilling and Dipole Sonic Dispersion Analysis," SPWLA Annual Logging Symposium, June 6–9, 2004, which is incorporated by reference herein. Velocity measurements can be made as pressure is cycled up, and back down. This could be done in large pressure cycles, or in very small pressure cycles, at any pressure along the larger cycle, to provide a more complete characterization of the static and dynamic rock moduli. See, e.g. Plona, T.J. and Cook, John M., "Comparison of static and dynamic moduli in Castlegate sandstone", SCR Scientific Report, SCR/SR1994/038/IGM/C, November 3, 1994, which is incorporated by reference herein. Additionally, this information can be correlated with the occurrence of the stress-induced fracture, which is a definite indicator of exceeding local tensile strength.

[0057] The extraction of derivatives of propagation speeds as a function of stress enables the determination of hyperelastic constants characterizing the rock, for example as in Sinha, B.K., 1996, "Estimation of formation nonlinear constants by sonic measurements while changing borehole pressures," 66th Annual Internat. Mtg., Soc. Expl. Geophys., 118-121, which is incorporated by reference herein.

[0058] Ultrasonic Doppler measurement of fluid velocity enable observation and mapping of the influx of borehole fluid into a propagating fracture and the back-flow when pumping pressure is relieved.

[0059] FIG. 11 is a block diagram showing a general workflow for interpreting acoustic data from a wellbore, according to embodiments. Downhole sensors 1110 and downhole electronics 1112 are preferably acoustic transducers and downhole electronics such as shown and described with respect to in FIGs. 1-10. Analog or digital telemetry arrow 1114 represents the transmission of the measurement data to the surface, such as via tool bus 193, telemetry unit 191, and wireline 103 to system 105 shown and described with respect to FIG. 1. Surface playback 1116 takes place on the surface and can either by live by human interpreter 1150, such as an engineer or other analyst in the wireline truck or wireline unit, or can be recorded and played back to an engineer or analyst either locally or in a remote location. The human interpreter 1150 preferably listens for sounds or changes in sound properties that tend to indicate conditions that are of interest for the particular application. For example, the human interpreter can be listening to the audio signal for signs of a fluid phase change, sand entry, rock fracturing, and/or the movement or slippage in the packers. Also shown in FIG. 11 is another method of interpreting the data using display or other visual techniques. Low sampling rate data 1130 such as pressure, flow rate, etc. which is conventionally measured and recorded during sampling and testing is combined with audio sampling rate sound pressure data 1132, for example made by transducers and electronics as shown and described with respect to FIGs. 1-10. The data is combined in audio-annotated graphs 1140 which can take the form, for example as is common in MP3 sound editing software that displays a visualization of the acoustic data. The combined graphs can then be viewed by the human interpreter 1150 who will visually analyzes the audio-annotated graphs for signs that indicate conditions that are of interest for the particular application. According to embodiments the techniques shown in FIG. 11 can be used to evaluate rock fractures induced by pumping and increasing pressure in the annulus of a packed off region. According other embodiment, the techniques shown in FIG. 11 can be used to monitor tool performance, for example monitoring pump performance, monitoring valves opening and closing and monitoring other moving parts within the tool. In another example, the techniques shown in FIG. 11 are used to detect phase change within tool. Using the arrangements shown in FIG. 4 and/or FIG. 5, phase breakout can be detected at low pressure side of the pump, and phase recombination can be detected at high pressure side of the pump.

[0060] FIGs. 12a and 12b are flow charts showing steps of interpreting acoustic data, according to embodiments. In step, 1210 uniform repeated acoustic energy pulses or chirps are generated. According to embodiments, the repeated pulse or chirp is caused by actuating the acoustic transducers to generate acoustic energy, as described with respect to FIGs. 2-10. According to further embodiments, the pulses are caused by opening or closing a valve or modifying a valve such as interval valve 656 that controls flow between the tool flow line and interval flowline 664 as shown in and described with respect to FIG. 6. According to yet further embodiments, the acoustic energy is caused by a pump, such as in the displacement unit 446 in pump out module 440 shown in and described with respect to FIG. 4. According to further embodiments, the acoustic transducers shown in and described with respect to FIGs. 1-10 are capable of generating cross-dipole acoustic energy. For example, in the arrangement shown in FIG. 2b, transducers 222 and 226 could be activated simultaneously with opposite polarity, to provide a dipole source. Similarly, the other pair of transducers 220 and 224 can act as another dipole source. Both pairs together provide a cross-dipole source by alternating the pairs. In step 1214, the audio-rate sound pressure information is recorded. This is accomplished, for example by surface data acquisition and processing system 105 as shown in and described with respect to FIG. 1. In step 1218, a delayed median or other reference trace is subtracted from the recorded data. The reference trace subtraction enhances the ability to detect see slight changes or drifts. The reference trace can be an average of a number of past traces, such as 10, 20 or 100 prior traces. For further detail in analyzing the sonic and ultrasonic waveforms, see, U.S. Patent No. 5,859,811, which is incorporated by reference herein. In step 1230, the difference waveforms are displayed to a visually. One example of a visual display is as a variable density log (VDL) which is commonly used, for example with cement logs. According to alternative embodiments, in step 1220 a parametric model can be fit to the recorded audio-rate waveform to estimate or determine parameters of interest. Preferably, in step 1220, a physics-based parametric model used which is parameterized with variables of interest such as fluid type, fracture size, temperature, pressure, and packer volume. The model generates synthetic waveforms based on the parameters. The parameters are then changed such that the synthetic waveform fits or suitably matches the recorded waveforms. The parameters are associated, in step 1224 with changing conditions in the acoustic signal such as changing reflection period, number of reflections, reflection amplitude decay in the time domain, and Q of resonance in the frequency domain.

[0061] FIG. 12b shows various steps for interpreting the changing waveforms (if viewed as a VDL) or changing parameters (according to a parametric model). In steps 1240 and 1242 an interpretation of the changing condition is made. For example, in step 1140 if there is a decrease of reflection period, this suggests either a decrease in volume (e.g. deflection of packer), or a replacement of some fluid in the volume by fluid with lower sound speed (e.g. gas fraction increase). Whereas in step 1242, if there is an increase in the reflection period, this suggests an increase in volume (e.g. deflection of packer), or replacement of some of the fluid in the volume by fluid with lower soundspeed (e.g. gas fraction decrease). Preferably, the interpretations in steps 1240 and 1242 take in consideration the application from which the data has been gathered. For example, if the pressure in the annulus is being increased through pumping into the interval, then an increase in reflection period in step 1242 is associated with an increase in the volume. It has been found for the many applications described herein, the velocity of the fluid, v_{fluid}, can be approximated using the following equation:

$$v_{fluid} = \sqrt{\frac{\text{bulk modulus}}{\text{density}}}$$

In step 1244, the opening of a fracture is associated with an increased decay (lower Q) of resonant reverberation. In step 1246, the development of a gas cap is associated with a new reflection from the liquid/gas interface. According to another embodiment fluid properties of the annulus can be monitored with sensors positioned inside the tool body and not directly acoustically exposed to the annular fluid. For example acoustic transducer 620 in FIG. 6 could be used to make the measurements which are interpreted using the techniques shown in and described with respect to FIGs 12a and 12b.

[0062] FIG. 13 shows steps involved in interpreting ultrasonic data, according to embodiments. In step, 1310 uniform repeated ultrasonic energy pulses or chirps are generated. The repeated pulses or chirps are caused by actuating the acoustic transducers to generate acoustic energy, as described with respect to FIGs. 2-10. In step 1314, the ultrasonic (pulse-echo) pressure information is recorded. This is accomplished, for example by surface data acquisition and processing system 105 as shown in and described with respect to FIG. 1. In step 1318, a delayed median or other reference trace is subtracted from the recorded data, thereby enhancing the ability to detect see slight changes or drifts. The reference trace can be an average of a number of past traces, such as 10, 20 or 100 prior traces. In step 1330, the difference waveforms are displayed to a visually, for example using a variable density log (VDL). According to alternative embodiments, in step 1320 a parametric model can be fit to the recorded ultrasonic waveform to estimate or determine parameters of interest, as in step 1220 of FIG. 12a. The parameters are associated, in step 1324 with changing conditions in the acoustic signal such as changing reflection period and the number of reflections. The development of a gas cap is detected in step 1340. Since the energy is ultrasonic, the development of the gas cap is not evident until fluid between the transducer and target is affected. In step 1342, the interpretations are compared with sonic data interpreted, for example, using the techniques shown in and described with respect to FIGs. 12a and 12b. By comparing the ultrasonic data, which is sensitive to local properties, with lower frequency sonic data, which is sensitive to average fluid properties, measurements to improve detection of inhomogeneity of fluid can be made. For example, gas entering in location remote from ultrasonic transducers can be determined if gas is detected by the sonic data but not the ultrasonic data.

[0063] According to embodiments, stress-related rock properties can be evaluated by detecting induced fractures in the formation rock. With a dual packer arrangement, the pressure in the annulus is increased to induce a fracture, such as in a microhydraulic fracturing test. Acoustic transducers are deployed against the borehole wall as shown in FIGs. 7-10. By making acoustic (including ultrasonic) measurements before and during the rock fracturing, the minimum stress direction can be evaluated. According to an embodiment a process is used analogous to that described in U.S. Patent No. 6,510,389, (hereinafter “the ‘389 patent”) incorporated herein by reference. Although in the ‘389 patent it is assumed that measurements will be made in an unchanging stress environment with a moving tool, the same analysis is used only the tool is stationary and the rock is fracturing. Specifically, a process shown in and described with respect to FIG. 1 of the ‘389 patent is carried out for successive acoustic measurements made while incrementing the fluid pressure in the annulus instead of incrementing the depth. Although ultrasonic-range transducers are primarily discussed in the ‘389 patent, according to present embodiments, sonic frequency transducers can also be used as the scale of measurement is increased.

[0064] For increasing azimuthal resolution, larger numbers of acoustic receivers should be provided. For example 8 or 16 or greater numbers of acoustic receivers can be provided in a azimuthally spaced apart manner for each of the embodiments shown in FIGs. 1-10. For example, arrangements of transmitter and receiver arrays such as shown in US. Patent No. 6,678,616, incorporated by reference herein (hereinafter “the ‘616 patent”), can be used. In particular arrays arrangements shown in FIGs. 10A-10D of the ‘616 patent can be used with the embodiments shown in and described with respect to FIGs. 1-10 herein. Much of the teaching of the ‘389 patent and the ‘616 patent applies to embodiments of the current invention for evaluating stress related rock properties. However, it has been found that by making measurement during the changes in stress, significantly improved evaluations can be made. For example, FIGS. 12A-12E of the ‘389 patent are variable density logs showing compressional arrival as a function of time and azimuth at a fixed source-receiver spacing of 12 cm for five different stress levels from Stress Test 1: 0 Mpa; 3 Mpa; 9 MPa; 13 MPa; and 19 Mpa, respectively. The data was gathered from tests performed while changing stress on rock samples on the surface. However, according to embodiments of the present invention, such evaluations can be made in-situ downhole. The stress changes may also occur due to other effects induced by pumping activity. For example, the stress changes can be caused by replacement of liquid by gas (or vice versa) in the pore space of the formation between the transmitters and receivers.

[0065] For further detail on sonic logging and interpretation, particularly relating to Stonely wave properties and their dependence on fluid properties, rock properties, and state of stress, see the following: Burns, D.R. and Cheng, C.H., "Determination of In-Situ Permeability from Tube Wave Velocity and Attenuation" SPWLA Twenty-Seventh Annual Logging Symposium, KK (Jun. 9-13, 1986); US Patent 4,797,859; and Co-pending U.S. Patent Application Serial No. 11/691,071 all of which are incorporated by reference herein. For theoretical and lab studies in geomechanics and stress-induced changes in acoustic properties, see: B.K. Sinha, P. Papanastasiou and T.J. Plona, "Influence of borehole overpressurization and plastic yielding on the borehole Stoneley and flexural dispersions", J. of Geophys. Res., vol.104(B7), pp. 15,451-15,459, 1999; Winkler, K.W., "Azimuthal velocity variations caused by borehole stress concentrations", J. Geophys. Res., 101, p.8615-8621, 1996; Winkler, K.W., "Acoustic evidence of mechanical damage surrounding stressed boreholes", Geophysics, 62, p16-22, 1997; and Plona, T. J. & Cook, J. M. 1995. "Effects of stress cycles on static and dynamic Young's moduli in Castlegate sandstone" Daemen, J.J.K. & Schulz, R. A. (ed.) Proceedings of the 35th U. S. Symposium on Rock Mechanics. Balkema, Rotterdam, 155-160., all of which are incorporated by reference herein.

[0066] According to other embodiments, the stress-related information can be evaluated using measurements in the annulus, but not in contact with the borehole wall, as shown in and described with respect to FIGs. 1-6.

[0067] Whereas many alterations and modifications of the present invention will no doubt become apparent to a person of ordinary skill in the art after having read the foregoing description, it is to be understood that the particular embodiments shown and described by way of illustration are in no way intended to be considered limiting.

Further, the invention has been described with reference to particular preferred embodiments, but variations within the spirit and scope of the invention will occur to those skilled in the art. It is noted that the foregoing examples have been provided merely for the purpose of explanation and are in no way to be construed as limiting of the present invention. While the present invention has been described with reference to exemplary embodiments, it is understood that the words, which have been used herein, are words of description and illustration, rather than words of limitation. Changes may be made, within the purview of the appended claims, as presently stated and as amended, without departing from the scope and spirit of the present invention in its aspects. Although the present invention has been described herein with reference to particular means, materials and embodiments, the present invention is not intended to be limited to the particulars disclosed herein; rather, the present invention extends to all functionally equivalent structures, methods and uses, such as are within the scope of the appended claims.

CLAIMS

What is claimed is:

1. A system for measuring acoustic signals in an annular region comprising:

a tool housed in a tool housing for deployment downhole in a borehole;

a downhole pumping system mounted within the tool housing and adapted to pump fluid between the tool and an annular region defined by at least the tool housing and a wall of the borehole; and

an acoustic transducer mounted on the tool adapted to be in acoustic communication primarily with the annular region.

2. A system according to claim 1 further comprising a first and second member designed and positioned to seal the region between the tool housing and the borehole wall such that the annular region is defined by the tool housing, the borehole wall, and the first and second members.

3. A system according to claim 2 wherein the first and second members are expandable packers attached to the tool and making contact with the borehole wall when deployed.

4. A system according to claim 1 wherein the transducer is isolated from the tool housing so as to reduce acoustic communication from the tool housing to the transducer.

5. A system according to claim 1 further comprising a source for generating acoustic energy which propagates into the annulus such that the acoustic transducer can measure part of the acoustic energy propagating within the annulus.

6. A system according to claim 5 wherein the source for generating acoustic energy is the acoustic transducer.

7. A system according to claim 5 wherein the source for generating acoustic energy is a second acoustic transducer.

8. A system according to claim 5 wherein the source for generating acoustic energy is a valve on a flowline operable such that actuating the valve causes significant acoustic energy to travel into the annular region.

9. A system according to claim 5 wherein the source for generating acoustic energy is a pump.

10. A system according to claim 5 wherein the source is capable of generating energy that propagates asymmetrically into the annular region.

11. A system according to claim 10 wherein the source is capable of generating cross-dipole energy into the annular region.

12. A system according to claim 1 wherein the transducer operates in an ultrasonic range.

13. A system according to claim 12 wherein measurements from the transducer in the ultrasonic range are analyzed such that deformation of the borehole wall can be evaluated.

14. A system according to claim 1 further comprising a second acoustic transducer mounted on the tool adapted to be in acoustic communication primarily with the annular region.

15. A system according to claim 14 further comprising a third acoustic transducer mounted on the tool adapted to be in acoustic communication primarily with the annular region, wherein the acoustic transducers are azimuthally spaced apart.

16. A system according to claim 1 further comprising a second acoustic transducer mounted on the tool body not primarily in acoustic communication with the annular region.

17. A system according to claim 16 further comprising a processor for combining measurements from the second acoustic transducer with measurements from the acoustic transducer primarily in acoustic communication with the annular region such that acoustic energy from within the tool body can be substantially reduced from acoustic energy measurement of the annular region.

18. A method for measuring acoustic signals in an annular region comprising the steps of:

positioning a downhole tool housing in a borehole;

pumping fluid between the tool housing and the annular region defined by at least an outer surface of the tool housing and a borehole wall; and

measuring acoustic energy propagating within the annular region.

19. A method according to claim 18 further comprising the step of sealing the annular region such that the annular region is a volume bounded by a first sealing member, a second sealing member, the outer surface of the tool housing, and the borehole wall.

20. A method according to claim 18 wherein the step of pumping includes pumping fluid from within the tool housing into the annular region thereby significantly increasing the fluid pressure in the annular region.

21. A method according to claim 20 wherein a rock fracture occurs as a result of the increase in fluid pressure in the annular region.

22. A method according to claim 21 further comprising the step of evaluating the rock fracture from the measured acoustic energy traveling within the annular region.

23. A method according to claim 18 further comprising generating acoustic energy which propagates into the formation rock such that the acoustic transducer can measure part of the acoustic energy propagating in the rock.

24. A method according to claim 23 wherein the acoustic energy is generated with the acoustic transducer.

25. A method according to claim 23 wherein the acoustic energy is generated with a second acoustic transducer.

26. A method according to claim 23 wherein the acoustic energy is generated by actuating a valve on a flowline.

27. A method according to claim 19 wherein the step of pumping includes pumping fluid from within the annular region to the tool housing thereby causing fluid to flow into the annular region from a rock formation behind the borehole wall.

28. A method according to claim 27 further comprising the step of evaluating properties of the fluid flowing into the annulus from the formation using the measured acoustic energy propagating within the annulus.

29. A method according to claim 28 wherein the evaluation of properties of the fluid include at least one condition selected from the group consisting of: an onset of gas flowing into the annulus, an onset of liquid flowing into the annulus, an onset of water flowing into the annulus, and an onset of sand flowing into the annulus.

30. A method according to claim 18 further comprising the step of analyzing the measured acoustic energy.

31. A method according to claim 30 wherein the step of analyzing includes detecting at least one condition selected from a group consisting of: changes in reverberation delay time; changes in amplitude decay, reflection period, and number of reflections.

32. A method according to claim 31 wherein the at least one condition indicates changes in the fluid composition of the annular region.

33. A method according to claim 31 wherein the at least one condition indicates changes in the borehole wall condition.

34. A method according to claim 18 further comprising the step of transmitting data representing the measured acoustic energy to the surface.

35. A method according to claim 34 further comprising the step of displaying a visual representation based at least in part on the data representing the measured acoustic energy.

36. A method according to claim 18 wherein the acoustic energy measured is ultrasonic acoustic energy.

37. A method according to claim 18 wherein both ultrasonic acoustic energy and sonic acoustic energy are measured.

38. A method according to claim 37 further comprising the step of comparing the measured ultrasonic energy with the measured sonic energy.

39. A system for measuring acoustic signals on a borehole wall comprising:

a downhole tool housed in a tool housing for deployment downhole in a borehole;

a downhole pumping system mounted within the tool housing; and

an acoustic transducer deployable to be in acoustic communication primarily with the rock formation.

40. A system according to claim 39 wherein the pumping system is adapted to pump fluid between the tool and a subterranean rock formation near the tool when deployed in a borehole.

41. A system according to claim 39 further comprising a first expandable packer member mounted on the tool housing and designed and positioned contact the borehole wall when expanded.

42. A system according to claim 41 further comprising a second expandable packer member mounted on the tool housing and designed and positioned contact the borehole wall when expanded, and wherein the first and second packer

members, when expanded act to seal the region between the tool housing and the borehole wall such that an annular region is defined by the tool housing, the borehole wall, and the first and second packer members.

43 A system according to claim 42 wherein the pumping system is adapted to pump fluid between the tool and the annular region.

44. A system according to claim 41 wherein the acoustic transducer is mounted and positioned on the expandable packer member such that the acoustic transducer makes contact with the borehole wall when the packer member is expanded.

45. A system according to claim 44 further comprising a second and third acoustic transducer mounted and positioned on the expandable packer member such that the second and third transducers make contact with the borehole wall when the packer member is expanded, and where said acoustic transducer and said second and third acoustic transducers are azimuthally spaced apart on the packer member.

46. A system according to claim 39 further comprising an extendable fluid probe designed and mounted on the tool housing such that the fluid prove makes contact with the borehole wall when extended and is in fluid communication with the pumping system such that fluid can be pumped between the fluid probe and the rock formation.

47. A system according to claim 39 further comprising a second acoustic transducer mounted within the tool so as not to be primarily in acoustic communication with the rock formation

48. A system according to claim 47 further comprising a processor for combining measurements from the second acoustic transducer with measurements from the acoustic transducer primarily in acoustic communication with the rock formation such that acoustic energy from within the tool body can be substantially reduced from acoustic energy measurement of the rock formation.

49 A system according to claim 39 further comprising an extendable mechanical member and a contact member on which the acoustic transducer is mounted such that the acoustic transducer is in acoustic communication primarily with the rock formation when the mechanical member is extended.

50. A system according to claim 49 wherein the extendable mechanical member is a mechanical arm and the contact member is a contact pad.

51. A system according to claim 50 further comprising second and third mechanical arms and second and third contact pads, wherein each contact pad has at least one acoustic transducer mounted thereon so as to make acoustic communication primarily with the rock formation when the mechanical arm is extended.

52. A system according to claim 39 further comprising a processor for detecting a change in fluid flowing in the rock formation induced by the pumping of fluid between tool and the rock formation.

53. A system according to claim 39 further comprising a processor adapted to evaluating one or more properties of the rock formation based on measured acoustic energy traveling through the rock formation.

54. A system according to claim 53 wherein a property of the rock formation that is to be evaluated relates to rock-strength sensitivity to changes in stress, and the evaluation is based at least in part on changes in velocity of acoustic energy propagating through the rock.

55. A system according to claim 53 wherein a property of the rock formation that is to be evaluated relates to a minimum stress direction of the rock formation, and the evaluation is based at least in part on detected induced fractures in the formation rock.

56. A system according to claim 39 wherein the acoustic transducer is designed to primarily operate at frequencies greater than about 500 Hz.

57. A system according to claim 56 wherein the acoustic transducer is designed to primarily operate at frequencies greater than about 1kHz.

58. A system according to claim 39 further comprising electronics adapted to sample signals form the acoustic transducers at a sampling rate of greater than 60 Hz.

59. A system according to claim 58 wherein the sampling rate of greater than 1kHz.

60. A system according to claim 40 further comprising a downhole fluid sample collection system adapted to collect at least one sample of formation fluid in a sample chamber.

61. A system according to claim 40 further comprising an extendable fluid probe member having a fluid flowline that can be in fluid communication with the rock formation when the probe member is extended, wherein the acoustic transducer is mounted such that the acoustic transducer contacts the borehole wall when the probe member is extended.

62. A system according to claim 61 further comprising a packer mounted on the probe member, wherein the acoustic transducer is mounted on the packer.

63. A method for measuring acoustic signals on a borehole wall comprising the steps of:

positioning a downhole tool in a borehole;

pumping fluid with a pumping system housed within the tool;

positioning an acoustic transducer such that it is acoustic communication primarily with the borehole wall; and

measuring acoustic energy propagating within the rock formation using the acoustic transducer.

64. A method according to claim 63 further comprising the step of sealing an annular region such that the annular region is a volume bounded by a first sealing member, a second sealing member, the outer surface of a portion of the downhole tool, and the borehole wall.

65. A method according to claim 64 wherein the first and second sealing members are expandable packers attached to the tool and making contact with the borehole wall when deployed.

66. A method according to claim 65 wherein the acoustic transducer is mounted and positioned on one of the expandable packers such that the acoustic transducer makes contact with the borehole wall when the packer member is expanded.

67. A method according to claim 66 further comprising a second, third and fourth acoustic transducer mounted and positioned on said one of the expandable packers such that the second, third and fourth transducers make contact with the borehole wall when the packer member is expanded, and where said acoustic transducer and said second, third and fourth acoustic transducers are azimuthally spaced apart on the packer member.

68. A method according to claim 63 further comprising the step of extending a mechanical arm and a contact member on which the acoustic transducer is mounted so as to position the acoustic transducer in acoustic communication primarily with the rock formation.

69. A method according to claim 63 further comprising the step of detecting a change in fluid flowing in the rock formation induced by the pumping.

70 A method according to claim 63 further comprising the step of evaluating one or more properties of the rock formation based on measured acoustic energy traveling through the rock formation.

71. A method according to claim 70 wherein a property of the rock formation that is to be evaluated relates to rock-strength sensitivity to changes in stress, and the evaluation is based at least in part on changes in velocity of acoustic energy propagating through the rock.

72. A method according to claim 70 wherein a property of the rock formation that is to be evaluated relates to a minimum stress direction of the rock formation, and the evaluation is based at least in part on detected induced fractures in the formation rock.

73. A method according to claim 63 wherein said step of measuring acoustic energy includes measuring ultrasonic frequency acoustic energy.

74. A method according to claim 63 further comprising the step of combining measurements from an acoustic transducer located within the tool body with measurements from the acoustic transducer primarily in acoustic communication with the rock formation such that acoustic energy from within the tool body can be substantially reduced from acoustic energy measurement of the rock formation.

75. A method according to claim 63 further comprising the step of extending a fluid probe member having a fluid flowline such that the fluid flowline is in fluid communication with the rock formation when the probe member is extended, and wherein the acoustic transducer is mounted such that the acoustic transducer contacts the borehole wall when the probe member is extended.

76. A system for measuring acoustic signals on a borehole wall comprising:

a downhole tool housed in a tool housing for deployment downhole in a borehole; and

an acoustic transducer deployable to be in acoustic communication primarily with the rock formation and operable primarily at frequencies above about 500 Hz.

77. A system according to claim 76 further comprising a pumping system adapted to pump fluid between the tool and a subterranean rock formation near the tool when deployed in a borehole.

78. A system according to claim 76 further comprising a first expandable packer member mounted on the tool housing and designed and positioned contact the borehole wall when expanded.

79. A system according to claim 76 further comprising an extendable mechanical member and a contact member on which the acoustic transducer is mounted such that the acoustic transducer is in acoustic communication primarily with the rock formation when the mechanical member is extended.

80. A system according to claim 76 further comprising a processor adapted to evaluate at least one property of fluid in the rock formation based on measured acoustic energy traveling through the rock formation.

81. A system according to claim 76 further comprising a processor adapted to evaluate one or more properties of the rock formation based on measured acoustic energy traveling through the rock formation.

82. A system according to claim 81 wherein a property of the rock formation that is to be evaluated relates to rock-strength sensitivity to changes in stress, and the evaluation is based at least in part on changes in velocity of acoustic energy propagating through the rock.

83. A system according to claim 81 wherein a property of the rock formation that is to be evaluated relates to a minimum stress direction of the rock

formation, and the evaluation is based at least in part on detected induced fractures in the formation rock.

84. A system according to claim 76 wherein the acoustic transducer is designed to primarily operate at frequencies greater than about 1 kHz.

85. A system according to claim 77 further comprising an extendable fluid probe member having a fluid flowline that can be in fluid communication with the rock formation when the probe member is extended, wherein the acoustic transducer is mounted such that the acoustic transducer contacts the borehole wall when the probe member is extended.

86. A system according to claim 85 further comprising a packer mounted on the probe member, wherein the acoustic transducer is mounted on the packer.

87. A system for measuring acoustic signals within a downhole tool comprising:

a downhole tool housed in a tool housing for deployment downhole in a borehole;

a downhole pumping system mounted within the tool housing and adapted to pump fluid between the tool and a subterranean rock formation near the tool when deployed in a borehole; and

an acoustic transducer mounted within the tool housing.

88. A system according to claim 87 further comprising a processing system adapted to record and playback audio signals representing measurements made by the acoustic transducer to a human interpreter such that the human interpreter can monitor conditions within the tool.

89. A system according to claim 88 wherein the conditions within the tool include the condition of moving parts within the tool.

90. A system according to claim 89 wherein the moving parts includes valves within the tool.

91. A system according to claim 89 wherein the moving parts includes at least part of the downhole pumping system.

92. A system according to claim 87 further comprising a processing system adapted to generate audio-annotated graphs based in part on measurements made by the acoustic transducer such that a human interpreter viewing the graphs can monitor conditions within the tool.

93. A system according to claim 87 wherein the acoustic transducer is positioned so as to be in acoustic communication with the pumping system such that phase breakout or phase recombination associated with the pump can be detected.

94. A system according to claim 87 wherein the acoustic transducer is positioned so as to be in acoustic communication with fluid in an annular region

defined by at least a portion of the exterior of the tool housing and the borehole wall, such that at least one property of the fluid can be evaluated.

95. A method for measuring acoustic energy propagating within a downhole tool comprising the steps of:

positioning a downhole tool in a borehole;

pumping fluid between the tool housing and a subterranean rock formation through which the borehole passes; and

measuring acoustic energy propagating within the tool.

96. A method according to claim 95 further comprising the step of sealing the annular region such that the annular region is a volume bounded by a first sealing member, a second sealing member, the outer surface of the tool and the borehole wall.

97. A method according to claim 95 further comprising playing audio signals representing measurements made by the acoustic transducer to a human interpreter such that the human interpreter can monitor conditions within the tool.

98. A method according to claim 97 wherein the conditions within the tool include the condition of moving parts within the tool.

99. A method according to claim 98 wherein the moving parts includes valves within the tool.

100. A method according to claim 98 wherein the moving parts includes at least part of the downhole pumping system.

101. A method according to claim 95 further comprising generating audio-annotated graphs based in part on measurements made by the acoustic transducer such that a human interpreter viewing the graphs can monitor conditions within the tool.

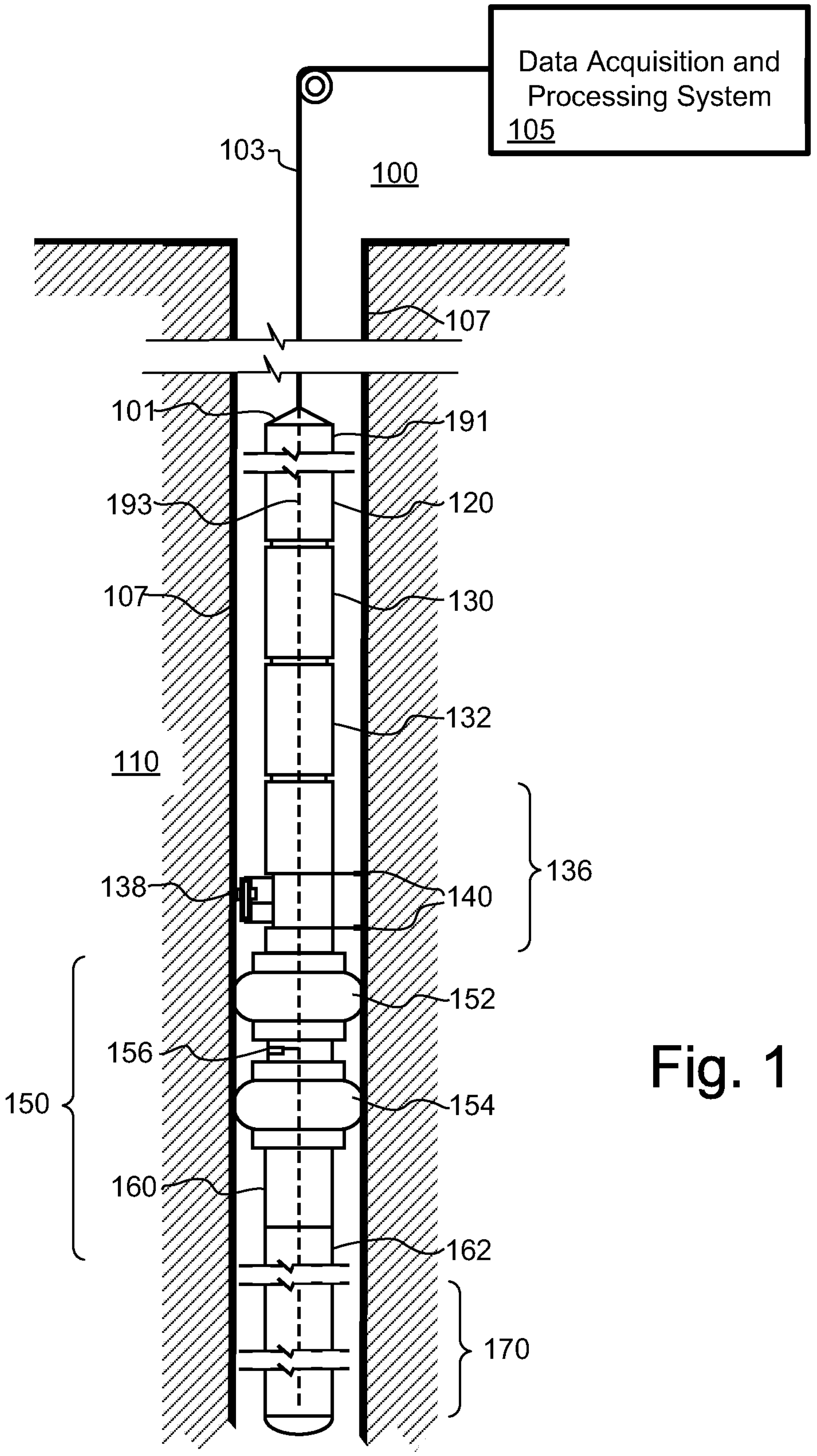
Data Acquisition and Processing System
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Fig. 1

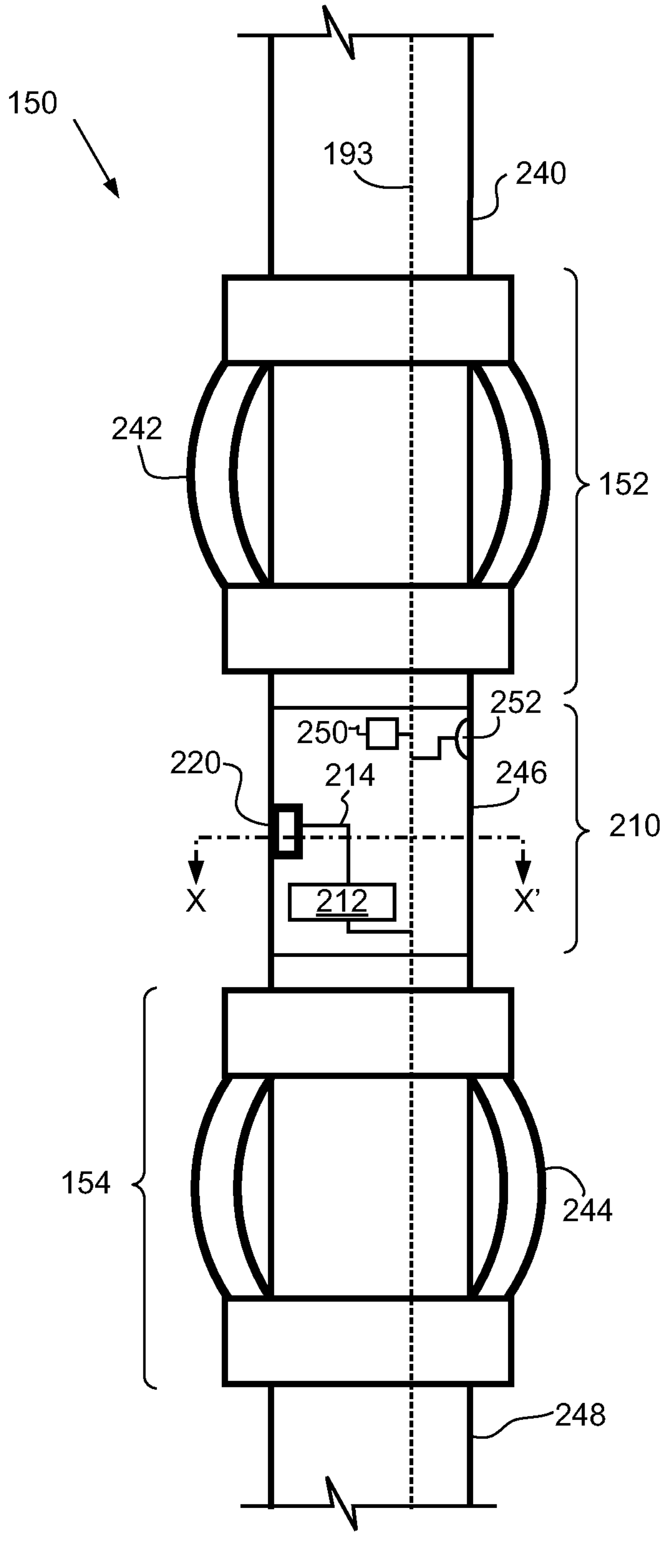
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Fig. 2a

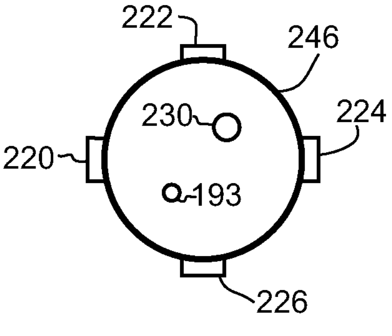
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Fig. 2b

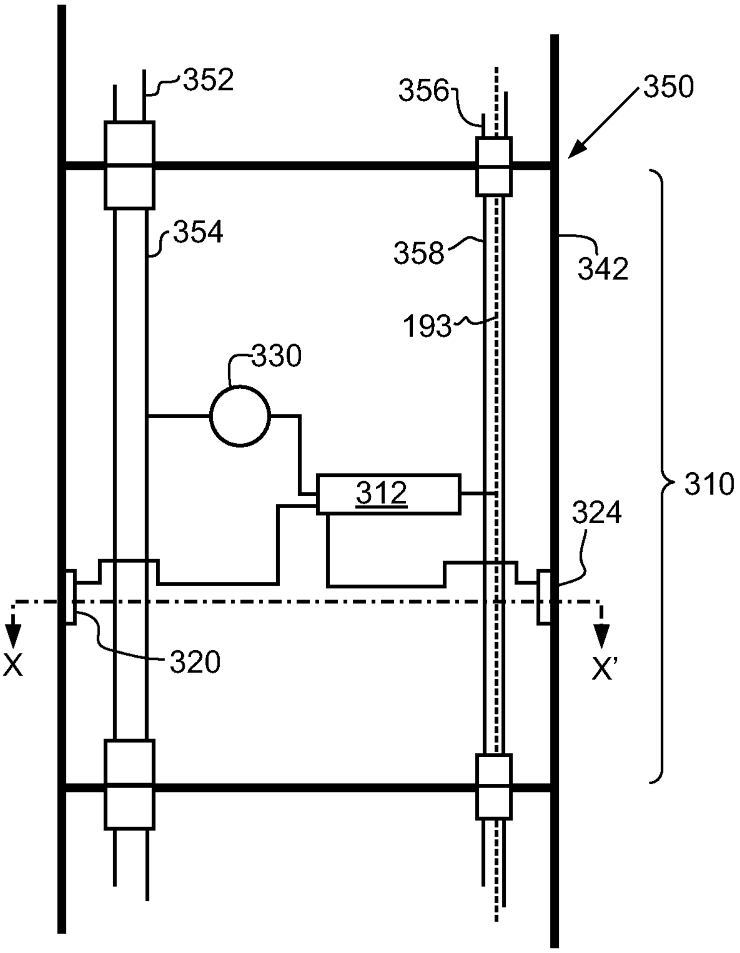

Fig. 3a

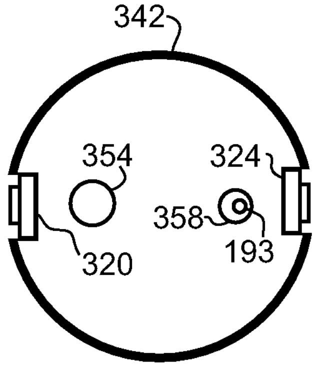

Fig. 3b

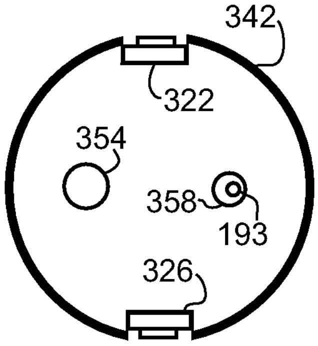

Fig. 3c

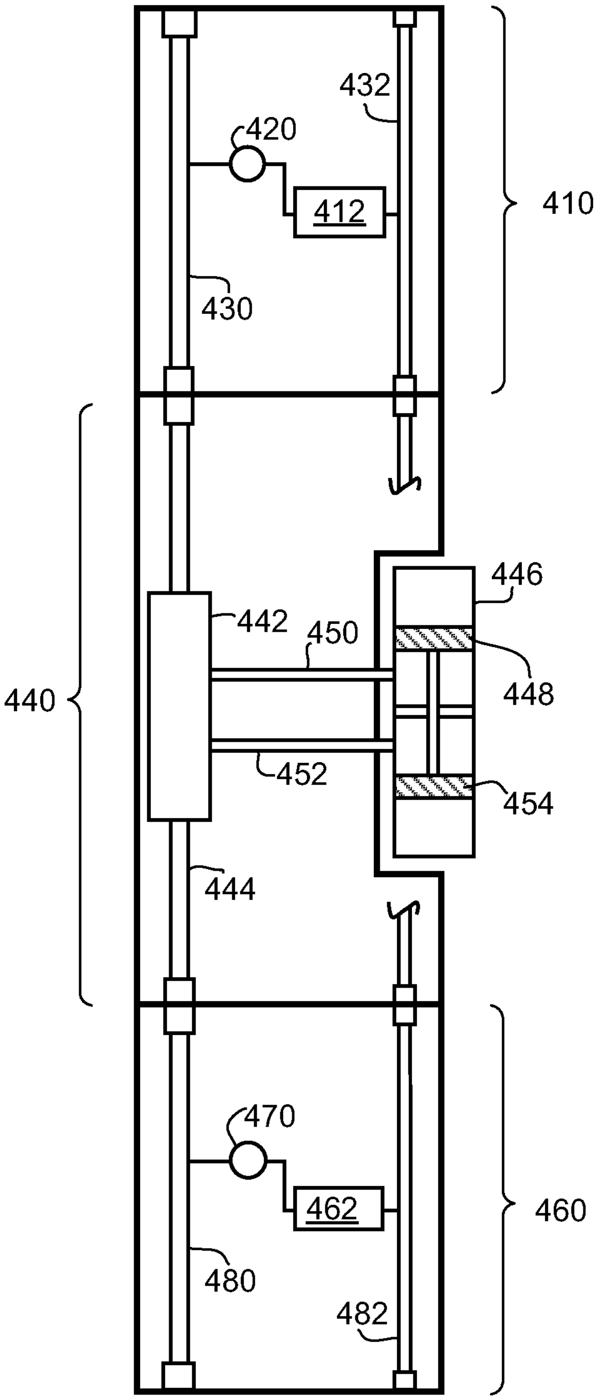
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Fig. 4

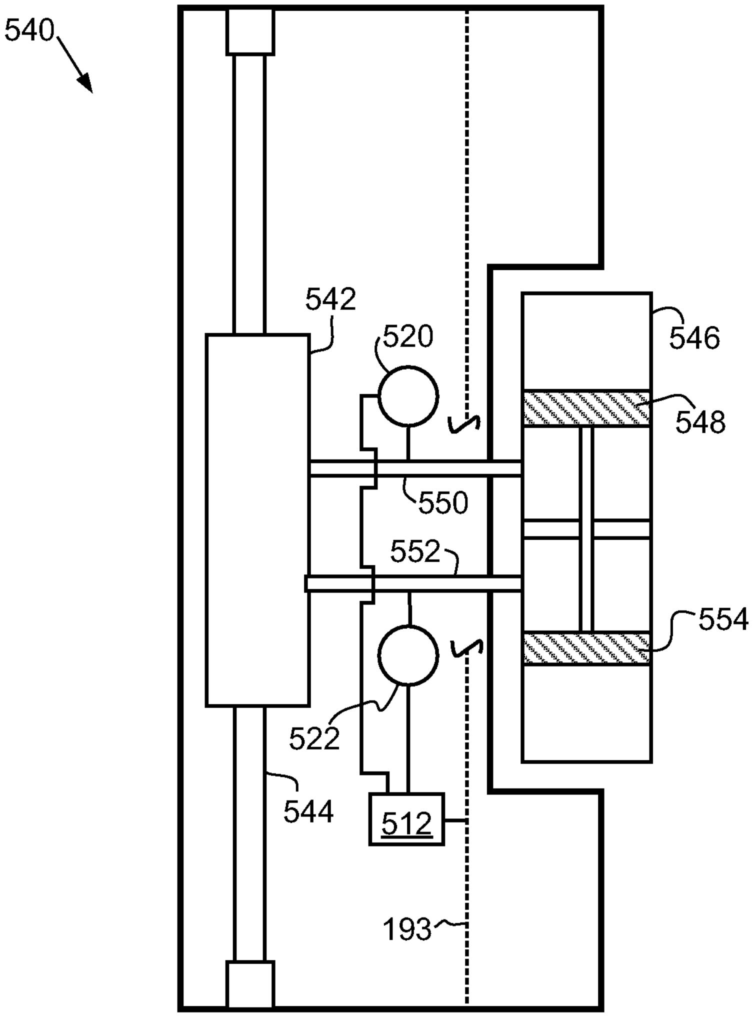

Fig. 5

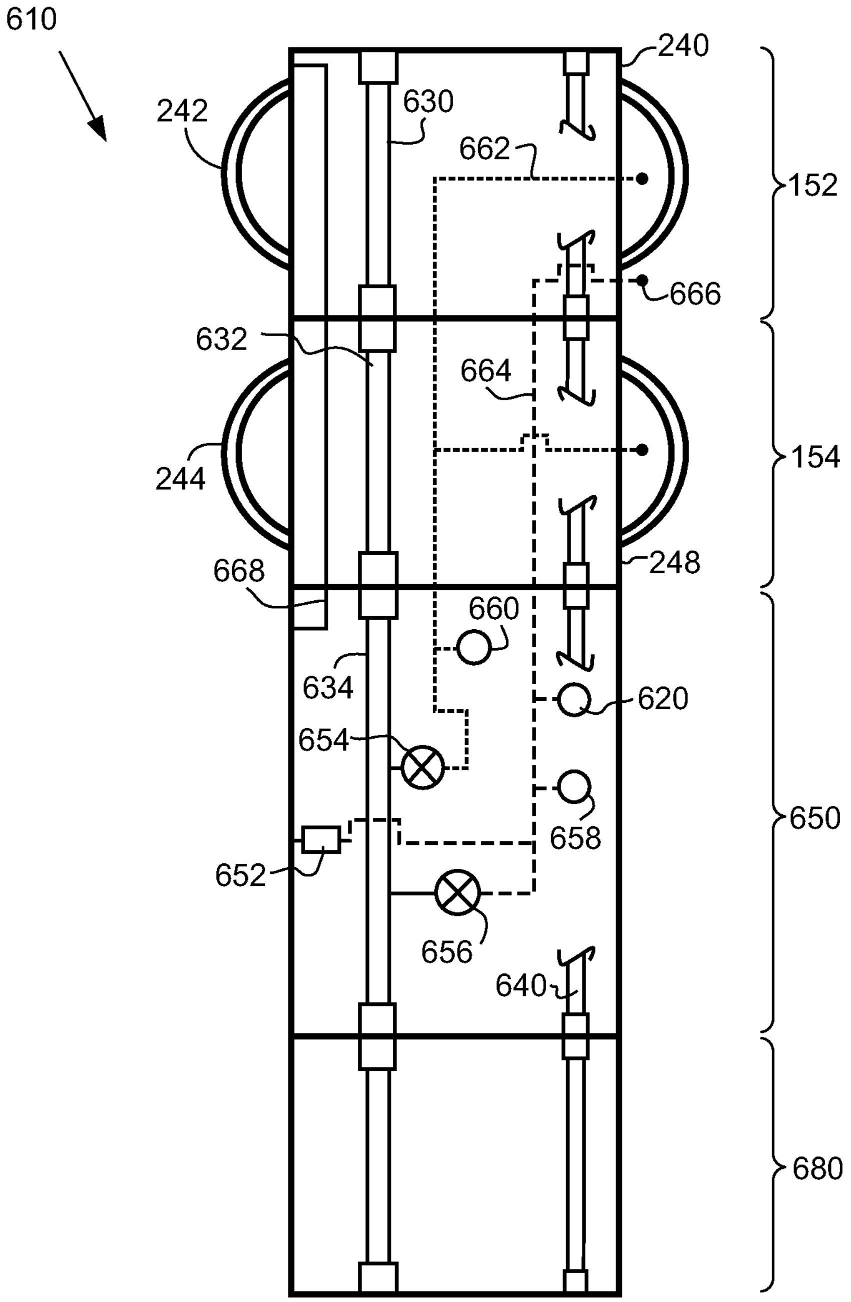
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Fig. 6

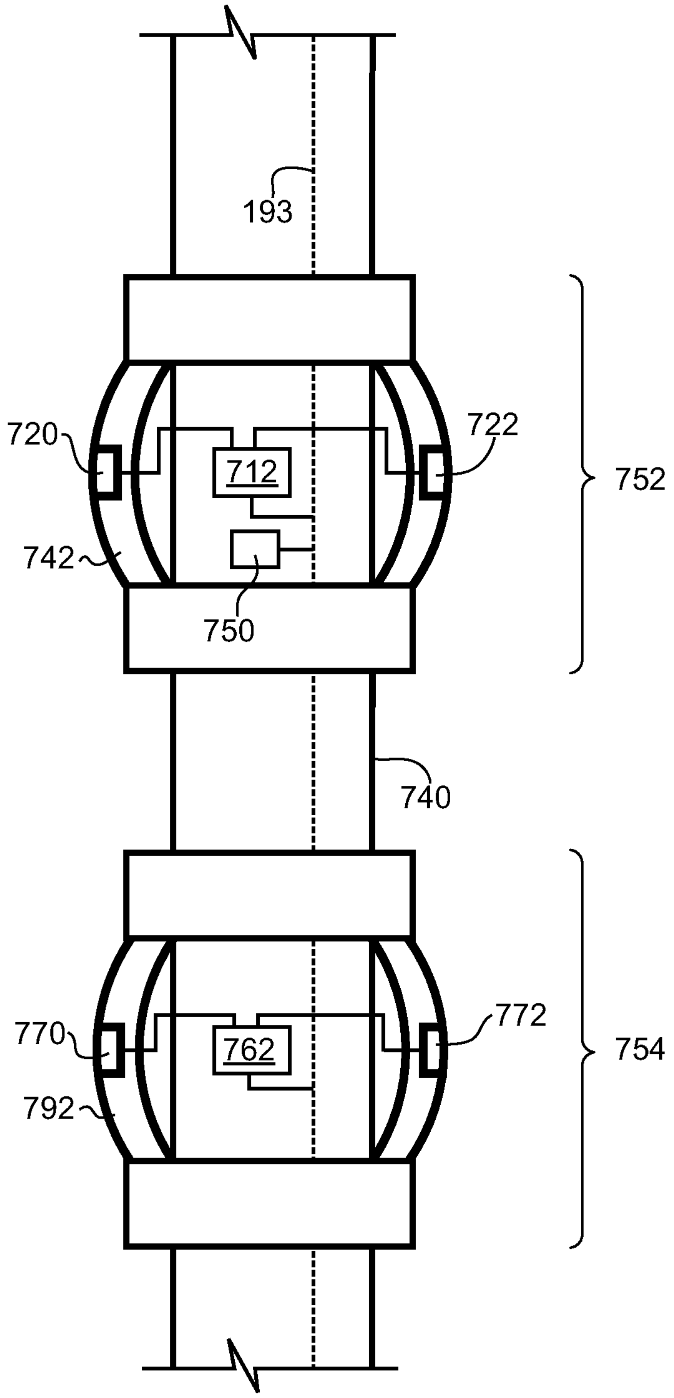

Fig. 7

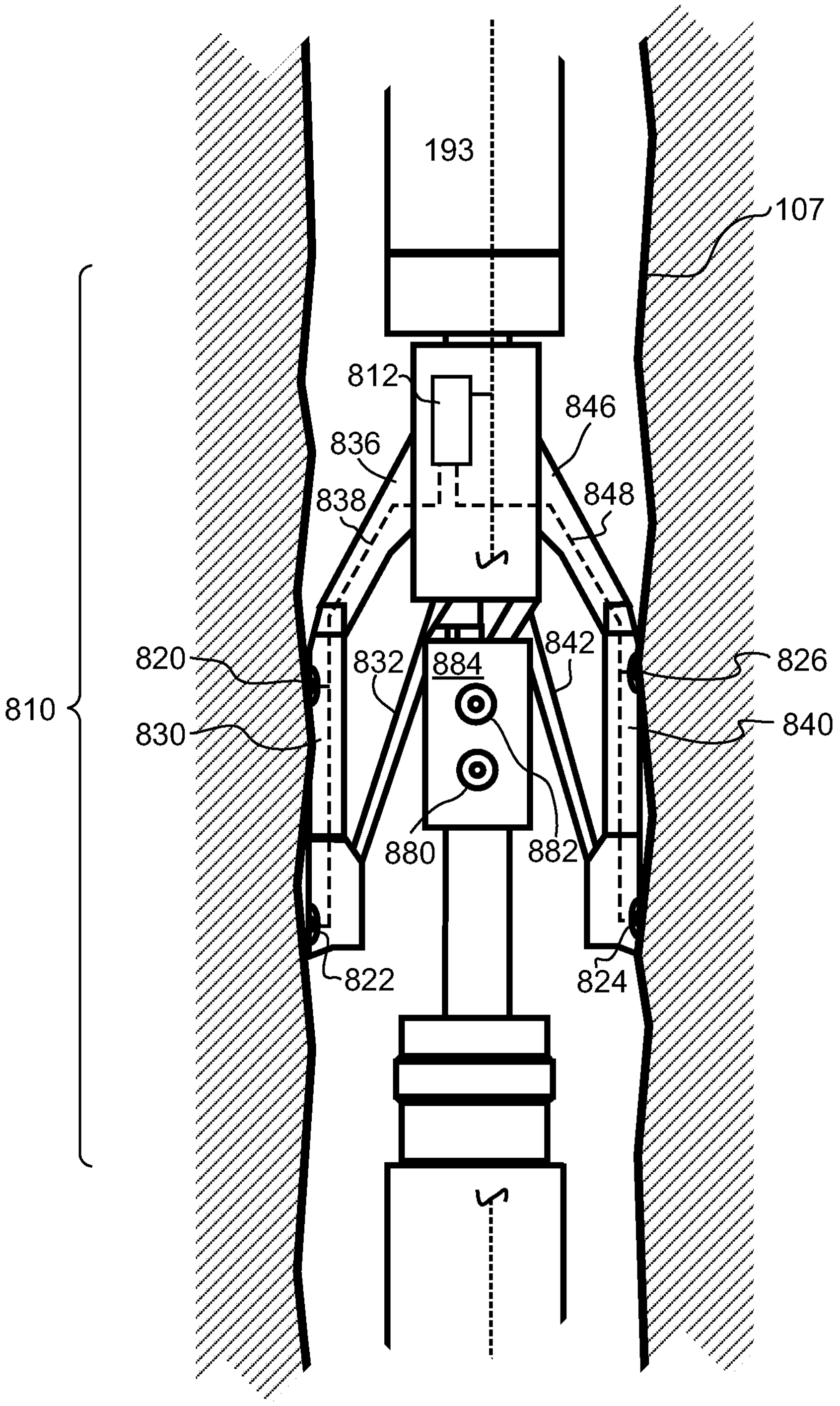
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Fig. 8

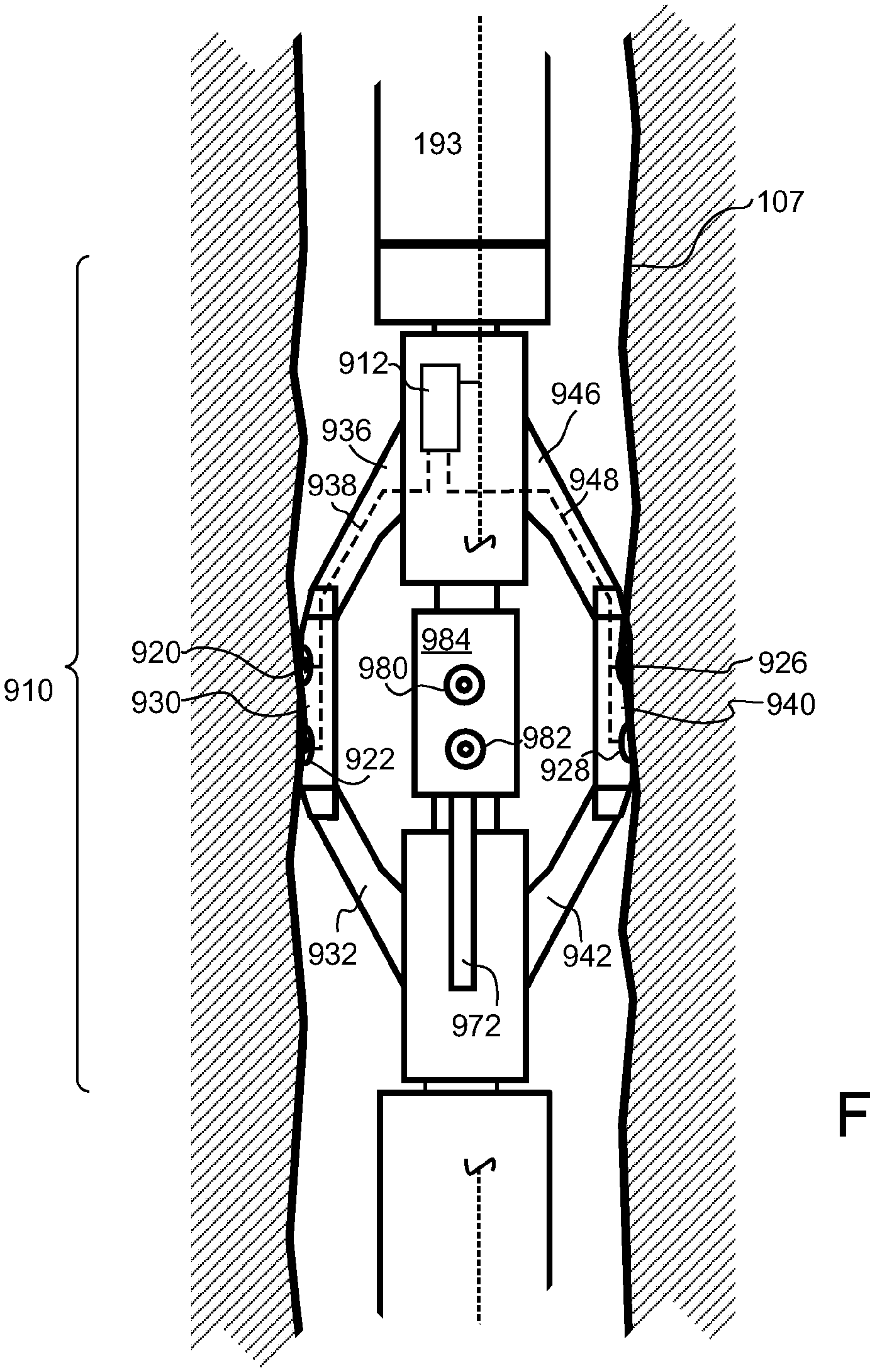
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Fig. 9

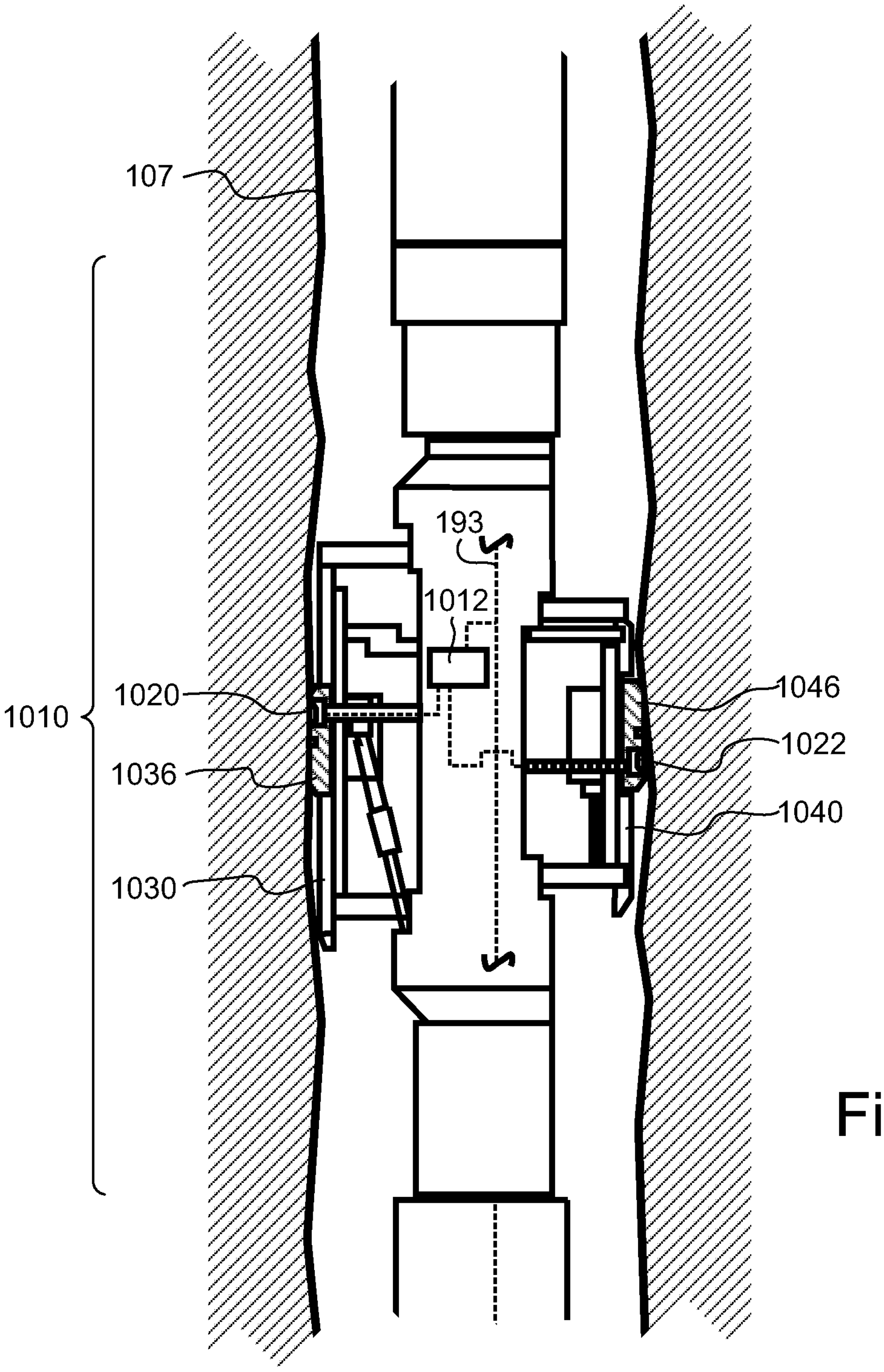

Fig. 10

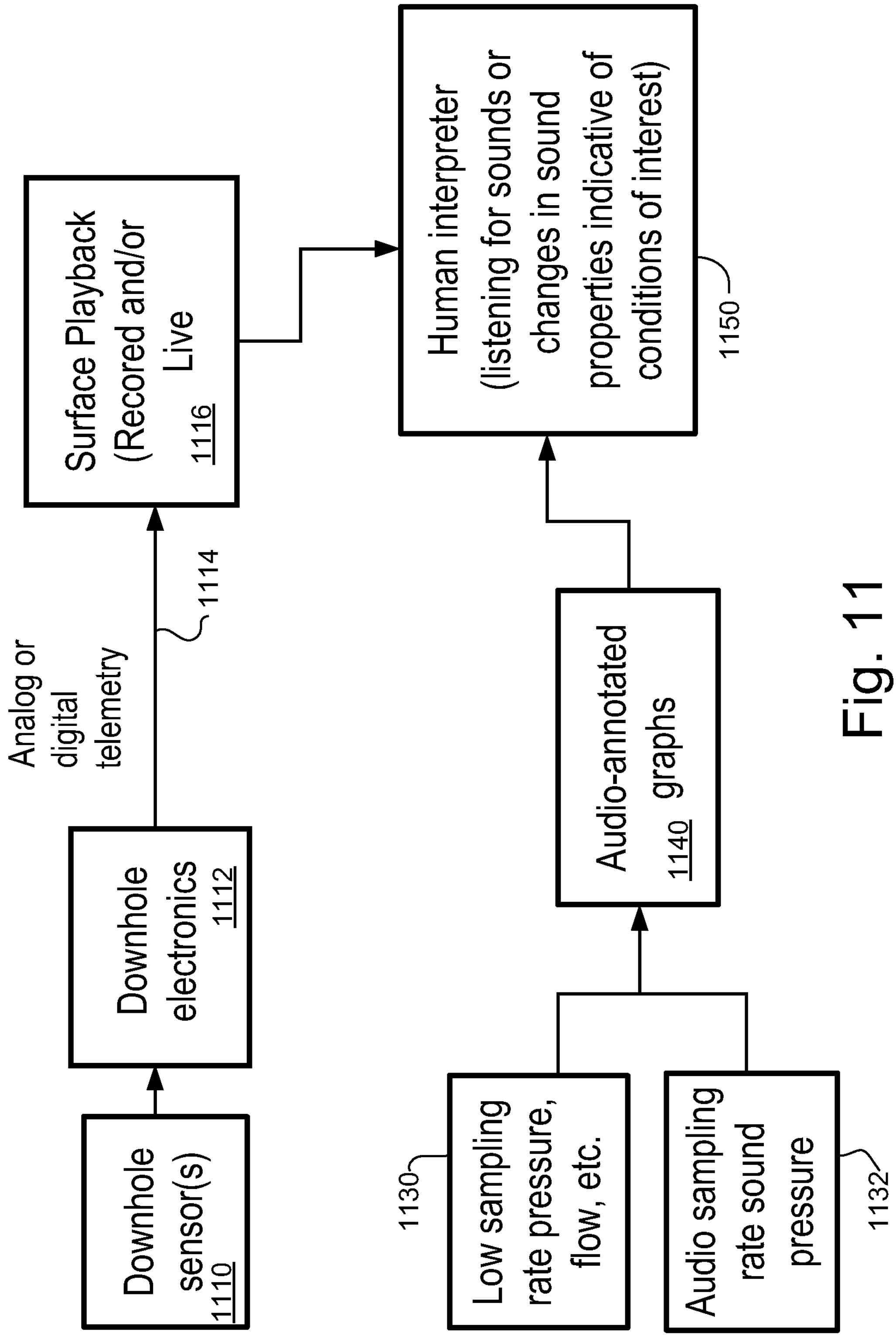
Downhole sensor(s)
1110
Downhole electronics
1112
Analog or digital telemetry
1114
Surface Playback (Recored and/or Live
1116
Human interpreter (listening for sounds or changes in sound properties indicative of conditions of interest)
1150
Low sampling rate pressure, flow, etc.
1130
Audio sampling rate sound pressure
1132
Audio-annotated graphs
1140

Fig. 11

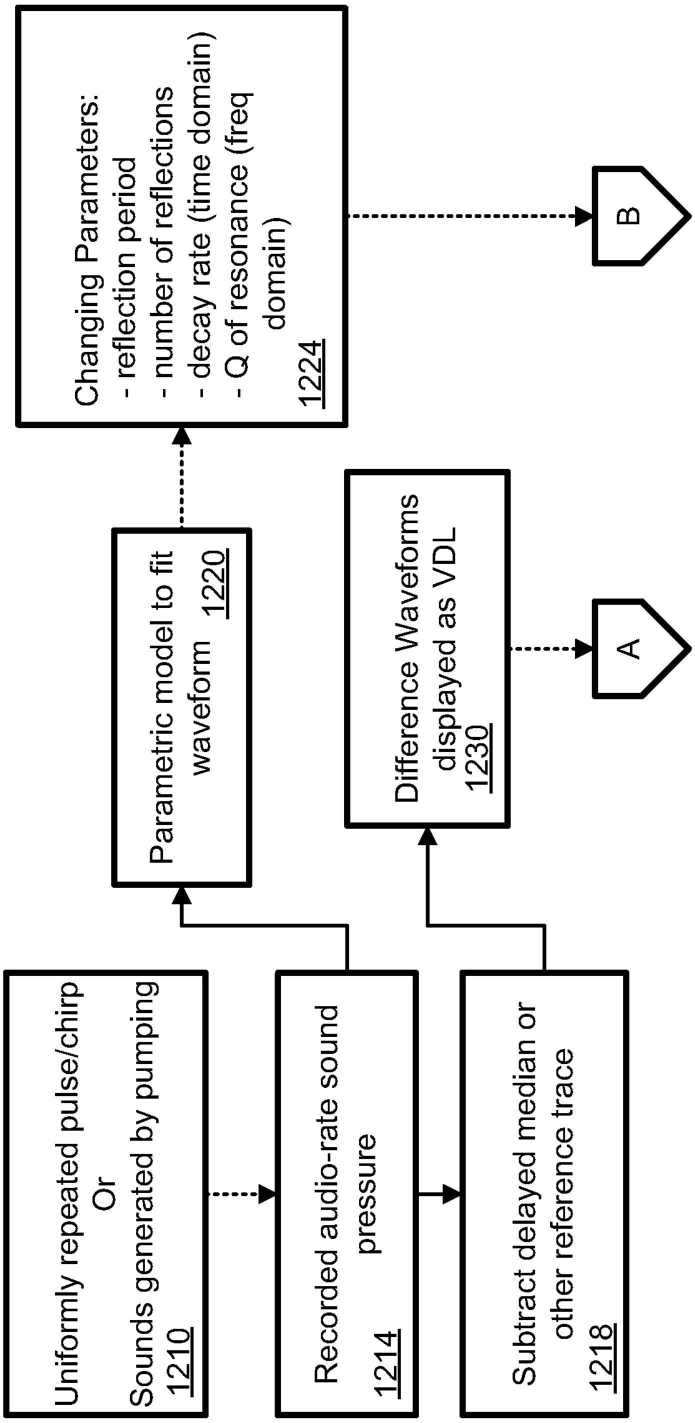
Uniformly repeated pulse/chirp
Or
Sounds generated by pumping
1210
Recorded audio-rate sound pressure
1214
Subtract delayed median or other reference trace
1218
Parametric model to fit waveform 1220
Difference Waveforms displayed as VDL
1230
Changing Parameters:
- reflection period
- number of reflections
- decay rate (time domain)
- Q of resonance (freq domain)
1224
A
B

Fig. 12a

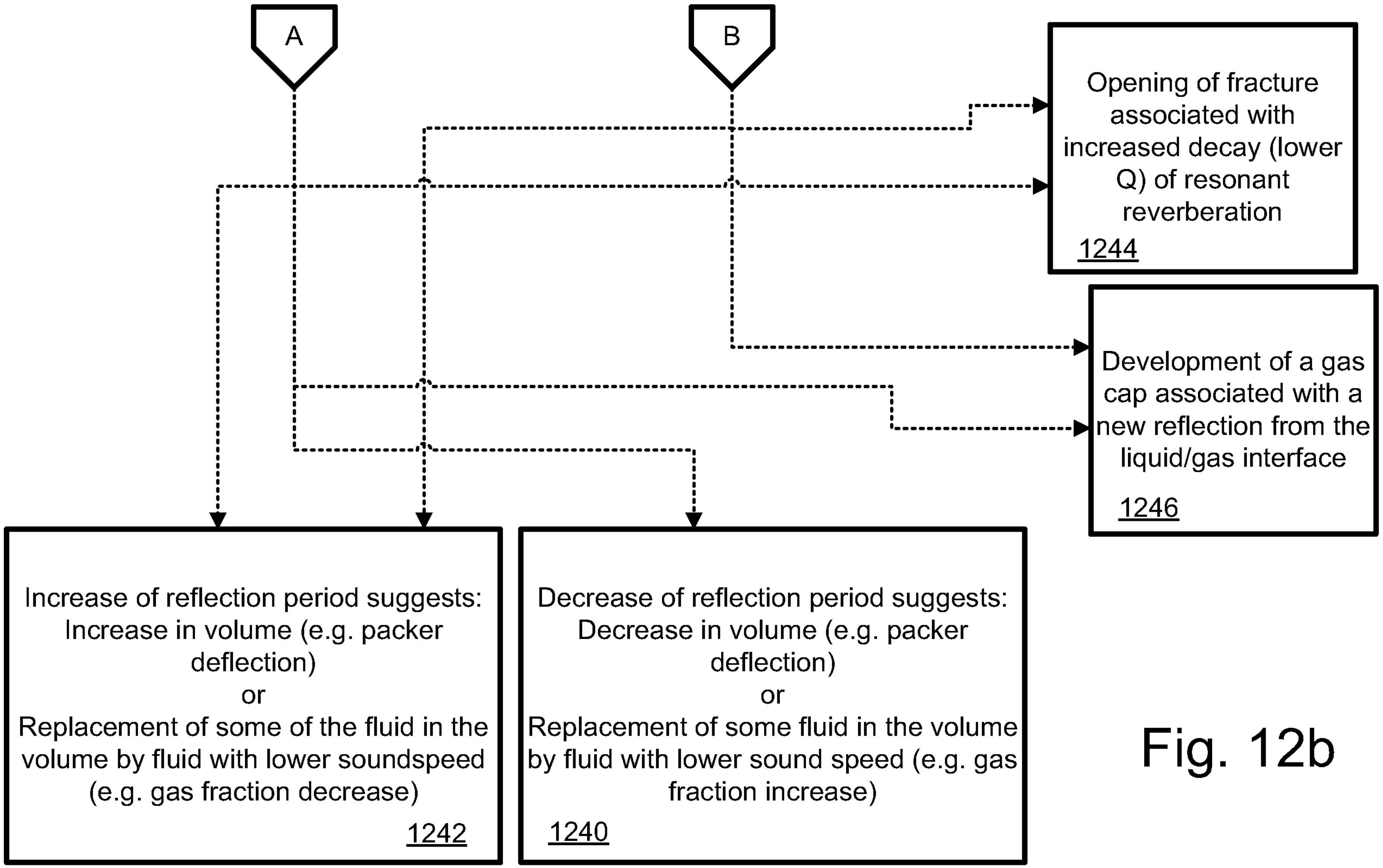
A
B
Opening of fracture associated with increased decay (lower Q) of resonant reverberation
1244
Development of a gas cap associated with a new reflection from the liquid/gas interface
1246
Increase of reflection period suggests:
Increase in volume (e.g. packer deflection)
or
Replacement of some of the fluid in the volume by fluid with lower soundspeed (e.g. gas fraction decrease)
1242
Decrease of reflection period suggests:
Decrease in volume (e.g. packer deflection)
or
Replacement of some fluid in the volume by fluid with lower sound speed (e.g. gas fraction increase)
1240

Fig. 12b

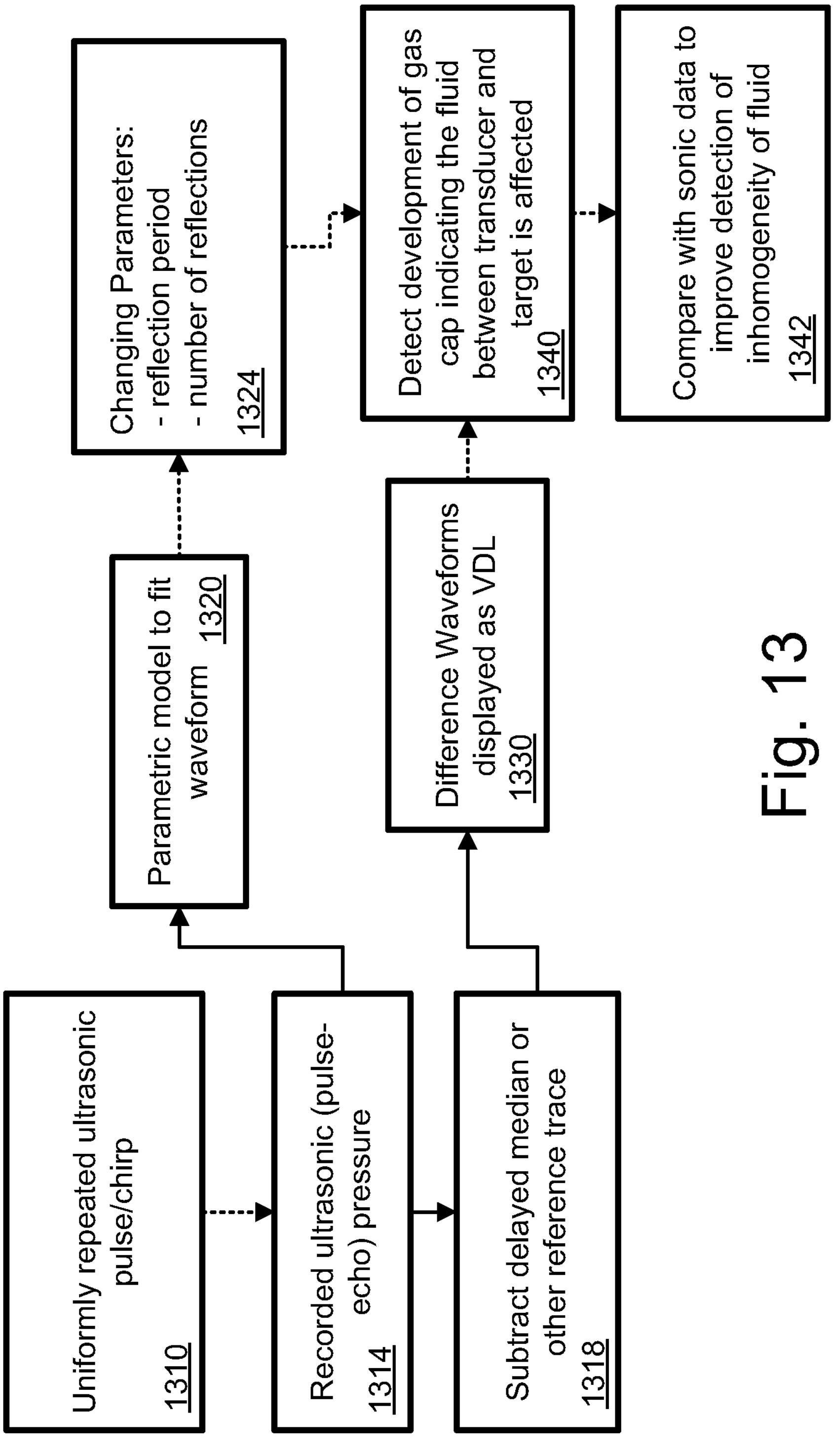
Uniformly repeated ultrasonic pulse/chirp
1310
Recorded ultrasonic (pulse-echo) pressure
1314
Subtract delayed median or other reference trace
1318
Parametric model to fit waveform 1320
Changing Parameters:
- reflection period
- number of reflections
1324
Difference Waveforms displayed as VDL
1330
Detect development of gas cap indicating the fluid between transducer and target is affected
1340
Compare with sonic data to improve detection of inhomogeneity of fluid
1342

Fig. 13