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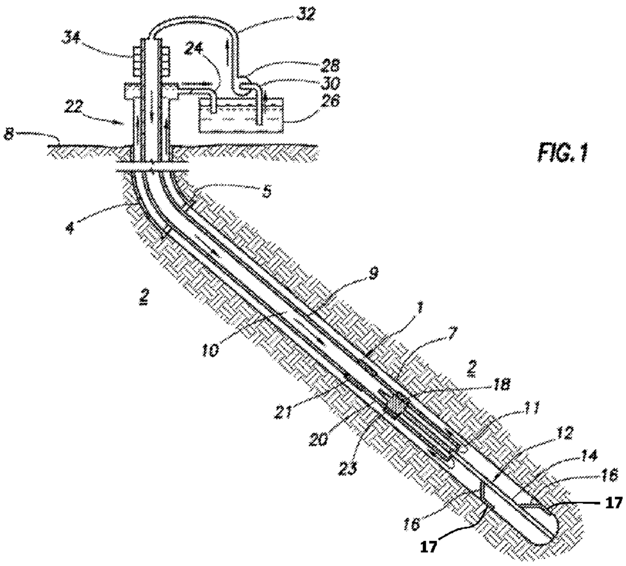

FIG. 1

(57) Abstract: A method of electrically logging a section of a wellbore includes circulating an oil-based wellbore fluid within the wellbore and allowing filtration of the oil-based wellbore fluid to form a conductive filtercake on a wall of the wellbore; placing within the wellbore a wellbore logging tool with at least one pad capable of applying a current to a portion of the conductive filtercake and wellbore wall; applying electrical current from the at least one pad; and collecting an electrical log of the portion of the wellbore that has had electrical current applied thereto.

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METHODS OF DRILLING WITH RESISTIVITY TOOLS

BACKGROUND

[0001] In the process of rotary drilling a well, a wellbore fluid or mud is circulated down the rotating drill pipe, through the bit, and up the annular space between the pipe and the formation or steel casing, to the surface. The wellbore fluid performs many different functions. For example, it removes cuttings from the bottom of the hole to the surface, suspends cuttings and weighting material when the circulation is interrupted, controls subsurface pressure, isolates the fluids from the formation by providing sufficient hydrostatic pressure to prevent the ingress of formation fluids into the wellbore, cools and lubricates the drill string and bit, maximizes penetration rate, etc. An important objective in drilling a well is also to secure the maximum amount of information about the type of formations being penetrated and the type of fluids or gases in the formation. This information is obtained by analyzing the cuttings and by electrical logging technology and by the use of various downhole logging techniques, including electrical measurements.

[0002] Various logging and imaging operations are performed during or after the drilling operation, for example, they may be performed while drilling in the reservoir region of an oil/gas well in order to determine the type of formation and the material therein. Such information may be used to optimally locate the pay zone, *i.e.*, where the reservoir is perforated in order to allow the inflow of hydrocarbons into the wellbore. The use of wireline well logs is well known in the art of drilling subterranean wells and in particular oil and gas wells. A wireline log is generated by lowering a logging tool down the well on a wireline. The tool is slowly brought back to the surface and the instruments on the logging tool take measurements that characterize the formation penetrated by the well in addition to other important properties of the well. For example, during logging wireline logs may use measurements of relative resistivity of the formation to determine the geological composition of the downhole formation. An alternative or supplement to wireline logging involves logging tools placed in a specialized drill collar housing and run in the drill string near the bit. This technique is known as logging-while-drilling

(LWD) or formation-evaluation-while-drilling (FEWD). Measurements such as electrical resistivity may be thereby taken and stored down-hole for later retrieval during a "tripping out" of the drill string, or transmitted to the surface via mud-pulse telemetry. Also, during drilling, such resistivity measurements may be useful to determine the location of the drill bit to enhance geosteering capabilities and directional drilling control, collected such as by a measurement while drilling (MWD) tool.

[0003] Thus, electrical logs and other wireline log techniques are depended upon in the oil and gas exploration industry to determine the nature of the geology and the reservoir properties of the petroleum bearing formations penetrated by the well, as well as other properties of the drilling process (*e.g.*, the location of the drill bit). Further, such well logs are often the only record of a formation penetrated by a well that are available for correlation amongst different wells in a particular field.

SUMMARY

[0004] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0005] In one aspect, embodiments disclosed herein relate to a method of electrically logging a section of a wellbore that includes circulating an oil-based wellbore fluid within the wellbore and allowing filtration of the oil-based wellbore fluid to form a conductive filtercake on a wall of the wellbore; placing within the wellbore a wellbore logging tool with at least one pad capable of applying a current to a portion of the conductive filtercake and wellbore wall; applying electrical current from the at least one pad; and collecting an electrical log of the portion of the wellbore that has had electrical current applied thereto.

[0006] In another aspect, embodiments disclosed herein relate to a system for electrically logging a section of a wellbore that includes a wellbore with at least a portion of its wellbore wall having a conductive filtercake formed thereon by an oil-based wellbore fluid; and a wellbore logging tool with at least one pad capable of applying a current to a portion of a wellbore wall.

[0007] Other aspects and advantages of the claimed subject matter will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0008] FIG. 1 shows an embodiment of the present disclosure with a wellbore extending vertically into a formation, a casing extending into the wellbore, and a resistivity logging tool located therein.

[0009] FIG. 2 shows an embodiment of the present disclosure with a wellbore extending vertically into a formation, a drill string extending into the wellbore, and a resistivity logging tool located therein.

[0010] FIG. 3 shows the embodiment of FIG. 2 during a further stage of operation.

[0011] FIG. 4 shows a wellbore extending vertically into a formation with a resistivity logging tool located therein.

[0012] FIG. 5 shows an enlarged perspective view, partly in section, of a portion of the sonde of the resistivity tool.

DETAILED DESCRIPTION

[0013] Embodiments disclosed herein generally relate to methods of using wellbore logging, and more specifically resistivity tools, to interrogate wellbores having electrically conductive fluids and/or filtercakes produced from oil-based wellbore fluids therein. In particular, one or more embodiments disclosed herein relate to methods of using resistivity tools to interrogate wellbores having conductive fluids and/or filtercakes comprising electrically conductive carbon materials, thereby allowing for improved clarity and resolution during the electrical logging of the subterranean well.

[0014] In the present disclosure, certain details are set forth such as specific quantities, concentrations, sizes, *etc.* so as to provide a thorough understanding of the various embodiments disclosed herein. However, it will be apparent to those skilled in the art that the present disclosure may be practiced without such specific details. In many cases, details concerning such considerations and the like have been omitted inasmuch as such details are not necessary to obtain a complete understanding of the present disclosure and are within the skills of persons of ordinary skill in the relevant art.

[0015] While most of the terms used herein will be recognizable to those of skill in the art, the following definitions are nevertheless put forth to aid in the understanding of the present disclosure. It should be understood, however, that when not explicitly defined, terms should be interpreted as adopting a meaning presently accepted by those of skill in the art.

[0016] When an electrical wireline log is made of a well, electrodes on the well logging tool are conventionally in contact with the wellbore fluid or filtercake and hence the formation rocks through which the well has penetrated. An electrical circuit is created and the resistance and other electrical properties of the circuit may be measured while the logging tool is withdrawn from the well. In conventional wellbore logging, the measurement of resistivity requires the presence of a highly conductive path between the logging tool and the formation (*i.e.*, through the wellbore fluid). The resulting data is a measure of the electrical properties of the drilled formations versus the depth of the well. The results of such measurements may be interpreted to determine the presence or absence of petroleum or gas, the porosity of the formation rock, and other important properties of the well.

[0017] The use of oil-based muds and wellbore fluids has become increasingly popular since the introduction of the technology in the 1950's. However, one disadvantage of oil-based muds is that normal resistivity and self-potential measurements cannot be taken when the well has been drilled with a conventional oil-based mud or wellbore fluid due to the non-conductive nature of the oil-based wellbore fluids and muds.

[0018] Thus, the use of resistivity logging tools is often limited to cases where a water-based wellbore fluid is used for the drilling operations because the low conductivity of the fluid and filtercakes produced by the base-oil in the case of oil/synthetic-base wellbore fluids severely limits the amount and clarity/resolution of resistivity information that may be gathered from a wellbore using wireline logging. The case is similarly true for invert emulsion wellbore fluids, since when invert emulsion fluids are used, any electrical path through the fluid is resistive due to the nature of the external oil phase. In other words, even though the brine dispersed in the oil phase is electrically conductive, the discontinuous nature of the droplets prevents the flow of electricity. Indeed, the inability of these emulsions to conduct electricity (until a very high potential difference is applied) is used as a standard test of emulsion stability. Thus, the resistive nature of invert emulsion wellbore fluids generally limits the amount and clarity/resolution of resistivity information that may be gathered from a wellbore using wireline logging.

[0019] However, the addition of conductive additives, such as the carbon materials detailed below, may allow for an increase in the conductivity of the oil-based wellbore fluid that is sufficient to facilitate wellbore logging via resistivity measurements. In one or more embodiments of the present disclosure, an oil-based wellbore fluid that produces a conductive filtercake may be circulated within the wellbore, which allows for resistivity measurements to be taken through the use of particular types of resistivity tools, such as, but not limited to, those that make physical contact with the filtercake. Examples of the resistivity tools include logging tools that extend through and beyond a drill bit or wireline logging tools, both of which are discussed below. The conductive filtercake may be formed from oil-based wellbore fluids having conductive additives therein that render the fluid conductive or it may be formed from oil-based wellbore fluids that remain relatively non-conductive even though they have conductive additives therein. For example, in the latter instance, the formation of the filtercake may effectively concentrate the conductive additives present in the wellbore fluid and lead to a filtercake that is significantly more conductive than the wellbore fluid.

[0020] Thru-Bit Logging

[0021] In one or more embodiments, the resistivity measurements may be collected using a logging tool that extends through and beyond the bit, with the resistivity measurements being obtained through the oil-based wellbore fluid that has conductive additives therein.

[0022] In FIG. 1, a schematic of a wellbore and tool that may be used in accordance with certain aspects of the present disclosure is shown. Referring to FIG. 1, there is shown a wellbore 1 formed in an earth formation 2. The wellbore may be filled with a drilling fluid or an oil-based wellbore fluid or another type of fluid. The wellbore 1 has an upper portion 4 provided with a casing 6 extending from a drilling rig or a production facility (not shown) at surface 8 into the wellbore 1 to a casing shoe 5, and an open lower portion 7 extending below the casing shoe 5.

[0023] A tubular conduit 9 extends from the surface 8 into the wellbore 1 whereby an open lower end 11 is arranged in the open lower portion 7 of the wellbore 1. Also the tubular conduit 9 may contain a fluid, such as for instance the same fluid that fills the wellbore 1. A wellhead 22 is connected to the upper end of the casing 5. The wellhead 22 may be connected to a production facility, but as shown in FIG. 1 it is provided with an outlet conduit 24 emptying in a fluid reservoir 26, which may be provided with a suitable sieve apparatus (not shown) for removing particulates from the fluid. A pump 28 having an inlet 30 and an outlet 32 may be arranged to pump a fluid from the fluid reservoir 26 into the upper end of the tubular conduit 9.

[0024] A logging tool string 12, capable of passing through the tubular conduit 9 by being lowered or raised through the tubular conduit 9, is retrievably suspended in the tubular conduit 9 by a suitable apparatus. In one or more embodiments, a suitable apparatus may include a wire line or a gripping mechanism. In the embodiment as shown in FIG. 1, the upper end of the logging tool string 12 is provided with a latch 20 for latching of a wireline (not shown) to the logging tool string 12.

[0025] In one embodiment as described now, the logging tool string 12 comprises a formation testing tool 14 having at least one retractable arm 16 with a pad 17 attached thereon, and a first member 18 of a communication interface arranged at the upper side of the formation testing tool 14. The formation testing tool 14 may be powered by a battery and may be provided with an electronic memory or other recording medium for storing measurement data. In one or more embodiments, the formation testing tool may be a resistivity tool capable of measuring the resistivity of the formation.

[0026] Inside the wellbore 1 is a telemetry device 21. The telemetry device 21 is capable of sending and receiving signals back and forth to and/or from a surface communication device 34, which is located at the surface 8. Such a communication device may in embodiments also comprise or be coupled to a control device. In the following, reference will be made to a communication device in the form of a communication and control device 34.

[0027] In embodiments as shown in FIG. 1, the telemetry device 21 may be mechanically coupled to the tubular conduit 9. Similarly, the sending and receiving part of the surface communication and control device 34 may also be mechanically coupled to the tubular conduit 9. Coupled to the telemetry device 21, or a part thereof, is a second member 23 of the communication interface. The communication interface establishes a capability of transmitting and receiving data and/or commands back and forth between the telemetry device 21 and the logging tool string 12. The logging tool string 12 is capable of passing from a position within the tubular conduit 9 to a position outside the tubular conduit 9 where it can be suspended by the tubular conduit 9. The position outside the tubular conduit 9 is the position shown in FIG. 1. The formation testing tool 14 extends below the lower end part 11 of the tubular conduit 9 and the first member 18 of the communication interface is arranged within the tubular member 9. In the embodiment of FIG. 1, the first member 18 aligns with the second member 23 of the communications interface to enable communication.

[0028] Electric signals transmitted by the formation testing tool 14 and/or the telemetry device 21 can be communicated from the first member 18 to the second member 23 of the communication interface and vice versa. These signals may represent commands and/or data comprising logging data produced by the formation testing tool 14 during logging of the earth formation 2. A control system 34 located at surface is connected to the tubular conduit 9 for sending or receiving signals representing the commands and/or data back and forth to the telemetry device 21.

[0029] The embodiment shown in FIG. 2 is largely similar to the embodiment shown in FIG. 1, except with respect to the following aspects. The tubular conduit 9 is provided in the form of a drill string, comprising a drill bit 40 attached at the lower end thereof. The logging tool string 12 is shown as being lowered through the drill string 9. The drill bit 40 is provided with a passage 44 in fluid communication with the interior of the drill string 9, which passage 44 is provided with a closure element 46 removable from the passage 44 in an outward direction. The lower end of the logging tool string 12 and the upper end of the closure element 46 are provided with respective co-operating latching members 48a, 48b capable of latching the logging tool string 12 to the closure element 46.

[0030] In addition, closure element 46 has a latching mechanism (not shown) for latching the closure element 46 to the drill bit 40. The latching mechanism is arranged to co-operate with the latching members 48a, 48b in a manner that the closure element 46 unlatches from the drill bit 40 upon latching of latching member 48a to latching member 48b, and that the closure element 46 latches to the drill bit 40, and thereby closes passage 44, upon unlatching of latching member 48a from latching member 48b.

[0031] Furthermore, the logging tool string 12 may be provided with pump cups 50 for pumping the logging tool string 12 through the drill string, either in a downward or an upward direction thereof, and/or a latch 20 for latching of a wireline (not shown) to the logging tool string 12.

[0032] In FIG. 3 is shown the embodiment of FIG. 2 during a further stage of operation whereby the logging tool string 12 has been latched to the closure element 46 and the closure element 46 has been unlatched from the drill bit 40. The drill string 9 has been raised a selected distance in the wellbore 1 so as to leave a space 52 between the drill bit 40 and the wellbore bottom. The logging tool string 12 is suspended by the drill string 9, in a manner that the formation testing tool 14 extends through the passage 44 to below the drill bit 40, and that the first member 18 of the communication interface is arranged within the drill string 9 aligned with the second member 23. The closure element 46 consequently extends below the logging tool string 12.

[0033] In one or more embodiments, the communications interface between the logging tool string 12 and the telemetry device 21 may be a wireless based communication such as radio frequency transmissions, electromagnetic frequency transmissions, inductive couplings and capacitance couplings. Alternatively, the communication interface may comprise a plug and socket arrangement that mate or interconnect when the logging tool string 12 is suspended by the conduit 9 in the position outside the conduit 9. It may include wiring across tool joints.

[0034] During normal operation of embodiments according to FIG. 1, the tubular conduit 9 is lowered into the wellbore 1 until the lower end 11 of the conduit 9 is positioned in the open wellbore portion 7. Next the logging tool string 12 is lowered from the surface through the conduit 9 by a wireline (not shown) latched to the logging tool string 12 at latch 20, whereby during lowering the arms 16 are in a retracted position. Lowering continues until the formation testing tool 14 extends below the tubular conduit 9 while the first member 18 of the communication interfaced is positioned within the tubular conduit 9 mated with the second member 23 of the communication interface. In this position the logging tool string 12 is suitably supported.

[0035] The arms 16 are then extended so that at least one pad 17 attached thereon may be placed against the wall of the wellbore 1 and formation testing tool 14 is induced to log the earth formation. The at least one pad 17 has an array of electrodes thereon. The method for obtaining the desired resistivity measurements using such a system as described above is to use the array of electrodes on the at least one pad 17 to apply an alternating current through the formation to a return electrode, which may also be located on the logging tool string 12. As the current emerges from the electrodes on the at least one pad 17, its path is initially focused on the small volume of earth formation 2 directly facing the respective electrodes but expands rapidly, in a magnitude dependent upon the properties of the earth formation 2, through the wall of the wellbore 1 and across the formation between the electrodes on the pad 17 and the return electrode. These measurements occur continuously as the formation testing tool 14 is dragged upwardly in the wellbore 1 via a wireline, as the drill string is tripped out of the wellbore, or in response to fluid being pumped out of the wellbore and are called microresistivity measurements because they measure the electrical resistivity of very small vertical segments of the wall of the wellbore 1 and earth formation 2 structure.

[0036] After the logging run has been completed, the logging tool string 12 may be retrieved through the tubular conduit 9 to the surface by wireline connected to latch 20. Optionally the tubular conduit 9 is then also removed from the wellbore 1.

[0037] During normal operation of embodiments according to FIGS. 2-3, the tubular conduit 9 is operated to drill the lower wellbore portion 7 whereby the closure element 46 is latched to the drill bit 40 so as to form a part thereof. Then, when it is desired to log the earth formation 2 surrounding the open wellbore portion 7, the logging tool string 12 may be pumped down the drill string 9 using pump 28 until the logging tool string 12 latches to the closure element 46 by latching members 48a, 48b. During lowering of the string 12, the arms 16 of the formation testing tool are in a retracted position. Then the drill string 9 may be raised a selected distance until there is sufficient space below the drill string for the formation testing tool 14 and the closure element 46 to extend below the drill bit 40. Of course, in one or more embodiments, the raising of the drill string 9 may also be done prior to or during the lowering of the logging tool string 12.

[0038] The arms 16 are then extended so that at least one pad 17 attached thereon may be placed against the wall of the wellbore 1 and formation testing tool 14 is induced to log the earth formation. The at least one pad 17 has an array of electrodes thereon. Similar to what is described above, the method for obtaining the desired resistivity measurements using such a system as described above is to use the array of electrodes on the at least one pad 17 to apply an alternating current through the formation to a return electrode, which may also be located on the logging tool string 12. As the current emerges from the electrodes on the at least one pad 17, its path is initially focused on the small volume of earth formation 2 directly facing the respective electrodes but expands rapidly, in a magnitude dependent upon the properties of the earth formation 2, through the wall of the wellbore 1 and across the formation between the electrodes on the pad 17 and the return electrode. These measurements occur continuously as the formation testing tool 14 is dragged upwardly in the wellbore 1 via a wireline, as the drill string is tripped out of the wellbore, or in response to fluid being pumped out of the wellbore and are called microresistivity measurements because they measure the electrical resistivity of very small vertical segments of the wall of the wellbore 1 and earth formation 2 structure.

[0039] As will be understood by a skilled artisan, the formation testing tools shown in FIGS. 1-3 may be configured in a variety of ways and have a variety of different components. Its inclusion here is not meant to limit the scope of the application in any way and is only intended to represent the basics of the process of obtaining an electrical log or resistivity measurement in a wellbore. For example, similar equipment and techniques may be used to acquire electrical logs in highly deviated wellbores. Additionally, similar equipment and techniques may be used when using conductive oil-based fluid of the present disclosure, which would not require that the pads be placed in contact with the formation. Instead, the measurement could be taken through the wellbore fluid itself.

[0040] After logging has been completed, and the logging tool has been retracted into the drill string 9, the logging tool string 12 is retrieved to the surface through the drill string 9 by a wireline connected to latch 20. During retrieval, the closure element 46 latches to the drill bit 40 (thereby closing the passage 44) and the latching members 48a, 48b unlatch. Alternatively, the logging tool string can be retrieved to the surface by reverse pumping of drilling fluid, *i.e.*, pumping of drilling fluid down through the annular space between the drill string 9 and the wellbore wall and into the lower end of the drill string 9. Optionally, in one or more embodiments, a further wellbore section then can be drilled, or the drill string 9 can be removed from the wellbore 1.

[0041] In one or more embodiments, instead of lowering the logging tool string from the surface through the drill string, the logging tool string can be latched into a lower section of the drill string during lowering of the drill string into the wellbore. At the desired depth the logging tool string is then moved to the exterior of the drill string by, for example, pumping a ball or a dart down the drill string so as to activate the latch release mechanism of the logging tool string.

[0042] **Wireline Logging**

[0043] In one or more embodiments, the resistivity measurements may be collected using wireline logging, with the resistivity measurements being obtained through the oil-based wellbore fluid that has conductive additives therein.

[0044] Referring now to FIG. 4, a schematic of a wellbore and tool that may be used in accordance with certain aspects of the present disclosure is shown.

[0045] FIG. 4 shows a wellbore 13 extending vertically into a formation 15 with a resistivity logging tool 27 located therein. The wellbore 13 has a generally cylindrically shaped exposed wall 19 upon which a filtercake will form as a wellbore fluid permeates the formation 15 during a drilling or other wellbore formation. A wellbore fluid 25 may be present in the wellbore 13 during the logging of the wellbore.

[0046] The resistivity logging tool 27 may be suspended in the wellbore 13 by a pulling cable 29, which at its upper end extends around sheaves 31 and 33 to the spool 35 of a winch 36. The spool of the winch 36 can be rotated in either direction, to either raise or lower the tool 27, by operator control of an engine 37 in the winch-carrying vehicle 39. Sheave 31 is typically supported from a derrick frame 38 centered over the wellbore 13. On the winch-carrying vehicle 39 there is also located electronic apparatus 41, which permits control of the various operations during a logging run, as well as providing signal processing and storage of the signals from the tool 27.

[0047] The resistivity logging 27 tool itself may comprise a sonde 41 and an electronic cartridge 44, connected to each other by an articulated physical connection 43. Centering of the resistivity logging tool 27 in the wellbore 13 may be facilitated by bowed-spring centralizers 42, which may comprise four equiangularly spaced spring bow members extending radially outward towards the wellbore wall 19.

[0048] Moving now to FIG. 5 which shows an enlarged perspective view, partly in section, showing more clearly a portion of the sonde 41 of the resistivity tool 27. Four pads 45, each having an array of electrodes 49 thereon, are each mounted on a pair of supports 47, which urge the pads 45 outwardly against the wellbore wall 19, by spring action or hydraulic pressure in a manner known in resistivity measuring systems. The method for obtaining the desired resistivity measurements using such a system as described above is to use the array of electrodes 49 on the pads 45 to apply an alternating current through the formation to a return electrode, which may be the housing of the electronic cartridge 43. As the current emerges from the electrodes 49 on the pads 45, its path is initially focused on the small volume of formation 15 directly facing the respective electrodes 49 but expands rapidly, in a magnitude dependent upon the properties of the formation, through the wellbore wall 19 and across the formation between the electrodes 49 and the return electrode. These measurements occur continuously as the resistivity tool 27 is dragged upwardly in the wellbore 13 and are called microresistivity measurements because they measure the electrical resistivity of very small vertical segments of the wellbore wall 19 and formation 15 structure.

[0049] As will be understood by a skilled artisan, the resistivity tool shown in FIGS. 4 and 5 may be configured in a variety of ways and have a variety of different components. Its inclusion here is not meant to limit the scope of the application in any way and is only intended to represent the basics of the process of obtaining an electrical log or resistivity measurement in a wellbore. For example, similar equipment and techniques may be used to acquire electrical logs in highly deviated wellbores. Additionally, similar equipment and techniques may be used when using conductive oil-based fluid of the present disclosure, which would not require that the pads be placed in contact with the formation. Instead, the measurement could be taken through the wellbore fluid itself.

[0050] To be clear, methods for using resistivity tools such as those above, to interrogate formations that have been drilled with non-conductive oil-based wellbore fluids do exist, but the non-conductivity of oil-based wellbore fluids and the filtercakes formed therefrom severely limits the amount and clarity/resolution of resistivity information that may be gathered from a wellbore using wireline logging. For example, where the measured current(s) at the sensor electrode(s) is used directly to measure resistivity, for a non-conductive oil-based wellbore fluid environment, the circuit frequency is in the 10 MHz to 100 MHz range in order to overcome the insulating nature of the conventional oil-based wellbore fluid filtercake, which limits the amount of current that can reach the formation to properly measure the formation properties. In contrast, for a water-based wellbore fluid environment, the filtercake is inherently conductive because it contains salts dissolved in the water and the current can penetrate the filtercake and formation easily. Thus, for a water-based and conductive wellbore fluid environment, the circuit frequency is around only 5 KHz, although the circuit can be operated at the higher frequencies needed for the oil-based wellbore fluid environment. Thus, by formation of a conductive oil-based wellbore fluid and/or filtercake, the circuit frequency may be less than the 10 MHz needed for a non-conductive oil-based wellbore fluid environment.

[0051] In some embodiments, the methods may include placing oil-based wellbore fluids into the subterranean well, including oil-based fluids such as invert emulsions, and forming a conductive filtercake on the wellbore walls. Thus, embodiments of the present disclosure may allow for the formation of a conductive wellbore fluid and/or a conductive filtercake that enables electrical logging to acquire data having high levels of clarity and resolution. Specifically, the oil-based wellbore fluids may include one or more carbon materials of the present disclosure in a concentration so as to permit or improve the electrical logging of the well using the above described tools, for example, by increasing the electrical conductance of the wellbore fluid and/or the filtercake formed therefrom. Thus, embodiments include the drilling of a subterranean well with an oleaginous-based wellbore fluid described herein so as to allow formation of a conductive filtercake by filtration of a portion of the fluid phase into a permeable formation. In such embodiments, the oleaginous-based wellbore fluids of the present disclosure may be formulated so as to enable one to take electrical log measurements of the subterranean well, despite the naturally low conductivity of conventional oil-based wellbore fluids.

[0052] In some embodiments, during logging and while using oil-based wellbore fluids and carbon materials as described herein, logs may be used to take measurements of relative resistivity of the formation. As discussed above, the measurements of relative resistivity of the formation may be used to determine the geological composition of the downhole formation. Also, in some embodiments, such resistivity measurements may optionally be useful to determine the location of the drill bit to enhance geosteering capabilities and directional drilling control. In some embodiments, the wellbore fluids and carbon materials disclosed herein may be used with drilling systems having a logging tool provided thereon so that the drilling and formation data and parameters may be determined from various downhole measuring devices and may be measured and then transferred to the surface.

[0053] In other embodiments, the measurements may be stored downhole for subsequent retrieval, or they may be both transferred *via* telemetry to the surface and/or stored downhole. In some embodiments, measurements may be depth-correlated, using depth measurements made downhole for improving accuracy of the measurements and the parameters of interest. In additional embodiments, the measurements and/or parameters may be correlated with stored reference data for providing additional information pertaining to the drilling operations and the formation characteristics. Thus, the logging measurements may be used to determine the drill bit location relative to the desired drilling path and to adjust the drilling activity downhole. Thus, these electrical logs and other wireline log techniques may determine the nature of the geology and the reservoir properties of the petroleum bearing formations penetrated by the well, as well as other properties of the drilling process (*e.g.*, the location of the drill bit).

[0054] **Wellbore Fluids with Carbon Materials**

[0055] The oil-based wellbore fluids of the present disclosure may include fluids that are substantially comprised of an oleaginous liquid, as well as emulsions of oleaginous and non-oleaginous fluids. In particular, various embodiments of the present disclosure may provide for an invert emulsion wellbore fluid. "Invert emulsion," as used herein, is an emulsion in which a non-oleaginous fluid is the discontinuous phase and an oleaginous fluid is the continuous phase.

[0056] “Oleaginous liquid," as used herein, means an oil which is a liquid at 25°C and is immiscible with water. Oleaginous liquids may include substances such as hydrocarbons used in the formulation of drilling fluids such as diesel oil, mineral oil, synthetic oil (including linear alpha olefins and internal olefins), ester oils, glycerides of fatty acids, aliphatic esters, aliphatic ethers, aliphatic acetals, or other such hydrocarbons and combinations of these fluids.

[0057] "Non-oleaginous liquid," as used herein, means any substance that is a liquid at 25°C and that is not an oleaginous liquid as defined above. Non-oleaginous liquids are immiscible with oleaginous liquids but capable of forming emulsions therewith. Non-oleaginous liquids may include aqueous substances such as fresh water, sea water, brine containing inorganic or organic dissolved salts, aqueous solutions containing water-miscible organic compounds and mixtures of these.

[0058] In the process of rotary drilling a well, a wellbore fluid or mud is circulated down the rotating drill pipe, through the bit, and up the annular space between the pipe and the formation or steel casing, to the surface. The wellbore fluid performs many different functions. For example, it removes cuttings from the bottom of the hole to the surface, suspends cuttings and weighting material when the circulation is interrupted, controls subsurface pressure, isolates the fluids from the formation by providing sufficient hydrostatic pressure to prevent the ingress of formation fluids into the wellbore, cools and lubricates the drill string and bit, maximizes penetration rate, etc. An important objective in drilling a well is also to secure the maximum amount of information about the type of formations being penetrated and the type of fluids or gases in the formation. This information is obtained by analyzing the cuttings and by electrical logging technology and by the use of various downhole logging techniques, including electrical measurements.

[0059] Various logging and imaging operations are performed during the drilling operation, for example, they may be performed after drilling sections in the reservoir region of an oil/gas well in order to determine the type of formation and the material therein. Such information may be used to optimally locate the pay zone, *i.e.*, where the reservoir is perforated in order to allow the inflow of hydrocarbons into the wellbore.

[0060] Some logging tools work on the basis of a resistivity contrast between the fluid in the wellbore (wellbore fluid) and that already in the formation. These are known as resistivity logging tools. Briefly, alternating current flows through the formation between two electrodes. Thus, the fluids in the path of the electric current are the formation fluids and the fluid that has penetrated the formation by way of filtration. The filtercake and filtrate result from filtration of the mud over a permeable medium (such as formation rock) under differential pressure.

[0061] The use of resistivity logging tools is often limited to cases where a water-based wellbore fluid is used for the drilling operations because the low conductivity of the base-oil in the case of oil/synthetic-base wellbore fluids precludes the use of resistivity tools in such fluids. The case is similarly true for invert emulsion wellbore fluids, since when invert emulsion fluids are used, any electrical path through the fluid is insulated due to the non-conductive nature of the external oil phase. In other words, even though the brine dispersed in the oil phase is electrically conductive, the discontinuous nature of the droplets prevents the flow of electricity. Indeed, the inability of these emulsions to conduct electricity (until a very high potential difference is applied) is used as a standard test of emulsion stability. The non-conductive nature of invert emulsion wellbore fluids severely limits the amount and clarity of resistivity information that may be gathered from a wellbore using wellbore logging techniques.

[0062] In some embodiments, the methods may include placing oil-based wellbore fluids into the subterranean well, including oil-based fluids such as invert emulsions, and forming a conductive filtercake on the wellbore walls. Embodiments of the present disclosure may allow for formation of a conductive filtercake that enables electrical logging even if the fluid from which the filtercake is formed is not conductive at a level that permits logging. Specifically, the oil-based wellbore fluids may include one or more carbon materials of the present disclosure in a concentration so as to permit or improve the electrical logging of the well by increasing the electrical conductance of the filtercake. Thus, embodiments include the drilling of a subterranean well with an oleaginous-based wellbore fluid described herein so as to allow formation of a conductive filtercake by filtration of a portion of the fluid phase into a permeable formation. In such embodiments, the oleaginous-based wellbore fluids of the present disclosure may be formulated so as to enable one to take electrical log measurements of the subterranean well, despite the naturally low conductivity of the fluid.

[0063] In some embodiments, during logging and while using oil-based wellbore fluids and carbon materials as described herein, logs may be used to take measurements of relative resistivity of the formation. The measurements of relative resistivity of the formation may be used to determine the geological composition of the downhole formation. In some embodiments, the wellbore fluids and carbon materials disclosed herein may be used with drilling systems having a logging tool provided thereon so that the drilling and formation data and parameters may be determined from various downhole measuring devices and may be measured and then transferred to the surface.

[0064] Carbon Materials

[0065] While there have been previous attempts to increase the conductivity of an oil-based fluid, such attempts heretofore have resulted in fluids that are not, in fact, usable in a drilling application. Specifically, in some instances, the loading requirements for the conductive particles exceeded pumpability/rheological requirements, while in others, the particles failed to disperse and remain suspended in the fluid. In contrast, the present inventors have advantageously found that the inclusion of the carbon materials of the present disclosure may allow for formation of a conductive wellbore fluid and/or a conductive filtercake at particle loading levels that enable formulation of a wellbore fluid that meets the rheological profile window suitable for use in drilling. Furthermore, it is also envisioned that the same or similar results may be achieved with non-carbon materials with characteristics similar to those detailed below but formed of other elements or having a composition that contains elements other than carbon. However, in particular embodiments of the present disclosure, the fluid may incorporate one or more carbon materials in a wellbore fluid in such an amount that the oil-based filtercake formed therefrom is electrically conductive. Further, it is also envisioned that such materials may be added in an amount to also make the fluid itself conductive, which might be used, for example, in low permeability formations that have minimal filtercake formed. In one or more embodiments, at least two grades of carbon materials, each having different characteristics (e.g., particle size, surface area, pore volume, surface chemistry, etc.) may be used in wellbore fluids of the present disclosure in order to render the wellbore fluid itself or a filtercake formed therefrom conductive. The carbon materials described herein may be added to any oil-based wellbore fluid, or a custom wellbore fluid formulation may be prepared.

[0066] Carbon materials in accordance with embodiments of the present disclosure may be carbon black, a particulate form of carbon that has high surface area and only short to medium range intraparticulate ordering (*i.e.*, paracrystalline ordering) of a graphite-like carbon lattice, and in particular the materials may be conductive carbon black. Generally, carbon black may have a morphology that includes primary aggregates of a plurality of primary particles. Specifically, carbon black aggregates are characterized as discrete and rigid masses of physically fused primary particles. These primary aggregates may be provided in the form of larger agglomerates which are subsequently broken down into the primary aggregates upon shearing during the formulation into the wellbore fluids of the present disclosure.

[0067] The electron transport between primary aggregates (and thus conductivity) may occur when the distance between the primary aggregates is short enough to form conductive paths allowing electron transport. Increasing particle loading would eventually result in particle-to-particle contact and thus greater conductivity by virtue of the physical contact between particles; however, contrary to this conventional wisdom, the inventors of the present disclosure have found that a conductive fluid and/or a conductive filtercake may be formed from a lower particle loading, which allows for formulation of a fluid that meets downhole drilling requirements. Some of the primary parameters that impact the conductivity efficiency (and ability to achieve conductivity in the fluid and/or the filtercake at a lower loading) include, for example, primary particle size, structure, and porosity. Both particle size and porosity impact surface area. The inventors of the present application have found that by increasing the porosity and the surface area, greater conductivity efficiency (and lower particle loading) may be achieved.

[0068] Specifically, in one or more embodiments, the carbon black materials of the present disclosure may be added to the wellbore fluid (and result in a conductive filtercake) in a total amount that ranges from about 0.5 to 30 pounds per barrel (1.43 to 85.59 kg/m^3, or in a total amount from about 1 to 25 pounds per barrel (2.85 to 71.33 kg/m^3), or in a total amount from about 1.5 to 20 pounds per barrel (4.275 to 57.06 kg/m^3). In more particular embodiments, the carbon black materials of the present disclosure may be added to the wellbore fluid (and result in a conductive filtercake) in a total amount that range from about 1 to 8 pounds per barrel (2.85 to 22.8 kg/m^3) or in a total amount from about 1.5 to 7.0 pounds per barrel (4.275 to 21.375 kg/m^3), or in a total amount from about 2 to 6 pounds per barrel (5.71 to 17.12 kg/m^3). Generally, the inventors have found that when working within lower permeability formations a higher loading level of carbon black materials may be needed to achieve the necessary logging conditions when compared against the amount needed to log a higher permeability formation.

[0069] As mentioned above, the carbon black aggregates may be formed from a plurality of physically fused primary particles. In one or more embodiments, the primary particles are non-spheroidal and in fact, have an egg-shell particle form that is similar to an open shell or a hollow shell. For example, the interior of the shell may be completely enclosed by the shell or there may only be a partial shell surrounding the interior. The "effective" diameter of the carbon black primary particles may be from about 5 nm to about 150 nm or from about 20 nm to about 115 nm.

[0070] The primary particles fuse together during production of the carbon black in the oven/furnace to form aggregates that may have a branched and fibroid-like structure, which may further entangle to form the agglomerate. In one or more embodiments, a circumscribing sphere encompassing a carbon black aggregate of the present disclosure may have a diameter from about 60 nm to 3 micrometers. In one or more embodiments, a circumscribing sphere encompassing a carbon black agglomerate of the present disclosure may have a diameter between about 1 micrometer and 5 millimeters in size.

[0071] The branched and fibroid-like structure (as well as egg-shell primary particle structure) may result in a relatively high pore volume, particular when considering the size of the aggregates. In one or more embodiments, a carbon black according to the present disclosure may have a pore volume, when measured using Di-Butyl-Phthalate (DBP) absorption method, of at least about 200 cm^3 DBP/100g carbon black and up to about 500 cm^3 DBP/100g carbon black. Carbon black aggregates with these values have a low bulk density and a highly branched structure, which may serve to provide better contact between aggregates and therefore a better three dimensional network of conductive aggregates at lower loadings in a filtercake (and thus a fluid that forms the filtercake).

[0072] The egg-shell primary particle structure also contributes to a higher surface area for the aggregates. In one or more embodiments, the carbon black may have a surface area between about 125 and 1500 m^2/g. In more particular embodiments, the carbon black may have a surface area of at least about 200 m^2/g, or at least about 500 m^2/g, or at least about 700 m^2/g, or at least about 800 m^2/g, or at least about 900 m^2/g, or at least about 1000 m^2/g, or at least about 1100 m^2/g, or at least about 1200 m^2/g, or at least about 1300 m^2/g, or at least 1400 m^2/g and/or up to 1500 m^2/g.

[0073] Collectively, the high pore volume and high surface area may allow for greater conductivity efficiency. This efficiency may be represented by the value of the loading multiplied by the surface area of the carbon materials, a number which may be hereinafter referred to as the "surface area loading factor". In one or more embodiments, wellbore fluids of this disclosure have a value of the loading (in pounds per barrel) multiplied by the surface area (in m^2/g) of the carbon materials of at least 2000 $lbm^2/gbbl$, or at least 2250 $lbm^2/gbbl$, or at least 2500 $lbm^2/gbbl$, or at least 2750 $lbm^2/gbbl$, or at least 3000 $lbm^2/gbbl$. In one or more embodiments, wellbore fluids of this disclosure have a value of the loading (in pounds per barrel) multiplied by the surface area (in m^2/g) of the carbon materials of at most 4500 $lbm^2/gbbl$, or at most 4000 $lbm^2/gbbl$. Such a "surface area loading factor" is dependent on both the surface area and loading, and thus theoretically can be achieved by simply increasing the loading. However, as discussed above, the carbon black materials of the present disclosure may be added to the wellbore fluid in a total amount as low as 1 pound per barrel (2.85 kg/m^3) with a maximum amount of up to 30 pounds per barrel (85.59 kg/m^3), or a maximum amount up to 25 pounds per barrel (71.33 kg/m^3), or a maximum amount up to 20 pounds per barrel (57.06 kg/m^3), or a maximum amount up to 15 pounds per barrel (42.8 kg/m^3), or a maximum amount up to about 10 pounds per barrel (28.53 kg/m^3). In more particular embodiments, the carbon black materials of the present disclosure may be added to the wellbore fluid (and result in a conductive fluid and/or filtercake) in a total amount that ranges from about 1 to 8 pounds per barrel (2.85 to 22.8 kg/m^3) or in a total amount from about 1.5 to 7.5 pounds per barrel (4.275 to 21.375 kg/m^3). It is envisioned that the surface area loading factor discussed above is achieved through the combination of these loading limits and the above discussed surface area limitations. Specifically, as discussed above, in one or more embodiments, the carbon black may have a surface area between about 125 and 1500 m^2/g. In more particular embodiments, the carbon black may have a surface area of at least about 200 m^2/g, or at least 500 m^2/g, or at least 700 m^2/g, or at least about 800 m^2/g, or at least about 900 m^2/g, or at least about 1000 m^2/g, or at least about 1100 m^2/g, or at least about 1200 m^2/g, or at least about 1300 m^2/g, or at least 1400 m^2/g and/or up to 1500 m^2/g.

[0074] The surface chemistry of the carbon black may also play a role in their potential conductive properties. Most carbon blacks are known to have surfaces that contain organic surface groups including polyaromatic hydrocarbons (PAH), lactones, chinones, phenolics, and carboxylics, which may be otherwise known as 'volatiles'. Too high of a concentration of these volatiles may act as a barrier for the electron-tunneling effect thought to provide the electroconductivity. In one or more embodiments, carbon black used in the wellbore fluids of the present disclosure may have a volatile content below about 1% by weight, or below about 0.85% by weight, or below about 0.7% by weight.

[0075] As mentioned above, the wellbore fluid containing conductive carbon materials may not be as conductive as a filtercake that it forms when used downhole due to the dilution of the carbon materials. For example, when a wellbore fluid is used downhole, a portion of the fluid filters into the formation as a filtrate leaving behind some of the solid or semi-solid materials from the wellbore fluid (e.g., particulate weighting materials, bridging agents, fibers, polymers, etc.) on the face of the formation as a filtercake with some amount of the fluid phase present therein. Thus, as a wellbore fluid containing carbon materials filters into the formation, the carbon materials, being solid, will tend to accumulate in the filtercake that is formed on the formation face. This accumulation may effectively concentrate the conductive carbon materials to a degree where conductivity would exist within the filtercake, where it did not exist in the wellbore fluid itself due to its dilution in the fluid.

[0076] In one or more embodiments, the wellbore fluid may have a conductivity of at most 0.02 siemens per meter (S/m), or at most 0.01 S/m, or at most 0.0075 S/m, or at most 0.001 S/m when measured at 20 kHz. In one or more embodiments, the wellbore fluid is at least about 100 times less, or at least about 500 times less, or at least about 1000 times, or at least about 1500 times less, or at least about 2000 times less, or at least about 2500 times less, or at least about 3000 times less conductive than a filtercake produced from the filtration of said wellbore fluid into the formation. In one or more embodiments, the conductivity of the wellbore fluid may be at most 100,000 times less than a filtercake produced from the filtration of said wellbore fluid into the formation. Said another way, the wellbore fluid is at least about 100, 500, 1000, 1500, 2000, 2500, or 3000 times more resistive than a filtercake produced from the filtration of said wellbore fluid into the formation. Further, it is also appreciated that the conductivity/resistivity of a wellbore fluid and/or filtercake may be considered relative to the formation (and the formation fluids) behind the filtercake so that there is enough contrast between the two materials that can be recognized by the logging tool. For example, in one or more embodiments, resistivity logging tools operating at frequencies less than about 50 kHz may provide suitable imaging data when there is up to a 100-fold difference between the resistivity/conductivity of the wellbore fluid and/or filtercake formed on the formation and the formation itself, *i.e.*, the filtercake is up to 100 times more resistive than the formation. However, when using other tools at other operating frequencies or depending on the desired level of image quality, different ranges may be used.

[0077] Further, it is relevant that the conductivity exists in the wellbore fluid and/or filtercake without breaking the emulsion. Breaking of the emulsion would independently result in conductivity due to the availability of the aqueous saline phase broken free from the emulsion. However, from a fluid stability perspective, it is not desirable for the emulsion to break (or the mud to fall apart) downhole during drilling and formation of the filtercake. Thus, in one or more embodiments, the filtrate collected from an API HPHT Fluid Loss test on the wellbore fluids of the present disclosure is substantially free of separated water (as compared to emulsified water). Specifically, in one or more embodiments, the filtrate has less than 10 percent of the portion of water in the fluid phase separate following an API HPHT Fluid Loss Test. That is, for an invert emulsion that is 80% oil and 20% water, less than 10% of the 20% water portion may phase separate from the emulsion. In more specific embodiments, the amount of phase separated non-oleaginous fluid in the filtrate is less than about 5% by volume of the amount of non-oleaginous fluid in the original wellbore fluid. Further, it is noted that the API HPHT Fluid Loss test may have at least 1 mL of filtrate collected, which may indicate that a filtercake is formed. In one or more embodiments, the conductivity arises through the formation of a filtercake and therefore, the formation in which the fluid is used should have a permeability at least in the millidarcy range to ensure that a filtercake forms during the wellbore operations. Further, drilling in an overbalanced condition may also aid in formation of a filtercake, depending on the permeability of the formation.

[0078] However, some shales have a permeability in the nanodarcy range and a substantial filtercake may not be expected to form during wellbore operations. In these situations and other situations where it would be beneficial for the wellbore fluid itself to be sufficiently conductive for logging, a higher loading (*i.e.*, greater than about 10 pounds per barrel) of carbon materials may be used in the wellbore fluid to increase the conductivity of the fluid itself and thereby enable effective resistivity imaging.

[0079] The rheological profile of the fluid is impacted by the degree of loading of the carbon materials. Fluids having carbon materials of the present disclosure incorporated therein may result in sufficient electrical conductivity for the wellbore fluid and/or filtercake while also arriving at acceptable rheological properties for drilling (and pumping downhole). One of ordinary skill in the art will appreciate that the precise rheological profile of a drillable fluid may depend on the formation (whether the formation can tolerate a thicker mud without fracturing), but generally, the fluids having the described carbon black loading may have a plastic viscosity of about 15-70 cP and yield point of less than about 35 lb/100ft^2. Further, the fluid may also have a GELS value ranging from 5-20 lb/100 ft^2, the GELS being a measure of the suspending characteristics or the thixotropic properties of a fluid, measured after 10 seconds and/or 10 minutes.

[0080] In one or more embodiments, the use of a resistive wellbore fluid (having the conductivity described herein) containing otherwise conductive carbon materials to form a conductive filtercake containing at least some of said conductive carbon materials upon the fluid's injection downhole may allow for beneficial rheological properties to be achieved by the wellbore fluid. For example, the rheological properties may be enhanced as a result of the reduced necessity for high loadings of conductive carbon materials in the fluid in order to make the wellbore fluid itself conductive. The enhanced rheological properties may allow for the wellbore fluid to be easily pumpable, used during a drilling or other wellbore operation, and capable of efficient particle suspension with low sag.

[0081] As mentioned above, wellbore fluids described herein may be oil-based wellbore fluids or invert emulsions in one or more embodiments. Suitable oil-based or oleaginous fluids may be a natural or synthetic oil and in some embodiments, in some embodiments the oleaginous fluid may be selected from the group including diesel oil; mineral oil; a synthetic oil, such as hydrogenated and unhydrogenated olefins including polyalpha olefins, linear and branch olefins and the like, polydiorganosiloxanes, siloxanes, or organosiloxanes, esters of fatty acids, specifically straight chain, branched and cyclical alkyl ethers of fatty acids, mixtures thereof and similar compounds known to one of skill in the art; and mixtures thereof.

[0082] Non-oleaginous liquids may, in some embodiments, include at least one of fresh water, sea water, brine, mixtures of water and water-soluble organic compounds, and mixtures thereof. In various embodiments, the non-oleaginous fluid may be a brine, which may include seawater, aqueous solutions wherein the salt concentration is less than that of sea water, or aqueous solutions wherein the salt concentration is greater than that of sea water. Salts that may be found in seawater include, but are not limited to, sodium, calcium, aluminum, magnesium, potassium, strontium, and lithium salts of chlorides, bromides, carbonates, iodides, chlorates, bromates, formates, nitrates, oxides, sulfates, silicates, phosphates and fluorides. Salts that may be incorporated in a brine include any one or more of those present in natural seawater or any other organic or inorganic dissolved salts. Additionally, brines that may be used in the drilling fluids disclosed herein may be natural or synthetic, with synthetic brines tending to be much simpler in constitution. In one embodiment, the density of the drilling fluid may be controlled by increasing the salt concentration in the brine (up to saturation). In a particular embodiment, a brine may include halide or carboxylate salts of mono- or divalent cations of metals, such as cesium, potassium, calcium, zinc, and/or sodium.

[0083] The amount of oleaginous liquid in the invert emulsion fluid may vary depending upon the particular oleaginous fluid used, the particular non-oleaginous fluid used, and the particular application in which the invert emulsion fluid is to be employed. However, in some embodiments, the amount of oleaginous liquid may be sufficient to form a stable emulsion when used as the continuous phase. In some embodiments, the amount of oleaginous liquid may be at least about 30, or at least about 40, or at least about 50 percent by volume of the total fluid. The amount of non-oleaginous liquid in the invert emulsion fluid may vary depending upon the particular non-oleaginous fluid used and the particular application in which the invert emulsion fluid is to be employed. In some embodiments, the amount of non-oleaginous liquid may be at least about 1, or at least about 3, or at least about 5 percent by volume of the total fluid. In some embodiments, the amount may not be so great that it cannot be dispersed in the oleaginous phase. Therefore, in certain embodiments, the amount of non-oleaginous liquid may be less than about 70, or less than about 60, or less than about 50 percent by volume of the total fluid.

[0084] **Wellbore Fluid Additives**

[0085] The wellbore fluids of the present disclosure may further contain additives so long as the additives do not interfere with the properties of the compositions described herein. For example, emulsifiers, wetting agents, organophilic clays, viscosifiers, weighting agents, bridging agents, fluid loss control agents, and corrosion inhibitors may be added to the compositions disclosed herein so as to impart additional functional properties.

[0086] Wetting agents and emulsifiers that may be suitable for use include, but are not limited to, crude tall oil, oxidized crude tall oil, surfactants, organic phosphate esters, ether carboxylic acids, fatty amines, amidoamines, modified imidazolines and amidoamines, fatty acid amidoamines (including dry fatty acid amidoamines) and salts thereof, alkyl aromatic sulfates and sulfonates, and the like, and combinations or derivatives of these. VERSAWET™ and VERSACOAT™, NOVAMUL™, FAZEMUL™, FAZEWET™, MEGAMUL™, SUREMUL™, ONEMUL™, ACTIMUL

RD™, and MUL-XT™ are non-limiting examples of commercially available emulsifiers manufactured and distributed by M-I, L.L.C. that may be used in the fluids and methods of this disclosure. Other suitable surfactants that are commercially available include SILWET™ series of emulsifiers such as L-77, L-7001, L7605 and L-7622, which are distributed by Union Carbide Chemical Company Inc.

[0087] In other embodiments, the emulsifier may be carboxylic acid-based emulsifier such as, for example, an emulsifier selected from dicarboxylic fatty acids, dimer acids, or dimers of fatty acids. Dicarboxylic fatty acids have the general formula HOOC-R-COOH, wherein R is an alkyl or alkenyl group containing from 10 to 50 carbon atoms, and in particular embodiments from 20 to 40 carbon atoms. In other embodiments, emulsifiers may be selected from the dimerization products of unsaturated dicarboxylic fatty acids, for example, such as products prepared by dimerization of unsaturated fatty acids containing from 8 to about 18 carbon atoms, including 9-dodecenoic(cis), 9-tetradecenoic(cis), 9-octadecenoic(cis), octadecatetranoic acids and the like.

[0088] Organophilic clays, normally amine treated clays, may be useful as viscosifiers in the fluid compositions disclosed herein. Other viscosifiers and gellants, such as oil soluble polymers, polyamide resins, polycarboxylic acids and soaps may also be used. Attapulgite clay and sepiolite clay may also be used as viscosifiers. The amount of viscosifier used in the compositions may vary depending on downhole conditions, as understood by those skilled in the art. However, normally about 0.1% to 6% by weight range may be sufficient for most applications. VG-69™, VG-SUPREME™, VG-HT™, and VG-PLUS™ are organoclay available from M-I, L.L.C. (Houston, TX), and VERSA-HRP™ is a polyamide resin material available from M-I L.L.C. (Houston, TX) that may be used in the fluids and methods of this disclosure.

[0089] Fluid loss control agents may act by coating the walls of the well. Suitable fluid loss control agents may include, but are not limited to, modified lignites, asphaltic compounds, gilsonite, organophilic humates or tannins prepared by reacting humic acid or tannic acid with amides or polyalkylene polyamines, amine-treated tannins such as ONE-TROL-HT™, and latex polymers. In embodiments, the fluid loss control agent may be selected from one or more of VERSATROL™, VERSATROL™, VERSALIG™, ECOTROL™ family of products, ONETROL-HT™, EMI 789, and NOVATECH™ F, which are all commercially available from MI SWACO (Houston, TX).

[0090] Corrosion inhibitors may also be added to the drilling fluids disclosed herein to control the corrosion of the drilling equipment. Depending upon the type of corrosion encountered, the corrosion inhibitor may be organic or inorganic or some combination thereof. Non-limiting examples of corrosion inhibitors include phosphates, silicates, borates, zinc compounds, organic amines, benzoic acid, and benzoic acid derivatives, phosphate esters, heterocyclic nitrogen and sulfur compounds, organic acids, and the like. Non-limiting examples of commercially available corrosion inhibitors include sodium benzoate and benzotriazole.

[0091] Weighting agents or density materials suitable for use in wellbore fluid formulations in accordance with the present disclosure include, but are not limited to, hematite, magnetite, iron oxides, illmenite, barite, siderite, celestite, dolomite, calcite, manganese oxides, halites and the like. In other embodiments, the micronized weighting agents may be coated with a dispersant.

[0092] In embodiments, the weighting agent may be coated, for example, with dispersants such as oleic acid and polybasic fatty acids, alkylbenzene sulphonic acids, alkane sulphonic acids, linear alpha-olefin sulphonic acids, phospholipids such as lecithin, including salts thereof and including mixtures thereof. Synthetic polymers may also be used, such as HYPERMER™ OM-1 (Imperial Chemical Industries, PLC, London, United Kingdom) or polyacrylate esters, for example. Such polyacrylate esters may include polymers of stearyl methacrylate and/or butylacrylate. In another embodiment, the corresponding acids methacrylic acid and/or acrylic acid may be used. One skilled in the art would recognize that other acrylate or other unsaturated carboxylic acid monomers (or esters thereof) may be used to achieve substantially the same results as disclosed herein.

[0093] The quantity of the coated or uncoated weighting agent added, if any, may depend upon the desired density of the final composition. Weighting agents may be added to result in a density of up to about 22 pounds per gallon (ppg). In other embodiments, the weighting agent may be added to achieve a density of up to 20 ppg or up to 19.5 ppg.

[0094] The method used in preparing wellbore fluids described herein is not critical. Conventional methods can be used to prepare the wellbore fluids in a manner analogous to those normally used, to prepare conventional oil-based drilling fluids. In one representative procedure, a desired quantity of oleaginous fluid such as a base oil and a suitable amount of carbon black materials are mixed together and the remaining components (if necessary) are added sequentially with continuous mixing. An invert emulsion of the present disclosure is formed by vigorously agitating, mixing or shearing the oleaginous fluid and the non-oleaginous fluid.

[0095] **Wellbore Fluid Use Downhole**

[0096] In one or more embodiments, the wellbore fluids described herein may be pumped and circulated downhole while drilling with overbalanced conditions or during another wellbore operation. During the circulation or drilling a conductive filtercake may be formed on the wellbore walls. Drilling/circulating the fluid in overbalanced conditions may include a pressure differential of at least 150 psi and up to the fracture gradient of the formation, such that a filtercake is formed on the walls of the formation. This conductive filtercake may be useful for performing resistivity measurements on the formation in order to characterize the reservoir, such as using one of the tools described above.

[0097] Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

CLAIMS

What is claimed:

1. A method of electrically logging a section of a wellbore, comprising:
circulating an oil-based wellbore fluid within the wellbore and allowing filtration of the oil-based wellbore fluid to form a conductive filtercake on a wall of the wellbore;
placing within the wellbore a wellbore logging tool with at least one pad capable of applying a current to a portion of the conductive filtercake and wellbore wall;
applying electrical current from the at least one pad; and
collecting an electrical log of the portion of the wellbore that has had electrical current applied thereto.

2. The method of claim 1, further comprising:
contacting the at least one pad against the conductive filtercake.

3. The method of claim 2, further comprising:
moving the wellbore logging tool within the wellbore to move the at least one pad along a section of the wellbore while continuously applying electrical current.

4. The method of claim 1, further comprising:
transmitting the electrical log to the surface.

5. The method of claim 1, wherein the electrical current is applied from the pad by an array of electrodes thereon.

6. The method of claim 1, wherein the wellbore logging tool comprises:
a sonde having a plurality of supports, each attached to a pad, and wherein the plurality of supports urge the pads outwardly against the conductive filtercake.

7. The method of claim 1, wherein placing within the wellbore a wellbore logging tool comprises:
lowering a tubular conduit into the wellbore;

passing a logging tool string from a position within the tubular conduit to a position outside a lower end portion of the tubular conduit; and

extending at least one arm of the logging tool string outward, the at least one arm comprising at least one pad.

8. The method of claim 7, wherein the tubular conduit is a drill string.

9. The method of claim 8, wherein the logging tool string is located below a drill bit of the drill string after passing from a position within the drill string to a position outside a lower end position of the drill string.

10. The method of claim 8, wherein the drill string is used to drill a section of the wellbore prior to passing the logging tool string from a position within the drill string to a position outside a lower end portion of the drill string, contacting the at least one pad of the logging tool string against the filtercake, applying electrical current from the at least one pad, and collecting an electrical log of the portion of the wellbore that has had electrical current applied.

11. The method of claim 8, further comprising:

after the collecting, retracting the logging tool string into the drill string and then drilling a second section of the wellbore with the drill string; and

passing the logging tool string from a position within the drill string to a position outside a lower end portion of the tubular conduit and within the second section of the wellbore;

extending at least one arm of the logging tool string outward, the at least one arm comprising at least one pad;

applying electrical current from the at least one pad; and

collecting an electrical log of the second section of the wellbore that has had electrical current applied thereto.

12. The method of claim 11, further comprising:

contacting the at least one pad against the filtercake in the second section of the wellbore.

13. The method of claim 1, wherein the oil-based wellbore fluid includes a conductive carbon materials and has a conductivity of at most 0.02 S/m when measured at 20 kHz.

14. The method of claim 13, wherein the oil-based wellbore fluid has a surface area loading factor of at least 2000 $lbm^2/gbbl$.

15. The method of claim 13, wherein the carbon materials is a carbon black that has spheroidal primary particles from about 5 nm to about 150 nm in diameter.

16. The method of claim 13, wherein the carbon materials is a carbon black wherein a circumscribing sphere encompassing a carbon black aggregate has a diameter from about 60 nanometers up to 3 micrometers.

17. The method of claim 13, wherein the carbon materials is a carbon black having a pore volume of at least about 200 cm^3 DBP/100g carbon black and up to about 500 cm^3 DBP/100g carbon black.

18. The method of claim 13, wherein the carbon materials is a carbon black having a volatile content below about 1% by weight.

19. The method of claim 13, wherein the carbon materials is present in the wellbore fluid in an amount of about 1 to 30 pounds per barrel.

20. The method of claim 1, wherein the oil-based wellbore fluid is an invert emulsion.

21. The method of claim 1, wherein the oil-based wellbore fluid has a conductivity two orders of magnitude less than the formed filtercake.

22. The method of claim 1, wherein the circulating is performed under a pressure differential of at least 150 psi.

23. A system for electrically logging a section of a wellbore, comprising:
a wellbore with at least a portion of its wellbore wall having a conductive filtercake formed thereon by an oil-based wellbore fluid; and

a wellbore logging tool with at least one pad capable of applying a current to a portion of a wellbore wall.

24. The system of claim 23, further comprising:
a tubular conduit housing the wellbore logging tool, the wellbore logging tool comprising an extendible and retractable logging tool string with the at least one pad with electrodes thereon capable of applying a current to a portion of a wellbore wall.

25. The system of claim 23, wherein the at least one pad is in direct contact with the conductive filtercake.

26. The system of claim 23, wherein the wellbore logging tool comprises:
a sonde having a plurality of supports, each attached to a pad, and wherein the plurality of supports urge the pads outwardly against the conductive filtercake.

27. The system of claim 23, further comprising:
a cable attached to the wellbore logging tool, the cable being capable of suspending the tool within the wellbore; and
a winch attached to the cable, the winch being capable of reversibly moving the wellbore logging tool, via the cable, vertically and horizontally within the wellbore.

28. The system of claim 25, wherein the at least one pad is in direct contact with the conductive filtercake when the logging tool string is in an extended position outside of the tubular conduit.

29. The system of claim 24, wherein the logging tool string is below a drill bit of the drill string when in an extended position.

30. The system of claim 23, wherein the oil-based wellbore fluid includes a conductive carbon materials and has a conductivity of at most 0.02 S/m when measured at 20 kHz.

31. The system of claim 23, wherein the oil-based wellbore fluid has a conductivity two orders of magnitude less than the formed conductive filtercake.

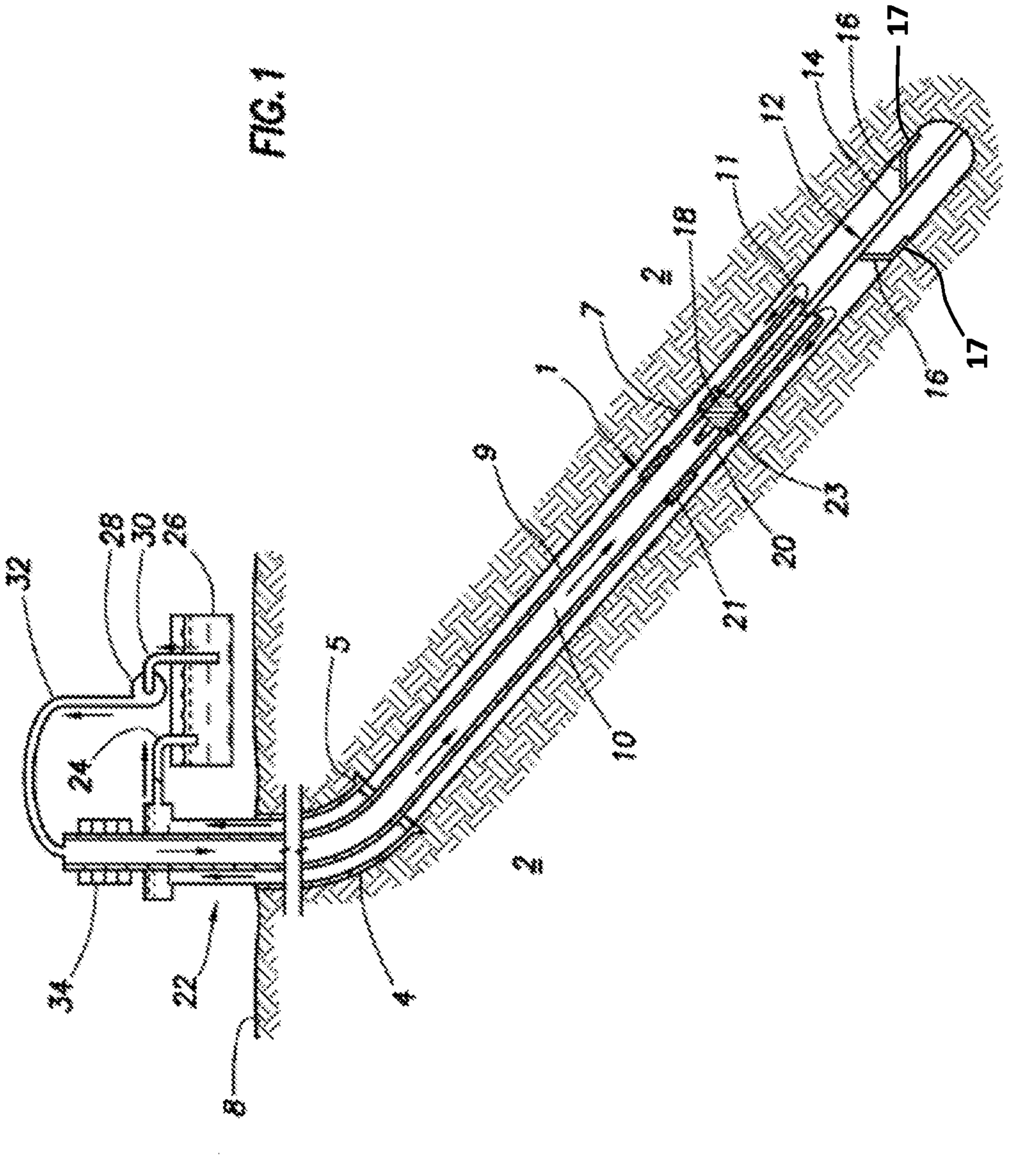

FIG. 1

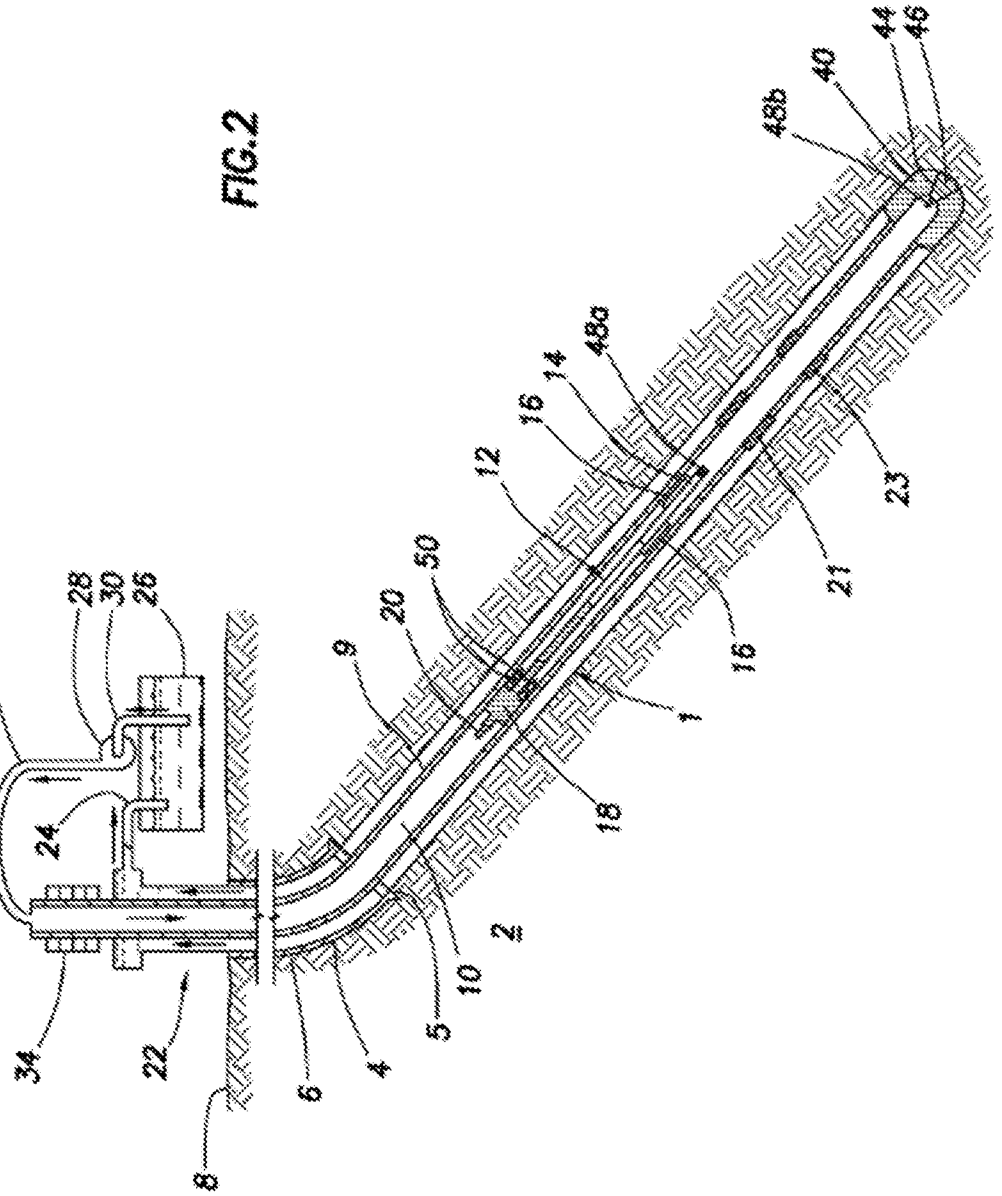
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FIG.2

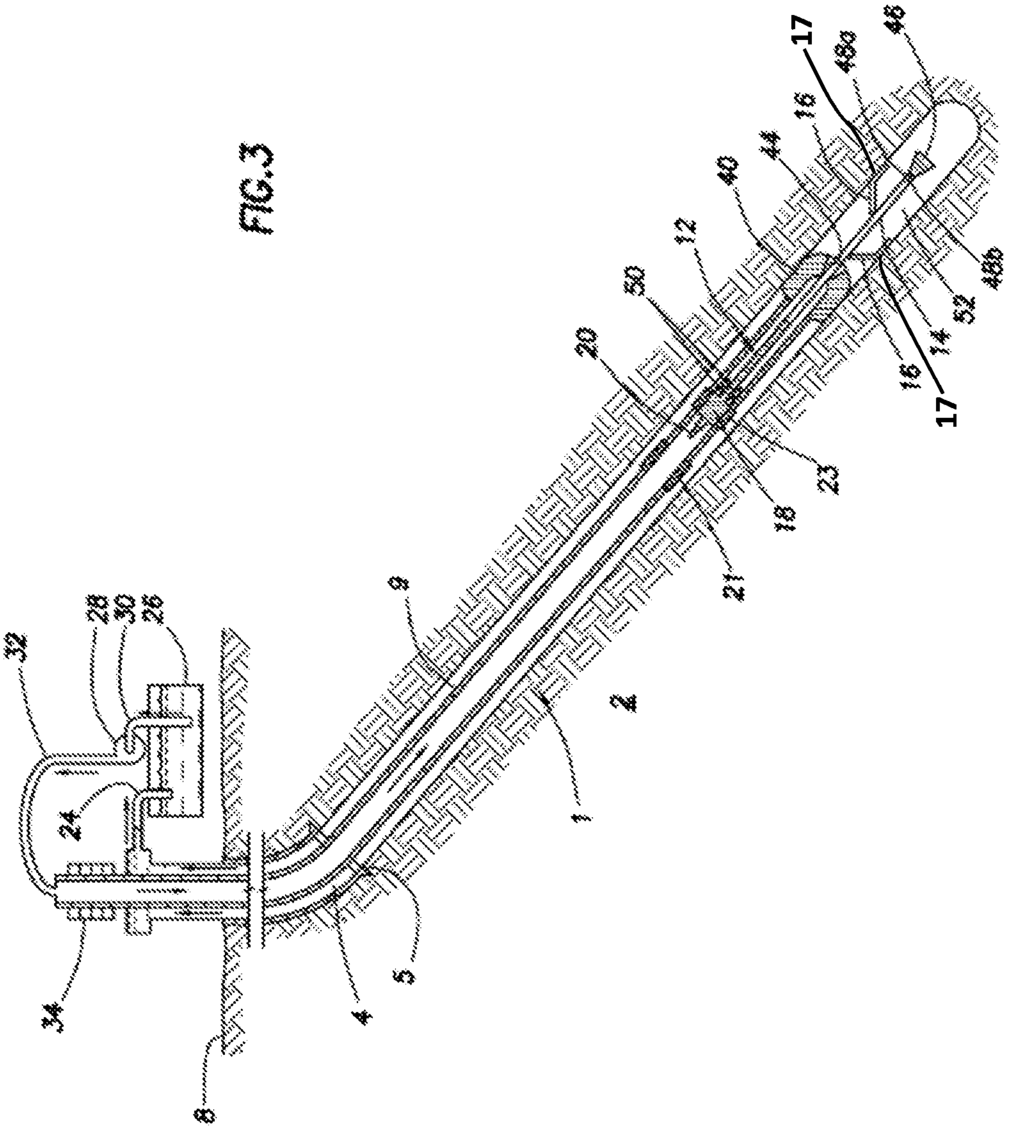
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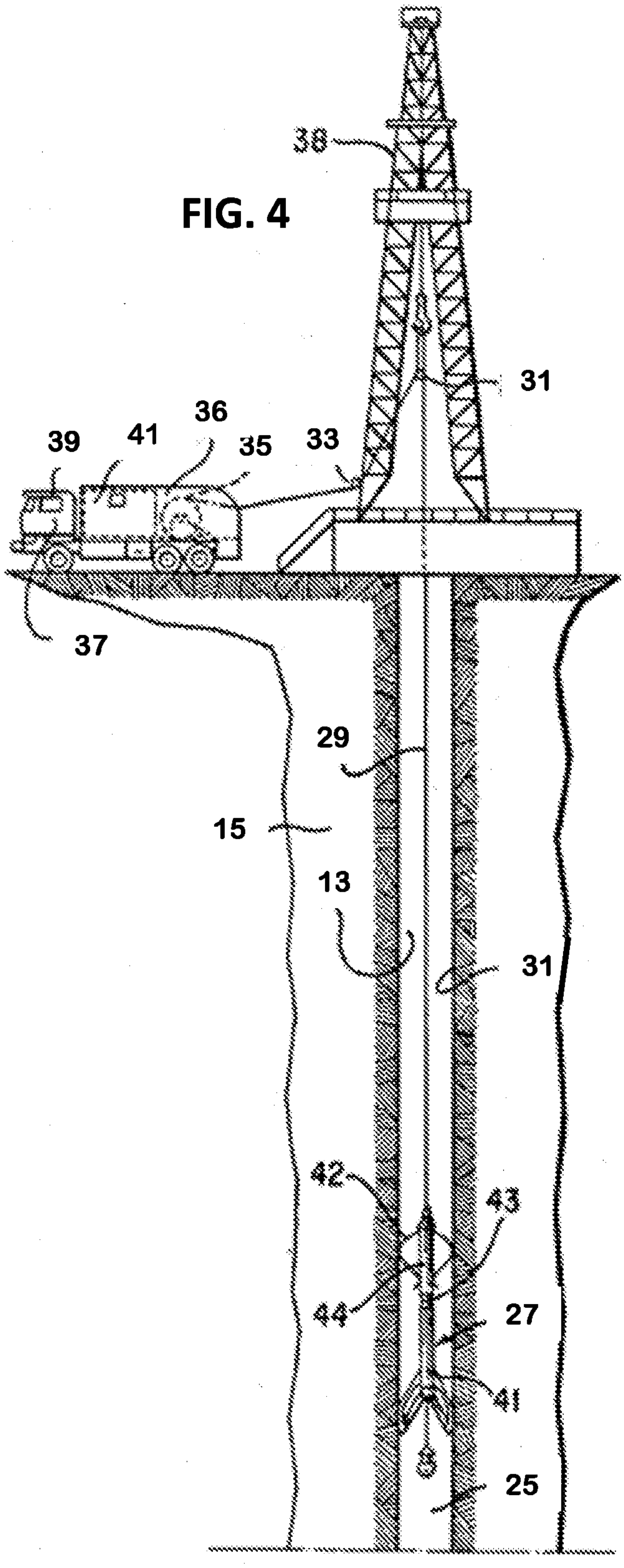
FIG.3

FIG. 4



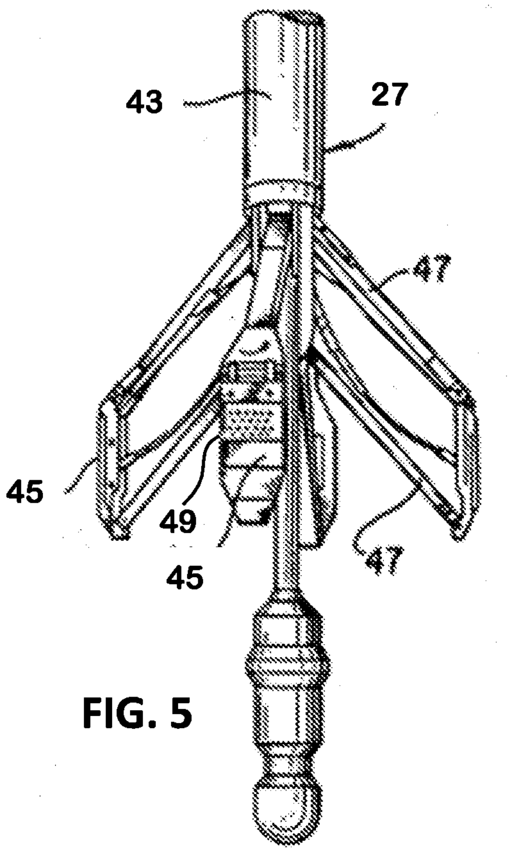


FIG. 5

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2017/030727

A. CLASSIFICATION OF SUBJECT MATTER

E21B 47/00(2006.01)i, G01V 3/26(2006.01)i, G01V 3/36(2006.01)i

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 47/00; G01V 3/20; G01V 3/18; G01V 3/26; G01V 3/36

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords:oil based, filtercake, carbon material, conductivity, electrode, measurement, transmit, current, pad

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2012-0131996 A1 (ANISH et al.) 31 May 2012 See paragraphs [0002], [0020]-[0043]; claims 9, 13; and figures 1, 4.	1-31
Y	US 2011-0254553 A1 (VAN ZANTEN, RYAN) 20 October 2011 See paragraph [0013]; and claims 1, 7, 9, 12.	1-31
Y	US 2008-0173481 A1 (MENEZES et al.) 24 July 2008 See paragraphs [0035]-[0037]; claims 20, 22; and figures 1a-1b.	7-12,24,28-29
A	US 2013-0030707 A1 (TABAROVSKY et al.) 31 January 2013 See paragraph [0016]; claims 1, 5; and figure 1.	1-31
A	US 2006-0225880 A1 (RADZINSKI et al.) 12 October 2006 See paragraphs [0026]-[0040]; and figures 2A-2B, 4A-4B.	1-31

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

☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
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"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
16 August 2017 (16.08.2017)	**17 August 2017 (17.08.2017)**

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Facsimile No. +82-42-481-8578

Authorized officer
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Telephone No. +82-42-481-8440

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