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(54) **WELL TREATMENT APPARATUS AND METHOD**

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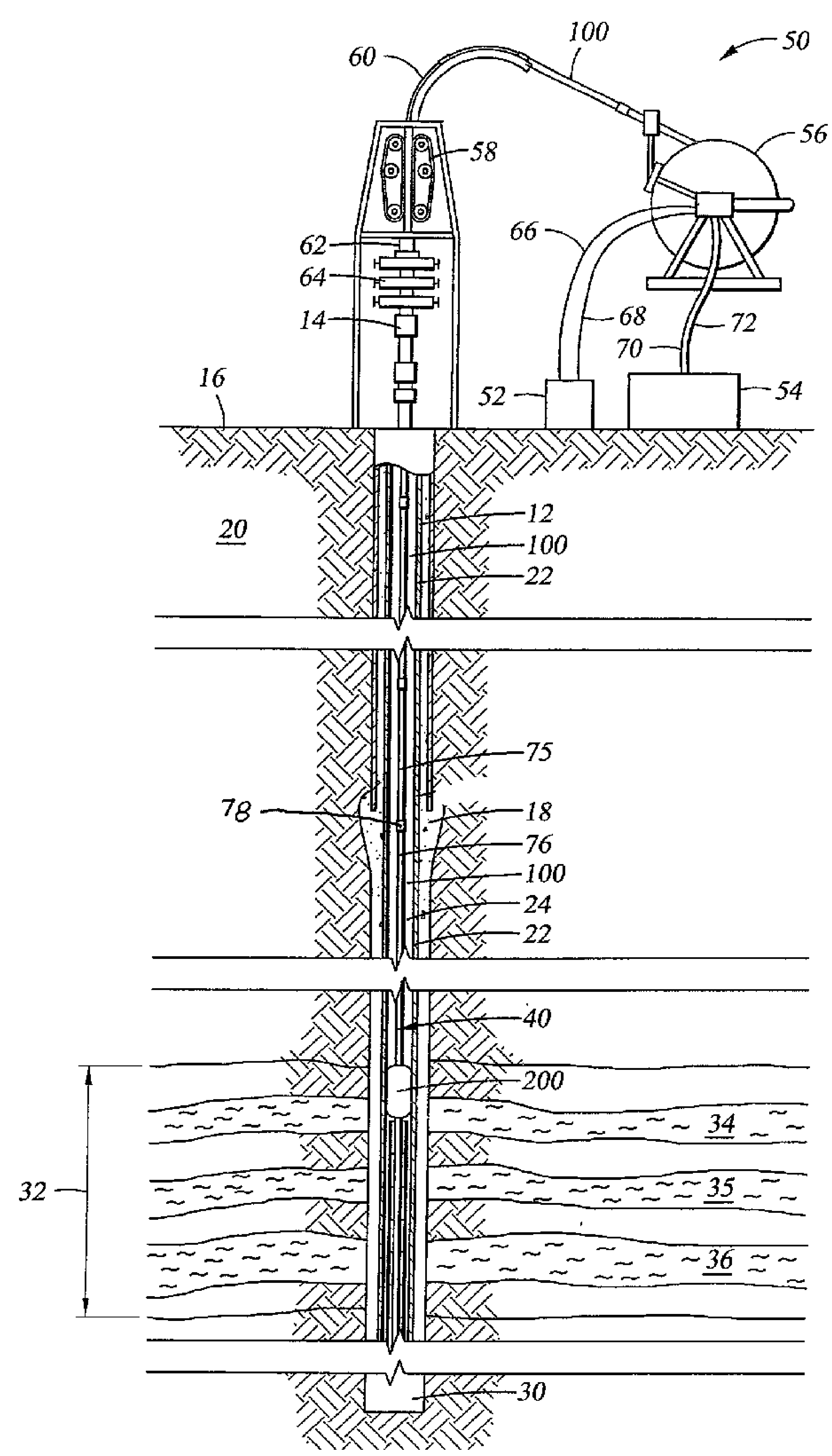
(57) **ABSTRACT**

Apparatus and methods are disclosed for sequentially treating multiple zones in underground formation in a single trip of the well treatment work string. In the one embodiment, the work string includes composite tubing having electrical conductors embedded within the walls, the conductors enabling power transmission and two way communication between the surface and the sensor or detectors downhole so that real time data can be sensed and communicated. Isolation packers are actuated via electrical signals from the surface communicated to the bottom hole assembly via the conductors. A detector located in the bottom hole assembly may be provided to detect perforations or other anomalies in the casing, such as joints, enabling the surface controller to position packers properly in blank segments of casing so that well intervals can be properly isolated and the adjacent formation effectively treated.



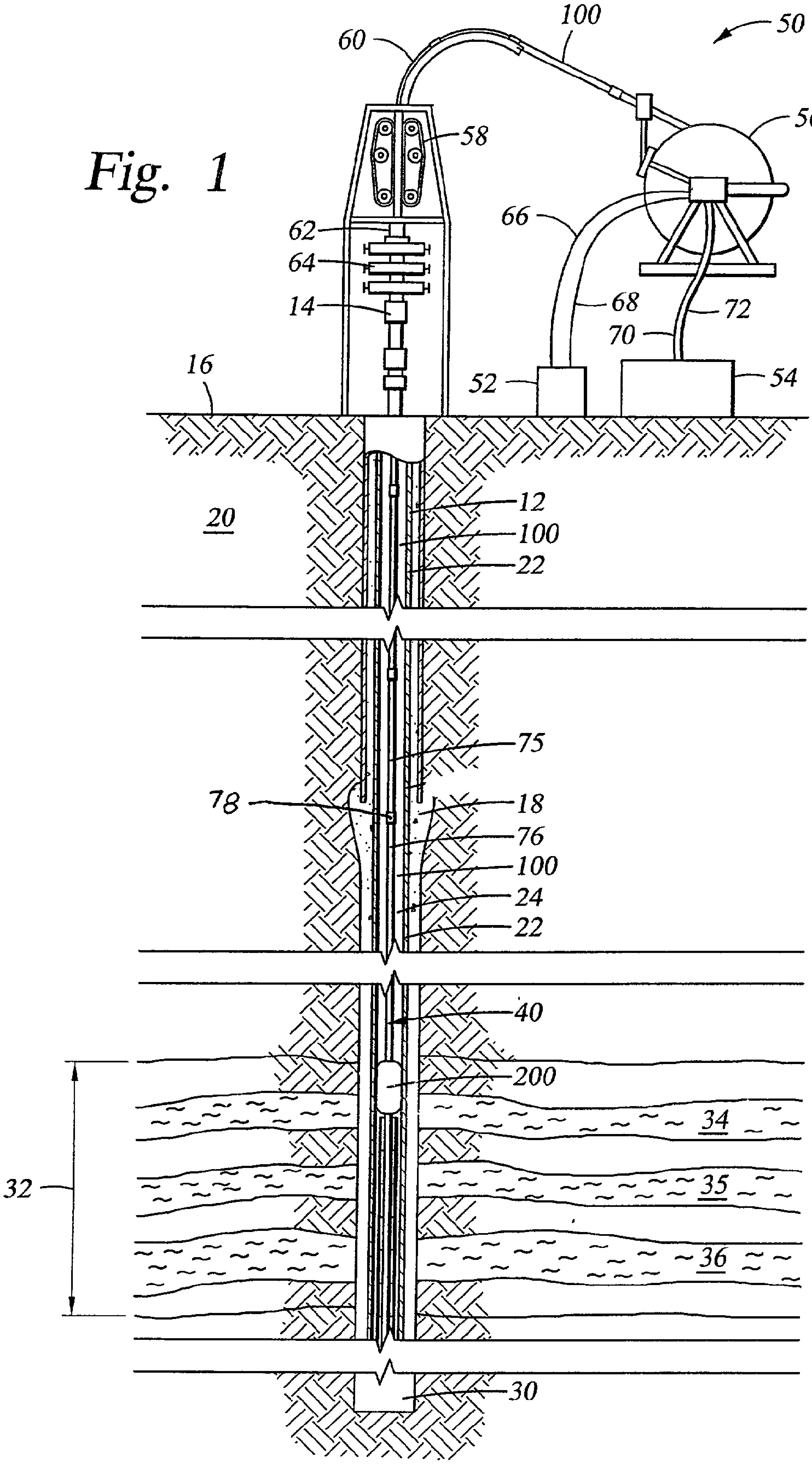

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Fig. 1

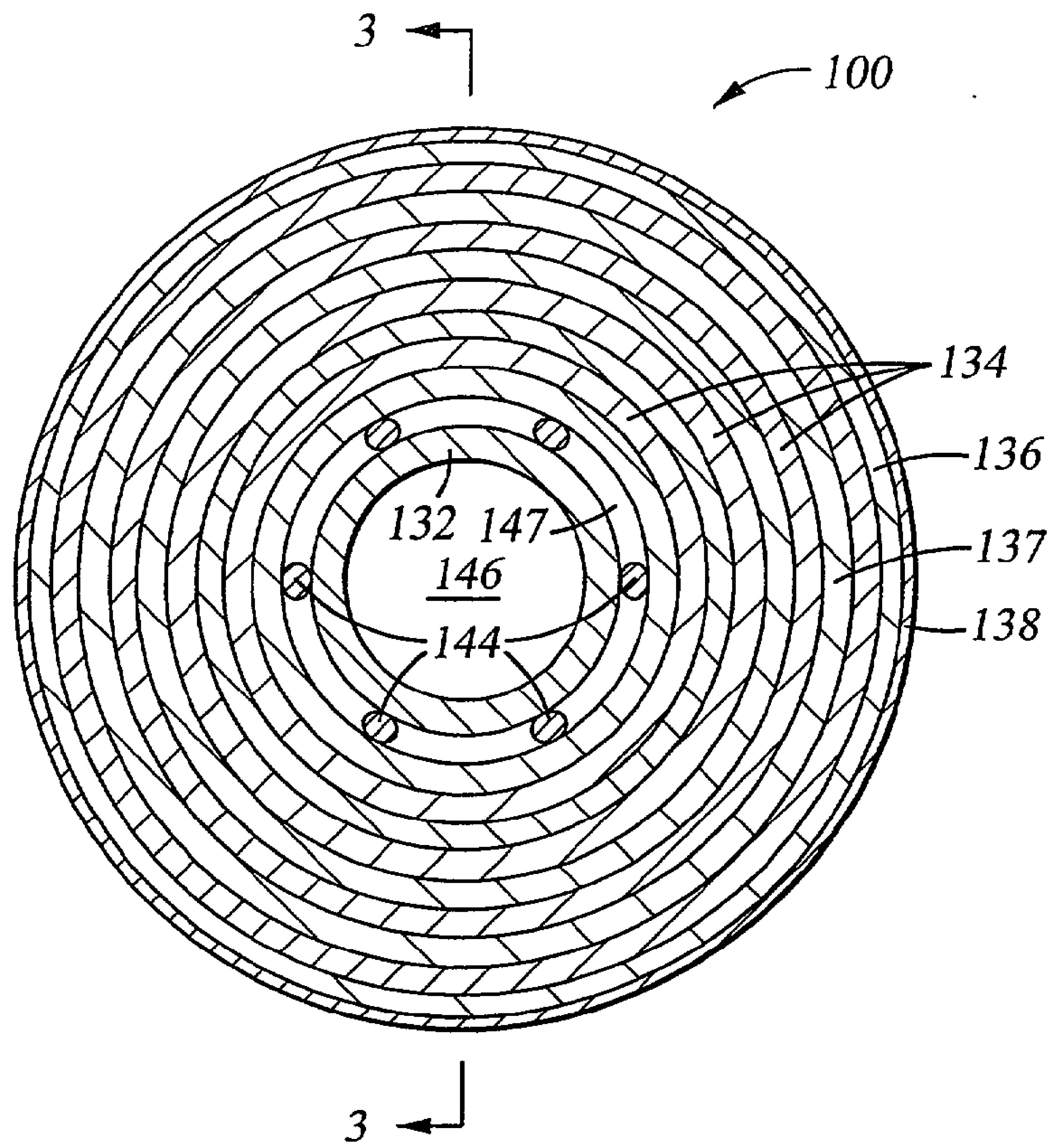
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Fig. 2

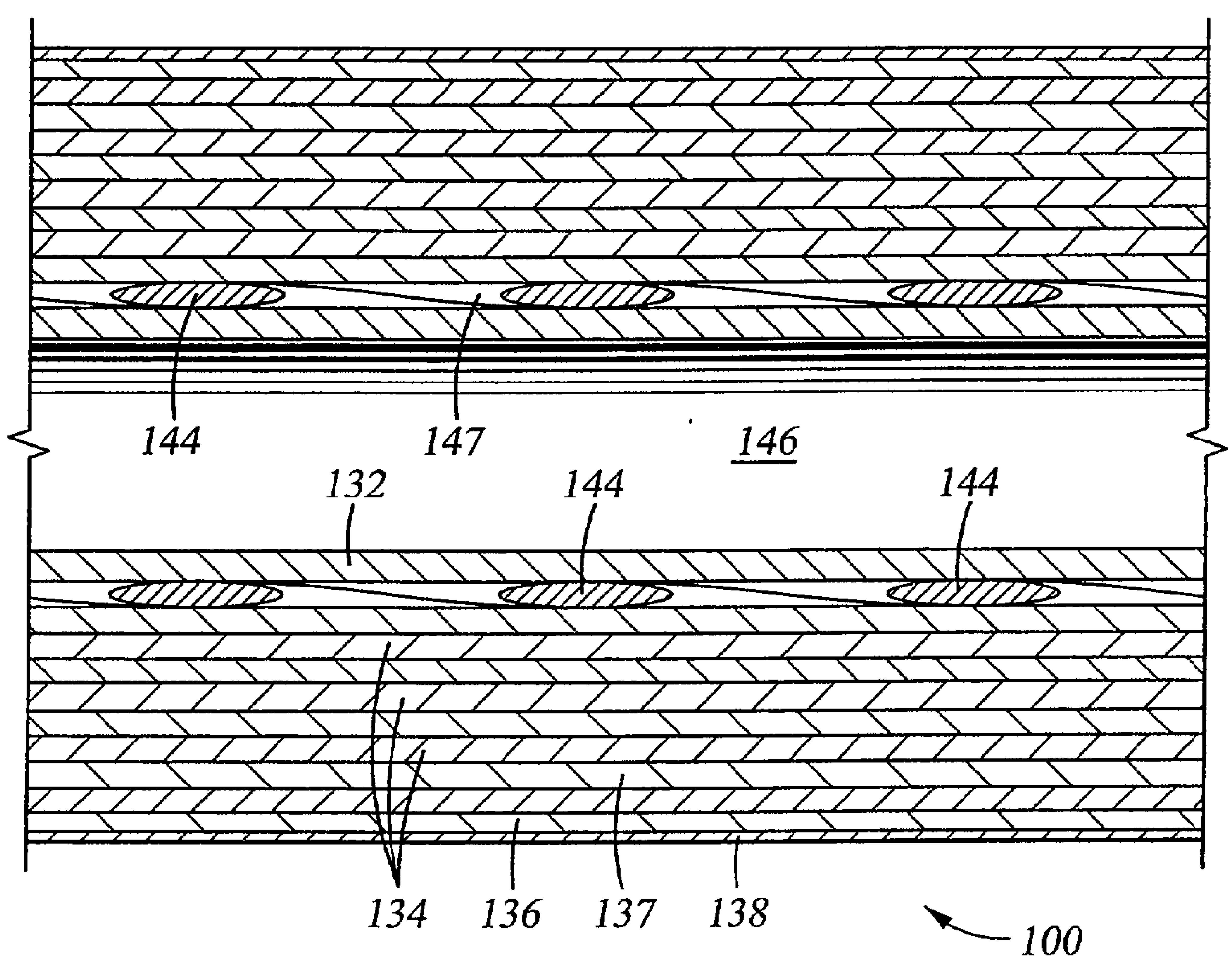
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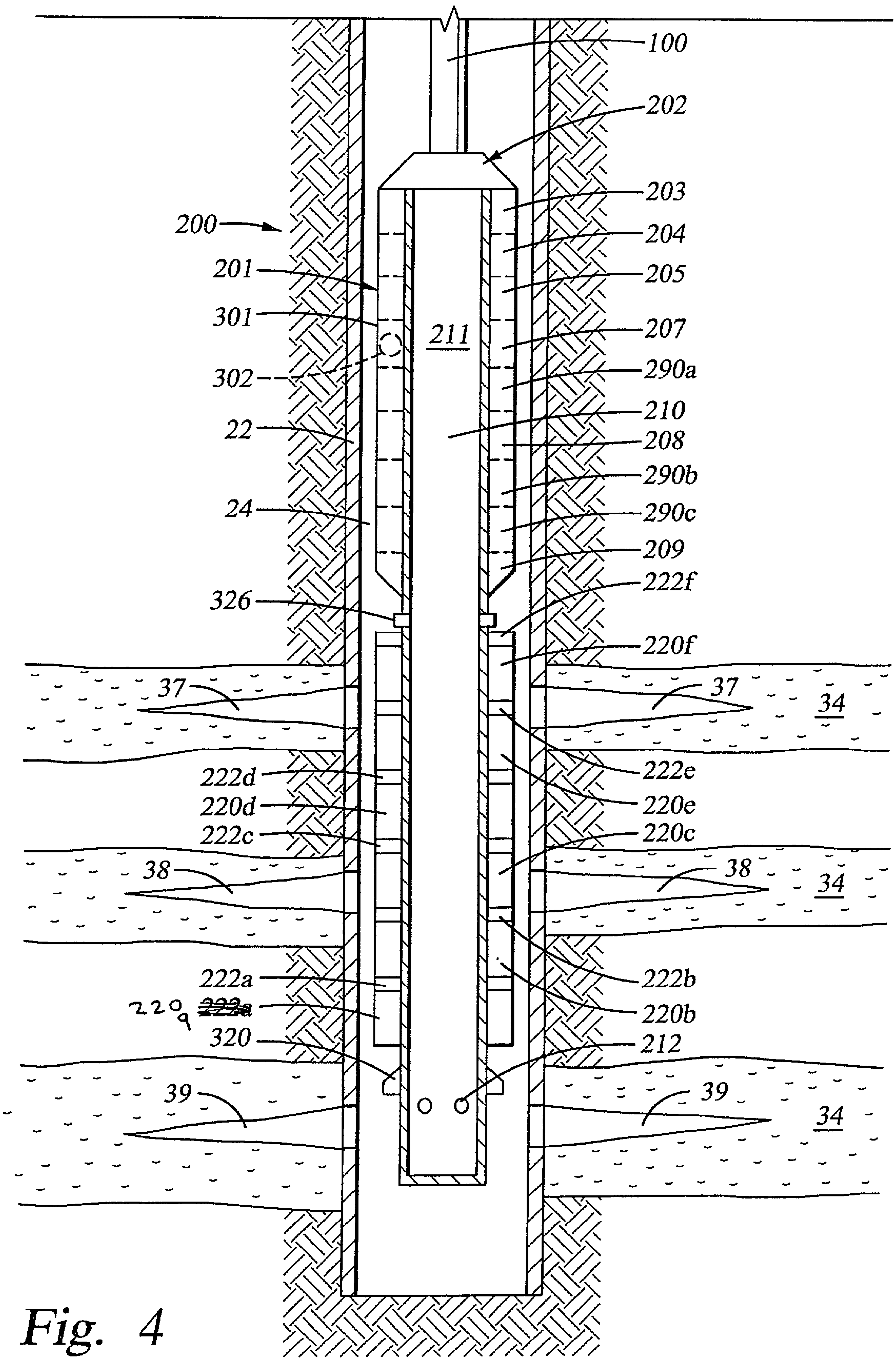
Fig. 3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222e
222d
220e
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Fig. 4

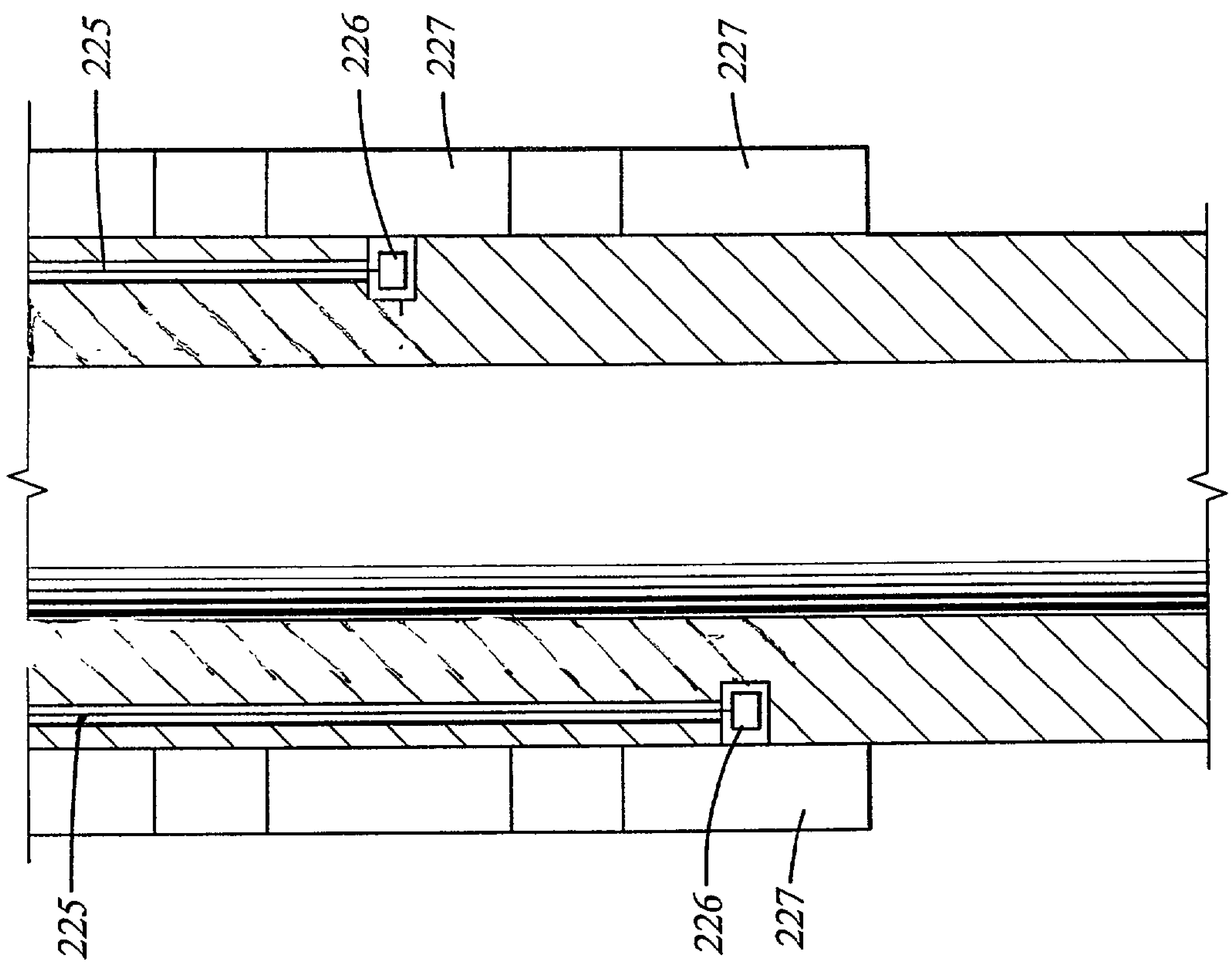
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Fig. 12

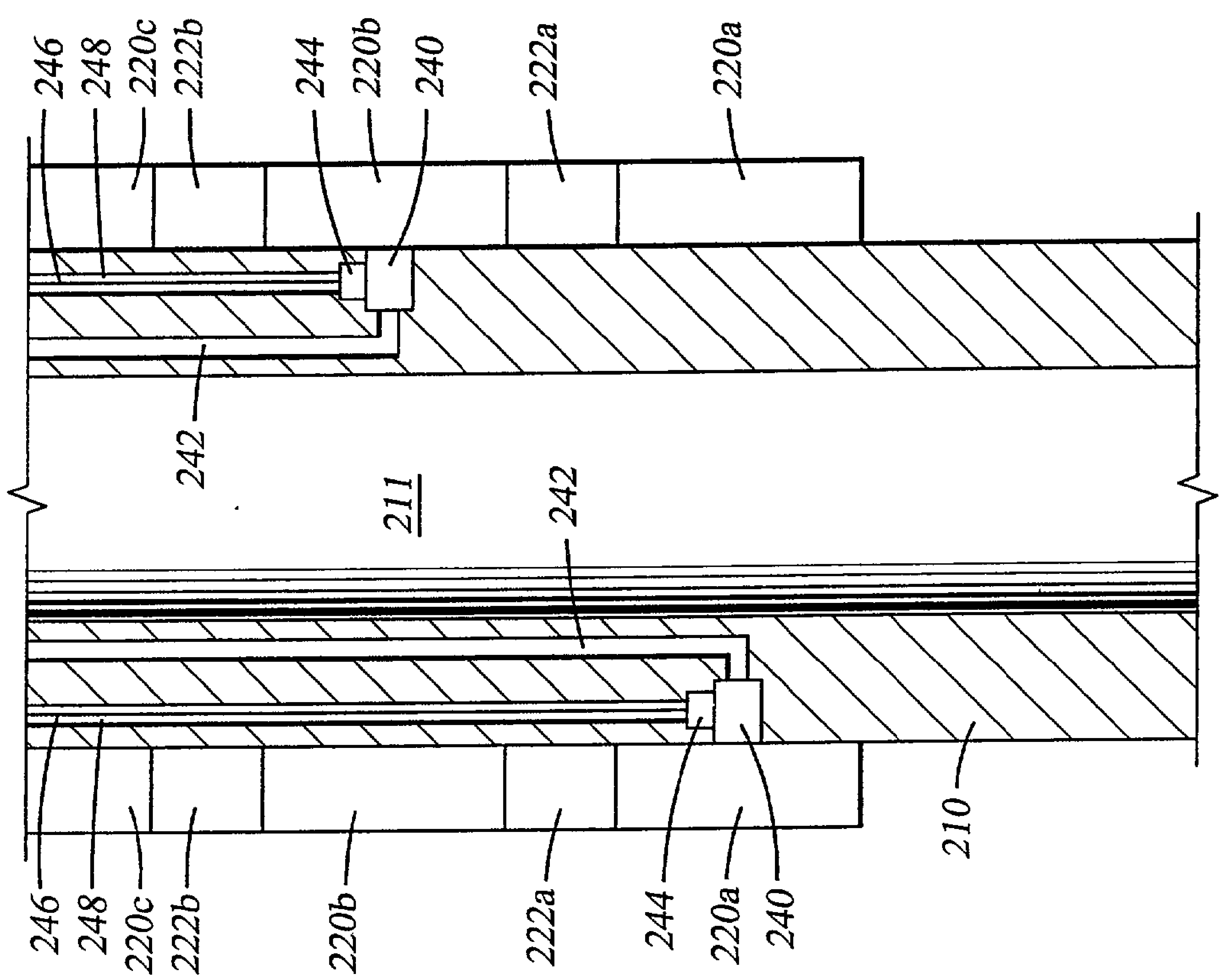
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Fig. 5

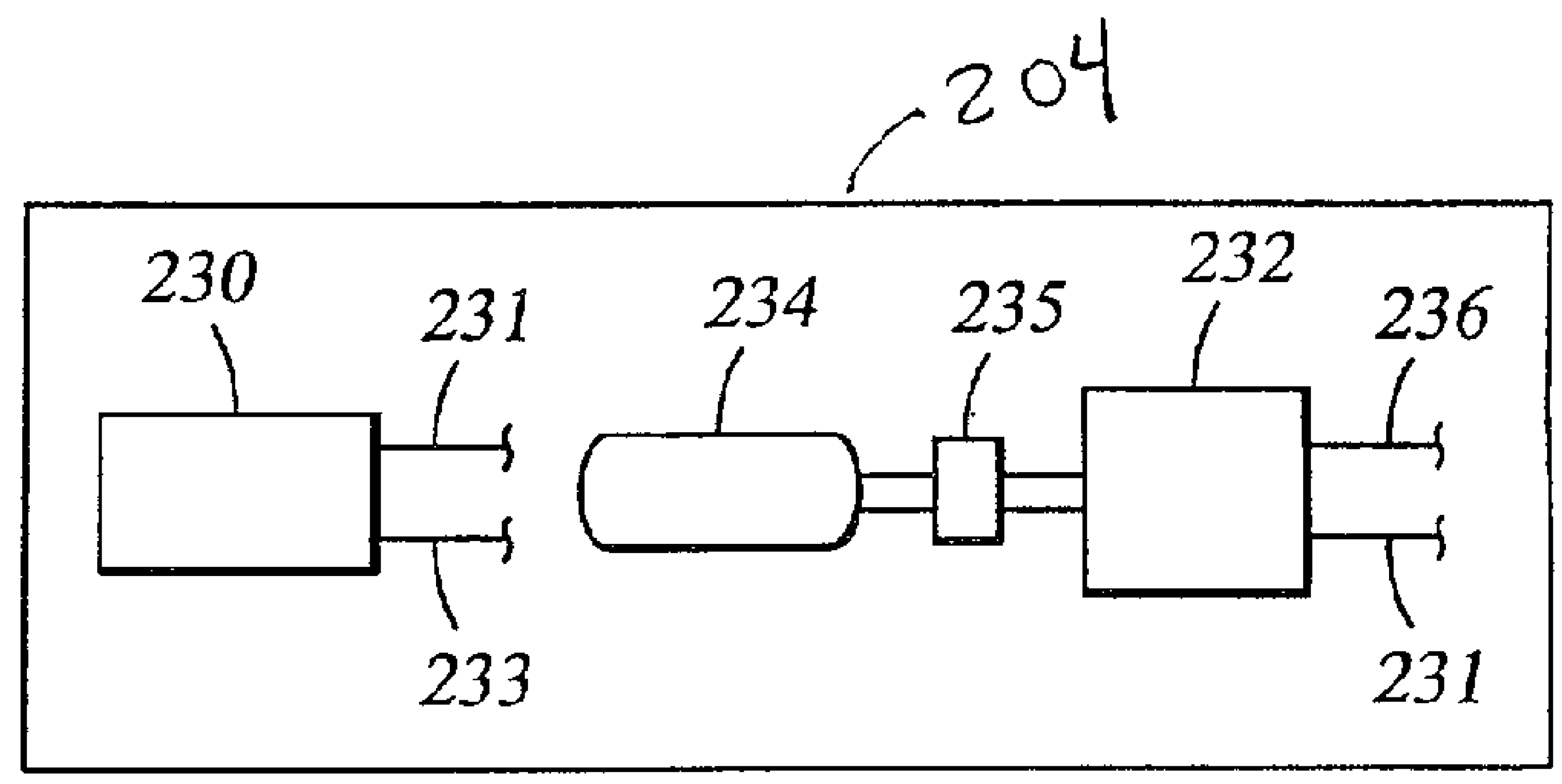
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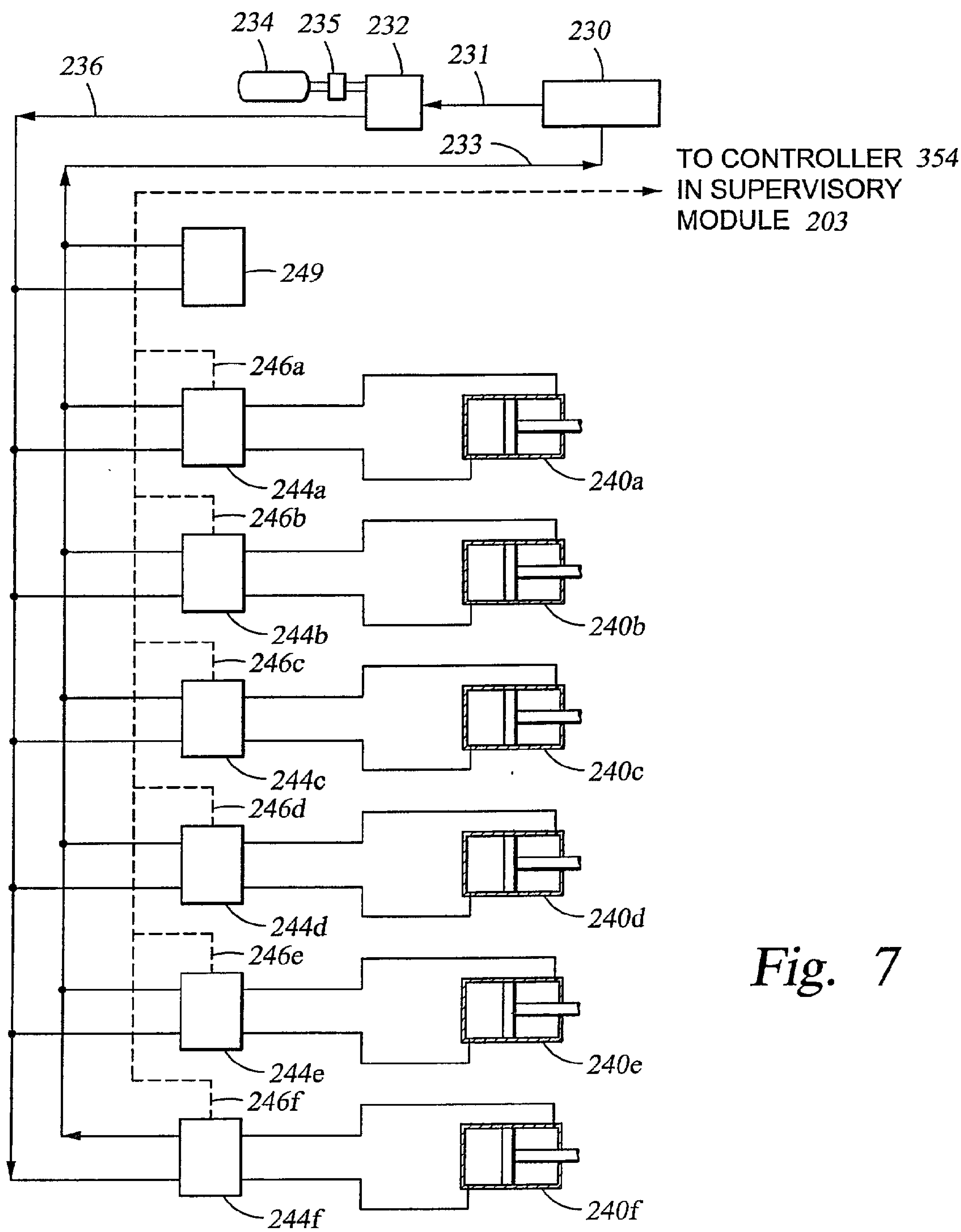
Fig. 6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TO CONTROLLER 354
IN SUPERVISORY
MODULE 203
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246b
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246c
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244d
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Fig. 7

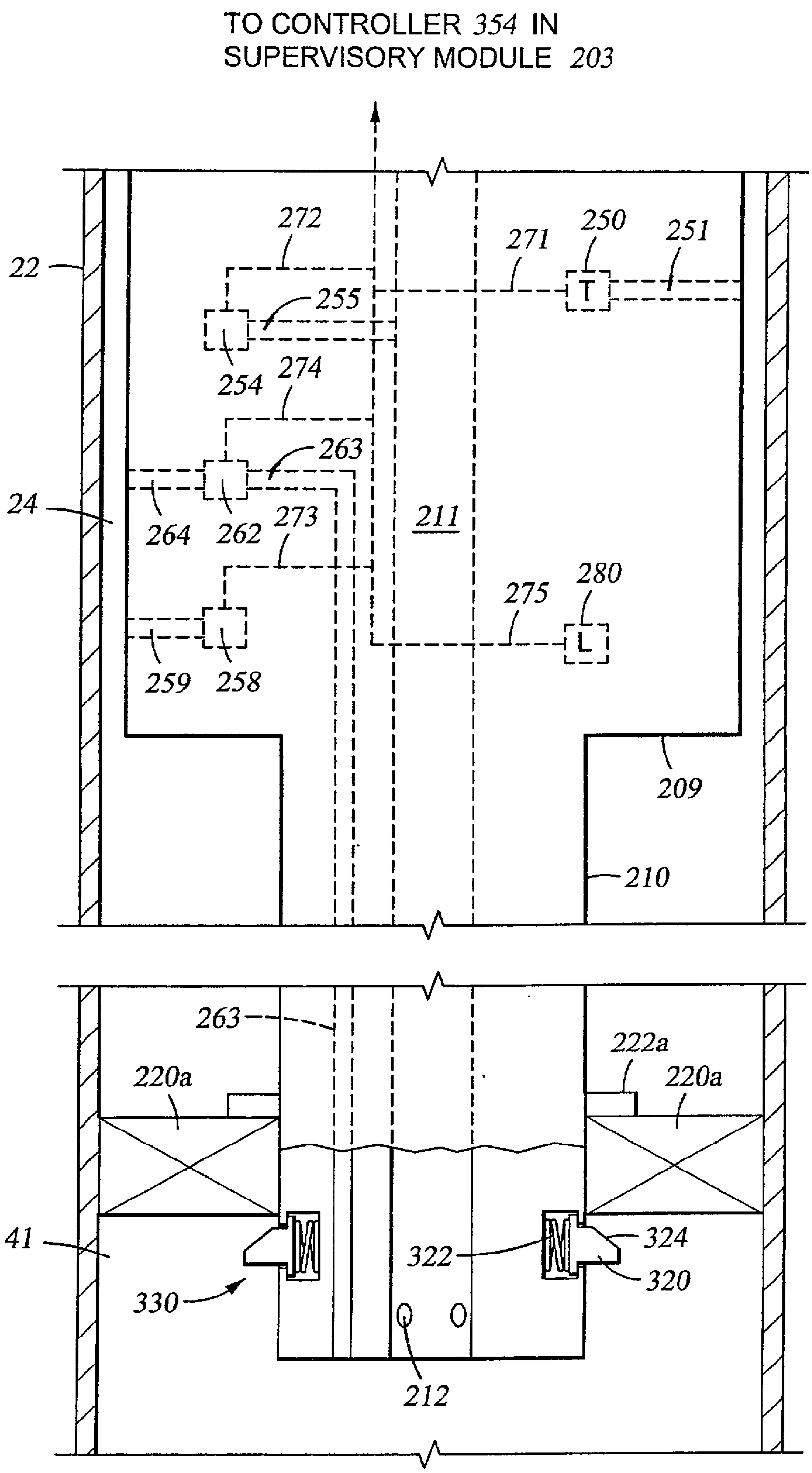
TO CONTROLLER 354 IN
SUPERVISORY MODULE 203
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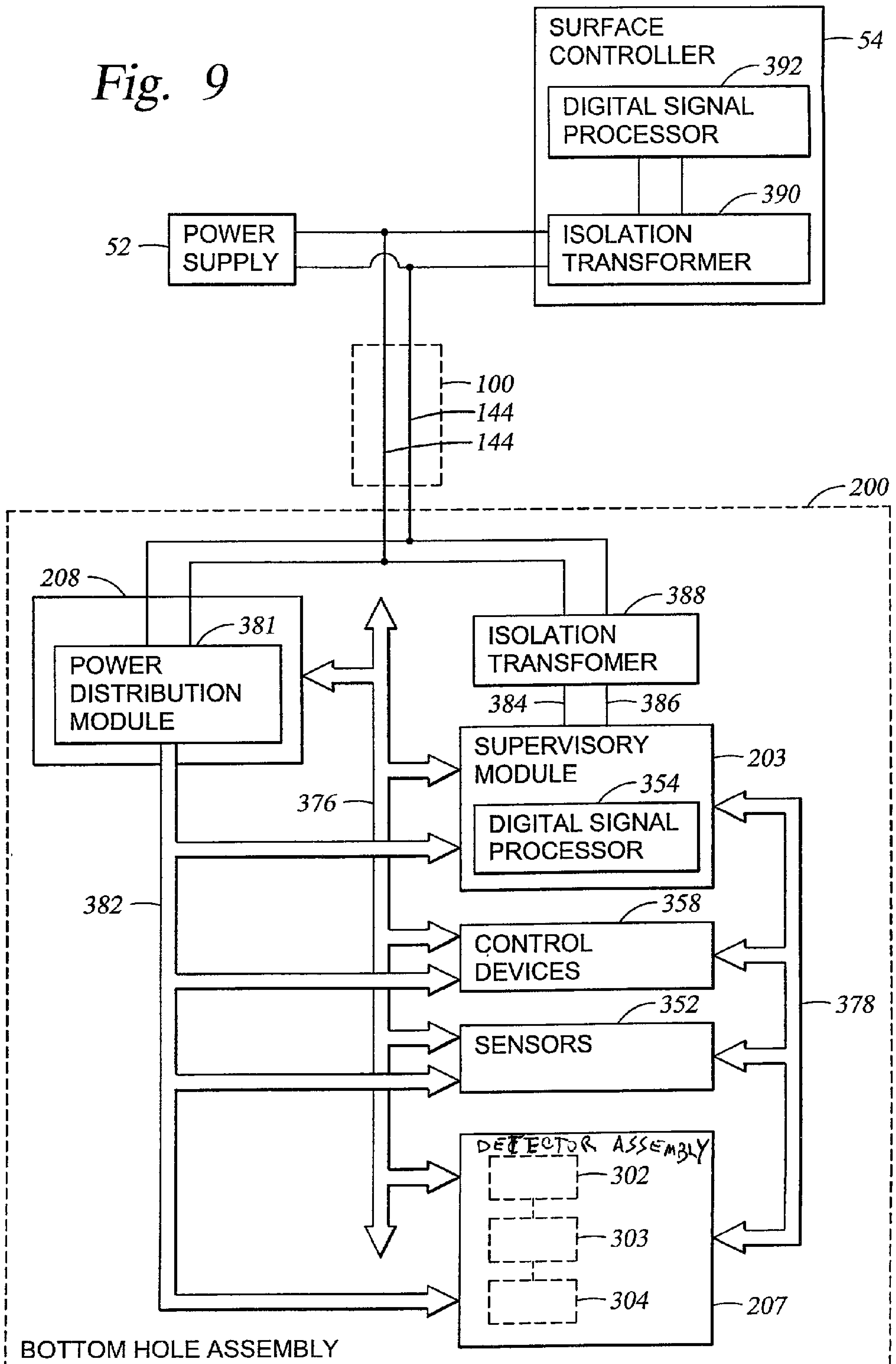
Fig. 8


SURFACE CONTROLLER
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DIGITAL SIGNAL PROCESSOR
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ISOLATION TRANSFORMER
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POWER SUPPLY
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381
POWER DISTRIBUTION MODULE
ISOLATION TRANSFOMER
384
386
SUPERVISORY MODULE
203
354
376
DIGITAL SIGNAL PROCESSOR
382
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CONTROL DEVICES
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SENSORS
DETECTOR ASSEMBLY
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207
BOTTOM HOLE ASSEMBLY

Fig. 9

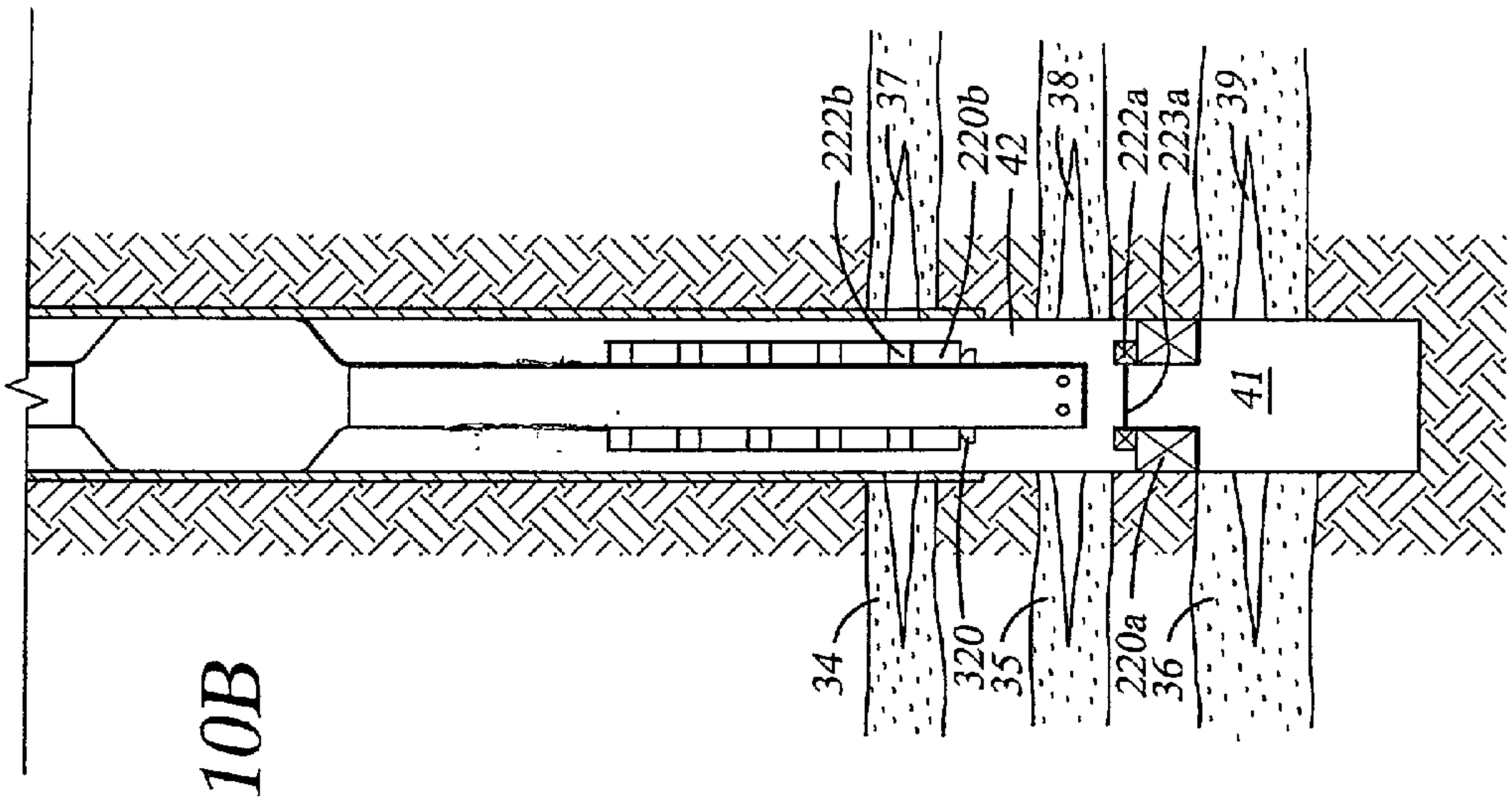

Fig. 10B

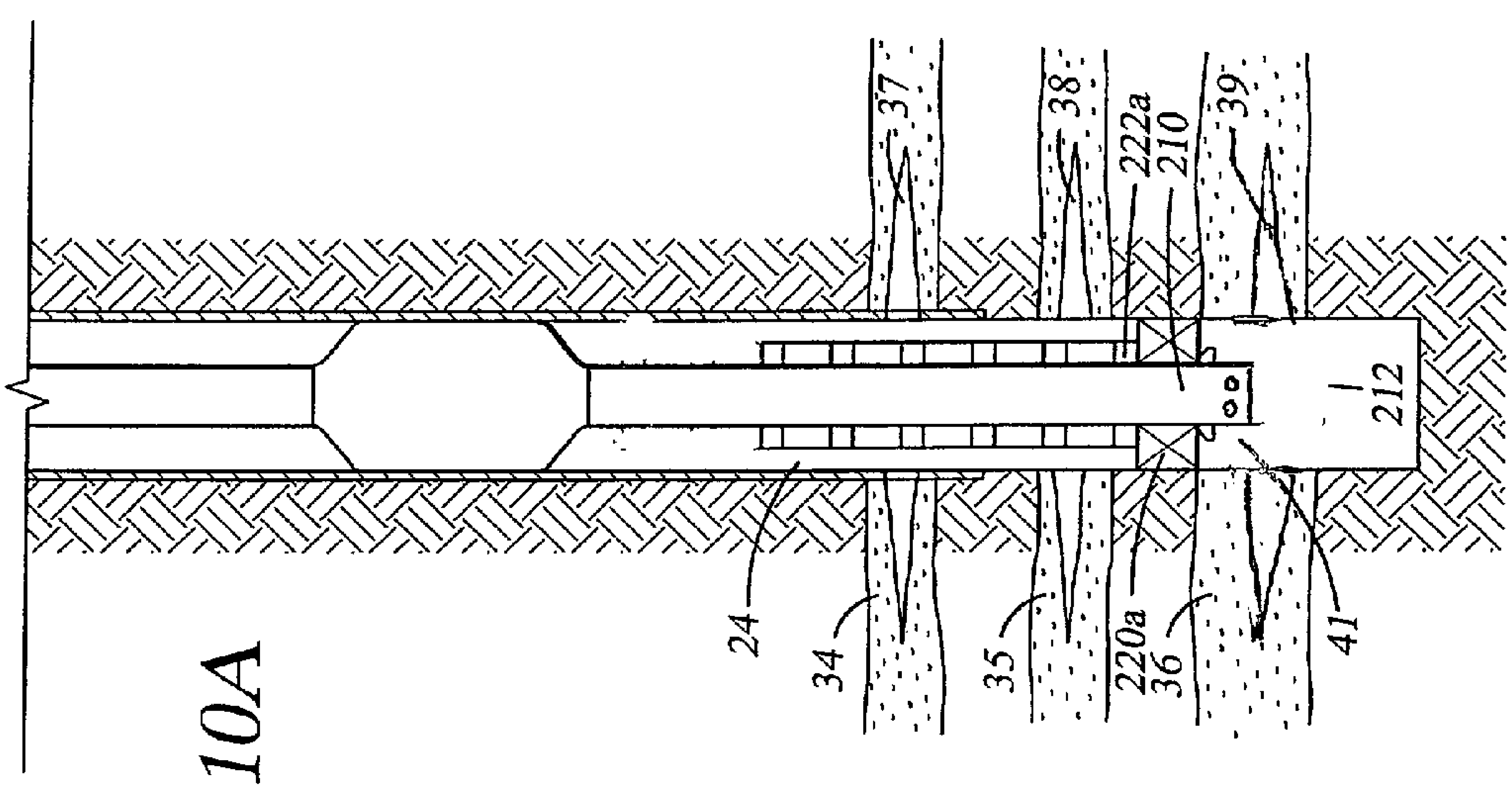

Fig. 10A

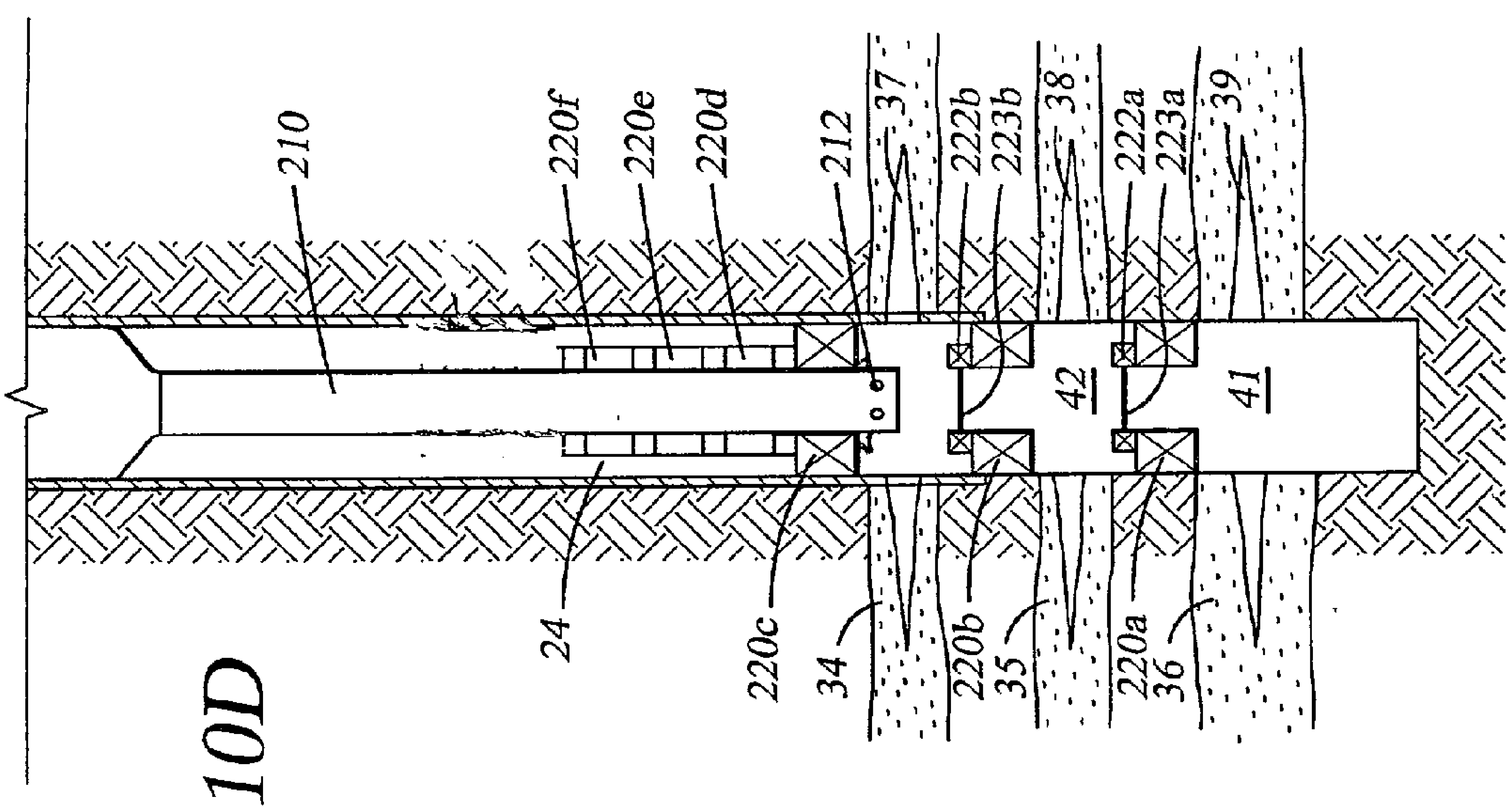

Fig. 10D

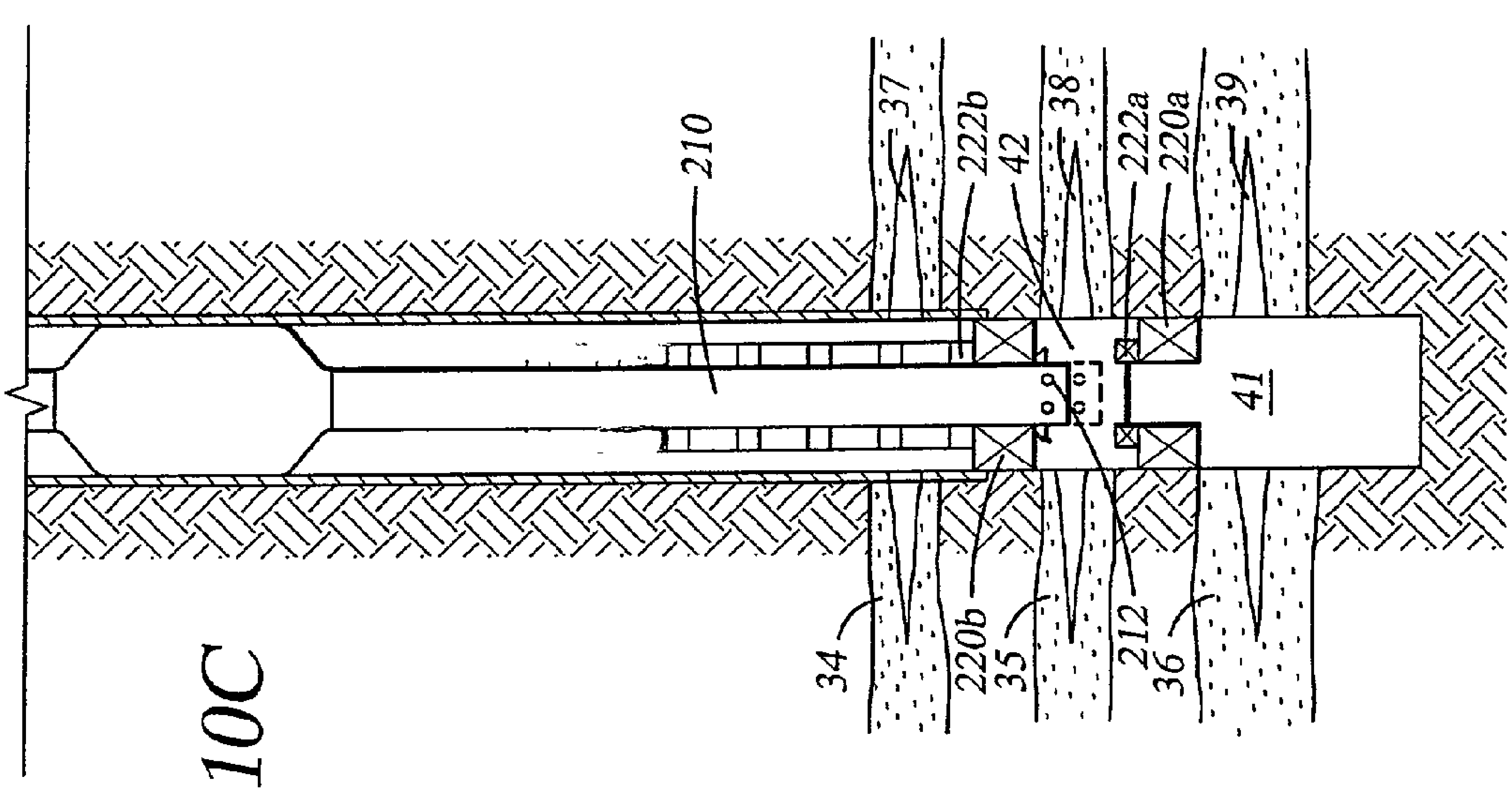

Fig. 10C

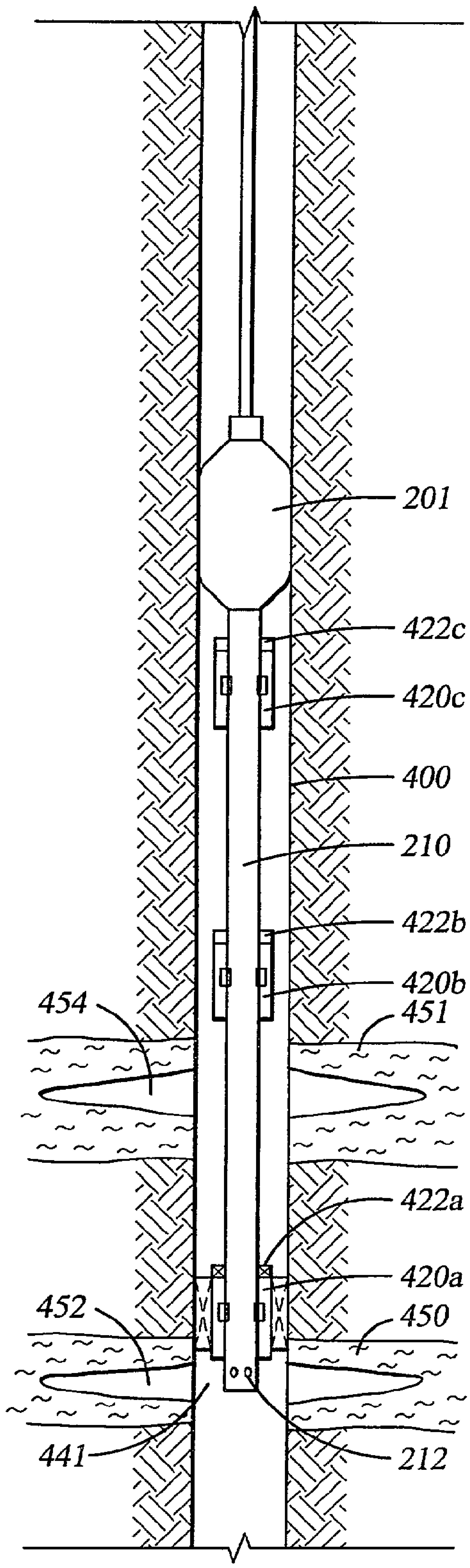

Fig. 11A

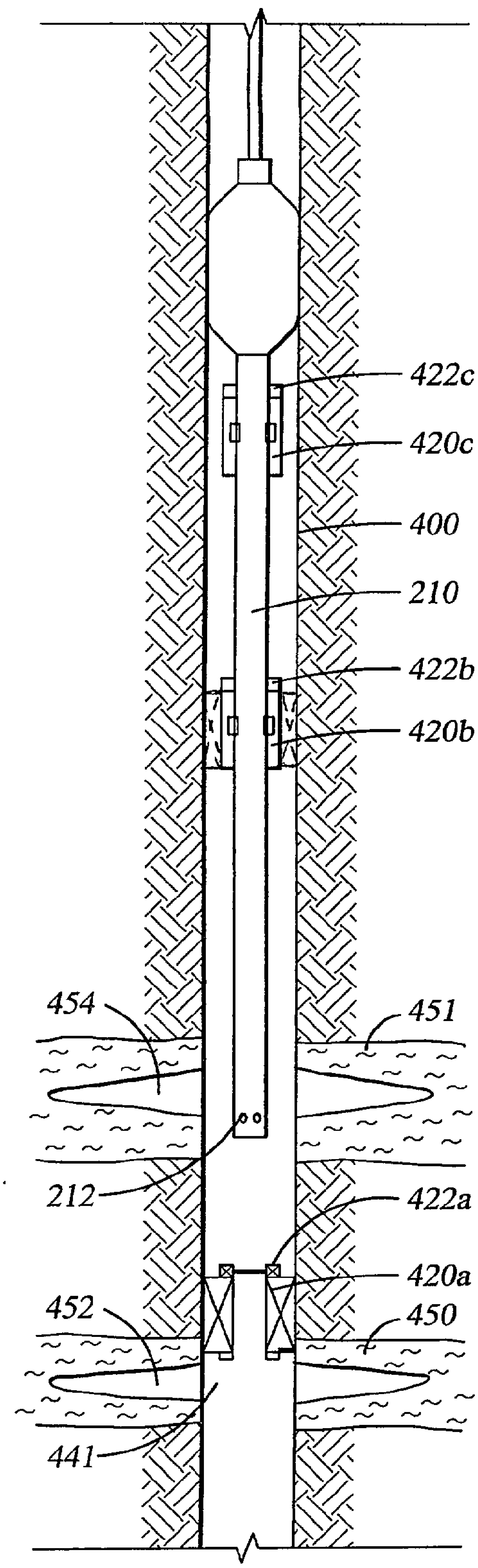

Fig. 11B

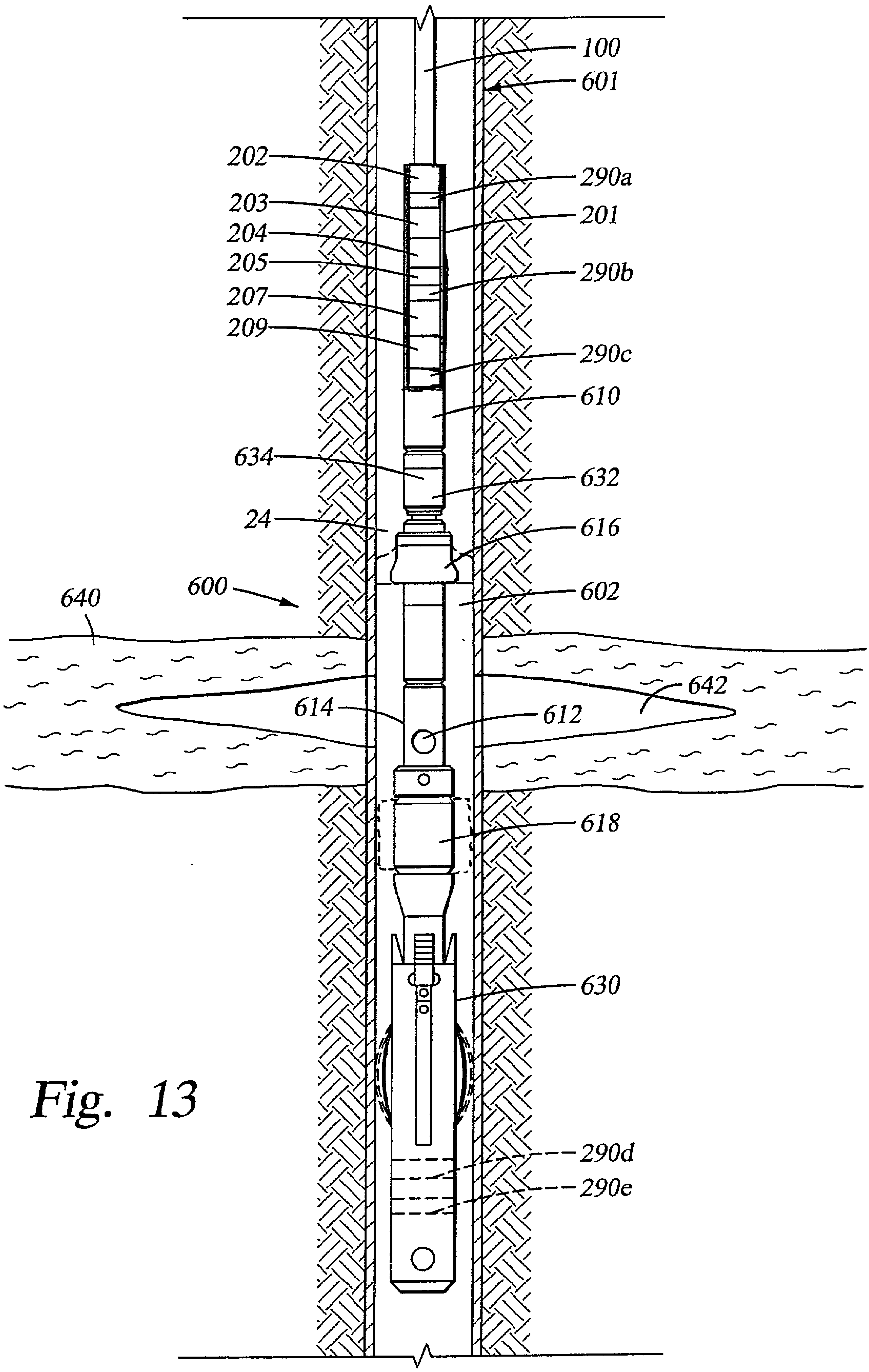
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Fig. 13

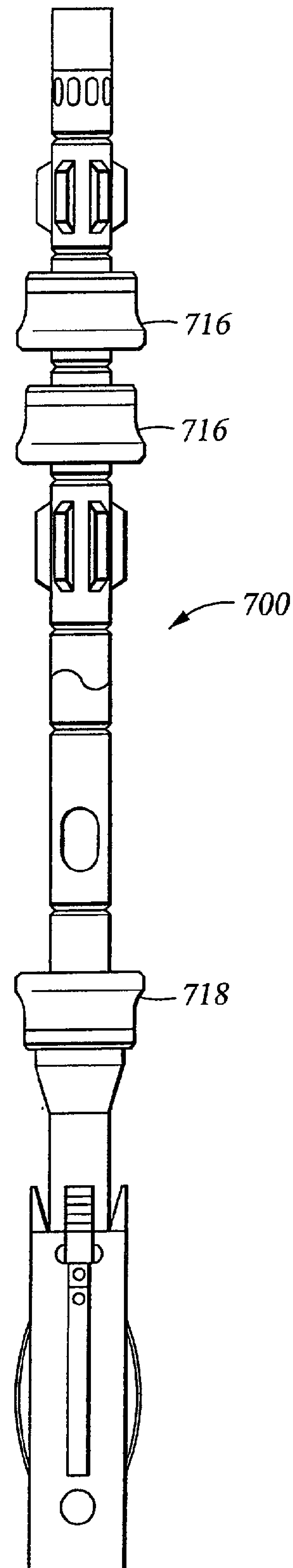

Fig. 14

WELL TREATMENT APPARATUS AND METHOD

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] Not Applicable.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not Applicable.

BACKGROUND OF THE INVENTION

[0003] 1. General Field of the Invention

[0004] The present invention relates generally to tools and methods used in treating subterranean wells and, in a preferred embodiment thereof, relates more particularly to apparatus and methods for conducting well stimulation and formation fracturing operations in subterranean wells.

[0005] 2. Background Information

[0006] A potentially productive geological formation beneath the earth's surface often contains a sufficient volume of valuable fluids, such as hydrocarbons, but also may be characterized as having a very low permeability. "Permeability" is a term relating to a quality of a geological formation which describes the ability of fluids to move about through the formation. The hydrocarbons are contained in the formation's pores, and a formation may be described in terms of its "porosity." If a formation's porosity is low, meaning that the pores are not sufficiently interconnected, the fluids cannot migrate through the formation and, thus, cannot be brought to the earth's surface without a structural modification or stimulation of the production zone.

[0007] When it is desired to recover hydrocarbons from a formation having low permeability, it becomes necessary to "stimulate" the well, meaning to artificially increase the formation's permeability. This is typically accomplished by "fracturing" the formation, a practice which is well known in the art and for which purpose many methods have been conceived. Basically, fracturing is achieved by applying sufficient fluid pressure to the formation to cause it to crack or fracture, hence the term "fracturing" or simply "fracing." The desired result of this process is that the cracks interconnect the formation's pores and allow the hydrocarbons to be brought out of the formation and to the surface. Typically in the fracing process, sand or another proppant is pumped into the formation to keep the cracks or voids open to allow the desired fluid migration. Other types of well treatment operations are used to enhance production, including acidizing and hydraulic jetting of the formation. Like fracing, these methods also involve pumping fluids downhole and into the formation.

[0008] In completing a well for production, the borehole in the earth is cased by tubular casing which is cemented within the borehole. To allow the formation fluids to flow into the production bore in the casing, the cased borehole is perforated in regions adjacent to the zones in the formation that are believed to be productive. To perforate the cased borehole, a perforating assembly mounted on the lower end of a tubular work string or wire line is lowered into the well bore. The perforation tool or "gun" assembly is then detonated to create a series of spaced perforations extending outwardly through the well casing, the cement holding the casing in place in the wellbore, and into the production zone. The discharged gun assembly is then pulled up with the work string to complete the perforating trip.

[0009] Using previously proposed apparatus and methods, the general sequence of steps needed to stimulate or frac a production zone includes lowering into the well a tubular proppant discharge member and one or more packers on a work string. The proppant discharge member includes discharge or exit ports formed therein, the discharge ports being located in close proximity to the gun-created perforations that extend outwardly through the perforated casing. Proppant slurry is then pumped down the work string and discharged through the ports in the discharge member where it flows outwardly through the perforations into the surrounding production zone. Once the appropriate amount of proppant has been injected into the formation, the work string is then removed from the wellbore to complete the stimulation trip and to initiate the production of the well

[0010] This previously proposed perforation and proppant fracturing technique has several well known and heretofore unavoidable problems, limitations and disadvantages. For example, when the proppant slurry discharge member is lowered into the well bore, it is difficult to obtain a precise alignment (in both the axial and angular directions) between the discharge ports in the discharge member and the perforations in the casing. The usual result is that some degree of misalignment exists between the discharge ports and the perforations. Because of such misalignment, the proppant must follow a tortuous path on its way to entering the perforations after it is discharged from the workstring. Because of the highly abrasive character of proppant slurry and because the slurry is under very high pressure, this tortuous flow path can cause severe abrasion and wear with respect to the components of the bottom hole assembly and to the casing.

[0011] Use of the above-described prior technique also limits the ability to isolate multiple production zones from one another—a requirement that may be necessary due to the fact that different zones may require different fracturing pressures, different types of fracturing fluids, and different amounts of proppant.

[0012] Isolating and fracing zones individually within a perforated interval that contains multiple zones is important due to other considerations as well. For example, in one type of prior fracing method, a relatively long interval with many producing zones is treated in a single fracing procedure after the entire interval had been perforated. A workstring having a ported discharge sub through which the fracing fluids are pumped is placed in the well bore in the vicinity of the perforated interval. The workstring includes a pair of packers spaced apart by a distance greater than the length of the entire perforated interval. One packer is set above and one below the interval, and the fracing slurry is then pumped downhole at a relatively high pressure so that the fluid, theoretically, is forced through all of the perforations and into all of the potentially productive zones in a single operation. In many such operations, however, the results were not satisfactory. Typically, certain of the producing zones in the isolated or "packed off" interval have weaker formation strength than the others. As a result, the fracing fluids tend to flow into the formation with the weakest formation strength, i.e., the formation with the highest permeability to fluids. Thus, because little fracing fluid actually enters the other zones when this occurs, certain potentially productive zones are not adequately stimulated or fraced, and do not thereafter produce to the desire degree.

[0013] Attempts have also been made to frac and treat potentially productive formations or zones one at a time. The procedure employed tends to eliminate the disadvantages associated with fracing simultaneously over a relatively large interval. To accomplish this, each potentially productive zone is provided with its own set of perforations through the well casing. Using a workstring with a ported discharge sub and a "straddle packer assembly," the work string is placed in the well bore with the packers straddling the first interval to be fraced. The packers are then actuated (set) so as to isolate that particular zone from the other zones such that it can be treated individually. Typically, the lower most zone is treated first. Thereafter, the packers are released (unset) and the work string raised to the next zone to be treated. As before, the packers are then set so as to straddle the perforations in that zone, and the zone is individually treated. Thereafter, the workstring is raised to still another zone. This method and apparatus for treating zones individually generally produces higher production rates.

[0014] The method and apparatus for individually treating zones is typically performed with a work string comprised of either jointed metal pipe or metal coiled tubing. The discharge member or ported sub is positioned at the lower end of the workstring. The method thus described, however, has inherent limitations. First, to succeed, it is important that the packers completely straddle the perforations and not be set in the perforated region. If either packer is set in an area having perforations, the fracing fluid flowing out of the ported sub and through the perforations into the formation will flow back into the wellbore annulus through the perforations that are beyond the region being isolated by the straddle packers. Turbulence caused by the abrasive fracing fluid flowing back into the annulus creates a pressure differential across the packers and tends to erode or "wash out" and ruin the packer assembly, an event that frustrates the fracturing operation.

[0015] Additionally, it is important that the packers not be set within a casing joint, but instead be set in the blank pipe extending between the casing joints. Typically, there are gaps between the terminal ends of adjacent casing sections at the casing joints. If the packers are set on those gaps, then the packers will not seal properly and hold pressure to isolate the intended interval. When this occurs, the packers have not isolated and sealed off the annulus in the desired interval, and the fracing fluid can flow out of the isolated annulus and into the annulus extending beyond the packers. This condition can cause the packers to wash out and erode. Further, depositing large quantities of proppant above the packer assembly may cause the assembly to stick in the hole or to otherwise become difficult to relocate. Accordingly, it is critical to know the location of the perforations and the casing joints and to ensure that the straddle packers are properly located and not set in perforations or a casing joint. Unfortunately, properly positioning the packers with respect to the perforations and casing joints has been difficult to achieve.

[0016] In shallow wells, it is easier to record depth in the well and to more accurately position at particular depths tools that are lowered via the work string. This is because in shallow wells, the work string have less weight and the downhole temperatures are not so great as to cause extreme changes in the pipe length due to stretching or contracting of the pipe as a result of weight or temperature. Accordingly, the depth of casing joints and perforations may be discerned and recorded with reasonable accuracy in shallow wells given that the length of the work string used in forming the perforations, for example, may be accurately determined by counting the pipes making up the string. Likewise, the length of a work string used to conduct a fracing operation in a shallow well may also be accurately determined by recording the length of tubing or number of pipes (multiplied by each pipe's length) such that the ported discharge sub may be properly positioned adjacent to the perforations, and the packers may be properly positioned in the blank pipe. For purposes of this application, a "shallow" well is defined as a well having a depth of 3000 feet or less and a "deep well" is a well having a depth of more than 3000 feet.

[0017] For deep wells, depth control is more problematic. For example, if the work string is jointed pipe, the weight of the work string extending into a deep well tends to cause the string to stretch such that its length, and thus the location of the downhole tool it supports, may not provide an accurate depth indication. Further, the work string will tend to expand and contract with downhole temperatures which also introduces inaccuracies in the length of the string and thus the actual depth of the tools.

[0018] In another example, when the workstring is coiled tubing and it is run into a deep well, it tends to bend and curl within the cased borehole, such that the exact distance from the surface to the downhole tool does not equal the length of coiled tubing that has been injected into the well. Further, the deeper the well, the higher the temperature and the greater the expansion of the coiled tubing. In a shallow well, the upper and lower straddle packers may be only ten feet apart, for example. Using closely-spaced straddle packers in a deep well however, and considering the expansion and contraction of the coiled tubing, as well as the tendency for the coiled tubing to bend and curl in the borehole, it is extremely difficult to determine exactly where the packers and fracing assembly are in relation to casing joints and the perforations.

[0019] Although conventional metal coiled tubing has been employed in shallow wells in certain fracing operations, it is not feasible in certain deep wells. For example, most conventional metal coiled tubing cannot withstand a 12,000 psi differential pressure as may be encountered at the surface when conducting deep well fracing operations. Further, metal coiled tubing is relatively heavy and transporting the number of spools of coiled tubing required for the operation and injecting and withdrawing the tubing from a deep well requires specially designed, heavy duty equipment

[0020] Furthermore, even if the depth of the fracing assembly were somehow to be precisely known, there still exist problems that are introduced due to inaccuracies in determining the actual depth of the perforations. As stated above, the step of perforating the well typically includes recording the depth and location of the perforations; however, using perforation equipment with wire line, jointed pipes and coiled tubing nevertheless does not always provide accurate depth measurements, due again to the tendency of the wireline, pipe and tubing to expand with weight and downhole temperatures, and to bend or coil in the borehole.

[0021] Another problem inherent in fracing operations in deep wells raises significant safety concerns. It is vitally important during fracing operations to have an understanding of the pressure downhole. In fracing, the objective is to inject high pressure fluid into the formation with the pressure being so great as to overcome the weight of overburden and pore pressure to cause the created fractures to widen. To maintain the fractures, a proppant, such as sand, is included in the fracing slurry and is flowed into the fractures to keep them open. The greater the degree of fracture that is achieved, the greater the flow of hydrocarbons out of the formation and into the wellbore. Thus, during the fracing operation, high pressure fluids and proppants are pumped downhole, out of the workstring, through the perforations and into the fracture. The proppant flows into the created fractures and begins filling the fractures from the outermost region back towards the wellbore. Once the proppant essentially fills the fractures back to the wellbore, and with fracing fluid continuing to be pumped downhole, the downhole pressure increases suddenly and dramatically. This condition is referred to as "screen out." Screen out is essentially when the formation will no longer accept more fracing fluid or proppant. When screen out occurs without warning, a potentially hazardous condition is created at the surface where the fracing fluid is continuing to be pumped through the work string at very high pressures, such as from 5,000 to 18,000 psi. When the downhole pressure suddenly spikes, the differential pressure as measured across the wall of the work string at the surface may exceed the margin of safety causing the pipe to burst, subjecting personnel and equipment to risk. It is thus extremely important to know when a screen out condition is imminent so that the pumps can be turned off or throttled back before the situation becomes dangerous.

[0022] Positioning a pressure sensor in the workstring adjacent to the discharge sub to sense downhole pressure and communicate the pressure data to the operator or controller at the surface would be advantageous; however, communicating data to the surface during fracing operations has presented a problem. Although it is common to use mud pulse telemetry in well operations for transmitting data to a surface controller, mud pulse telemetry is difficult if not impossible to employ in fracing operations because there is too much hydrostatic noise which prevents transmission of telemetry up the annulus to the surface. Further, although electrical signals can be sent uphole via conductors strapped on the outside of the work string, the conductors are subjected to abuse and damage as the work string scraps against the sides of the well bore while the workstring is lowered into or removed from the bottom of the wellbore, and as well fluids flow around the conductors. The problems arising from the conductors being subjected to extreme physical abuse are magnified tremendously in deep well applications.

[0023] As a consequence of the inability to accurately transmit actual, real-time downhole pressure measurements to the surface, it is conventional in prior art fracing operations to attempt to calculate downhole pressure by considering a variety of parameters such as surface pressure. However, for several reasons, it is extremely difficult to extrapolate the downhole pressure from the measured surface pressure and the other available data, particularly in deep well operations.

[0024] The pressure measured at the surface is a combination of the friction pressure, the hydrostatic pressure and fracture gradient pressure. The gradient pressure may vary significantly depending on particular local conditions. A typical fracture gradient pressure is approximately 0.7 psi per foot of depth of well bore. Thus, in this example, at a depth of 3000 feet, the downhole pressure attributable to the fracture gradient will be approximately 2100 psi. Obviously, as the well extends deeper, the fracture gradient pressure increases. The other pressure components are not so easily quantified. In pumping the fracing fluid downhole, a large component of the pressure measured at the surface is the friction pressure created by the fluid moving at high velocities through a relatively small diameter pipe. In addition to the friction pressure, there exists a hydrostatic pressure in the flow bore of the work string caused by the weight of the column of fluid in the flow bore. However, the concentration of the proppant in the slurry is typically increased during the course of a fracing operation. Thus, the weight of fluid being pumped downhole increases as the process continues over time. As the density of the fluid changes during the fracturing job, the hydrostatic pressure and the friction pressure in the flow bore also change. These changing variables, coupled with the high volume of fluid that is pumped during the fracing operation, makes calculating the downhole pressure very complex. In deep wells, the friction pressure and hydrostatic pressure are so great that it masks the onset of the screen out condition. The fluids and their density change so fast that it is difficult if not impossible to calculate accurately downhole pressure. Once again, if the downhole pressure spikes quickly and the spike cannot be seen or predicted soon enough based on the pressures calculated at the surface, the excessive pressure can cause the work string to burst, endangering both crew and equipment. Thus, rather than extrapolating and relying on calculations based on changing variables, it would be much more desirable to have a means for accurately measuring downhole pressure and communicating that measurement to the surface in real time to enable appropriate decision making.

[0025] Also important to conducting a proper fracing job is to know the temperature downhole. This is because the fracing fluid will often be multi-phased, and it is important to the operation to know the percent of fluid in the gaseous phase and in the liquid phase. The respective liquid/gas percentages of the fluid are a function of the downhole temperature. If the temperature downhole were known and could be communicated accurately to the surface in real time, adjustments could be made to ensure that the appropriate and optimum fluids were being injected into the formation. The fact that the fracing fluid is in two phases and that the volume of gas changes continuously as the fluid moves down into the well bore also makes it even more difficult to calculate bottom hole pressure.

[0026] It is also desirable in fracing operations to determine the size, orientation and shape of the fracture being created so that the operation can be ceased or altered if the fracture propagates in a manner that is undesirable. Presently, it is known to convey tilt sensors downhole via a wireline, and to attach the sensors magnetically to the casing wall at various locations along or adjacent to the interval being treated. In what are referred to as "mini fracing" operations, that is, when pumping fluid but not proppant, tilt sensors are capable of detecting the tilt in the casing that results from the pumping operation and communicating the sensed data to the surface via the wire line's conductors. Unfortunately, when the fracing operation includes pumping proppant downhole, this prior method of employing a wire line communication link is not believed to be viable because of erosion to the conductors that occurs at the well head where the proppant is injected, and because of the danger of proppant building-up around the downhole tilt sensors which might cause the downhole assembly to become stuck. Nevertheless, because of the significant benefits to be derived from such data, a means for measuring the tilt and communicating the sensed value in real time to the surface in a proppant fracing operation would be highly desirable.

[**0027**] As can be readily seen from the foregoing, it is advantageous to provide improved well treatment and proppant fracturing apparatus and methods which eliminate or at least substantially reduce the above-mentioned problems, limitations and disadvantages commonly associated with the previous stimulation techniques generally described above. It is accordingly an object of the present invention to provide such improved apparatus and methods.

SUMMARY OF PREFERRED EMBODIMENTS OF THE INVENTION

[**0028**] Accordingly, there is provided herein apparatus and methods enabling multiple zones within a formation to be treated sequentially with a single trip of the work string and which, in certain embodiments, provide transmission of power and transmission of data indicative of actual wellbore conditions for enhanced safety and system reliability.

[**0029**] A preferred apparatus includes a bottom hole assembly having a tubular, ported sub and a tubing string connected to the bottom hole assembly. The tubing string and bottom hole assembly include fluid passageways that are in fluid communication so that treatment fluids may be pumped from the surface through the tubing string and out of the ports in the tubular sub when positioned adjacent to the zone to be treated. Preferably, the tubing string is a composite tubing having conductors embedded in the walls of the tubing and extending from the bottom hole assembly to the surface. Alternatively, metal tubing or jointed pipe may be employed with an umbilical of electrical conductors supported by the tubing or pipe, the conductors again extending from the bottom hole assembly to the surface.

[**0030**] It is preferred that the bottom hole assembly include at least one sensor for measuring wellbore parameters and communicating in real time the sensed data to the surface controller, with the sensor being coupled to the surface controller via the conductors supported by the tubing. The conductors may include electrical conductors, fiber optics conductors or others.

[**0031**] To isolate the appropriate well interval to be treated, it is preferred that the bottom hole assembly include one or more packers and a packer actuator associated with each packer for causing the packer to expand and isolate a well interval in response to an electrical signal transmitted from the surface to the bottom hole assembly via the conductors. The conductors supported by the tubing string provide two way communication between the surface and the bottom hole assembly, as well as a means for transmitting electrical power from the surface to the bottom hole assembly. Further, given this direct communication link from the bottom hole assembly to the surface, real time well data may be sensed and communicated to the surface controller enabling adjustments to the treatment operation to be performed, both to enhance the effectiveness of the operation and to provide a means to determine downhole conditions accurately, such as pressure, and, when required, to throttle back or shut down pumping equipment before any dangerous situation develops.

[**0032**] In another preferred apparatus, the bottomhole assembly includes a detector sub having a sensor that detects anomalies in the casing, such as perforations and casing joints. Such a detector communicates the sensed data to the surface via the conductors supported by the tubing string so that the bottom hole assembly can be appropriately positioned. More specifically, the detector permits the packers to be set in blank sections of casing so as to properly isolate a particular well interval so that the fluids pumped downhole can penetrate into the intended zone via the perforations, and so that the packers are not eroded or washed out due to improper packer placement within a casing anomaly.

[**0033**] A preferred method is disclosed and includes placing a tubing string with a bottom hole assembly having a ported sub and a plurality of sequentially settable packers into a wellbore, locating a blank segment of casing above the first producing zone, setting a first packer in that blank region of casing to isolate a first well interval, pumping treatment fluid through the ported sub from the surface and into the first isolated interval, and sensing at least one downhole parameter and communicating the sensed parameter to the surface via conductors extending along the tubing string. The method may also include stopping the flow of treatment fluid when the sensed parameter meets a predetermined criteria, such as when a downhole pressure is sensed that indicates that a "screen out" condition is about to occur, or when downhole tilt meters indicate that a fracture is propagating in an unanticipated or undesirable manner.

[**0034**] The disclosed methods also include raising the bottom hole assembly to a position above the first set packer, locating a blank segment of casing above the depth of the next producing zone, setting a second packer in that blank region of casing to isolate a second well interval, pumping treatment fluid through the ported sub and into the second isolated interval, and sensing at least one downhole parameter and communicating the sensed parameter to the surface via conductors.

[**0035**] The preferred embodiments summarized above thus permit multiple zones within a given formation to be treated sequentially, with a single trip of the well treatment work string. Given the real time communication link provided via conductors, either embedded in the wall of the tubing string or supported by other means along the length of the tubing or pipe, real time communications of important downhole conditions can be communicated to the surface, enabling the surface controller and operator to avoid dangerous conditions and better tailor the treatment operation, such as by varying the density or makeup of the fluid being pumped downhole.

[**0036**] Thus, the embodiments of the invention summarized above comprise a combination of features and advantages which enable them to overcome various problems of prior devices systems and methods. The various characteristics described above, as well as other features, will be readily apparent to those skilled in the art upon reading the following detailed description of the preferred embodiments of the invention, and by referring to the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

[0037] For a more detailed description of the preferred embodiments of the present invention, reference will now be made to the accompanying drawings, wherein:

[0038] **FIG. 1** is a schematic elevation view, partly in cross section, of a preferred embodiment of the well treatment apparatus the present invention disposed in a subterranean well.

[0039] **FIG. 2** is a cross sectional view of a work string including composite continuous tubing for the apparatus shown in **FIG. 1**.

[0040] **FIG. 3** is a cross sectional view of the composite tubing shown in **FIGS. 1 and 2**, the section taken along the longitudinal axis of the tubing.

[0041] **FIG. 4** is an enlarged view of a bottom hole assembly of the well treatment apparatus shown in **FIG. 1**.

[0042] **FIG. 5** is a schematic elevation view, partly in cross section, of a portion of the bottom hole assembly shown in **FIG. 4**.

[0043] **FIG. 6** is a schematic elevation view, partly in cross section, of a hydraulic distribution sub in the bottom hole assembly shown in **FIG. 4**.

[0044] **FIG. 7** is a schematic view of the hydraulic circuit employed in the bottom hole assembly shown in **FIG. 4**.

[0045] **FIG. 8** is a schematic elevation view, partly in cross section, of the sensor sub and stinger of the bottom hole assembly of **FIG. 4**.

[0046] **FIG. 9** is a functional block diagram of the electric power and control system for the well treatment apparatus shown in **FIG. 1**.

[0047] FIGS. **10A-10D** are schematic elevation views, partly in cross section, of a well including producing zones which are to be treated using the system and apparatus of **FIG. 1**, the figure showing the bottom hole assembly in various positions as it conducts sequential operations on the individual zones.

[0048] **FIGS. 11A, 11B** are schematic elevation views, partly in cross section, of another preferred embodiment of the well treatment apparatus, the bottom hole assembly being shown in various positions in the well bore as it is used to sequentially treat various zones.

[0049] **FIG. 12** is a schematic elevation view, partly in cross section of a portion of the embodiment of **FIG. 4** employing propellant-activated packers.

[0050] **FIG. 13** is a schematic elevation view, partly in cross section, of still another preferred embodiment of the well treatment apparatus.

[0051] **FIG. 14** is a schematic elevation view, partly in cross section, of still another preferred embodiment of the well treatment apparatus.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0052] The present invention relates to methods and apparatus for well treatment such as fracing or stimulation operations. The present invention is susceptible to embodiments of different forms. There are shown in the drawings, and herein will be described in detail, specific embodiments of the present invention with the understanding that this disclosure is to be considered an exemplification of the principles of the invention, and is not intended to limit the invention to that illustrated and described herein. Further, it is to be fully recognized that the different teachings of the embodiments discussed below may be employed separately or in any suitable combination to produce desired results.

[0053] In the following discussion and in the claims, the terms "including" and "comprising" are used in an open-ended fashion, and thus should be interpreted to mean "including, but not limited to . . . ". Also, the terms "couple,""couples" and "coupled" is intended to mean and refer to either an indirect or a direct electrical connection. Thus, for example, if a first device "couples" or is "coupled" to a second device, that interconnection may be through a direct electrical connection of the two devices, or through an indirect electrical connection via other devices, conductors and connections. Further, reference to "up" or "down" are made for purposes of ease of description with "up" meaning towards the surface of the wellbore and "down" meaning towards the bottom of the wellbore. In addition, in the discussion and claims that follow, it is sometimes stated that certain components or elements are in "fluid communication." By this it is meant that the components are constructed and interrelated such that a fluid could be communicated between them, as via a passageway, tube or conduit.

[0054] Referring now to **FIG. 1**, there is shown a preferred embodiment of the present invention including a surface operating system **50**, a work string of composite coiled tubing **100**, and a bottom hole assembly (BHA) **200**. Operating system **50** is positioned at the surface adjacent to well **12** and generally includes a well head **14** disposed atop of a well bore **18** that extends downwardly into an earthen formation **20**. Borehole **18** extends from surface **16** to borehole bottom **30** and includes casing **22** extending therebetween. In the example shown, wellbore **18** includes at least one interval **32** containing three, spaced apart zones **34-36** that are believed to contain hydrocarbons that can be economically recovered. Hereinafter, such zones may sometimes be referred to as "producing zones"**34-36**. It should be appreciated that this well environment is described for explanatory purposes, and that the present invention is not limited to the particular borehole thus described, it being appreciated that the present invention may be used in a variety of well bores. In particular, although the wellbore **18** is shown vertical, the wellbore may be a deviated wellbore and may further include a horizontal portion. BHA **200** is attached to the lower most end of coiled tubing **100**. Coiled tubing **100** and BHA **200** make up a well treatment assembly **40** that is injected into and retrieved from borehole **18** by operating system **50**.

[0055] Surface operating system **50** includes a power supply **52**, a surface controller **54**, a coiled tubing spool **56** and a tubing injector head unit **58**. Injector head **58** feeds and directs coiled tubing **100** from the spool **56** into the well **12**. Although the coiled tubing **100** is preferably composite coiled tubing hereinafter described, it should be appreciated that the present invention is not limited to composite coiled tubing and in certain embodiments, may be steel coiled tubing with an electrical umbilical mounted on or within the steel coiled tubing. See for example, U.S. Pat. No. 5,920, 032, hereby incorporated herein by reference. Certain embodiments may likewise be practiced using jointed metal pipe, rather than continuous metal or composite coiled tubing as discussed below.

[**0056**] Referring still to **FIG. 1**, tubing spool **56** feeds composite tubing **100** over guide **60** and through injector head **58** and stripper **62**. The composite coiled tubing **100** is injected through blowout preventer **64** and into well **12** by injector head **58**, the tubing **100** forming an annulus **24** with the casing **22**. The composite coiled tubing **100** preferably includes conductors **144** embedded in the wall of tubing **100**, as hereinafter described and best shown in **FIGS. 2 and 3**. Electrical conductors **66**,**68** electrically couple power supply **52** with the electrical conductors **144** in the wall of composite coiled tubing **100**. Similarly, conductors **70**, **72** couple controller **54** with the electrical conductors **144** in composite coiled tubing **100**. It should be appreciated that, in this embodiment, both data and electrical power are transmitted through the electrical conductors **144**. These conductors **144** extend along the entire length of composite coiled tubing **100** and are coupled to various components in BHA **200**, as hereinafter described.

[**0057**] Composite coiled tubing **100** is best described with reference to **FIGS. 2 and 3**. Coiled tubing **100** is similar to composite coiled tubing described in U.S. Pat. Nos. 6,246, 066; 6,257,332; and U.S. patent application Serial No. 60/353,654 filed Feb. 1, 2002, the entire disclosure of each being hereby incorporated herein by reference. Coiled tubing **100** preferably has an inner impermeable fluid liner **132**, a plurality of load carrying layers **134** (only exemplary layers being shown), and at least one wear layer **138**. As best shown in **FIG. 3, a** plurality of conductors **144** are embedded in the wall of the tubing and are preferably embedded between the load carrying layers **134** and the inner liner **132**. Conductors **144** includes conductors for conducting power and data as described more fully below.

[**0058**] Referring still to **FIGS. 2 and 3**, load carrying layers **134** are preferably formed of a resin and fiber and energized to provide the required tensile strength and burst strength to sustain the load of the well treatment assembly **40** suspended in fluid, including the weight of the composite coiled tubing **100** and bottom hole assembly **200**, and to sustain the differential pressure placed on the tubing **100** by internal and external fluid pressures. The fibers of load carrying layers **134** are preferably wound into a thermal setting or curable resin. Carbon fibers are preferred because of their strength. Although glass fibers are not as strong, glass fibers are much less expensive than carbon fibers and may also be employed. Further, a hybrid of carbon and glass fibers may be used for load carrying layers **134**. Thus, the particular fibers for the load carrying layers **134** will depend upon the well, particularly the depth of the well, such that an appropriate compromise of strength and cost may be achieved in the fibers selected. Typically, an all carbon fiber is preferred for layers **134** because of its strength and its ability to withstand pressure.

[**0059**] The load carrying layers **134** are engineered so as to provide the composite coiled tubing **100** with various mechanical properties including tensile and compressive strength, burst strength, flexibility, resistance to caustic fluids, gas invasion, external hydrostatic pressure, internal fluid pressure, ability to be stripped into the borehole, density i.e. flotation, fatigue resistance and other mechanical properties. Layers **134** are wrapped and braided to maximize the mechanical properties of composite coiled tubing **100**, adding substantially to its strength.

[**0060**] The impermeable fluid liner **132** is an inner tube preferably made of a polymer, such as polyvinyl chloride or polyethylene or PDVF. Liner **132** can also be made of a nylon, other special polymer, or elastomer. In selecting an appropriate material for fluid liner **132**, consideration is given to the chemicals in the fluids to be used in performing the well treatment operations in zones **34**-**36** and the temperatures that are to be encountered downhole. The primary purpose for inner liner **132** is to serve as an impermeable fluid barrier since carbon fibers of load carrying layers **134** are not impervious to fluid migration, particularly after they have been bent. The inner liner **132** is impermeable to fluids and thereby isolates the load carrying layers **134** from the fluids that are conducted through the flow bore **146** of liner **132**. Inner liner **132** also serves as a mandrel for the application of the load carrying layers **134** and the other layers during the manufacturing process for the composite coiled tubing **100**.

[**0061**] A wear layer **138** is preferably braided around the outermost load carrying layer **134**. The wear layer **138** is a sacrificial layer since it will engage the inner wall of the borehole **18** and will be subjected to wear as the composite coiled tubing **100** is tripped into the well **12**. Wear layer **138** protects the underlying load carrying layers **134**. One preferred material for wear layer **138** is Kevlar™ which is a very strong material that is resistant to abrasion. It may be desirable to employ multiple wear layers. For example, a wear indicator layer **136** may be provided between the outermost load carrying layers **134** and wear layer **138**. One advantage of providing wear indicator layer **136** is that it can be of a different fiber and color relative to wear layer **138**, making it easy to determine the wear locations on composite coiled tubing **100**. The wear indicator layer **136** is for convenience and is not essential to the tubing **100**. Wear layer **136**, may be made of glass fibers, such as fiberglass. It should be appreciated that, in certain applications, inner liner **132** and wear layers **136**, **138** may not be critical to the use of composite coiled tubing **100** and may not be required.

[**0062**] Another impermeable fluid layer **137** is preferably provided to serve as another impermeable layer to liquids and gases. Outer layer **137** is preferably made of a polymer, such as polyvinyl chloride or polyethylene or PDVF, and provides an outer impermeable layer to resist negative permeability. Negative permeability occurs when there is a higher pressure in the annulus **24** then in the flowbore **146**, i.e. the differential pressure is greater towards the flowbore **146**.

[**0063**] The composite tubing **100** is engineered in accordance with the preferred characteristics previously described and for the particular application of the tubing. The tubing has a ratio of carbon fiber to the matrix holding the fiber together. Each layer of fiber is wrapped at a predetermined angle which typically is varied between the layers **134**. The layers of carbon fiber are wrapped around liner **132** in a prescribed angle. Layers **134** can be added or subtracted, and by adding more or less fiberglass, the weight of the composite coiled tubing can be controlled. For example fiberglass may be substituted for carbon fiber which is lighter than the fiberglass. The fiberglass includes layers of glass fibers which typically make the composite coiled tubing heavier. Thus the composite coiled tubing may be made to be substantially neutrally buoyant allowing the composite coiled tubing to float in the borehole fluids.

[**0064**] During the braiding process, conductors **144**, which may include electrical conductors, data transmission conductors, sensors and other data links, are embedded within coiled tubing **100**, preferably between the load carrying layers **134** and inner liner **132**. These conductors **144** are wound into and become encased within the wall of composite coiled tubing **100**. It should be appreciated that any number of electrical conductors, data transmission conduits, and sensors may be embedded as desired in the wall of composite coiled tubing **100**. As shown in **FIGS. 2 and 3**, the conductors **144** are preferably disposed about the liner **132** in a layer of fiberglass **147**. The principal function of fiberglass layer **147** is to contain the conductors **144** and to provide a continuous circumferential outer surface upon which load carrying layers **134** can be disposed. The fiberglass **147** serves as a filler between the conductors **144**. The conductors **144** are first wrapped around the liner **132** and then the fiberglass **147** is applied. Disposed around the layer of fiberglass **147** and conductors **144** are the multiple load carrying layers **134**.

[**0065**] Coiled tubing **100** may include a myriad of conductor types. For example, coiled tubing **100** may include one or more fiber optic cables; mono-cables (consisting of an insulated copper core conductor having a ground shield disposed about the insulated core); multi-conductor cables; single conductors (solid or braided wire); flat ribbon conductors and coaxial cables. In the embodiment of **FIGS. 2, 3**, for example, there are shown six single cooper conductors **144** (i.e., three pairs of conductors), which transmit both power and data. However, including other types of conductors embedded within composite tubing **100** may be desirable for providing power or data between the surface and bottom hole assembly **200** as may be useful for equipment or applications beyond those described specifically with reference to the present embodiments of the invention.

[**0066**] In the embodiment shown in **FIGS. 2, 3**, the conductors **144** used for power transmission from the power supply **52** at the surface to the bottom hole assembly **200** is preferably one pair of individual copper wires **144**. Such conductors allow the transmission of a large amount of electrical power from the surface to the bottom hole assembly **200**. One cooper wire **144** serves as a high potential conductor, with the other being the return or ground. For transmitting the power necessary for a deep well application of the embodiment of the invention now being discussed, it is preferred that cooper wire **144** be approximately 24-18 gauge. Copper wire **144** may conduct at high voltages, such as 400 volts. Further, by employing multiplexing techniques, there is provided a two-way communication or data transmission through conductors **144**. In this embodiment, two additional pairs of wires **144** are provided for redundancy in the event that a first pair becomes damaged.

[**0067**] As discussed above, data and communication signals may be multiplexed and conducted via power-conducting cooper conductors **144**; however, in some applications it may be preferred that the data and communication signals be sent via separate conductors, such as by fiber optic cable or by one or more pairs of conductors within a multi-conductor cable. Where provided, in composite tubing **100**, a multi-conductor cable includes a plurality of separately insulated conductors, preferably about 24-18 gauge, enclosed in a further layer of insulation. Alternatively, data and communications can be transmitted between BHA **200** and the surface via fiber optics, such as via a fiber optic cable, or via a mono cable. In each case, such conductors constitute a high speed data link carrying communications from downhole to the surface such that it is transmitted to the surface in real time.

[**0068**] Sensors may also be embedded within the load carrying layers **134** and coupled to one or more of the data transmission conductors such as conductors **144**. As an alternative to embedded sensors, a fiber optic cable may itself be etched at various intervals along its length and disposed in composite coiled tubing **100** to serve as a sensor at predetermined locations along the length of composite coiled tubing **100**. This allows the parameters, in particular, temperatures, to be monitored along the length of composite coiled tubing **100** and transmitted to controller **54** at the surface.

[**0069**] Composite coiled tubing **100** may be made of various diameters. Although 1¼"-2" are typical diameters for metal coiled tubing, composite coiled tubing **100** preferably has a diameter greater than 2 inches. The size of coiled tubing **100**, of course, will be determined by the particular application and well for which it is to be used.

[**0070**] Composite coiled tubing **100** has all of the properties requisite to enable the stimulation of deep wells. In particular, composite coiled tubing **100** has good longevity and, as compared to ferrous materials, has great strength for its weight when suspended in fluid. Composite coiled tubing **100** also is compatible with the fluids that are used to treat the producing zones, and approaches buoyancy (dependent upon weight and density of the treatment fluid) upon passing fluids down its flowbore **146** and back up the annulus **24**. This reduces to acceptable limits drag and other friction factors previously encountered by metal pipe. Since the composite coiled tubing **100** is not rotated during insertion or during the treatment operation, little torque is placed on composite coiled tubing **100**.

[**0071**] Although it is possible that the composite coiled tubing **100** may have any continuous length, such as up to 25,000 feet, it is preferred that the composite coiled tubing **100** be manufactured in shorter lengths such as, for example, in 1,000, 5,000, and 10,000 foot lengths. In deep well operations, it is typical to require multiple spools **56** of composite coiled tubing **100**. These additional spools, of course, are used to add to the length of the composite coiled tubing **100**. With respect to the diameters and weight of the composite coiled tubing **100**, there is no practical limitation as to its length. The various lengths of coiled tubing **100** are added serially together to form one continuous length and are connected together. As shown in **FIG. 1**, adjacent lengths **75**, **76** of tubing are interconnected by connector **78** so as to form continuous coiled tubing **100**. A detailed description of the connector **78** is set forth in U.S. patent application Ser. No. 09/534,685, filed Mar. 24, 2000, hereby incorporated herein by reference. For electrical conductors in tubing, see U.S. Pat. No. 5,146,982, hereby incorporated herein by reference. Other types of connectors are shown in U.S. Pat. Nos. 4,844,516 and 5,332,049, both hereby incorporated herein by reference.

[**0072**] Referring now to **FIG. 4**, bottom hole assembly (BHA) **200** generally includes a plurality of series-connected BHA components **201**, a mandrel or stinger **210** extending downwardly from the BHA component series **201**, and a plurality of isolation packers **220** disposed about stinger **210**. Each packer **220** includes an interconnected valve sub **222** at its uppermost end that, in turn, is connected via one or more shear pins (not shown) to the packer **220** immediately above.

[**0073**] The uppermost sub of BHA component series **201** is an end connector sub **202** for releaseably connecting composite coiled tubing **100** to BHA **200**. Connector sub **202** can be any releasable connection capable of interconnecting a composite coiled tubing to a bottom hole assembly and providing the releasable connections for electrical and data connections and the flow of fluids that are pumped downhole. One such connector sub particularly useful for this embodiment of the invention is disclosed in U.S. Ser. No. 09/998,125 entitled Downhole Assembly Releasable Connection, filed Nov. 30, 2001, the entire disclosure which is hereby incorporated herein by reference. As described in Ser. No. 09/998,125, connector sub **202** includes a "fishing neck" allowing BHA to be retrieved with minimal cost and inconvenience should BHA **200** become stuck in the well or it otherwise be necessarily to disconnect composite tubing **100** from BHA **200** and to retrieve BHA **200** at a later time.

[**0074**] BHA component series **201** further includes supervisory sub **203**, hydraulic distribution sub **204**, gamma tool **205**, detector assembly **207**, power distribution sub **208**, and sensor sub **209**, tilt sensor subs **290**, described in more detailed below. A common flowbore **211** extends throughout the BHA component series **201**.

[**0075**] As shown in FIGS. **4-5**, flowbore **211** in stinger **210** is in fluid communication with central bore **146** of composite tubing **100**. The stinger **210** includes near its lower end, a plurality of discharge ports **212** that are provided to convey treatment fluids from common flowbore **211**, through the perforations **37-39** and into producing zones **34-36**. The stacked series of isolation packers **220** with valve subs **222** are mounted on stinger **210**. Six packers **220***a-f* are shown in **FIG. 4**, it being understood that more or fewer than this number of packers will be employed depending upon, among other factors, the number of zones to be treated in a single trip of BHA **200**. The lower most end of each packer **220** includes an engaging surface for engaging spring loaded latch members **320** of collet **330** that is disposed about stinger **210** as best shown in **FIG. 8**. Referring momentarily to **FIG. 8**, each latch member **320** is spring biased radially outward by spring **322** housed within stinger **210** and includes a camming surface **324** at its uppermost surface. As shown in **FIGS. 4 and 8**, stinger **210** is latched initially into the engaging surface of lowermost packer **220***a*. A stop member **326** (**FIG. 4**) is attached to stinger **210** above the uppermost packer **220***f* to prevent packers **220***a-f* from being forced upward and against BHA component series **201** during injection of well treatment assembly **40** into the borehole or during well treatment operations.

[**0076**] Packers **220** may be any conventional annulus sealing assembly known to those skilled in the art for use in packing off or sealing one section of the annulus from another. In this instance, the packer believed most useful is one that is inflated or actuated by pressurized hydraulic fluid and that radially expands in order to seal between stinger **210** and the wall of casing **22**. Each packer **220** includes a pair of mechanical slips (not shown) that, once actuated, cause the packer to expand radially outward. A packer **220** useful in this application includes that disclosed in U.S. patent application Ser. No. 10/116,572 filed Apr. 4, 2002 entitled "Multiple Zones Frac Tool" the entire disclosure of which is hereby incorporated herein by reference. Packer **220** includes a valve sub **222** having a spring-actuated flapper member **223**, such a valve sub also being described in application Ser. No. 10/116,572. Additional valve subs **222** suitable for adaptation and use in the present embodiment include those shown in U.S. Pat. Nos. 6,152,232, and 4,825,902, hereby incorporated herein by reference. The material used to construct valve sub **222** preferably is a composite material that can be drilled out and thus easily removed after the well treatment process is complete.

[**0077**] Referring more particularly to **FIG. 5**, the wall of stinger **210** houses hydraulic actuators **240** for actuating packers **220**. Each actuator **240** is associated with one packer **220** and is connected to a conduit **242** for conducting pressurized hydraulic fluid from hydraulic distribution sub **204** to actuator **240**. Actuator **240** is controlled by actuation of connected solenoid valve **244**. Each solenoid valve **244** is associated with one actuator **240** and is coupled electrically to supervisory sub **203** (**FIG. 4**) by conductors **246** disposed in passageway or conduit **248** in the wall of stinger **210**.

[**0078**] The treatment operations enabled by this embodiment are, in part, carried out by means of a self contained hydraulic power system in bottom hole assembly **200**, the major components of which are housed in hydraulic distribution sub **204**. In total, the hydraulic system is best understood with reference to FIGS. **4-7**. Referring now to **FIG. 6**, hydraulic distribution sub **204** generally includes hydraulic fluid reservoir **230**, hydraulic pump **232** and electric motor **234**, along with conventional hydraulic piping extending the length of sub **204** and into stinger **210** where it interconnects with conduits **242**, shown in **FIG. 5** for providing pressurized hydraulic fluid for actuating individual packers **220**, as described in more detail below.

[**0079**] Referring now to FIGS. **6-7**, hydraulic reservoir **230** contains hydraulic fluid and is connected to hydraulic pump **232** via suction line **231** and to a hydraulic fluid return line **233**. Hydraulic pump **232** is a conventional hydraulic pump and is coupled to electric motor **234** through a mechanical coupling **235** such that rotation of electric motor **234** causes hydraulic pump shaft to drive the pump. The output of pump **232** is connected to the supply line **236** for supplying hydraulic pressurized fluid to packer actuators **240***a-f*.

[**0080**] A schematic diagram of the hydraulic distribution system is shown in **FIG. 7**. Referring to **FIGS. 7 and 9**, hydraulic supply line **236** is connected to the discharge end of hydraulic pump **232**, and return line **233** is connected to the hydraulic reservoir **230**. Each solenoid valve **244***a-f* is connected to both the hydraulic supply line **236** and the return line **233** to control the flow of pressurized hydraulic fluid to actuators **240***a-f*. Control wires **246** couple each solenoid valve **244** to controller **354 (FIG. 9)** in supervisory module **203 (FIG. 9)**. Power is supplied to the electric motor **234** via a power distribution module **381** located in power sub **208 (FIG. 9)**. Motor **234** drives pump **232** causing the pump to supply hydraulic fluid under pressure to the various hydraulic components. Selectively, controller **354** in supervisory module **203 (FIG. 9)** sends an electrical signal via conductors **246***f* to open solenoid **244***f*, for example, causing pressurized hydraulic fluid to energize actuator **240***f* which, in turn, actuates packer **240***f* to expand and engage the wall of casing **22**. In this embodiment, once actuated, each packer **220***a-f* remains in its extended or "set" position.

[**0081**] Referring once again to **FIG. 4**, BHA **200** also includes a detector assembly sub **207** used to locate anomalies in casing **22**, such anomalies including perforations **37-39**, and the casing joints in casing **22**. Detector assembly sub **207** is best described in U.S. patent application Ser. No. 09/286,362 entitled Casing Joint Locator Methods and Apparatus, and U.S. patent application Ser. No. 10/121,399 filed Mar. 12, 2002 entitled Magnetically Activated Well Tool the entire disclosure of which is hereby incorporated herein by reference.

[**0082**] Detector assembly sub **207** includes one or more sensors (not shown) for detecting, identifying and locating anomalies in steel metal casing **22**. Detector assembly sub **207** is used to locate and determine the depth of the anomaly, the depth being the distance between the anomaly and the surface measured through the bore of the casing string **22**. The detector sub **207** may further determine the angular orientation of the anomaly, such as a perforation, within the cylindrical wall of the casing **22**. In the vertical casing string, the angular orientation will be the azimuth of the anomaly. Detector sub **207** senses an increase or decrease in the mass of the casing wall **22** and a particular point, as well as sensing the absence of mass. Anomalies, including perforations and casing joints, form fringe effects which cause perturbations in the naturally-induced magnetic field of the casing **22**. The variation of the mass and/or the fringe effects alter the external magnetic field around the sensors in the sensor sub **207** causing an increase or decrease in the resistance of the sensor and thereby altering the flow of current through the sensor. A signal is generated in detector sub **207** by the change in current flow and is transmitted to the surface to provide a detection, identification, or location of the anomaly in the casing **22**.

[**0083**] Referring to **FIGS. 4 and 9**, detector assembly sub **207** includes an outer enclosure or pressure barrel **301** constructed of a non-magnetic material such a beryllium cooper. The pressure barrel **301** is constructed to be resistant to fluids and is capable of withstanding downhole pressures without collapsing. Detector assembly **207** further includes a sensor **302** which preferably is a "giant magnetoresistive" or GMR magnetic field sensor housed in pressure barrel **301**.

[**0084**] By way of background, giant magnetoresistive or GMR magnetic field sensors are know for use in high accuracy compasses and geophysical applications such as magnetic field anomaly detection in the earth's crust. GMR sensors are constructed from alternating, ultrathin layers of magnetic and non-magnetic materials. GMR sensors provide high sensitivity to changes in a nearby or surrounding magnetic field. GMR sensors of this type are described in the brochure entitled "NVE—Nonvolatile Electronics, Inc. The GMR Specialists" with errata sheets, and are currently manufactured and marketed by Nonvolatile Electronics, Inc., 11409 Valley View Road, Eden Prairie, Minn. 55344-3617, (612) 829-9217. The GMR sensor uses a "giant magnetoresistive effect" to detect a change in electrical resistance that occurs when stacked layers of ferromagnetic and non-magnetic materials are exposed to a magnetic field.

[**0085**] The GMR sensor **302** is adapted to detect a change in a surrounding magnetic field and, in response thereto, generate a signal indicative of the change. The sensitivity of the GMR sensor permits detection of small anomalies in the surrounding magnetic structure, such as the perforations **37-39** and the discontinuities that exist between a pair of interconnected casing sections making up casing string **22**. It is noted that a GMR sensor **302** itself generates essentially no magnetic signature and, therefore, will not affect the operation of other downhole equipment that detect or rely upon magnetic readings.

[**0086**] The preferred sensor **302** is very small having typical dimensions of 0.154 inches by 0.193 inches by 0.054 inches. Thus, sensor **302** is sufficiently sensitive to detect perturbations of a similar size, i.e., substantially less than an inch. The advantages of the GMR sensor include reduced size, high signal level, high sensitivity, high temperature stability, and low power consumption.

[**0087**] Referring to **FIG. 9**, the detector assembly **207** also includes a signal processor **303** that is operably interconnected with the sensor **302**. The signal processor **303** receives the signal provided by the sensor **302**, amplifies the signal, and shapes it in order to provide a processed signal more recognizable. At the surface, in the preferred embodiment described here, the processed signal features a readily recognizable square wave, the high state portion of which corresponds to the presence of a casing joint or perforation. The signal processor **303** includes an amplifier and an analog-to-digital converter (neither shown), which are well-known components. The amplifier enhances the signal while the converter is used to convert the analog readings obtained by the sensor **302** into a more readily recognizable digital signal. If desired, the signal processor **303** may incorporate one or more noise filters of a type known in the art in order to remove noise from the signal generated by the sensor **302**. Other signal processing techniques used to enhance the quality of such signals may be applied.

[**0088**] The detector assembly **207** further includes a data transmitter **304** that is operably interconnected with the signal processor **303**. The data transmitter **304** receives the amplified and processed signal created by the signal processor **303** and transmits it supervisory module **203** to be processed and relayed to controller **54** located at the surface of the wellbore.

[**0089**] In operation, the sensor **302** senses the perturbation created by the increased or changed magnetic fields associated with anomalies in the wall of the casing string, such as the connections or joints between casing sections. The detector assembly **207** operates in the same manner to detect perforations **37-39** in the wall of the casing **22**. Perforations **37-39** are small, generally less than one inch in diameter, and typically having a diameter of between approximately 0.18 and 0.5 inches. Thus, perforations **37-39** have the same magnetic force qualities as gaps in casing joints. Due to the natural magnetic field of the casing **22**, the perforations produce fringe effects due to the lines of attractive magnetic forces across the sides of the perforations **37-39**. The attractive magnetic forces produce an increased magnetic signature just as with the joints in casing as discussed above. With a detector assembly **207** having a resolution high enough to detect the increased magnetic signatures of the perforations **37-39**, the exact location of the perforations can be determined.

[**0090**] For perforation patterns having perforations **37-39** on one side of the casing **22** in a given plane perpendicular to the longitudinal axis of the casing **22**, only one sensor **302** is needed. For perforation patterns with perforations **37-39** on more than one side of the casing **22** per plane, more than one sensor **207**, is needed to detect individual opposed perforations. However, with perforation patterns having perforations **37-39** on more than one side per plane, one sensor **302** may still be used to detect the perforation zone of the casing **22** because it is not necessary to detect the individual perforations **37-39**.

[**0091**] Bottom hole assembly **200** further includes gamma tool sub **205** useful for receiving gamma radiation from the surrounding formation and signaling to the surface controller **54** the sensed value. Those values, at the surface, can then be correlated via previously recorded data, to determine the location of bottom hole assembly **200**. Similarly, radioactive tags may be attached to the wall of casing **22** during well completion operations, and gamma tool **205** used to detect and transmit to surface controller **54** the identification and location of the tags. This, again, provides a means to determine the position and depth of BHA **200**. Gamma tool sub **205** may be any conventional tool well known to those skilled in the art for measuring gamma radiation given off by the formation.

[**0092**] Referring now to **FIGS. 4 and 8**, sensor sub **209** houses and protects various sensors used to collect downhole data and to transmit the sensed data to the surface controller **54** via conductors **144** in composite coiled tubing **100**. Although any of a variety and number of sensors may be employed, it is preferred that sensor sub **209** include at least a temperature sensor **250**, as well as various pressure sensors **254**, **258**, **262**, and load sensor **280**. Temperature sensor **250** may be, for example, a thermocouple having on a probe **251** for measuring temperature in the borehole annulus. The sensed temperature is then communicated via lead **271** to controller **354** in supervisory module **203**. An auxiliary or backup temperature sensor (not shown) is preferably provided as a backup in the event that temperature sensor **250** fails. Alternatively, both sensors may be provided with their outputs being averaged or otherwise considered by processor **354** in supervisory module **203**.

[**0093**] Sensor sub **209** in bottom hole assembly **200** includes a load sensor **280**. Load sensor **280** will sense both tension and compression on the bottom hole assembly **200**, and thus on coiled tubing string **100** and transmit a signal representative of the sensed value to controller **354** in supervisory module **203** via conductors **275**. Excessive tension or compression will indicate to the surface controller **54** that the well treatment assembly **40** is hung up in the borehole, necessitating that appropriate action be taken before well treatment assembly **40** becomes damaged. Load sensor **280** is also advantageous in indicating when a packer has failed. More specifically, as treatment fluid is pumped into an isolated interval, high pressure exerts an upward force on bottom hole assembly **200**. If a mechanical problem occurs with a packer **220**, such as when the packer **220** or bottom hole assembly **200** begins to move up hole because it is no longer stationary, the composite coiled tubing **100** could become damaged. Thus, load sensor **280** can be used to give the operator warning so that the pumps can be turned off or adjusted before damage occurs.

[**0094**] Referring to **FIG. 4**, BHA **200** includes a plurality of tilt sensor subs **290***a-c*. Tilt sensor subs **290***a-c* are spaced apart along BHA component series **201** and are provided to sense the tilt or inclination of the casing at various locations so as to provide an indication to the surface controller **54** as to the extent and geometry of a fracture and the prorogation thereof. Tilt sensor subs **290***a-c* are of any conventional design and preferably include bubble type tilt meters that extend from the sub **290***a-c* and magnetically attach to the casing. Such tilt meters are known in the art and, for example, may comprise the apparatus and methods disclosed in U.S. Pat. No. 4,271,696, No. 4,353,244, No. 6,330,914 and No. 5,934,373, the disclosures of which are hereby incorporated by reference. Once the tilt meters are positioned on the casing wall and calibrated, the meter will provide an electrical signal representative of the tilt resulting from the well treatment operation. The electrical signal is communicated to supervisory module **203** via electrical conductors (not shown) within BHA **200**. The signal is thereafter communicated from controller **354** in module **203** to the surface controller **54** via conductors **144** in composite tubing **100**. Such data is evaluated by surface controller **54** to determine if and when certain conditions have occurred. For example, the data evaluation may determine that a fracture has propagated to an undesirable extent, indicating that the treatment process of a particular zone should be terminated.

[**0095**] Although the embodiments of the present invention may be used in a variety of well treatment operations, the following is an example of using these embodiments in a fracing operation. It should be appreciated that the descriptions relative to fracing are provided for illumination purposes only and should not be considered as limiting the present invention only to fracing operators. As previously explained with respect to well treatment in general, it is particularly important to understand the downhole pressure during fracing operations due to the high pressure fluid operation. In actuality, it is desirable to know various pressures. As shown in **FIG. 8**, pressure sensor **254** is connected via tube or conduit **255** to flow bore **211** such that the fluid pressure in the flow bore can be sensed during fracing operations. The pressure sensed in flow bore **211** at the upper end of stinger **210** will closely approximate the pressure in the isolated or "packed off" section of the well bore and will thus provide a pressure signal to the surface by which dangerous pressure spikes and screen out conditions can be anticipated. Pressure sensor **254** may be any standard pressure sensor such as a strain gage type or quartz crystal type. The output from pressure sensor **254** is communicated to controller **354** in supervisory module **203** via leads **272**.

Supervisory module **203** thereafter communicates the sensed value to surface controller **54** via conductors **144** in coiled tubing **100**.

[**0096**] It is also desirable to know the differential pressure as measured across a packer **220**. Referring to **FIG. 8**, Packer **220***a* is shown in a "set" position sealing isolated annular interval **41** that is adjacent one of zones **34-36** from the upper annulus **24** extending above packer **220**. If such differential pressure exceeds that which packer **220***a* can withstand, the packer will fail and no longer isolate the interval **41** from the remainder of the annulus **24**, thereby rendering the fracing operation ineffective. Accordingly, it is desirable to provide a differential pressure sensor **262**. Pressure sensor **262** measures the pressure at the isolated annulus **41** adjacent the lower most portion of stinger **210** by means of conduit **263**. Sensor **262** is likewise coupled to the upper annulus **24** above packer **220** via conduit **264**. In a conventional manner, sensor **262** compares the two pressures from isolated annular interval **41** and upper annulus **24** and provides an output signal via leads **274** to controller **354** in supervisory module **203**. In turn, and as described more fully below, module **203** communicates the sensed differential pressure to the surface controller **54**. Pressure sensor **262** may be any conventional sensor for sensing differential pressures and providing a representative output.

[**0097**] It is also desirable to determine the pressure in upper annulus **24**. A rapid increase in pressure in upper annulus **24** sensed by pressure sensor **258** may indicate a packer failure or may instead indicate that the packer was improperly set within a perforated region of the casing **22** such that some of the fracing fluid injected into the interval believed to have been "isolated" is actually migrating back into the upper annulus **24** via the perforations that are above the location in which the packer was set. Accordingly, it is preferred that an upper annulus pressure sensor **258** be provided in sensor sub **209**. Sensor **258** senses the annulus pressure via conduit **259** and communicates a resulting output signal along leads **273** to supervisory module **203**. Pressure sensor **258** may be identical to sensor **254**.

[**0098**] As an alternative to the arrangement shown in **FIG. 8**, conduit **255**, shown associated with pressure sensor **254**, may connect with conduit **263** rather than to flowbore **211** so that the pressure sensed by pressure sensor **254** is the pressure of the isolated annulus **41** adjacent the lower most end of the stinger **210**. Likewise, sensors **258, 262** may share a single conduit to sense the pressure in upper annulus **24**, as opposed to having separate conduits **259, 264** as is shown in **FIG. 8**.

[**0099**] Still further, given the arrangement shown in **FIG. 8**, differential pressure sensor **262** may be eliminated with the differential pressure instead being calculated based on the signal received from annulus pressure sensor **258** and flow bore pressure sensor **254**, such calculation being made by processor **354** in supervisory module **203**. Because of the importance of collecting pressure data and the ability to communicate large amounts of data via conductors **144** in composite tubing **100**, it is believed generally preferable to have more pressure sensors, rather than fewer. Including pressure sensor **254, 258** and **262** can thus provide a measure of redundancy that is advantageous.

[**0100**] Referring now to **FIG. 9**, there is shown a schematic of the power and electronic control system **300** for the bottom hole assembly **200**. The system **300** includes a plurality of downhole sensors or data acquisition devices **352**, a plurality of control devices **358**, power distribution module **381**, detector module **207** and supervisory module **203**. As represented in **FIG. 9**, downhole data acquisition devices **352** include, for example, gamma tool sub **205**, temperature sensor **250**, pressure sensors **254, 258, 262**, load sensor **280** and tilt sensors **290***a-c*. It should be appreciated that sensors **352** and control devices **358** may not only include the particular sensors and control devices described above, but other data collection and measurement sensors and control devices well know in the art.

[**0101**] Surface power supply **52** provides power to power distribution module **381** in power sub **208** through conductors **144** which, as previously described, are embedded within coiled tubing **1100** in this embodiment. Power distribution module **381** distributes power via a power bus **382** to supervisory module **203**, detector sub **207**, and the various other sensors **352** and control devices **358** in the bottom hole assembly **200**.

[**0102**] A "slow" data bus **376** provides a command and data communication path between controller **354** in supervisory sub **203** and power distribution module **381**, detector sub **207**, and the various sensors **352** and control devices **358**. Microcontrollers in each of the above components can communicate with each other via the slow bus **376**. A "high speed" data bus may also be provided between the supervisory module **203**, detector sub **207**, and other data acquisition devices such as sensors **352**. An example of a suitable high speed data bus may be a **1553** wireline data bus as is commonly used for wirelines.

[**0103**] The slow data bus **376** and high speed data bus **378** are coupled to supervisory module **203** which acts as a downhole controller for detector sub **207** and all downhole data acquisition devices **352** and control devices **358**. Supervisory module **203** is coupled to a transformer **388** by data leads **384, 386**. Leads **384, 386** are, in turn, coupled to conductors **144** embedded in coiled tubing **100** and extending to the surface. Conductors **144** are coupled to a second isolation transformer **390** in the surface operating system **50** at the surface. At the upper end of composite coiled tubing **100**, transformer **390** couples these conductors to a digital signal processor **392** housed within surface controller **54**. Transformers **388, 390** provide direct current isolation to protect uphole and downhole electronics from electrical faults.

[**0104**] The digital signal processor **392** in the surface controller **54** is a programmable device which serves as a modem (modulator/demodulator) at the surface. Likewise, controller **354** in supervisory module **203** includes a digital signal processor and modem. Digital signal processor **392** and controller **354** each preferably includes analog-to-digital conversion circuitry to convert received signals into digital form for subsequent processing.

[**0105**] Each downhole sensor **352** and control device **358** and detector sub **207** has a modem with a unique address from data busses **376, 378**. Thus, each modem may communicate individually and directly with the surface controller **54** using its unique address; however, it is preferred that each communicate with controller **354** in supervisory sub **203** and that, in turn, supervisory sub **203** communicate with surface controller **54**. Surface controller **54** can initiate communications with a particular device's modem by sending a message to the unique address. The modem in the receiving device responds by communicating an acknowledgment to the surface. This allows the surface to communicate with each of the downhole control devices **358** and sensors **352**. The downhole-surface communications preferably occur serially over conductors **144**. The command signals down to the power distribution module **381** directs the power to the appropriately designated downhole device.

[**0106**] Generally no signal is sent downhole requesting that the data from the sensors **352** or detector **207** be forwarded to the surface. Instead, it is preferred that data collected by the downhole devices be constantly communicated to the surface in a coded stream which can be read or ignored as desired by processor **392** in surface controller **54**. The high speed data bus **378** is normally reserved for data communications. All of this data is in digital form.

[**0107**] The commands from the surface to the downhole control devices **358** are preferably time- or frequency-multiplexed and sent downhole via conductors **144**. As previously mentioned, these communications may alternatively be sent downhole via conductors of other types that may be included in composite coiled tubing **100**. In their simplest form, the command may simply be on and off signals. The electrical power on power conductors **144** is preferably provided in the form of direct current.

[**0108**] Although a certain amount of data processing may occur downhole in some of the devices **358**, or in supervisory module **203**, it is preferred that the bulk of the data processing occur at the surface. Some of the data is initially conditioned downhole in module **203** prior to being forwarded to the surface. Each downhole control device **358** includes a microprocessor which acts as a controller. These microprocessors are normally not used for the processing of data. Such downhole processing is unnecessary since more than adequate bandwidth is provided to send all data to the surface for processing.

[**0109**] All of the downhole control devices **358** are electrically powered from the surface. Although some downhole control devices **358** may have hydraulic components, such components are preferably electrically controlled.

[**0110**] The supervisory module **203** serves as the controller for the bottom hole assembly **200**. The supervisory module **203** basically serves as a bus master and might be considered the hub of the downhole activity. It takes commands from the surface and retransmits them to the individual downhole devices. The supervisory module **203** also receives acknowledgements and data from the individual sensors **352** and detector sub **207** and retransmits them to the surface controller **54**. The commands and data are preferably provided in a frame format that allows the supervisory module **203** to efficiently multiplex and route the frames to the desired destination. The supervisory module **203** preferably transmits information to the surface using quadrature amplitude modulation (QAM), although other modulation schemes are also contemplated. Currently the QAM modulation provides a 65 kilobit per second transmission rate, but it is expected that transmission rates of 160 kilobits per second or greater can be achieved. The commands transmitted from the surface controller **54** to the supervisory module **203** are preferably sent using a frequency-shift keying (FSK) modulation scheme that supports a transmission rate of approximately 2400 baud. A QAM telemetry system useful for the embodiment of the invention now being described is disclosed in more detailed in U.S. patent application Ser. No. 09/599,343, filed Jun. 22, 2000 the entire disclosure of which is hereby incorporated herein by reference.

[**0111**] The surface processor **54** provides a way to "close the loop" between the sensors **352**, detector sub **207** and the downhole control devices **358**. The surface controller **54** can direct the downhole control devices **358** to perform an action and received sensed data indicative of the results. If the results are not what was expected, or if the data acquisition devices **352** indicate the need for a different action, then the surface controller **54** can direct the control devices **358** to adjust their actions accordingly. This form of feedback enables precise control and a fast response to changing conditions.

[**0112**] The data telemetry system described above provides many additional features and capabilities beyond those necessary solely to practice the embodiments of the well treatment apparatus and methods contemplated by the present invention. That is, more specifically, to practice the methods and use the apparatus described herein, data reflecting downhole conditions such as pressure, temperature, loading on the tubing and similar parameters is the preferred data needed to be transmitted uphole. That being the case, the more sophisticated QAM telemetry system described herein is not a requirement, the necessary data being capable of transmission up hole on a single pair of conductors via multiplexing techniques that are well known to those skilled in the art. The QAM telemetry system described herein is believed useful in that activation of other instrumentation and controls within bottom hole assembly **20** may be desirable.

[**0113**] Referring now to **FIGS. 4 and 10**A-D, in operation, zones **34**-**36** are treated in a single trip of well treatment assembly **40**, the zones being treated sequentially, starting with the lower most zone **36**. Thus, bottom hole assembly **200** is lowered into the borehole at surface **16** on coiled tubing **100** which is injected into the wellbore by means of tubing injector **58**. Referring to **FIG. 10**A, bottom hole assembly **200** is lowered to a depth where it is believed that ports **212** in stinger **210** are below the region of perforations **39** in zone **36**. Surface controller **54** activates detector assembly **207**. Tubing **100** and bottom hole assembly **200** are raised as detector assembly **207** detects, identifies and locates perforations **39** and the casing joints in casing **22**. Bottom hole assembly **220** is substantially rigid and the distance thus fixed between ports **212** and detector assembly **207**. Accordingly, when detector assembly **207** locates perforations **39** into zone **36**, the operator then directs controller **54** to raise bottom hole assembly **200** that known distance such that stinger ports **212** are substantially aligned with perforations **39**. Likewise, the distance between stinger ports **212** and the lower terminal end of packer **220***a* is a known distance such that bottom hole assembly **200** is raised still further until lower most packer **220***a* is above the perforations **39** in a "blank" section of pipe casing, meaning a section free of perforations and casing joints. Raising BHA **200** this additional distance also positions ports **212** above the uppermost performation **39** in interval **36**. Controller **54** receives signals from gamma tool **205** and compares that data with previously stored formation data or radioactive tags to verify that ports **212** in stinger **210** are appropriately positioned with respect to perforations **39**. Proper placement of packers in blank casing and ensuring that ports **212** are above the uppermost perforation **39** in the interval **36** is very important so as to prevent erosion or washout, and to reduce the possibility of a false indication that a screen out condition is occurring.

[**0114**] Once the position is confirmed, controller **54** sends the appropriate electrical signal to supervisory sub **203** to pack off the zone to be treated. Controller **354** in supervisory sub **203** causes solenoid valve **244***a* to actuate actuator **240***a* so that pressurized hydraulic fluid can actuate the slips in packer **220***a* thereby expanding packer **220***a* to engage the wall of casing **22** and thereby create an isolated, generally annular zone **41** that is packed off from upper annulus **24** by packer **220***a* as shown in **FIG. 10A**. As is known in the art, the outermost surface of packer **220***a* seals the wall of casing **22**, and the packer's seal bore seals with seals on the exterior of stinger **210**. With packer **220***a* set, stinger **210** is pulled upward slightly to sever a shear pin (not shown) thereby releasing packer **220***a* from stinger **210** and the remainder of the stack of packers **220**. This allows further adjustment to the location of stinger **210** within packer **220***a* so as to position ports **212** just above perforations **39**.

[**0115**] With BHA **200** properly positioned and interval **41** isolated, fracing fluid is then pumped through composite coiled tubing **100** and bore **211** of BHA **200** and stinger **210** where it exits ports **212** and passes into zone **36** through perforations **39**. As the proppant is injected in to the fracture, the bottom hole pressure increases. The pressure sensors **354**, **358**, **362** (**FIG. 8**) monitor the downhole pressure and continuously transmit signals to the controller **354** in supervisory sub **203**, which relays the sensed data to surface controller **54**. Likewise, tilt sensors **290***a-c* continuously monitor the orientation of the casing and, in real time, transmit data indicative of fracture geometry to surface controller **54** via supervisory sub **203**. By continuously monitoring the various pressures in the isolated interval **41** and, in particular, the rate of change in those pressures, the operator at the surface can determine when it is desirable or, for safety reasons necessary, to reduce or turn off the pumping operations or make other adjustments to the proppant slurry flow. Likewise, continuously monitoring temperature in the isolated interval **41** provides important information about the proppant slurry properties, enabling adjustments to be made to the composition and density of the slurry to optimize the fracing operation. Real time transmission of data from the tilt sensors **290** indicating fracture height, width and other geometries likewise provides valuable information as to how the reservoir is responding to treatment, and thereby enables better decision making with respect to the treatment process. The continuous monitoring of downhole parameters and the ability to communicate the sensed values to the surface in real time via conductors **144** in the tubing **100**, all as provided by the embodiment of the invention described above, permit accurate and precise control of the well treatment operation. These advantages provided by this embodiment thereby eliminate the necessity of having to rely on prior, less reliable techniques where downhole conditions had to be estimated or crudely calculated.

[**0116**] When it is determined that the appropriate volume of fluid and proppant has been injected into zone **36**, and before or immediately after screen out occurs, pumping of treatment fluid is ceased. The annulus **24** is then pressured up with water, brine or other suitable fluid, and bottom hole assembly **200** is raised such that stinger **210** is lifted out of the seal bore of packer **220***a*. Pressuring annulus **24** above isolated interval **41** before pulling stinger **210** out of valve sub **222** prevents fluids in interval **41** from flowing upwardly and into annulus **24** as stinger **210** is repositioned. Referring momentarily to **FIG. 8**, raising stinger **210** causes caming surface **324** on latch members **320** of collet **330** to engage the lower surface of packer **220***a* and forces latch members **320** into a retracted position permitting stinger **210** to be pulled out of the flow bore of packer **220***a*. Valve sub **222***a* is then actuated so that flapper member **223***a* closes off the seal bore through packer **220***a* and prevents pressurized fluid above from flowing through packer **220***a* and from entering isolated annular interval annulus **41** as shown in **FIG. 10B**. In this manner, a new isolated annular interval can be created above the actuated flapper sub **220***a* and can be pressurized in order to frac adjacent zone **35**, as described below.

[**0117**] Referring to **FIGS. 4 and 10**B, if excess proppant remains in workstring **100** or bottom hole assembly **200** after treating interval **36**, it can be "reversed out" by pumping fluid down annulus **24** from the surface where it passes around unset packers **220** and enters bottom hole assembly **200** via ports **212**. Such fluids then flow back up through bottom hole assembly **200** and tubing string **100** to clear excess proppant, allowing the next treatment to then take place.

[**0118**] Referring now to FIGS. **10**B-**10**D, to treat the next producing zone **35**, BHA **200** is raised and detector assembly **207** detects, identifies and locates the perforations **38** in the interval or region adjacent zone **35**. When BHA **200** is raised, the latch members **320** on stinger **210** engages the lower most surface on packer **220***b*. With the surfaces thus engaged, raising stinger **210** thereby also raises the remaining stack of packers **220***b*-**220***f*. Because packers **220***b*-**220***f* are not set, there is not enough reactive force applied by the packers to latch members **320** of collet **330** as is required to cause latch members **320** to retract. Once again, knowing the fixed distances associated with detector assembly **207** and stinger **210**, stinger **210** is raised to a position where packer **220***b* is in blank pipe above the region of perforations **38** as shown in **FIG. 10B**. With packer **220***b* above perforations **38**, surface controller **54** (via supervisory sub **203**) signals solenoid valve **244***b* which, in turn, actuates hydraulic actuator **240***b* to expand packer **220***b* so that it seals with the wall of casing **22** at the location shown in **FIG. 10C**. Stinger **210** may thereafter be raised slightly to sever the shear pin (not shown) securing packer **220***b* to the packer stack above it and then can be lowered, if needed, so as to locate ports **212** just above perforations **38**, such position being represented by the dashed lines in **FIG. 10C**. Fracing fluid is then pumped downhole through tubing **100** and out ports **212** of stinger **210** so as to treat producing zone **35**. As before, pressure is monitored and pumping is reduced and then shut down at the surface before a spike in downhole pressure causes a dangerous overpressure at the surface. Likewise, data transmitted by the other downhole sensors, such as temperature sensor **250** and tilt sensors **290**, is likewise monitored at the surface and evaluated. When zone **35** has been treated, annulus **24** is pressured and stinger **210** is raised to a position above expanded packer **220***b*, at which time flapper member **223***b* of valve sub **222***b* closes thereby sealing interval **43** from upper annulus **24** and isolating zone **35** as shown in **FIG. 10D**. In a similar manner, using detector assembly **207**, perforations **37** into zone **34** are located, packed off and the zone treated. Packers **220***d, e* and f may then be used to treat upper zones (not shown) as BHA **200** is raised still further.

[**0119**] In the manner thus described above, packers **220***a-f* are actuated remotely from the surface, and are actuated sequentially and selectively to isolate specific wellbore intervals so as to enable well treatment operations that are specifically tailored for the particular zone that is adjacent to the isolated interval. The embodiment of the invention thus described permits each zone, in a well containing several producing zones, to be treated one at a time, and ensures that each zone can be treated in a manner that enhances the potential for maximizing the recovery of valuable hydrocarbons from that particular zone, and from the well as a whole. In contrast to conventional packers and work strings previously used in well treatment operations, the embodiments of the invention described above allow packers to be set and well intervals to be isolated without requiring mechanical movement of the work string or the pressuring of fluids contained in the work string. Instead, once they are properly positioned, the packers are set simply and quickly via electrical signals that are communicated downhole via conductors. Further, the severe forces that are imposed on a work string that employs weight set packers are eliminated.

[**0120**] Referring now to **FIG.** 11A, another preferred embodiment of the well treatment apparatus and method is shown in which composite coiled tubing **100** is connected to a bottom hole assembly **400** having a series **201** of connected BHA components and a downwardly extending stinger **210**. BHA component series **201** include a connector sub **202**, supervisory sub **203**, hydraulic distribution sub **204**, gamma tool **205**, a detector assembly **207**, power distribution sub **208** and sensor sub **209**, all as previously described. Disposed in spaced apart position along stinger **210** are packers **420***a-c*. A flapper valve assembly **422** is connected to each packer **420**. Stinger **210** includes a solenoid valve and hydraulic actuator such as those previously described with reference to FIGS. **6-7** that are controlled by supervisory sub **203** so as to cause each packer **420** to expand and seal against the well casing upon receipt of the appropriate signal. Each packer **420***a-c* is connected to stinger **210** by a latch member (not shown) that is released upon actuation of packer **420**.

[**0121**] Referring to **FIGS. 11A and 11B**, bottom hole assembly **400** may be employed to treat, for example, zones **450**, **451** which have been perforated at intervals **452**, **454** respectively. To treat these zones, bottom hole assembly **400** is first lowered to a position below zone **450**. The bottom hole assembly **400** is then be raised and, using detector assembly **207** in conjunction with gamma tool **205**, packer **420***a* is positioned above the perforated interval **452** in blank pipe away from any casing joints. At this juncture, packer **420***a* is actuated so as to isolate the interval **441** of the cased borehole below packer **420***a*, the packer **420***a* in its expanded or set position being represented by dashed lines in **FIG. 11A**. The fracing procedure is then commenced with temperature and pressures continuously monitored downhole as previously described. When the fracing operation is complete, and prior to screen out, bottom hole assembly **400** is raised such that stinger **210** is pulled out of set packer **420***a*, at which time flapper valve assembly **422***a* closes, as shown in **FIG. 11B**. The above-described procedure is then repeated such that packer **420***b* is positioned above perforated interval **454** in zone **451**, and then actuated. Thereafter, stinger **210** can be reciprocated within packer **420***b* to center ports **212** in relation to perforated interval **454**. A producing zone above zone **451** may thereafter be treated in a similar manner by employing packer **420**C. The embodiment shown in FIGS. 11A-B having spaced apart packers along stinger **210** are believed to have particular utility in treating formations having very long intervals with many producing zones.

[**0122**] The embodiments of the invention described to this point preferably include the use of composite coiled tubing **100**. Because such composite tubing cannot be subjected to substantial tension or compression, conventional weight set packers cannot be employed, such that the electrically controlled, and electrically/hydraulically actuated packers previously described are the preferred packers for use with composite coiled tubing **100**. Additionally, however, other packers and packer actuators may be employed. For example, a propellant may be provided in the stinger body adjacent to each packer as the actuator. The propellant can then be electrically ignited in response to a signal from the surface controller **54**. The pressure created by the burning propellant may be used to actuate mechanical slips as necessary to set the packer. As known to those skilled in the art, many existing wire line packers are set using a propellant. Thus, referring now to **FIGS. 9 and 12**, it will be understood that a signal from surface controller **54** relayed via to supervisory module **203** along wires **144** may then cause power distribution module **381** in power sub **208** to ignite the propellant **226** via power sent along conductors **225** **(FIG. 12)** and thereby expand the associated packer **227**. In this manner, the hydraulic distribution system previously described would not be necessary.

[**0123**] Another embodiment of the invention includes the use of electric motors as actuators for the packers **220***a-f*. In such an arrangement, associated with each packer **220***a-f* is a separately controlled electric motor (not shown) housed in the body of stinger **210**. Referring again to the control schematic of **FIG. 9**, each motor constitutes a control device **358** and receives power from power distribution module **381** in power sub **208** and is controlled by controller **354** in supervisory module **203**. Upon receipt of the appropriate control signal from surface controller **54**, processor **354** in supervisory module **203** causes power to be switched to the motor. Thereafter, the motor drives any of a number of conventional mechanical energy converters, such as a screw or screw and piston combination, and actuates mechanical slips that cause the associated packer to expand. See for example, U.S. patent application Ser. No. 09/678,817 filed Oct. 4, 2000 entitled Actuator Assembly, hereby incorporated herein by reference.

[**0124**] Another preferred embodiment of the present invention is best described with reference to **FIG. 13** wherein bottom hole assembly **600** is shown connected to coiled tubing **100** and disposed in a borehole **601** adjacent to zone **640**. BHA **600** generally comprises a connected series of BHA components **201** and stinger **610** extending therefrom. BHA component series **201** include a connector sub **202**, supervisory sub **203**, hydraulic distribution sub **204**, gamma tool **205**, detector assembly sub **207**, sensor sub **209**, and tilt sensors **290***a-c* all as previously described. Stinger

610 includes an internal flowbore, like bore **211** shown in **FIG. 4**, in fluid communication with flowbore **146** (**FIG. 3**) of coiled tubing **100**. Stinger **610** includes ported discharge sub **614** having ports **612** for directing fracing fluid into zone **640** that is to be treated.

[0125] Disposed in spaced apart relation on stinger **610** are upper cup packer **616** and lower packer **618**. Packers **616**, **618** are hydraulically actuated via interconnection with hydraulic distribution module **204** so that they can repeatedly be expanded (set) to engage the casing side wall and contracted (unset or released) so that bottom hole assembly **600** can be repositioned in the wellbore. Unlike the packers in the embodiments previously described, packers **616**, **618** remain fixed to stinger **610** in bottom hole assembly **600**. Packer **618** may be, for example, a Halliburton type RR4 packer. Alternatively, packer **618** may likewise be a cup packer such as packer **616** with the cup facing upwards and thus facing in the opposite direction as cup packer **616**.

[0126] Bottom hole assembly **600** further includes an anchor **630** at the terminal end of stinger **610**. Anchor **630** may be, for example, a single grip, multiset compression packer. An additional packer, such as packer **618**, may likewise be employed as anchor **630**. An anchor such as anchor **630** may likewise be employed at the upper end, lower end, or both ends of the bottom hole assemblies **200**, **400**, previously described, where desirable for added stability. BHA **600** further includes tilt sensors **290***d*, **290***e* below anchor **630**. Like tilt sensors **290***a-c* that are positioned above cup packer **616**, sensors **290***d,e* are used to sense a change in inclination (tilt) of the casing, indicating a characteristic of the fracture geometry and propagation.

[0127] Referring still to **FIG. 13**, packers **616**, **618** together form a straddle packer arrangement with upper cup packer **616** being spaced apart from lower packer **618** a fixed distance selected for isolated zone **640** which has been perforated in interval **642**. In operation, bottom hole assembly **600** is lowered on coiled tubing **100** to a position where detector assembly **207** is below zone **640**. Sub assembly **600** is then raised and perforated interval **642** located by detector assembly **207**. Gamma tool **205** may likewise be employed to verify the location of zone **640** and perforated interval **642**. Thereafter, bottom hole assembly **600** is raised the fixed and known distance between ported sub **614** and detector assembly **207** so as to align ports **612** with the perforated interval **642**. In this position, anchor **630** is actuated hydraulically so as to set and stabilize bottom hole assembly **600**. Likewise, hydraulic packer **616**, **618** are actuated so as to isolate the interval **602** adjacent to zone **640**. The dashed lines in **FIG. 13** represents packers **616**, **618** and anchor **630** in their expanded positions. Proppant fracing fluid is then pumped from the surface through coiled tubing **100** and stinger **610** where it exists through ports **612** and enters formation **640** through perforated interval **642**. Pressure sensors **354**, **358**, **362** in sensor sub **209** monitor the downhole pressure as previously described so that a dangerous screen out condition can be predicted. When the stimulation procedure has been completed, packers **616**, **618** and anchor **630** are retracted, and bottom hole assembly **600** may then be raised to another position to treat another producing zone. As understood by those skilled in the art, once set, cup packer **616** seals pressure from below packer **616** in interval **602** but will allow fluid to flow downwardly through the annulus **24** and past cup packer **616**. Such a packer is advantageous in that it provides a means to flush sand and remaining fracing fluid from bottom hole assembly **600** before beginning fracing operations in the next zone. This is accomplished by raising bottom hole assembly **600** above the treated zone **640** to a blank area of casing beneath the next zone that is to be treated. Packers **616** and **618** are then actuated so as to engage the casing wall. Fluid may then be pumped down the annulus from above the isolated interval that exists between the packers where it is allowed to pass downwardly past cup packer **616** and into the ported sub **614** through ports **612**. Once this "reverse circulation" has flushed out the sand and any undesirable fluid, bottom hole assembly **600** is then raised to the next zone where packer **616**, **618** and anchor **630** are then set.

[0128] Referring to **FIG. 14**, bottom hole assembly **700** is shown connected to coiled tubing **100** and disposed in borehole **701** adjacent to zone **740**. Bottom hole assembly **700** is substantially the same as assembly **600** previously described with respect to **FIG. 13**; however, bottom hole assembly **700** includes two cup packers **716**. Packers **716** may be identical to packer **616** previously described. Two such packers **716**, or more, are provided on bottom hole assembly **700** to enhance tool reliability and eliminate the necessity of withdrawing bottom hole assembly **700** should the first packer **716** fail. In this embodiment, lower packer **718** is also a cup packer and is identical to packers **716**, however, cup packer **718** is positioned with its cup facing uphole. As will be understood, bottom hole assembly **700** may likewise include two or more lower packers **718** for enhanced tool reliability. Operation of BHA **700** is identical to that described with respect to BHA **600**, with packers **716** being selectively actuatable.

[0129] The specific examples of the invention described to this juncture have related to the use of composite coiled tubing, which is preferred for deep well applications; however, it is to be understood that metal coiled tubing can also be employed in certain applications, although certain advantages and features of the preferred composite tubing are lost. For example, conductors cannot be embedded within the metal tubing, but must be supported within or on the outside of the tubing string. Although this can be accomplished, it is less convenient and exposes the conductors to abuse due to the harsh conditions prevalent when the tubing is injected into a borehole. Further, metal coiled tubing fatigues relatively quickly when cycled in and out of wells. By contrast, composite coiled tubing is believed to have a significantly longer pipe life compared to that of metal coiled tubing in the well stimulation activities described herein.

[0130] While preferred embodiments of this invention have been shown and described, modifications thereof can be made by one skilled in the art without departing from the spirit or teaching of this invention. The embodiments-described herein are exemplary only and are not limiting. Many variations and modifications of the system and apparatus are possible and are within the scope of the invention. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims which follow, the scope of which shall include all equivalents of the subject matter of the claims.

What is claimed is:

1. Apparatus for treating zones in a subterranean formation intersected by a wellbore that extends from the surface through the zones, the apparatus comprising:

a bottom hole assembly comprising a tubular sub, said tubular sub having an internal fluid passageway and a fluid port for conducting fluids from said internal passageway into the wellbore;

a composite tubing string having an internal flow bore and interconnected with said bottom hole assembly such that said flow bore of said tubing string and said fluid passageway of said tubular sub are in fluid communication.

2. The apparatus of claim 1 further comprising:

a controller located at the surface;

a sensor in said bottom hole assembly;

a conductor coupling said sensor to said surface controller, said conductor being embedded in said composite tubing string and extending from said bottom hole assembly to the surface.

3. The apparatus of claim 1 further comprising:

a controller located at the surface;

a packer on said bottom hole assembly;

a packer actuator for causing said packer to expand in response to an electrical signal transmitted by saidsurface controller;

a conductor embedded in said composite tubing string coupling said packer actuator to said surface controller.

4. The apparatus of claim 3 further comprising:

an electric power supply at the surface;

a power distribution sub in said bottom hole assembly;

a conductor embedded in said composite tubing string coupling said surface power supply to said power distribution sub;

conductors in said bottom hole assembly coupling said power distribution sub to said packer actuator.

5. The apparatus of claim 2 wherein said sensor senses anomalies in the casing and transmits signals indicative of the anomaly to said surface controller via said conductor.

6. The apparatus of claim 5 wherein said sensor is a magnetoresistive sensor.

7. The apparatus of claim 5 further comprising:

a packer on said bottom hole assembly;

a packer actuator for causing said packer to expand in response to an electrical signal transmitted by said surface controller; and

a conductor embedded in said composite tubing string coupling said packer actuator to said surface controller.

8. The apparatus of claim 7 further comprising a conductor embedded in said composite tubing transmitting power from the surface to said bottom hole assembly, and transmitting data from said bottom hole assembly to said surface controller.

9. The apparatus of claim 8 further comprising a pressure sensor in said bottom hole assembly sensing pressure adjacent said fluid port and communicating the sensed pressure to said surface controller via a conductor in said composite tubing string.

10. The apparatus of claim 9 wherein said bottom hole assembly includes a plurality of packers supported along said tubular sub, said packers being sequentially actuatable in response to electrical signals from said surface controller.

11. An apparatus for treating a subterranean zone in a formation that is intersected by a wellbore, the apparatus comprising:

a surface controller;

a composite tubing string extending from the surface into the wellbore;

a bottom hole assembly releaseably attached to said composite tubing string, said bottom hole assembly comprising a plurality of packers that are sequentially actuatable in response to electrical signals from said controller, and an actuator associated with each of said packers for selectively actuating its associated packer;

wherein said composite tubing string includes embedded conductors, and wherein said conductors couple said actuators with said surface controller.

12. The apparatus of claim 11 further comprising a hydraulic unit in said bottom hole assembly for generating hydraulic power; and wherein at least one of said actuators is a solenoid valve directing hydraulic fluid from said hydraulic unit to said associated packer in response to receiving a signal transmitted from said surface controller to said bottom hole assembly via a conductor embedded in said composite tubing.

13. The apparatus of claim 11 wherein at least one of said actuators is a propellant disposed in said bottom hole assembly adjacent to said associated packer and electrically ignited in response to a signal transmitted from said surface controller to said bottom hole assembly via a conductor embedded in said composite tubing.

14. The apparatus of claim of **11** wherein at least one of said actuators is an electric motor disposed in said bottom hole assembly, said motor actuating to actuate its associated packer in response to receipt of a signal transmitted from said surface controller to said bottom hole assembly via a conductor embedded in said composite tubing.

15. The apparatus of claim of **11** further comprising a detector assembly in said bottom hole assembly capable of detecting anomalies in the casing of the wellbore, said detector transmitting to the surface controller data relating to the anomalies via said embedded conductors.

16. The apparatus of claim of **15** further comprising a sensor in said bottom hole assembly for sensing data indicative of a condition in the well bore and communicating the sensed data to the surface controller via said embedded conductors.

17. The apparatus of claim 16 further comprising a power supply on the surface, and wherein said embedded conductors transmit power from said power supply to said bottom hole assembly, transmit control signals from said surface controller to said bottom hole assembly, and transmit well bore data from said bottom hole assembly to said surface controller.

18. The apparatus of claim 11 further comprising a disconnect assembly connecting said bottom hole assembly to said composite tubing string, said disconnect being actu-

ated electrically via electrical signals communicated from said surface controller via said embedded conductors.

19. The apparatus of claim 18 further comprising a latch releasably latching said plurality of packers on said bottom hole assembly.

20. Apparatus for conducting well treatment operations in a wellbore that extends from the surface through a subterranean formation having producing zones, the apparatus comprising:

a work string extending into the wellbore from the surface;

a bottom hole assembly connected to said work string and having an elongate tubular member with a central flow bore and discharge ports;

a surface controller;

electrical conductors supported by said work string for communicating signals from said surface controller to said bottom hole assembly;

a plurality of packers supported on said tubular member, said packers being sequentially operable so as to isolate different intervals of the well bore in response to signals transmitted from said surface controller to said bottom hole assembly.

21. The apparatus of claim 20 further comprising a detector in said bottom hole assembly coupled to said surface controller via said conductors, said detector detecting segments of the well casing that are free of perforations and casing joints.

22. The apparatus of claim 20 further comprising a sensor in said bottom hole assembly coupled to said surface controller via said conductors.

23. The apparatus of claim 22 wherein said work string includes metal tubing and wherein said conductors extend between said bottom hole assembly and the surface in an umbilical supported by said metal tubing.

24. The apparatus of claim 22 wherein said work string includes composite tubing and wherein said conductors extend between said bottom hole assembly and the surface and are embedded in the wall of said composite tubing.

25. The apparatus of claim 20 further comprising:

a plurality of actuators, each of which being associated with a packer for selectively actuating its associated packer;

a hydraulic unit in said bottom hole assembly for generating hydraulic power;

wherein at least one of said actuators is a solenoid valve directing hydraulic fluid from said hydraulic unit to said associated packer in response to receiving a signal transmitted from the surface controller to said bottom hole assembly via said electrical conductors.

26. The apparatus of claim 20 further comprising:

a plurality of actuators, each of which being associated with a packer for selectively actuating its associated packer;

wherein at least one of said actuators is a propellant disposed in said tubular member adjacent to its associated packer and electrically ignited in response to a signal transmitted from said surface controller to said bottom hole assembly via said electrical conductors.

27. The apparatus of claim 22 wherein said sensor includes a pressure sensor sensing pressure indicative of the pressure in the well bore adjacent said tubular member.

28. The apparatus of claim 22 wherein said sensor is a differential pressure sensor sensing the pressure in the wellbore above and below one of said packers.

29. The apparatus of claim 22 wherein said sensor is a temperature sensor sensing temperature in the well bore adjacent said tubular member.

30. A method of treating zones in a subterranean formation intersected by a cased well bore that extends from the surface through the zones, the method comprising:

placing into the wellbore a tubing string with a bottom hole assembly having a ported sub and a plurality of sequentially settable packers;

locating a blank segment of casing above the depth of a first producing zone;

setting a first packer in the blank region of casing to isolate a first well interval below the first packer from the annulus extending above the first packer;

pumping treatment fluid through the ported sub into the first isolated interval;

sensing within the first isolated interval at least one downhole parameter and communicating the sensed parameter to the surface via conductors that extend along the tubing string between the bottom hole assembly and the surface.

31. The method of claim 30 further comprising:

ceasing the pumping of treatment fluid when the sensed parameter meets a predetermined criteria.

32. The method of claim 30 further comprising:

ceasing the pumping of treatment fluid;

raising the bottom hole assembly to a position above the set first packer;

locating a blank segment of casing above the depth of a next producing zone;

setting a second packer in the blank region of casing to isolate a second well interval above the first packer and below the second packer from the annulus extending above the second packer;

pumping treatment fluid through the ported sub into the second isolated interval;

sensing within the second isolated interval at least one downhole parameter and communicating the sensed parameter to the surface via conductors that extend along the tubing string between the bottom hole assembly and the surface.

33. A method of stimulating subterranean zones that are intersected by a wellbore comprising:

positioning a tubing string in the wellbore;

isolating a first interval of the wellbore adjacent to a first zone;

stimulating the first zone by pumping fluids through the tubing string into the first isolated interval;

sensing at least one downhole parameter while stimulating the first zone;

communicating the sensed parameters to the surface via conductors in the tubing string while stimulating the first zone.

34. The method of claim 33 further comprising sensing the pressure in the first isolated interval and ceasing the stimulation when the rate of change in the pressure sensed exceeds a predetermined value.

35. The method of claim 33 further comprising:

ceasing the stimulation of the first zone;

raising the tubing string in the well bore;

isolating an interval adjacent to a second zone;

stimulating the second zone by pumping fluids through the tubing string into the second isolated interval;

sensing parameters within the second isolated interval while stimulating the second zone;

communicating the sensed parameter to the surface via conductors in the tubing string while stimulating the second zone.

36. A method of treating a subterranean formation having a casing extending through the formation, the casing having perforations adjacent the formation and casing joints adjacent the perforations, the method comprising:

lowering a detector assembly, packer and mandrel on a coiled tubing into the casing;

locating the perforations using the detector assembly;

transmitting the location of the perforations to the surface;

setting the packer to isolate the perforations; and

pumping fluid through ports in the mandrel and through the perforations and into the formation.

37. The method of claim 36 further comprising providing a conductor on the coiled tubing to transmit the location of the perforations to the surface.

38. The method of claim 36 further comprising sensing the pressure downhole providing and a conductor on the coiled tubing to transmit the pressure to the surface.

39. The method of claim 36 further comprising transmitting a signal from the surface through a conductor on the coiled tubing to actuate the packer.

40. An apparatus for treating a formation adjacent a casing extending from the surface into a well, the casing having anomalies such as casing joints and perforations, comprising:

a coiled tubing having a flowbore and at least one conductor supported by a wall of said coiled tubing;

a detector assembly having a detector sensor to detect one or more of the anomalies in the casing, the detector assembly transmitting signals of the detection through said conductor to the surface;

a mandrel having a packer mounted thereon and a port in fluid communication with a flow passage through said mandrel and with said flowbore of said coiled tubing;

said detector assembly and mandrel being supported by said coiled tubing.

41. The apparatus of claim 40 wherein said detector sensor is a magnetoresistive sensor.

42. The apparatus of claim 40 wherein said detector sensor senses anomalies in the casing wall which form fringe effects that cause perturbations in the naturally induced magnetic field of the casing.

43. The apparatus of claim 40 wherein said detector sensor detects the perforations and determines the depth of the perforations.

44. The apparatus of claim 40 wherein said detector sensor detects the casing joints and determines the depth of the casing joints adjacent the formation.

45. The apparatus of claim 40 wherein said coiled tubing is metal tubing and said conductor is mounted on the interior or exterior wall of said metal tubing.

46. The apparatus of claim 40 wherein said coiled tubing is composite coiled tubing with said conductor embedded in a wall of the composite coiled tubing.

47. The apparatus of claim 40 wherein power is transmitted downhole through said conductor.

48. The apparatus of claim 47 wherein data is transmitted to the surface through said power conductor.

49. The apparatus of claim 40 further including a pressure sensor supported on said coiled tubing.

50. The apparatus of claim 49 wherein said pressure sensor senses the pressure adjacent a lower end of said mandrel.

51. The apparatus of claim 49 wherein said pressure sensor senses the pressure above said packer.

52. The apparatus of claim 49 wherein said pressure sensor senses the differential pressure between the pressure adjacent a lower end of said mandrel and the pressure above said packer.

53. The apparatus of claim 40 further including a temperature sensor supported on said coiled tubing.

54. The apparatus of claim 40 further including a load sensor supported on said coiled tubing.

55. The apparatus of claim 54 wherein said load sensor senses compression and/or tension on said coiled tubing.

56. The apparatus of claim 40 further comprising an electrically actuated valve, wherein said conductor conducts electricity causing actuation of said valve.

57. The apparatus of claim 40 wherein said conductor conducts electricity and further including a disconnect between said coiled tubing and said mandrel actuated electrically by said conductor.

58. The apparatus of claim 40 wherein said conductor conducts electricity and further including an anchor on said coiled tubing actuated electrically by said conductor.

59. The apparatus of claim 40 wherein said conductor conducts electricity and said packer is electrically actuable by said conductor.

60. The apparatus of claim 40 wherein said conductor conducts electricity and said packer is actuable by a propellant which is actuated electrically by said conductor.

61. The apparatus of claim 40 further including a latch releasably latching said packer onto said mandrel.

62. The apparatus of claim 61 further including a closure member for closing said packer upon releasing said packer from said mandrel.

63. The apparatus of claim 40 further including another packer mounted on said mandrel.

64. The apparatus of claim 63 further including a latch releasably latching said another packer onto said mandrel.

65. An apparatus for treating a formation adjacent a casing extending from the surface into a well, comprising:

a coiled tubing having a flowbore and at least one conductor supported by a wall of said coiled tubing;

a mandrel having a packer mounted thereon and a port in fluid communication with a flowpassage through said mandrel and with said flowbore of said coiled tubing;

a pressure sensor to detect downhole pressure, said pressure sensor transmitting through said conductor to the surface signals that are representative of the downhole pressure;

said pressure sensor and mandrel being supported by said coiled tubing.

66. The apparatus of claim 22 wherein said sensor comprises a tilt meter in said bottom hole assembly coupled to said surface controller via said conductors.

67. The method of claim 33 further comprising:

providing a tilt meter in said tubing string;

transmitting to the surface the data sensed by the tilt meter via the conductors in the tubing string.

68. The method of claim 67 further comprising:

evaluating the data transmitted by the tilt sensor;

ceasing stimulation when the data transmitted by the tilt meter indicates that predetermined conditions have occurred.

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