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(54) **Titre** : OUTIL DE MESURE LE LONG D'UNE RAME AVEC RESEAU DE CAPTEURS DE PRESSION
(54) **Title**: ALONG STRING MEASUREMENT TOOL WITH PRESSURE SENSOR ARRAY

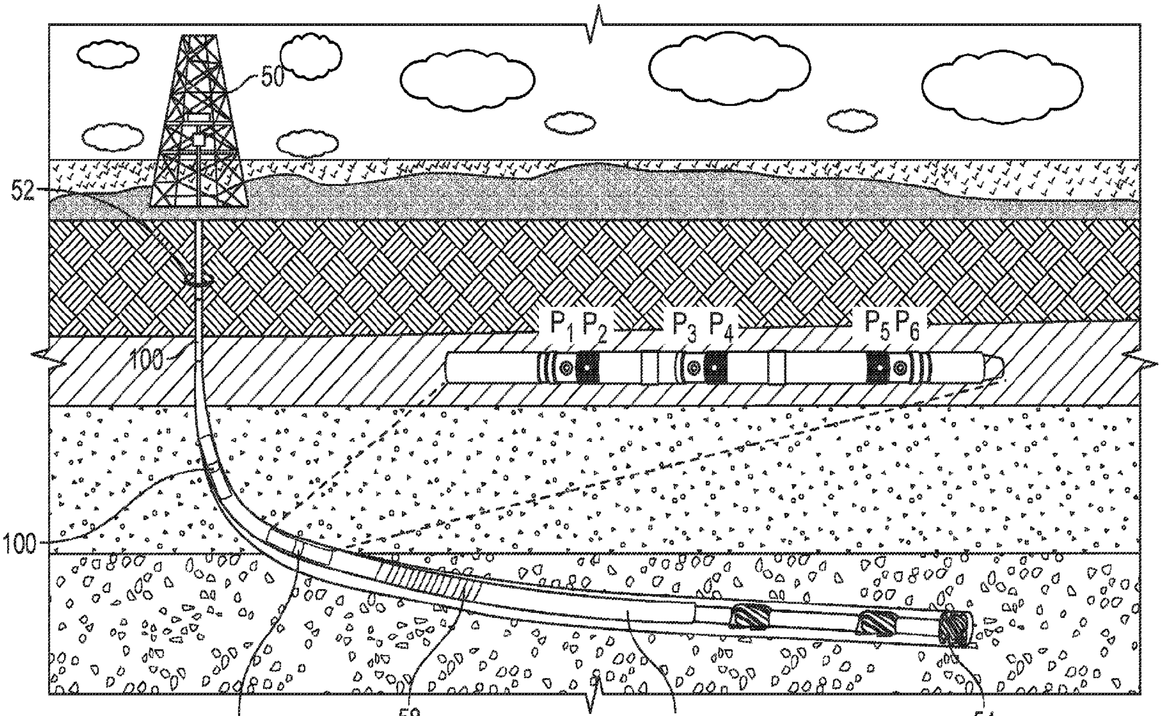

FIG. 1

(57) **Abrégé/Abstract:**

An along string measurement tool may include an elongate body configured for loading into a drill string and a sensor array arranged on the body. The sensor array may include a first sensor arranged at a first sensor location on the body and the first sensor may be oriented relative to the body and configured for sensing annular pressures in a wellbore. The sensor array may include a second sensor arranged at a second sensor location on the body and the second sensor location may be spaced longitudinally along the body from the first sensor location by a first distance. The second sensor may be oriented relative to the body and configured for sensing annular pressures in a wellbore.

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(54) **Title:** ALONG STRING MEASUREMENT TOOL WITH PRESSURE SENSOR ARRAY

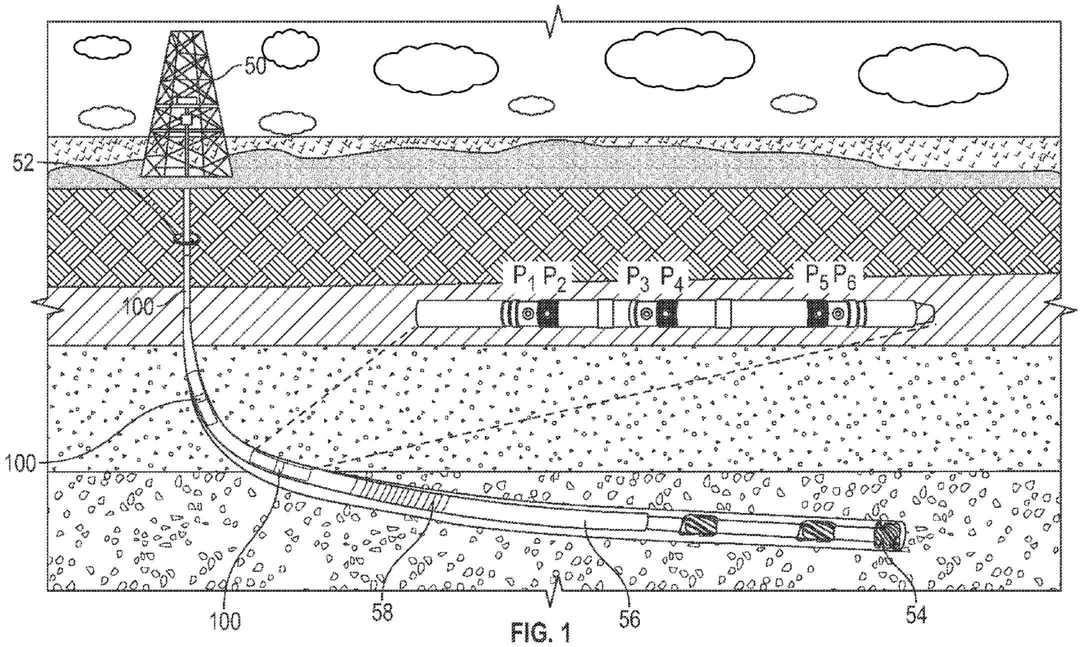

FIG. 1

(57) **Abstract:** An along string measurement tool may include an elongate body configured for loading into a drill string and a sensor array arranged on the body. The sensor array may include a first sensor arranged at a first sensor location on the body and the first sensor may be oriented relative to the body and configured for sensing annular pressures in a wellbore. The sensor array may include a second sensor arranged at a second sensor location on the body and the second sensor location may be spaced longitudinally along the body from the first sensor location by a first distance. The second sensor may be oriented relative to the body and configured for sensing annular pressures in a wellbore.

[Continued on next page]

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# ALONG STRING MEASUREMENT TOOL WITH PRESSURE SENSOR ARRAY

## CLAIM OF PRIORITY

**[001]** This PCT application claims the benefit of the filing date of U.S. Provisional Patent Application Serial No. 63/202,825, filed June 25, 2021 entitled, "ALONG STRING MEASUREMENT TOOL WITH PRESSURE SENSOR ARRAY," and U.S. Provisional Patent Application Serial No. 63/202,805, filed June 25, 2021 entitled, "ALONG STRING MEASUREMENT TOOL WITH PRESSURE SENSOR ARRAY." The entire content of each of the above applications is incorporated herein by reference.

## FIELD OF THE INVENTION

**[002]** The present disclosure relates to a measurement while drilling (MWD) tool. More particularly, the present disclosure relates to an MWD tool adapted to measure annular pressure in the wellbore. Still more particularly, the present disclosure relates to an MWD having a sensor array adapted to collect several annular pressures along the length of the tool providing the ability to observe differential pressures within the length of the MWD tool resulting in a higher fidelity view of pressure changes in the wellbore.

## BACKGROUND OF THE INVENTION

**[003]** The background description provided herein is for the purpose of generally presenting the context of the disclosure. Work of the presently named inventor, to the extent it is described in this background section, as well as aspects of the description that may not otherwise qualify as prior art at the time of filing, are neither expressly nor impliedly admitted as prior art against the present disclosure.

**[004]** Measurement while drilling (MWD) generally involves one or more tools arranged along a drill string that allow for capturing downhole information during drilling and/or tripping drill pipe. In some cases, MWD tools are placed at selected locations along the drill string and are adapted to measure inclination angles providing support for directional drilling operations. Other along string measurement (ASM) tools may also be adapted to capture data relating to the downhole environment for logging while drilling (LWD) operations. For example, ASM tools may include temperature sensors, pressure sensors, gamma ray sensors, or other sensors. These sensors may allow for capturing wellbore data and/or data relating to the surrounding geological formations. In some cases, the ASM tool may measure density, porosity, resistivity, acoustic-caliper, inclination at the drill bit, magnetic resonance and/or formation pressure.

**[005]** One type of ASM tool may be adapted to measure the annular pressure surrounding the drill string within the wellbore. These pressures may be used to estimate the density of the drilling fluid surrounding the drill string and may help to capture information relating to changing conditions in the wellbore. Knowledge of these changing conditions can be helpful, for example, to allow a drilling rig operator to control kicks (e.g., influx of fluid into the wellbore from a formation) and/or loss of fluid from the wellbore. Both situations can lead to wellbore stability problems. Nonetheless, current systems do not provide a sufficient ability to avoid or reduce random and systematic errors nor do they provide information having sufficient fidelity.

## BRIEF SUMMARY OF THE INVENTION

**[006]** The following presents a simplified summary of one or more embodiments of the present disclosure in order to provide a basic understanding of such embodiments. This summary is not an extensive overview of all contemplated embodiments and is intended to neither identify key or critical elements of all embodiments, nor delineate the scope of any or all embodiments.

**[007]** In one or more embodiments, an along string measurement tool may include an elongate body configured for loading into a drill string and a sensor array arranged on the body. The sensor array may include a first sensor arranged at a first sensor location on the body and the first sensor may be oriented relative to the body to sense annular pressures in a wellbore and may also be configured for sensing annular pressures in a wellbore. The sensor array may include a second sensor arranged at a second sensor location on the body. The second sensor location may be spaced longitudinally along the body from the first sensor location by a first distance. The second sensor may be oriented relative to the body to sense annular pressures in a wellbore and may also be configured for sensing annular pressures in a wellbore.

**[008]** In one or more embodiments, a method of monitoring wellbore characteristics may include receiving pressure sensor signals from first and second sensors arranged on and spaced longitudinally along an along string measurement tool.

The first and second sensor may be spaced apart by a first distance. The method may also include calculating a differential pressure signal based on the signals from the first and second sensors. The method may also include displaying a differential pressure signal for a drilling operator.

**[009]** While multiple embodiments are disclosed, still other embodiments of the present disclosure will become apparent to those skilled in the art from the following detailed description, which shows and describes illustrative embodiments of the invention. As will be realized, the various embodiments of the present disclosure are capable of modifications in various obvious aspects, all without departing from the spirit and scope of the present disclosure. Accordingly, the drawings and detailed description are to be regarded as illustrative in nature and not restrictive.

## BRIEF DESCRIPTION OF THE DRAWINGS

**[010]** While the specification concludes with claims particularly pointing out and distinctly claiming the subject matter that is regarded as forming the various embodiments of the present disclosure, it is believed that the invention will be better understood from the following description taken in conjunction with the accompanying Figures, in which:

**[011]** FIG. 1 is a cross-section view of a drilling rig drilling a well and having a drill string with several along string measurement (ASM) tools arranged in the string, according to one more embodiments.

**[012]** FIG. 2 is a view of a portion of the drill string of FIG. 1, showing several ASM tools on the string, according to one or more embodiments.

**[013]** FIG. 3 is a side or lengthwise view of one of the ASM tools having a pressure sensor array, according to one or more embodiments.

**[014]** FIG. 4 is a diagram depicting a method of monitoring a wellbore, according to one or more embodiments.

**[015]** FIG. 5A is a graph of a differential pressure signal measured between two ASM Tools arranged 270 feet apart in a wellbore, according to one or more embodiments.

**[016]** FIG. 5B is a graph of an estimated density based on the differential pressure signal of FIG. 5A, according to one or more embodiments.

**[017]** FIG. 5C is a graph of a surface density signal for the well pressures depicted in FIG. 5A, according to one or more embodiments.

**[018]** FIG. 6A is a focused view of a portion of FIG. 5A.

**[019]** FIG. 6B is a focused view of a portion of FIG. 5A with denoised measured data (e.g., measured data passed through a denoising filter) and including a computed differential pressure.

**[020]** FIG. 7 includes of a series of comparable zero measurement error effective density graphs showing the comparison of effective density within a single tool as compared to effective density between spaced apart tools, according to one or more embodiments.

**[021]** FIG. 8 includes of a series of comparable 1% measurement error effective density graphs showing the comparison of effective density within a single tool as compared to effective density between spaced apart tools, according to one or more embodiments.

**[022]** FIG. 9 includes of a series of comparable 5% measurement error effective density graphs showing the comparison of effective density within a single tool as compared to effective density between spaced apart tools, according to one or more embodiments.

**[023]** FIG. 10A includes a diagram of the effect on differential pressures from an influx, where the pressure sensors have a 100 ft spacing, according to one or more embodiments.

**[024]** FIG. 10B includes a diagram of an effective density based on the differential pressures of FIG. 10A, according to one or more embodiments.

## DETAILED DESCRIPTION

**[025]** The present disclosure, in one or more embodiments, relates to a measurement while drilling tool having an annular pressure sensor array. Particular arrangements of the sensors in the array may provide for the ability to reduce random error as well as systematic error in downhole pressure measurements. The arrangement of the sensors in the array may also provide high fidelity data relating to the downhole pressures and related fluid densities that are present in the wellbore. The reduced error and higher fidelity data may allow the drilling operator to better control influxes of fluid into the wellbore from the formation (e.g., kicks), loss of fluid from the wellbore into the formation, and otherwise have a better understanding of the conditions that are present in and along the wellbore.

**[026]** FIG. 1 is a cross-section view of a drilling rig 50 drilling a well and having a drill string 52 with several tools arranged in the string, according to one or more embodiments. As shown, the drilling system may include a drill rig 50 having a mast, a drill floor, and a variety of pipe handling equipment adapted to connect drill pipe, stands, or tubulars end-to-end to feed a drill string into a wellbore. The equipment may include, for example, a top drive, an iron roughneck, one or more pipe elevators, drill floor slips, a racking board, and other equipment used to manage drilling and tripping operations. Drill fluid systems may also be provided for pumping drilling fluid into and through the drill string to operate a drill bit arranged at the tip of the drill string. The drill fluid system may also include a recovery portion for capturing drilling fluid returning from the wellbore carrying cuttings. The drill fluid system may clean the returning drill fluid and deliver it for reuse in the wellbore.

**[027]** As shown, the drill string 52 may include a series of drill pipes connected end-to-end extending downward from the drill rig 50 into a wellbore in the ground. The drill string 52 may include a bottom hole assembly (BHA) 54 arranged at the tip of the string that includes drill bit, a steering system, one more measuring devices and the like. Upward from the BHA may be a measurement while drilling (MWD) tool 56 that is particularly adapted to assist with directional drilling by sensing and providing inclination information to the drilling operator or drilling system. Upward from the MWD tool may be a logging while drilling (LWD) tool 58 that is adapted to capture geological and/or wellbore information that allows the operator, well servicers, or other operators with information about the geological formations the well extends through. In addition, and as shown, the drill string 52 may include one or more along string measurement (ASM) tools 100. As shown, the ASM tools 100 may be spaced along the drill string and may be adapted for sensing pressures in the wellbore as discussed in more detail below. While a particular arrangement of tools has been discussed, other arrangements may be provided where, for example, the particular order of tools behind the BHA is changed or modified.

**[028]** Turning now to FIG. 2, an isolated view of a drill string 52 is shown. As shown, the drill string 52 may include one or more along string measurement (ASM) tools 100 spaced along the string behind the bottom hole assembly (BHA). In one or more embodiments, an ASM tool 100 may be arranged relatively close to the BHA so as to capture bottom hole pressures. The other ASM tools 100 may be spaced along the drill string at equal spacings or unequal (e.g., asymmetric) spacings may be provided.

**[029]** In one or more embodiments, the ASM tools 100 may be part of a wired drill pipe (WDP) system allowing for power and/or communication signals to be transmitted along the length of the drill pipe to and/or from the several tools on the drill string. The system may be, for example, a data telemetry system. The data telemetry system may include a surface unit configured for sending and receiving signals through the drill string and/or for processing data received and displaying the data to the operator. In one or more embodiments, the data telemetry system may include an electromagnetic telemetry system or a pulsed flow telemetry system.

**[030]** Turning now to FIG. 3, a single along string measurement (ASM) tool 100 is shown. The ASM tool 100 may be adapted for assembly along a drill string 52 and configured to sense annular pressure in the wellbore at the location of the tool 100. In particular, the ASM tool 100 may be adapted to sense absolute annular pressure and differential pressures along the length of the tool 100. The ASM tool may include a body portion 102 and a sensor array 104.

**[031]** The body portion or body 102 of the ASM tool 100 may be configured for loading, installing, and/or securing within a drill string 52 and adapted to function similarly to the rest of the drill string 52. That is, the body portion 102 may be adapted for threadably engaging drill pipe or tubulars on each end thereof and adapted to provide a conduit through which drilling fluid may pass on its way to the bottom hole assembly (BHA). The body portion 102 may be an elongate and substantially cylindrical element having a box end 106 and a pin end 108. The box end 106 may include a relatively broad cylindrical portion having internal threading on a conically shaped internal surface. The pin end 108 may include a relatively narrower conical portion having threading on an external surface thereof. The pin end 108 may be adapted for stabbing into a box end 106 of an adjacent tubular and for threadably engaging the adjacent tubular. In this fashion, the ASM tool 100 may be placed along the drill string 52 simply by taking the place of an otherwise present tubular of the drill string 52. In one or more embodiments, the body portion 102 may have a length that is the same or similar to a length of drill pipe and, as such may range from approximately 20 feet to approximately 40 feet, or from approximately 25 feet to approximately 35 feet, or a length of approximately 30 feet may be provided. Still other sizes of the body portion may be provided.

**[032]** The sensor array 104 may be configured to provide several annular pressures along the length of the ASM tool 100. In particular, the sensor array 104 may be configured to provide several absolute pressure measurements and further to allow for several differential pressure measurements within the length of the tool. In one or more embodiments, the sensor array may include a plurality sensors 110 spaced along the length of the ASM Tool 100. The sensors 110 may be arranged on the body portion 102 and oriented facing out so as to be exposed to an outboard side of the body portion and, thus, exposed to pressures in the annulus between the drill string 52 and the wellbore wall when the ASM tool 100 is in use in a wellbore. In one or more embodiments, the ASM tool 100 may include two sensors 110 arranged at opposing ends of the ASM tool 100. In other embodiments, three sensors 110 may be provided with two sensors 110 arranged at or near the ends of the tool 100 and a third sensor 110 arranged between the outer sensors 110. The third sensor 110 may be centered between the outer two sensors 110 or it may be located to create unequal spaces on either side thereof (e.g., an asymmetric spacing). Still other numbers of sensors 110 may be provided along the length of the ASM tool 100 including 4, 5, 6, 7, 8, or more sensors 110. In one or more embodiments, each sensor 110 may be a sensor pair. That is, in one or more embodiments, an additional sensor 110 may be provided in close proximity to the sensors 110 on the ASM tool 100 such that each sensor location 112 along the length of the ASM tool 100 includes two sensors 110 instead of one. In one or more embodiments, the additional sensor 110 may be spaced a short distance longitudinally along the ASM tool 100 as shown in FIG. 3. Alternatively or additionally, the additional sensor 110 may be arranged at a same longitudinal location, but at a different radial location around the circumference of the ASM tool 100. In any case, where sensor pairs are provided, the 2-sensor tool described may be a 4-sensor tool and the 3-sensor tool described may be a 6-sensor tool. Still other numbers of sensors at particular sensor locations along the length of the ASM tool 100 may be provided.

**[033]** FIG. 3 shows a particular sensor array including three sensor locations 112 and a pair of sensors 110 at each of the sensor locations 112. As shown, a first pair of sensors 110 may be provided at or near a first end of the ASM tool 100. The first pair of sensors 110 may include a first sensor 110 with a second sensor 110 spaced a short distance longitudinally and/or circumferentially away from the first sensor 110. A second pair of sensors 110 may be provided along the length of the ASM tool 100 and spaced from the first pair of sensors 110. The second pair of sensors 110 may include a third sensor 110 with a fourth sensor 110 spaced a short distance longitudinally and/or circumferentially away from the third sensor 110. A third pair of sensors 110 may be provided spaced from the second pair of sensors and at or near a second end of the ASM tool 100 opposite the first end.. The third pair of sensors 110 may include a fifth sensor 110 with a sixth sensor 110 spaced a short distance longitudinally and/or circumferentially away from the fifth sensor 110. The second pair of sensors may be arranged between the first and third pairs of sensors 110. As shown, the second pair of sensors 110 may be located so as to be spaced a first distance 114 from the first pair of sensors and a second distance 116 from the third pair of sensors. While this first and second distance 114/116 may be equal, FIG. 3 shows these distances 114/116 being unequal. This unequal spacing may provide for additional measurement advantages discussed in more detail below. The sensors 110 in each pair may be spaced from one another by a short distance. The short distance may range from approximately 0.5 inches to approximately 18 inches, or from approximately 3 inches to approximately 12 inches or a short distance of approximately 6 inches may be provided. In contrast, the spacing of the pairs of sensors relative to adjacent pairs of sensors may range from approximately 24 inches to approximately 300 inches, or from approximately 36 inches to approximately 120 inches, or from approximately 48 inches to approximately 96 inches, or from approximately 60 inches to approximately 72 inches, for example.

**[034]** In one or more embodiments, the sensors 110 in the sensor array 104 may be pressure sensors. For example, mechanical pressure transducers or capacitance pressure transducers may be provided. Additionally or alternatively, strain pressure transducers or quartz pressure transducers may be provided. In any case, the sensors may be adapted to emit a signal based on the pressure it is experiencing at any given time. The sensors may emit a signal continually, periodically, or when prompted, for example. In one or more embodiments, the sensors 110 may be in wired or wireless communication with a controller or other receiver for analyzing the sensor data and/or displaying the sensor data for a drill rig operator.

**[035]** The sensors 110 in the array 104 may be in powered and/or signal communication with the telemetry system and/or one another. That is, for example, where differential sensor measurements within the tool are desired, one or more sensors or sensor pairs may be hardwired to another so as to emit a differential pressure signal to the telemetry system.

**[036]** In operation and use, and in reference to FIG. 4, a method of monitoring a wellbore 200 with the above-described along string measurement (ASM) tool may be provided. In one or more embodiments, the method may include drilling a well or tripping drill pipe into or out of a well. 202. The method may also include loading an ASM tool onto the drill string and/or loading multiple ASM tools onto the drill string as the drill string is advanced into a wellbore. 204. As mentioned, the tools may be loaded onto the drill string by adding the tool to the drill string instead of a pipe or pipe stand, for example. Where a single ASM tool is provided, the ASM tool may be loaded onto the drill string at or near the bottom hole assembly or at a location further up the drill string. Where multiple ASM tools are provided, a first ASM tool may be loaded onto the drill string at or near the bottom hole assembly. A second ASM tool may be loaded onto the drill string and spaced up the drill string a first distance from the first ASM tool. A third ASM tool may be loaded onto the drill string and spaced up the drill string a second distance from the second ASM tool. The first distance and the second distance may be the same or they may be unequal providing for an asymmetric arrangement of ASM tools along the drill string. Still other arrangements of multiple ASM tools on the drill string may be provided including arrangements without an ASM tool at or near the bottom hole assembly.

**[037]** With the one or more ASM tools loaded onto the drill string and arranged in a wellbore, the method may include activating the one or more ASM tools. 206. In one or more embodiments, the ASM tools may be activated upon loading onto the drill string. In other embodiments, the ASM tools may be activated by the telemetry system, which may provide power and/or an activation signal to the ASM tool or tools.

**[038]** The method may also include collecting wellbore pressures with the ASM tool or tools. 208. The method may include continuously, periodically, or selectively collecting wellbore pressures during drilling and/or during tripping into or out of a well. For example, continuously collecting may include beginning to collect pressures upon activation of the ASM tool, periodically may include collecting pressures at particular time intervals or during particular events, and selectively may include user selected collection, for example. The wellbore pressures may be in the form of signals that provide pressure vs. time.

**[039]** The method may also include transmitting the collected pressures to a surface unit of a telemetry system, for example. 210. The transmitting may be performed wirelessly or via wired drill pipe, for example. In one or more embodiments, the transmitting may be via pulsed flow telemetry, for example. The method may also include receiving the transmitted pressure signals 212 and monitoring and/or analyzing pressures received from the ASM tools. 214. In one or more embodiments, the monitoring and/or analyzing may include monitoring and/or analyzing absolute pressures or differential pressures with a particular ASM tool and/or between multiple ASM tools in the drill string. Still further, the monitoring and/or analyzing may include watching for pressure conditions that are indicative of an influx of fluid from the underground formation into the wellbore, outflow of fluid from the wellbore into the formation, pack off, or other downhole problems that can occur and may be evident from changing pressure conditions.

**[040]** For example, drill fluid may be designed and selected with a goal of providing downhole pressures that are sufficient to counteract internal pressures in underground formations. That is, the drill fluid density may be selected such that at particular wellbore depths, the hydrostatic pressure developed in the annular space around the drill string due to the weight of the drill fluid is the same as or slightly above the formation pressure. This may help prevent formation fluid from entering the wellbore. However, sometimes unanticipated high pressures are encountered as drilling progresses and high-pressure fluids may enter the wellbore. When this happens, the fluids may mix with the drilling fluid and change the density of the drilling fluid, often making it less dense, further exacerbating the problem and causing the influx to propagate quickly up the wellbore. In some cases, the influx can lead to a blow out at the surface of the drilling operation. The fluid influx into the wellbore may be liquid or gas, which can also change the effect of the influx on the wellbore characteristics.

**[041]** Other downhole problems can also occur such as pack off, for example. A pack off occurs when the cuttings from the drill bit get clogged in the annular space around the drill string and fail to flow upward in the annular space to the surface. With the continual pumping of fluid down the wellbore to operate the drill bit, pressures in the annular space around the drill string and below the pack off may increase. Still other scenarios can occur that may change the pressures in the annular space around the drill string. For example, a high permeable formation zone may cause mud fluid loss from the wellbore to the formation, which can lead to a wellbore stability problem. The loss of fluid may change the pressure gradient.

**[042]** It is to be appreciated that as the driller drills into the ground, the absolute pressures in the well bore may continue to increase and, as such, it may be difficult to establish a benchmark for changes in well pressure because the absolute pressure is changing. That is, the further down a driller drills, the higher the hydrostatic pressure is in the annular space around the drill string at or near the bottom hole assembly. As such, absolute pressures at any given ASM tool may continue to increase as the wellbore gets deeper. However, where the spacing between any given two sensors along the drill string remains substantially constant, as is the case with ASM tools spaced along the drill string, the difference between the hydrostatic pressure at one sensor relative to another sensor remains constant. For this reason, it can be helpful for a driller to monitor the differential pressures between sensors spaced along the drill string. In one or more embodiments, the monitoring and/or analyzing pressures may include calculating differential pressures. In some embodiments, these differential pressures may be further normalized by dividing them by a factor depending on the length between the sensors, which may result in an interval density or effective density of the fluid between the sensors.

**[043]** As shown in FIG. 5A, a differential pressure signal based on a differential between sensors that are spaced approximately 270 feet from one another along a drill string are shown. As shown, the signal may remain substantially constant and oscillating around about 140 psi from time 0 minutes to time 110 minutes. At that point, the differential pressure begins to drop until 113 or 114 minutes and returns to approximately 140 psi at about 117 or 118 minutes. Another drop is seen at approximately 160 minutes. This particular data set may result from a fluid influx into the bottom of the wellbore that reduces the pressure in the wellbore. FIG. 5B shows the density estimated from the differential pressure given in FIG. 5A. FIG. 5C shows the density measured on the surface using a Coriolis meter. FIG. 5C is relatively clear and shows a relatively consistent mud density of about 9.5 ppg. However, two influxes of 7.0 ppg diesel at around 127 minutes and 8.33 ppg water at around 172 minutes are also shown. The estimated density (FIG. 5B) also shows the first influx at around 113-114 minutes. The Coriolis density lags behind the estimated density by approximately 10-15 minutes ($\Delta t$) due to the time it takes for the influx to reach the surface. The second influx is barely visible in the estimated density plot of FIG. 5B. This is because the difference in the density of water (8.33 ppg) and the drilling mud (9.5 ppg) is relatively small. The diesel influx, on the other hand, has a larger density disparity with the mud and the influx shows up a bit more clearly. A similar effect may occur when the volume of the influx is relatively low. The effect of noise and/or error can make it difficult to identify pressure changes, which, although small, can be meaningful.

**[044]** FIG. 6A is a closeup view of the differential pressure graph along with a denoised signal showing the two influx events. FIG. 6B is a closeup view as well with the measured data removed and showing only the denoised data. FIG. 6B also shows computed data in the form of a solid line. For example, the first influx event included 25 barrels of diesel fuel having a density of 7 ppg. The second influx event included 50 barrels of water having a density of 8.33 ppg.

**[045]** In view of the above, the method steps of monitoring and/or analyzing the pressures received from the ASM tools 214 may include one or more steps such as the following. The multiple pressure values from a given sensor set may be averaged to help reduce statistical error. 214A Moreover, where asymmetric arrangements of sensors are used along the drill string or on a given tool, systematic error may be reduced. The method may also include calculating differential pressures between selected sets of sensors 214B and/or calculating interval or effective densities based on those pressures. 214C It is to be appreciated that sets of sensors at varying locations within the wellbore may provide different information depending on the range of the wellbore that the sensors cover. As such, multiple sets of differential pressures and/or interval densities may be calculated. For example, as between ASM Tools, each permutation of differential pressure and/or interval density may be calculated. That is, where there are three ASM Tools, the differential pressure and/or interval density may be calculated between the first and third tool, between the first and second tool, and between the second and third tool. Still further, and as between sensor sets on a single tool, each permutation of differential pressure and/or interval densities may be calculated. That is, where there are three sensor sets on a given tool, the differential pressure and/or interval density may be calculated as between the first and third sensor set, between the first and second sensor set, and between the second and third sensor set

**[046]** In one or more embodiments, the method may also include applying a denoising filter to the sensor data (e.g., to the differential pressure data or the interval density data). 214D. The denoising filter may include a time, frequency, and/or time-frequency filter based on an understanding of the reasonable times or frequencies the pressure data falls in, for example. The method may also include displaying the calculated differential pressure and/or density signals to a user. 216. The method may also include watching for reductions or increases in the differential pressure or density. 218. An operator, for example, may have a continual feed of one or more differential pressure or interval density signals and may monitor the feed for changes and may take action accordingly.

**[047]** As may be appreciated, the differential pressures and corresponding densities that are computed for sensors within a tool and/or between different tools in a drill string may provide for a hierarchical, multiresolution analysis of the data. This may improve the detection, identification, and quantification of various influxes/losses during drilling operations.

**[048]** It is to be appreciated that the spacing of the sensors and their position in the wellbore may provide for differences in the data available to the drilling operator. For example, the data shown in FIGS. 5A-6B is based on sensors that are arranged 270 feet apart in a wellbore. As shown and mentioned, the influxes that occurred do not reflect drastic departures of the differential pressure line and when sensor error is present (e.g., the oscillations around 140 psi), the changes in the differential pressure can get lost.

**[049]** However, and in reference to FIGS. 7-9, the presently described ASM tool may provide for a higher fidelity depiction of the effect of an influx on a wellbore, for example. Moreover, as shown, the presently described ASM tool may be better suited to detect influxes where the difference between the density of the influx fluid and the drilling mud is relatively small.

**[050]** As shown in FIG. 7, several diagrams of interval densities are shown. The graphs relate to three ASM Tools arranged in a wellbore: a top ASM Tool, a middle ASM Tool, and a bottom ASM Tool. The top graph is an interval density based on sensors arranged on a same tool. The remaining graphs in the FIG. show interval densities based on sensors arranged on separate tools. A comparison of the top graph to the remaining graphs reveals that the close proximity of the sensors on the tool cause the influx of fluid to be very apparent even though the density of the influx fluid is close to the mud density (8 ppg vs. 10 ppg). This is because the differential pressure between the two sensors is relatively low due to their close proximity and, as such, a change in pressure at one of the sensors reflects a relatively large departure from the interval density baseline. The next graph down, for example, may be a graph of interval densities between the bottom ASM Tool and the middle ASM Tool and the third graph may be a graph of interval densities between the middle ASM Tool and the top ASM

Tool. Finally, the bottom graph may be a graph of the interval density between the bottom ASM Tool and the top ASM Tool. Since the differential pressure from these further spaced apart sensors is greater, the significance of the change in pressure gets diluted. That is, the middle two graphs show a density change of approximately 1.25 ppg as compared to the density change of approximately 2 ppg in the top graph. In the bottom graph, the interval density change is closer to 0.5 ppg. When error is present, the effect of the influx on the interval density can get lost. For example, as shown in FIG. 8, a 1% error is included in the interval density readings. While still discernible, the lower three graphs begin to lose the clarity relating to the fluid influx, while the top graph remains quite clear. In FIG. 9, a 5% error is included in the interval density readings. Here, the effect of the influx in the bottom graph is all but lost and the effect of the influx in the middle two graphs is barely discernible, if at all. However, the effect of the influx in the top graph remains very clear. This higher fidelity view of the effect of an influx in a wellbore is provided by the presently described ASM Tool and reflects a substantial improvement in the detectability of density change in fluid mix and/or changes in the pressure gradient. That is, the inventors of the present ASM Tool embarked on a designing a tool with higher redundancy and higher spatial resolution that could reduce statistical error while improving the detectability and the trackability as the fluid influx/loss moves along the wellbore, and provides a hierarchical approach to measurement and data analysis.

**[051]** FIGS. 10A and 10B show another example of the limited measurement sensitivity of systems having sensors with relatively large spacings. For example, as shown, sensors may be arranged 100 feet apart along a drill string and an influx fluid having a 7 ppg density may flow into a wellbore that is using a 9.5 ppg drilling mud. Varying volumes of influx from 2 bbl to 20 bbl are shown. As shown, volumes below 2 bbl may be difficult to detect. Accurate estimation of fluid density may involve a minimum volume influx of 14 bbl for detection. Detectability may also depend on the contrast between the densities of the influx and the drilling mud. Moreover, the effective density may not match exactly with the influx densities because of the hydrostatic assumptions in the density computation, while the pressure computation includes the fluid flow velocity and corresponding corrections. This is yet another example revealing that tool configurations with multiple short-spaced sensors may enhance detectability and accuracy.

**[052]** As used herein, the terms “substantially” or “generally” refer to the complete or nearly complete extent or degree of an action, characteristic, property, state, structure, item, or result. For example, an object that is “substantially” or “generally” enclosed would mean that the object is either completely enclosed or nearly completely enclosed. The exact allowable degree of deviation from absolute completeness may in some cases depend on the specific context. However, generally speaking, the nearness of completion will be so as to have generally the same overall result as if absolute and total completion were obtained. The use of “substantially” or “generally” is equally applicable when used in a negative connotation to refer to the complete or near complete lack of an action, characteristic, property, state, structure, item, or result. For example, an element, combination, embodiment, or composition that is “substantially free of” or “generally free of” an element may still actually contain such element as long as there is generally no significant effect thereof.

**[053]** To aid the Patent Office and any readers of any patent issued on this application in interpreting the claims appended hereto, applicants wish to note that they do not intend any of the appended claims or claim elements to invoke 35 U.S.C. § 112(f) unless the words “means for” or “step for” are explicitly used in the particular claim.

**[054]** Additionally, as used herein, the phrase “at least one of [X] and [Y],” where X and Y are different components that may be included in an embodiment of the present disclosure, means that the embodiment could include component X without component Y, the embodiment could include the component Y without component X, or the embodiment could include both components X and Y. Similarly, when used with respect to three or more components, such as “at least one of [X], [Y], and [Z],” the phrase means that the embodiment could include any one of the three or more components, any combination or sub-combination of any of the components, or all of the components.

**[055]** In the foregoing description various embodiments of the present disclosure have been presented for the purpose of illustration and description. They are not intended to be exhaustive or to limit the invention to the precise form disclosed. Obvious modifications or variations are possible in light of the above teachings. The various embodiments were chosen and described to provide the best illustration of the principals of the disclosure and their practical application, and to enable one of ordinary skill in the art to utilize the various embodiments with various modifications as are suited to the particular use contemplated. All such modifications and variations are within the scope of the present disclosure as determined by the appended claims when interpreted in accordance with the breadth they are fairly, legally, and equitably entitled.

## Claims

What is claimed is:

1. An along string measurement tool, comprising:

an elongate body extending from a box end to a pin end and having a length similar to a length of drill pipe; and

a sensor array arranged on the body, the sensor array comprising:

a first sensor arranged at a first sensor location on the body, the first sensor being oriented relative to the body and configured for sensing annular pressures in a wellbore; and

a second sensor arranged at a second sensor location on the body, the second sensor location being spaced longitudinally along the body from the first sensor location by a first distance, the second sensor being oriented relative to the body and configured for sensing annular pressures in a wellbore.

2. The tool of claim 1, further comprising a third sensor arranged at a third sensor location on the body, the third sensor location being spaced longitudinally along the body from the second sensor location by a second distance and in a direction opposite the first sensor location, the third sensor being oriented relative to the body and configured for sensing annular pressures in a wellbore.

3. The tool of claim 2, wherein the first distance is equal to the second distance.

4. The tool of claim 2, wherein the first distance is not equal to the second distance.

5. The tool of claim 2, wherein the first sensor comprises a first pair of sensors, the second sensor comprises a second pair of sensors, and the third sensor comprises a third pair of sensors, the pairs of sensors being arranged longitudinally relative to one another or circumferentially relative to one another at their respective sensor locations.

6. The tool of claim 1, wherein the first sensor and the second sensor are configured for communicating a pressure sensor signal to a surface where drilling is being performed.

7. The tool of claim 6, wherein the first and second sensor are configured for wireless communication.

8. The tool of claim 6, wherein the first and second sensor are configured for communicating using a telemetry system.

9. The tool of claim 8, wherein the telemetry system is a pulse flow telemetry system.

10. The tool of claim 8, wherein the telemetry system is an electromagnetic telemetry system.

11. A method of monitoring wellbore characteristics, comprising:

receiving pressure sensor signals from first and second sensors arranged on and spaced longitudinally along an along string measurement tool comprising an elongate body extending from a box end to a pin end and having a length similar to a length of drill pipe, the first and second sensor being spaced apart by a first distance;

calculating a differential pressure signal based on the signals from the first and second sensors;

displaying a differential pressure signal for a drilling operator.

12. The method of claim 11, further comprising, calculating an interval density signal based on the differential pressure signal.

13. The method of claim 12, further comprising displaying the interval density signal.

14. The method of claim 11, further comprising receiving a pressure sensor signal from a third sensor arranged on and spaced longitudinally along the along string measurement tool, the third sensor being spaced from the second sensor by a second distance and in an opposite direction as the first sensor.

15. The method of claim 14, further comprising calculating a differential pressure signal based on the signals from the third and first sensors.

16. The method of claim 15, further comprising calculating a differential pressure signal based on the signals from the third and second sensors.

17. The method of claim 16, further comprising calculating interval density signals based on the differential pressure signals between the third and first sensor and the third and second sensor.

18. The method of claim 11, wherein the first sensor comprises a first sensor pair and the second sensor comprises a second sensor pair, the method further comprising calculating an average sensor signal for the first sensor pair and for the second senor pair.

19. The method of claim 18, wherein calculating an average sensor signal occurs prior to calculating a differential pressure signal.

20. The method of claim 11, wherein receiving is performed by a telemetry system.

21. The method of claim 11, further comprising receiving multiresolution data including the pressure sensor signals from the first and second sensor and receiving a pressure sensor signal from a third sensor arranged on another along string measurement tool.

22. The method of claim 21, further comprising performing a hierarchical analysis of the multiresolution data.

23. The method of claim 11, further comprising denoising the pressure sensor signals or the differential pressure signal or both using at least one of a time-domain filter, a frequency-domain filter, and a combined time-frequency filter.

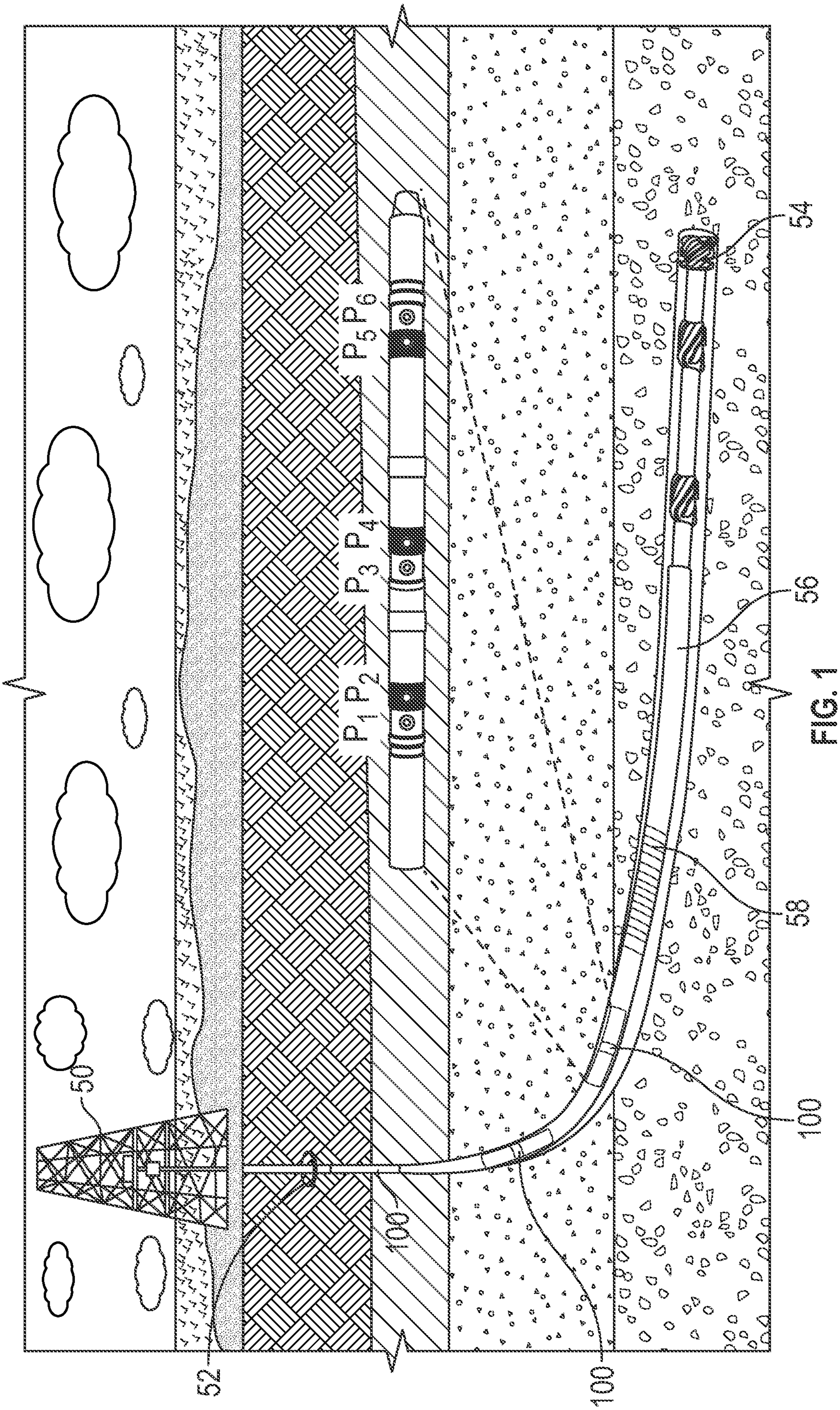

FIG. 1

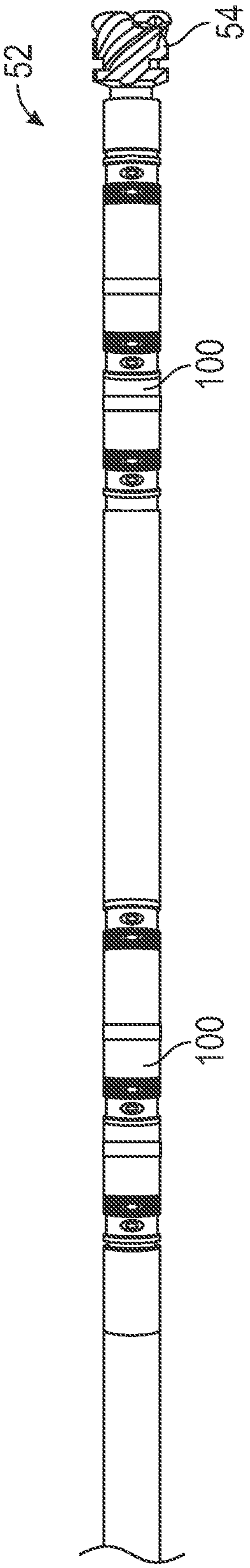
52
54
100
100

FIG. 2

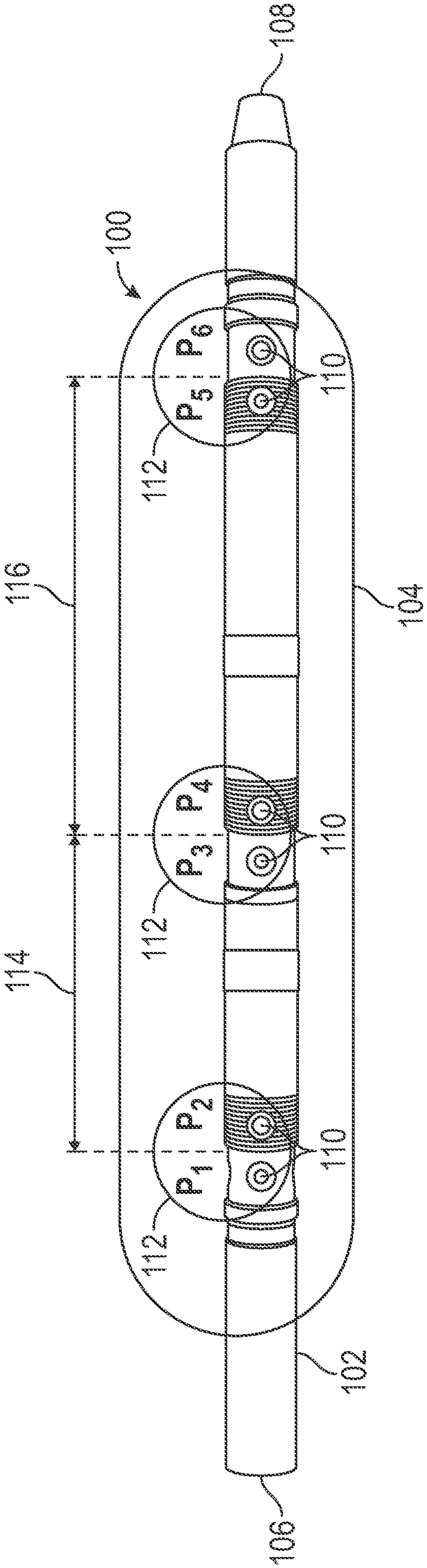
108
100
$P_6$
$P_5$
110
112
116
104
$P_4$
$P_3$
110
112
114
$P_2$
$P_1$
110
112
102
106

FIG. 3

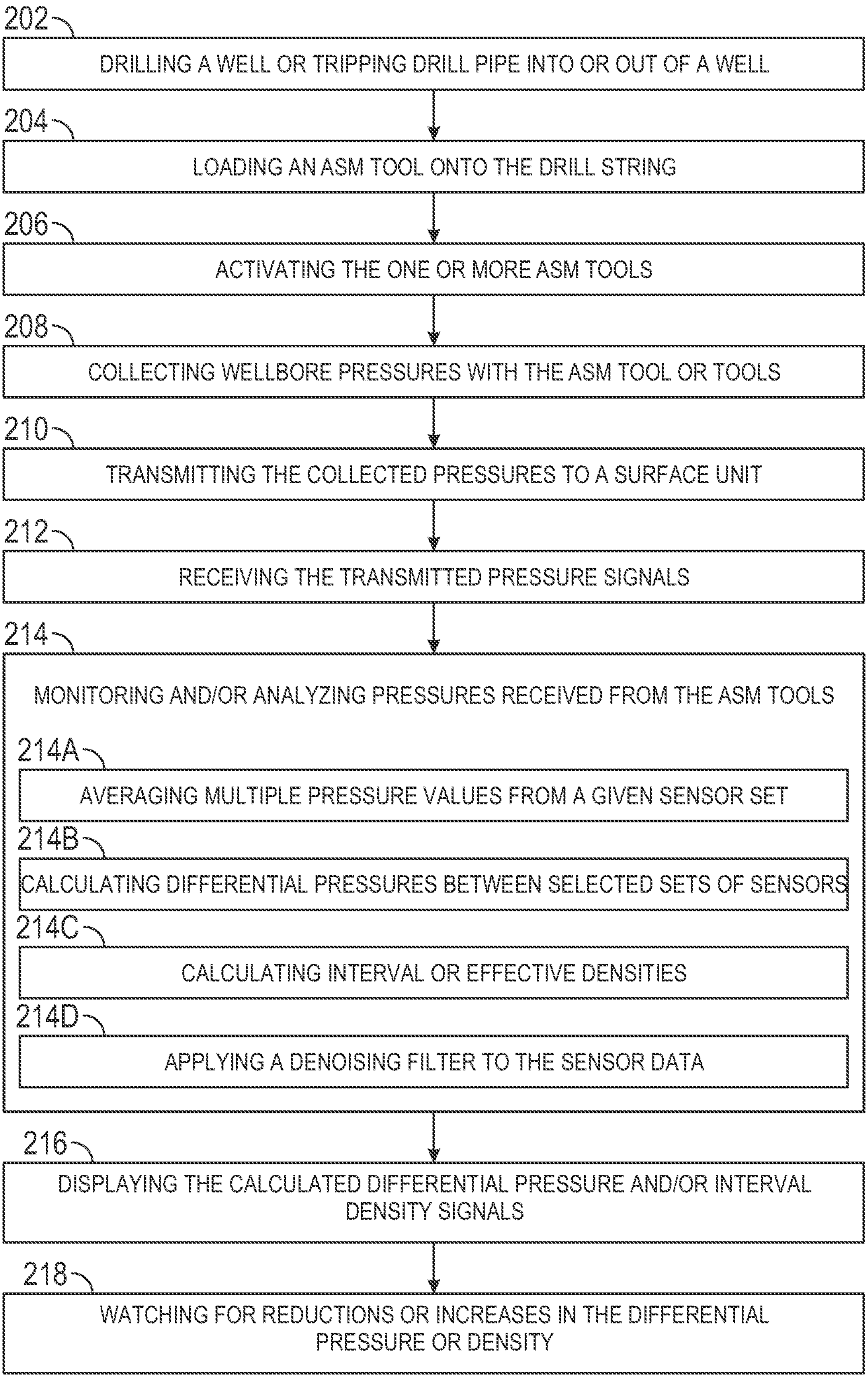
202
DRILLING A WELL OR TRIPPING DRILL PIPE INTO OR OUT OF A WELL
204
LOADING AN ASM TOOL ONTO THE DRILL STRING
206
ACTIVATING THE ONE OR MORE ASM TOOLS
208
COLLECTING WELLBORE PRESSURES WITH THE ASM TOOL OR TOOLS
210
TRANSMITTING THE COLLECTED PRESSURES TO A SURFACE UNIT
212
RECEIVING THE TRANSMITTED PRESSURE SIGNALS
214
MONITORING AND/OR ANALYZING PRESSURES RECEIVED FROM THE ASM TOOLS
214A
AVERAGING MULTIPLE PRESSURE VALUES FROM A GIVEN SENSOR SET
214B
CALCULATING DIFFERENTIAL PRESSURES BETWEEN SELECTED SETS OF SENSORS
214C
CALCULATING INTERVAL OR EFFECTIVE DENSITIES
214D
APPLYING A DENOISING FILTER TO THE SENSOR DATA
216
DISPLAYING THE CALCULATED DIFFERENTIAL PRESSURE AND/OR INTERVAL DENSITY SIGNALS
218
WATCHING FOR REDUCTIONS OR INCREASES IN THE DIFFERENTIAL PRESSURE OR DENSITY

FIG. 4

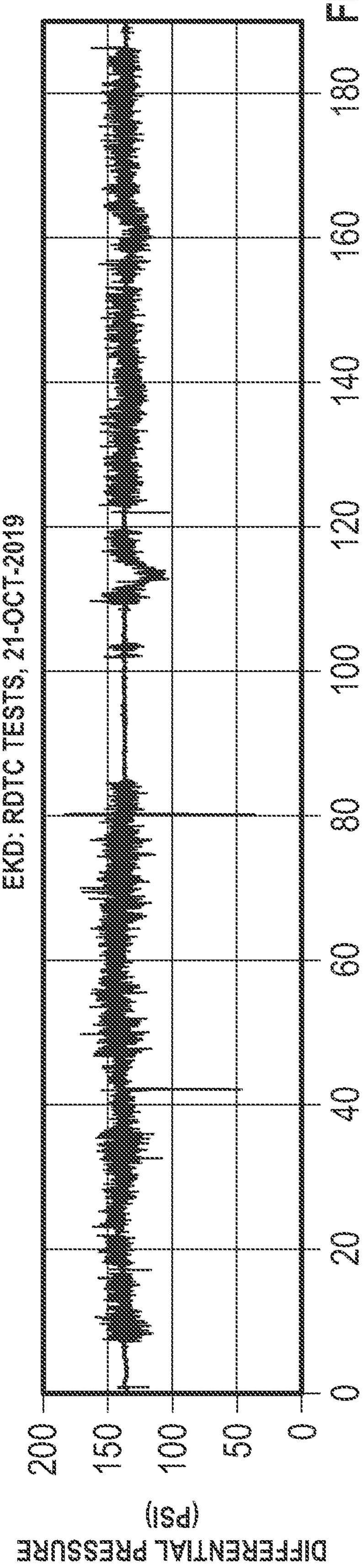

FIG. 5A

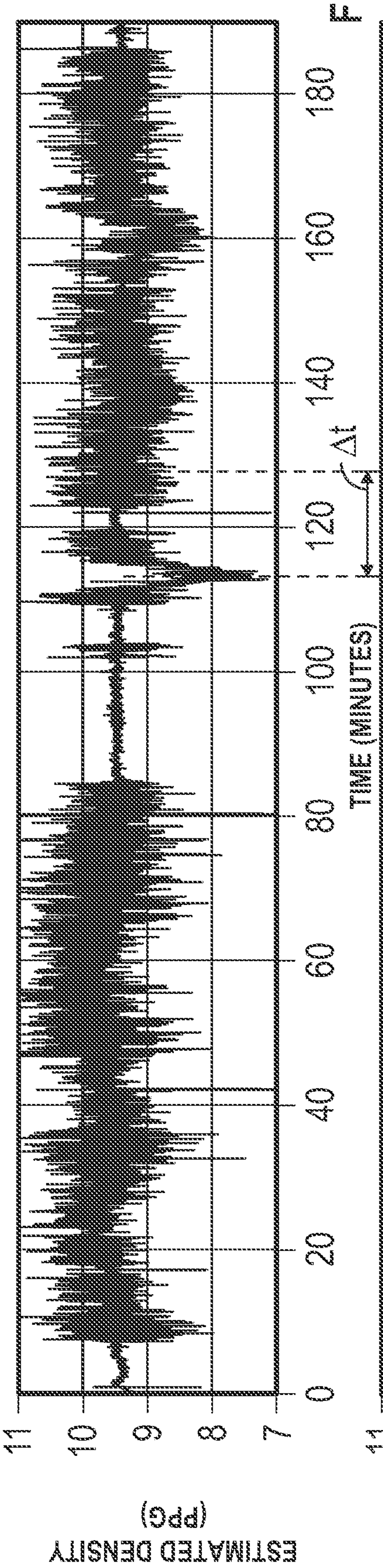

FIG. 5B

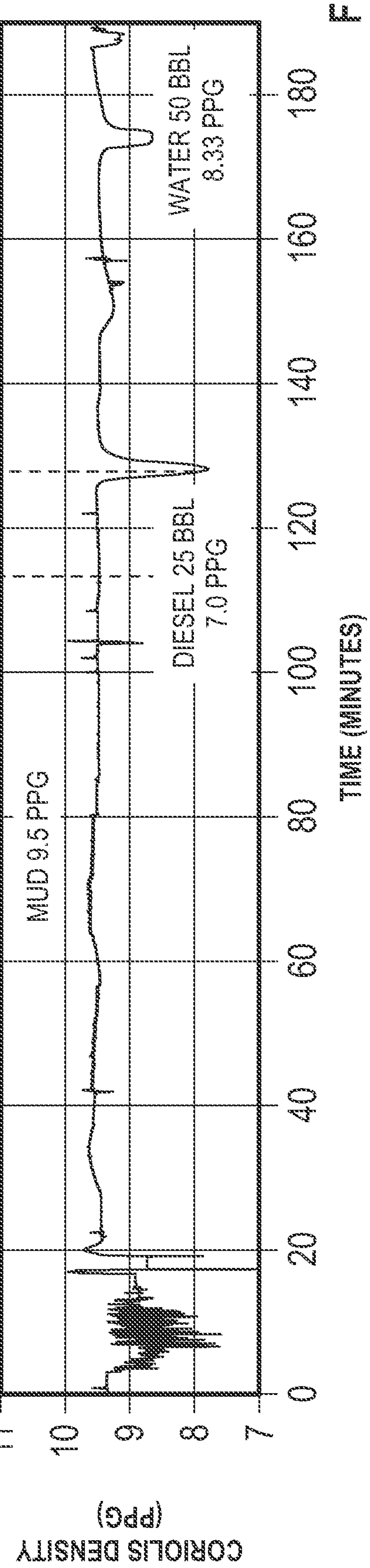

FIG. 5C

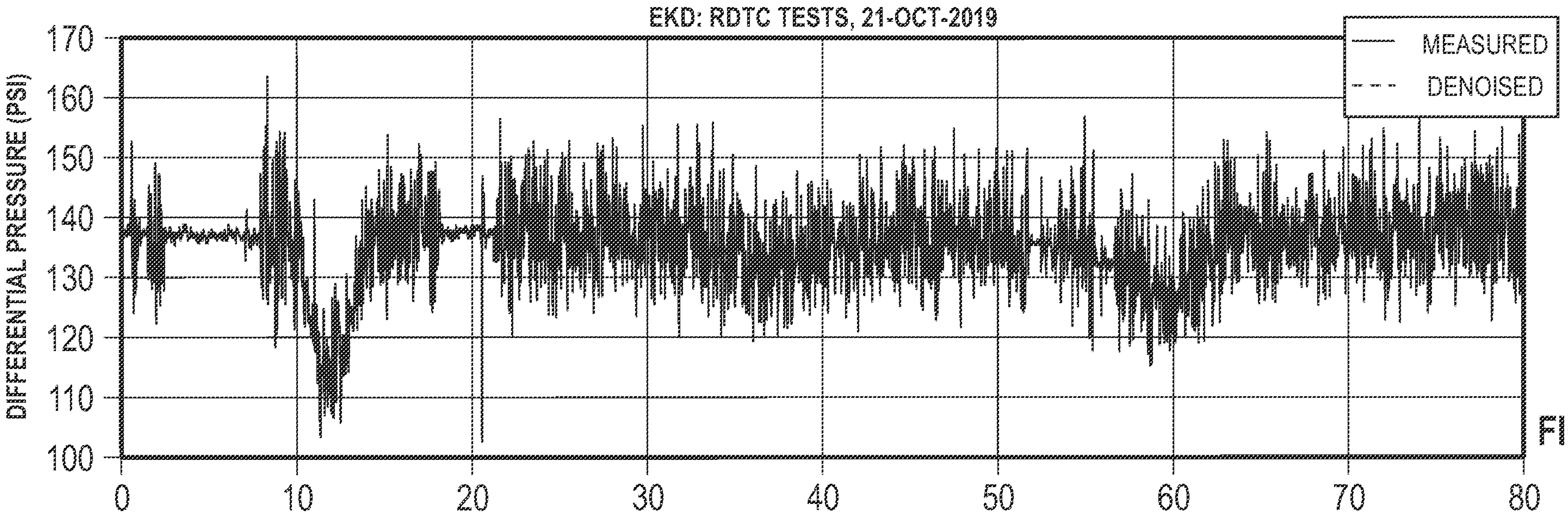
EKD: RDTC TESTS, 21-OCT-2019
MEASURED
DENOISED
DIFFERENTIAL PRESSURE (PSI)
170
160
150
140
130
120
110
100
0
10
20
30
40
50
60
70
80

FIG. 6A

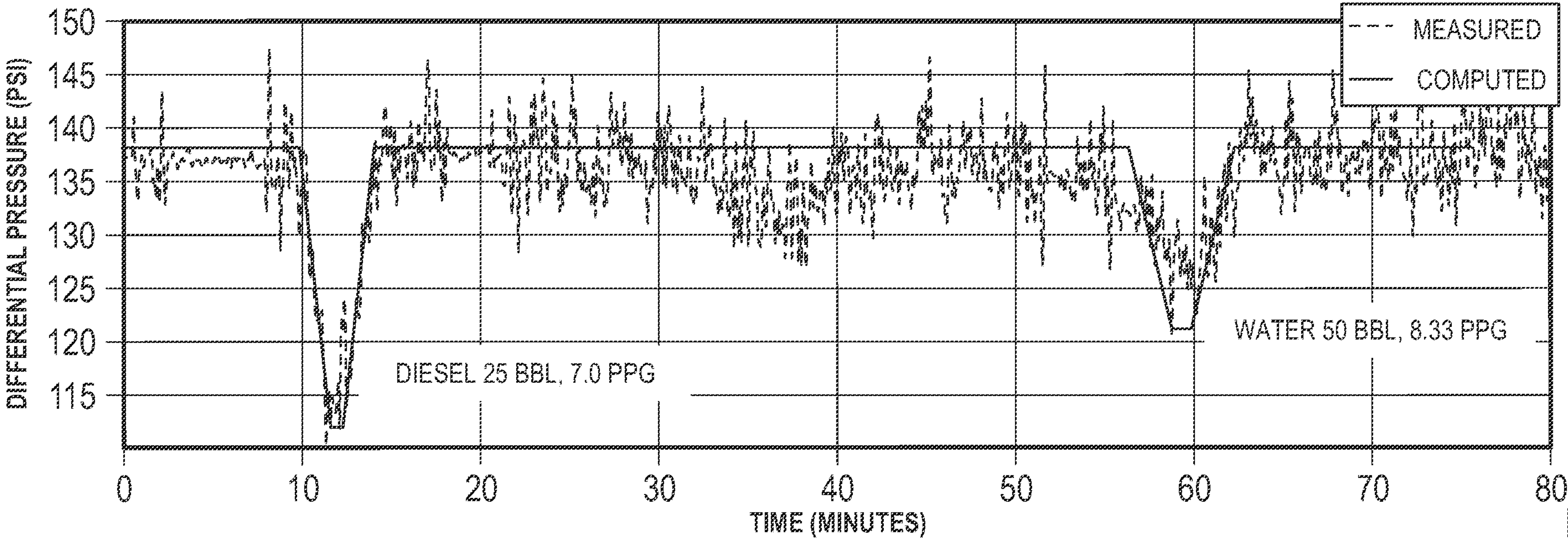
MEASURED
COMPUTED
DIFFERENTIAL PRESSURE (PSI)
150
145
140
135
130
125
120
115
DIESEL 25 BBL, 7.0 PPG
WATER 50 BBL, 8.33 PPG
0
10
20
30
40
50
60
70
80
TIME (MINUTES)

FIG. 6B

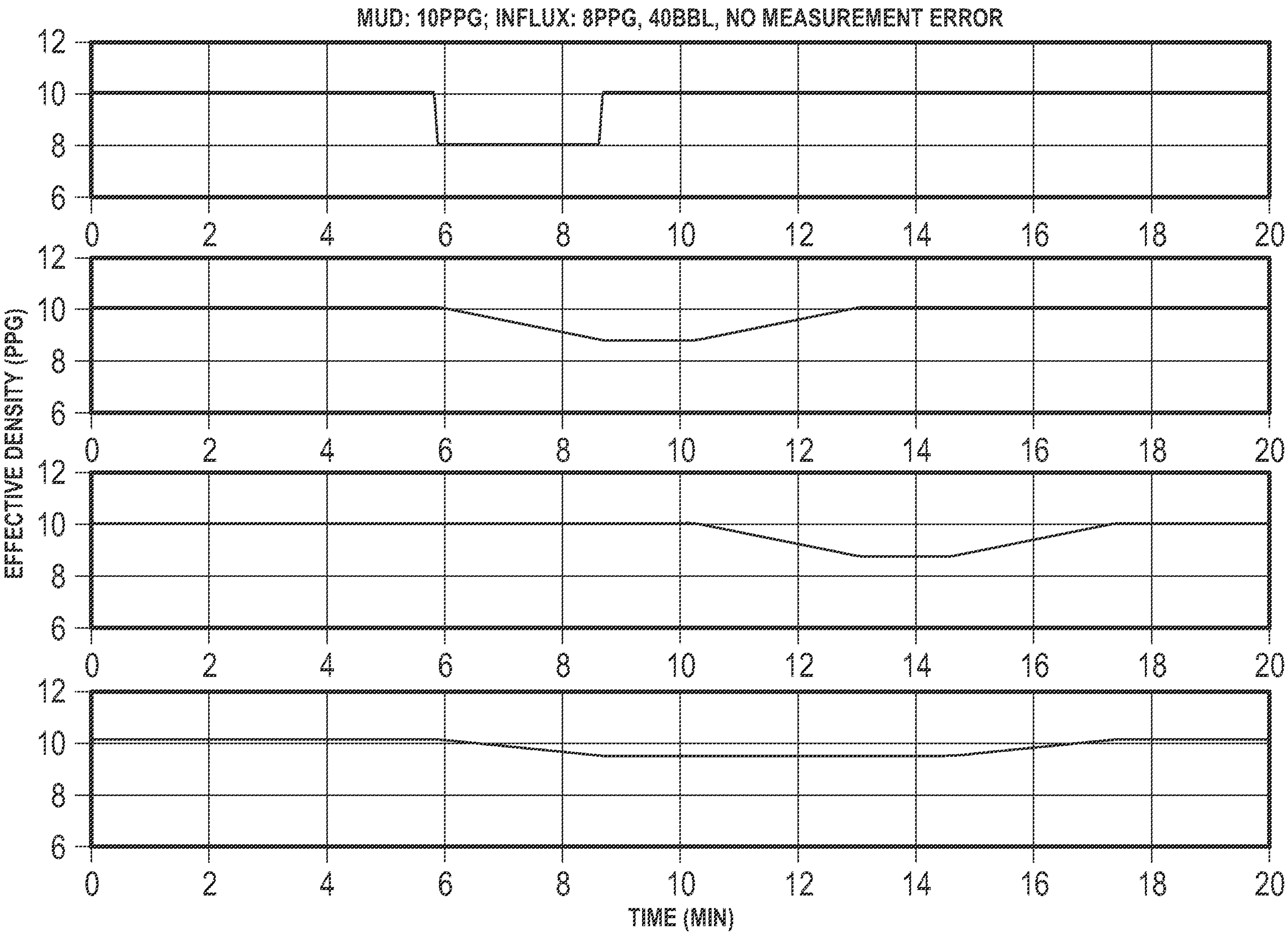
MUD: 10PPG; INFLUX: 8PPG, 40BBL, NO MEASUREMENT ERROR

FIG. 7

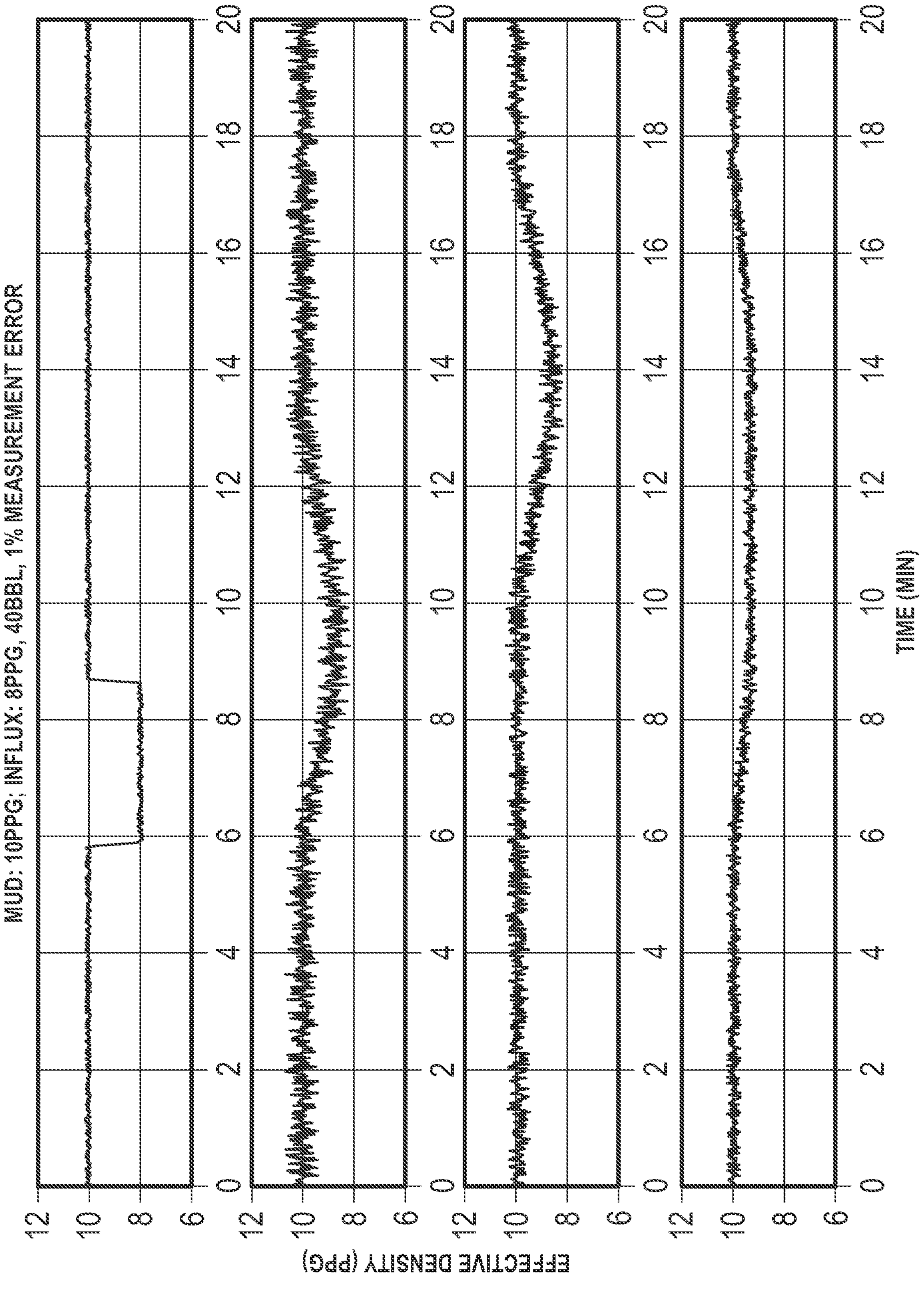
MUD: 10PPG; INFLUX: 8PPG, 40BBL, 1% MEASUREMENT ERROR
EFFECTIVE DENSITY (PPG)
12
10
8
6
12
10
8
6
12
10
8
6
12
10
8
6
0
2
4
6
8
10
12
14
16
18
20
TIME (MIN)

FIG. 8

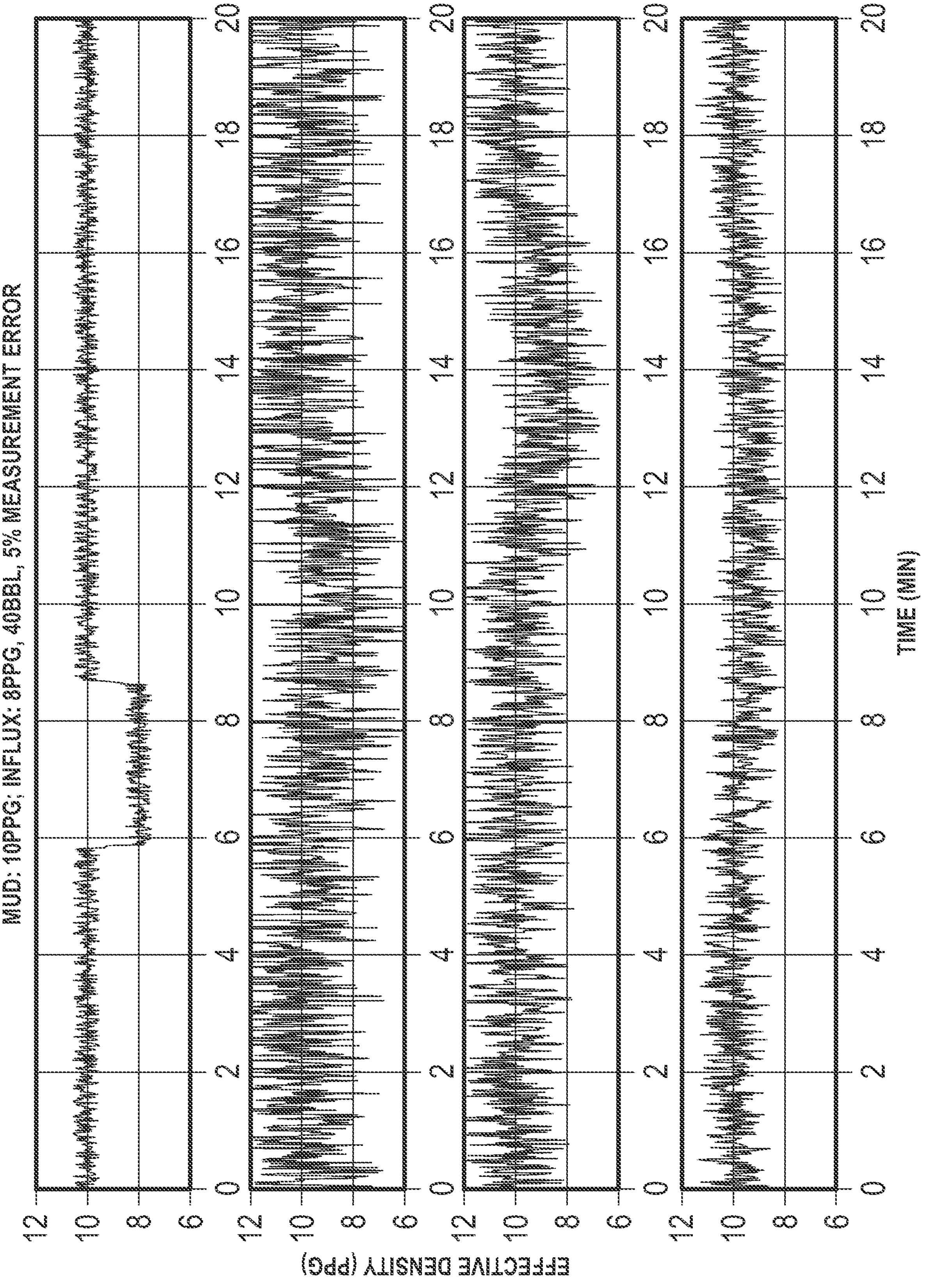
MUD: 10PPG; INFLUX: 8PPG, 40BBL, 5% MEASUREMENT ERROR
EFFECTIVE DENSITY (PPG)
12
10
8
6
0
2
4
6
8
10
12
14
16
18
20
TIME (MIN)

FIG. 9

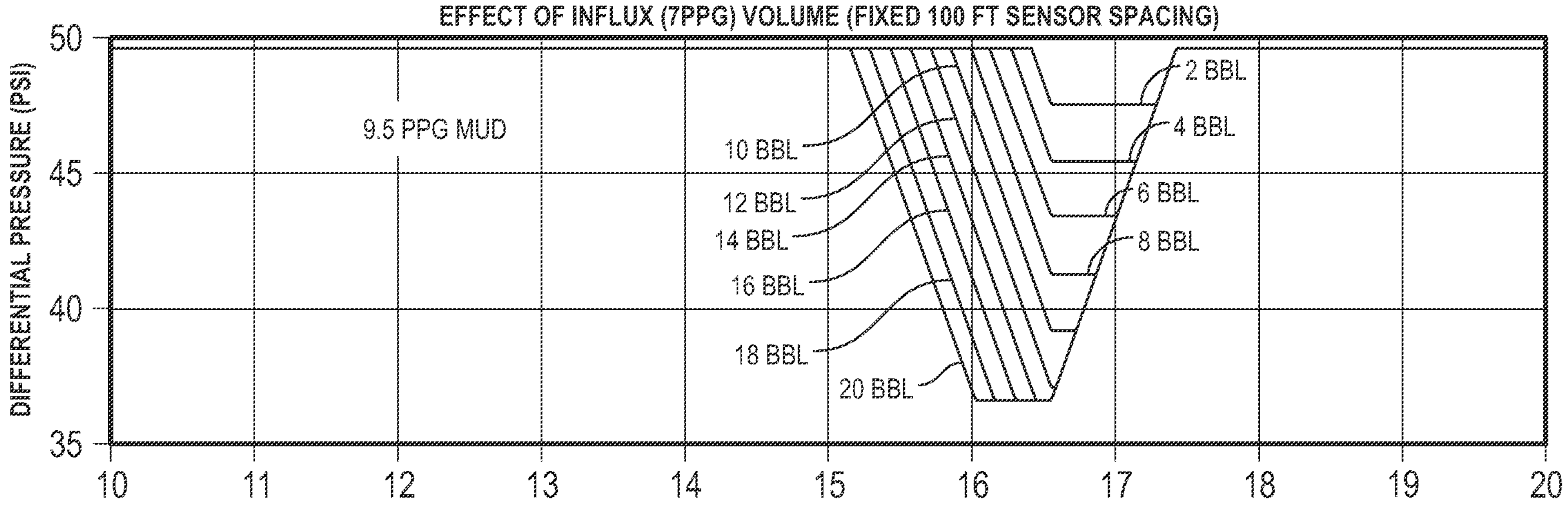

FIG. 10A

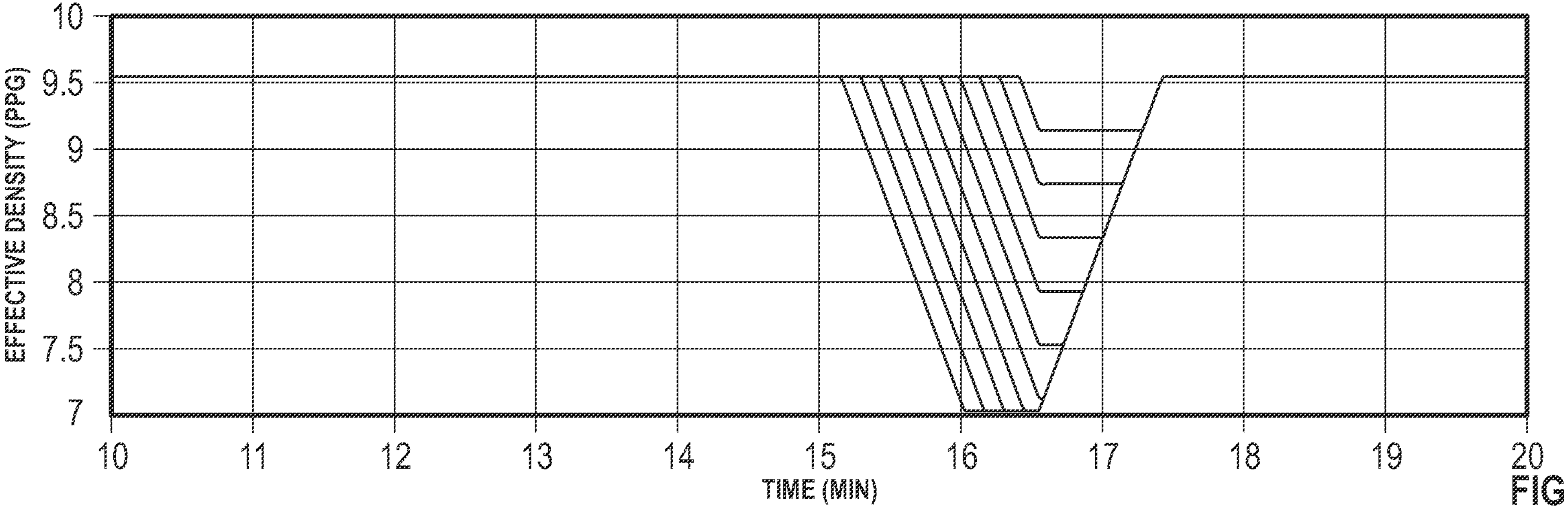

FIG. 10B

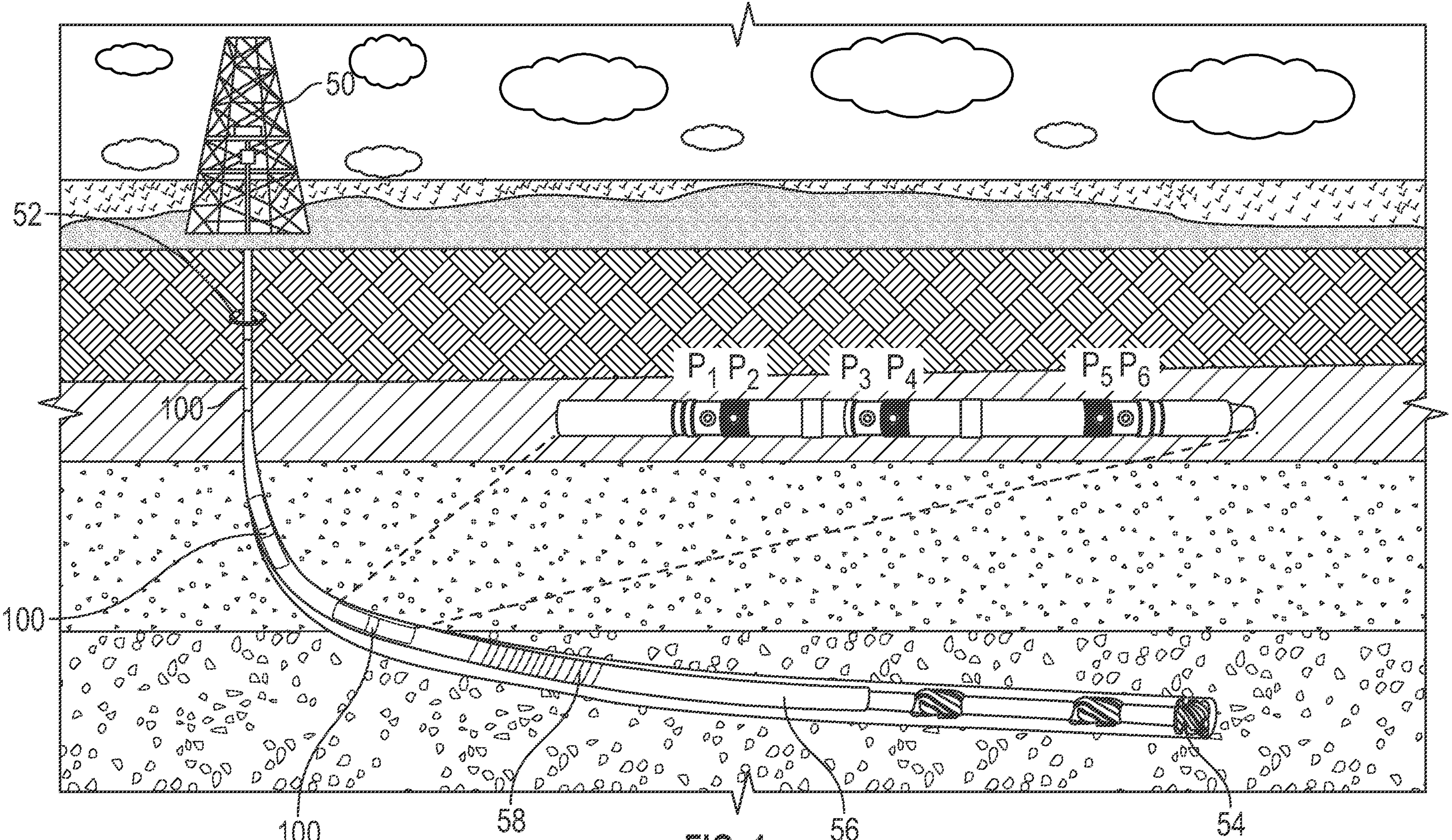

FIG. 1