



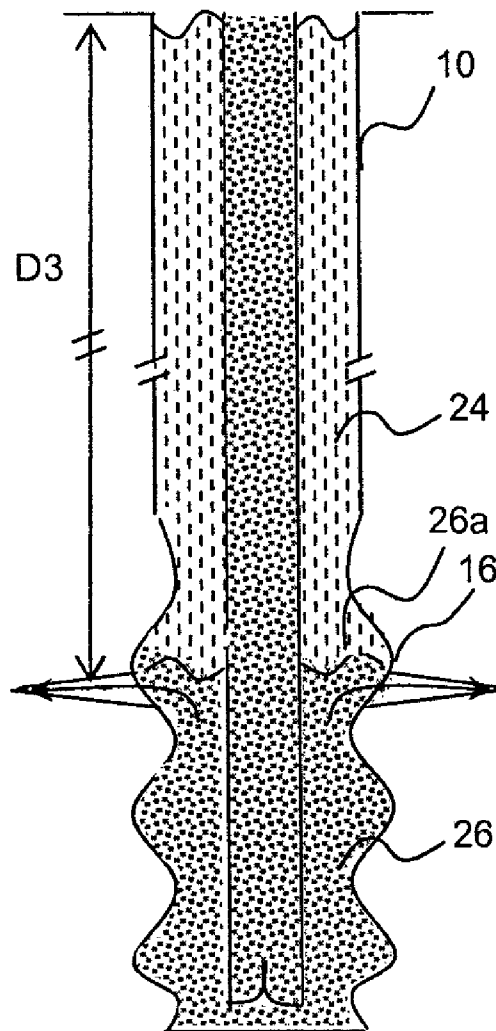
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(19) **United States**(12) **Patent Application Publication**
Dakin(10) **Pub. No.: US 2011/0220349 A1**(43) **Pub. Date: Sep. 15, 2011**(54) **METHODS FOR MINIMIZING FLUID LOSS
TO AND DETERMINING THE LOCATIONS
OF LOST CIRCULATION ZONES**(52) **U.S. Cl. 166/250.08**(75) **Inventor: Eugene Dakin, Langdon (CA)**(73) **Assignee: M-I L.L.C., Houston, TX (US)**(21) **Appl. No.: 13/128,456**(22) **PCT Filed: Nov. 13, 2009**(86) **PCT No.: PCT/US09/64327**§ 371 (c)(1),
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(57) **ABSTRACT**

A method for determining a location of a lost circulation zone in a wellbore having a first wellbore fluid therein that includes allowing loss of the first wellbore fluid to the lost circulation zone to stabilize; adding a volume of a second wellbore fluid having a density less than the first wellbore fluid to the wellbore on top of the first wellbore fluid to a predetermined wellbore depth; determining an average density of the combined first wellbore fluid and second wellbore fluid; mixing the first wellbore fluid and the second wellbore fluid together; pumping a volume of a third wellbore fluid having a density greater the average density of the combined first and second wellbore fluid into the wellbore bottom until fluid loss occurs; and determining the location of the lost circulation zone is disclosed.



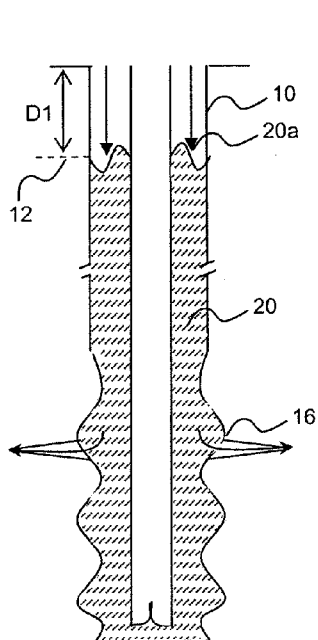


FIG. 1

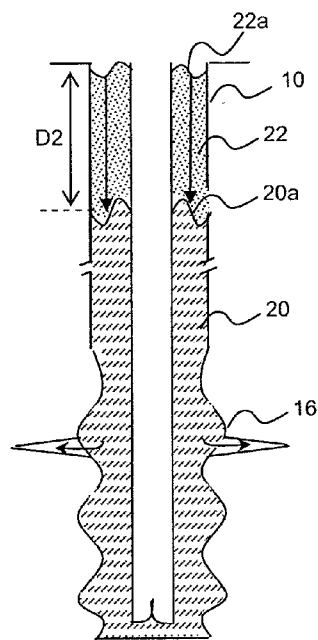


FIG. 2

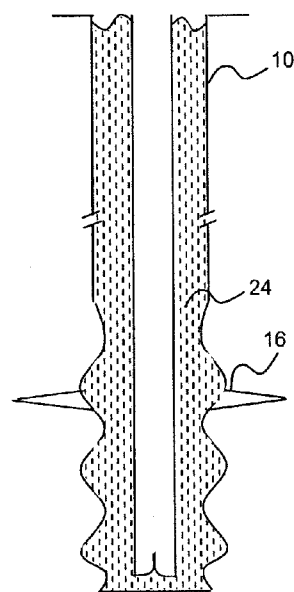


FIG. 3

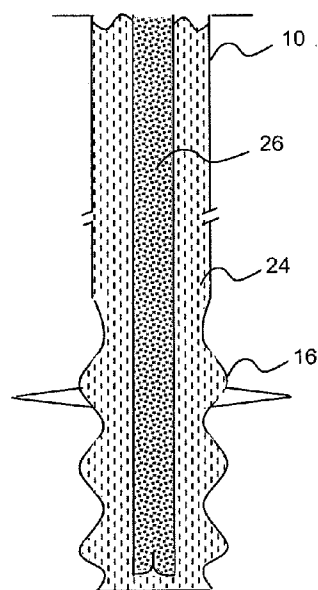


FIG. 4

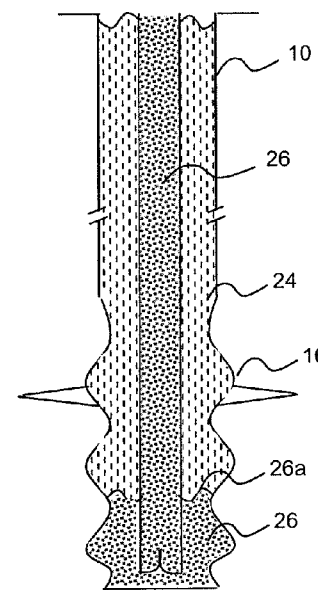


FIG. 5

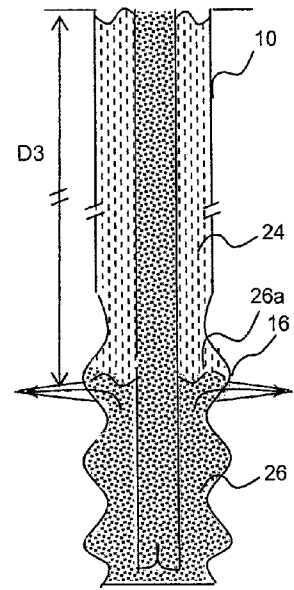


FIG. 6

METHODS FOR MINIMIZING FLUID LOSS TO AND DETERMINING THE LOCATIONS OF LOST CIRCULATION ZONES

BACKGROUND OF INVENTION

[0001] 1. Field of the Invention

[0002] Embodiments disclosed herein relate generally to lost circulation experienced during drilling a wellbore. In particular, embodiments disclosed herein relate to the identification or determination of the location(s) of loss zones in a wellbore for lost circulation treatments.

[0003] 2. Background Art

[0004] During the drilling of a wellbore, various fluids are typically used in the well for a variety of functions. The fluids may be circulated through a drill pipe and drill bit into the wellbore, and then may subsequently flow upward through the wellbore to the surface. During this circulation, the drilling fluid may act to remove drill cuttings from the bottom of the hole to the surface, to suspend cuttings and weighting material when circulation is interrupted, to control subsurface pressures, to maintain the integrity of the wellbore until the well section is cased and cemented, to isolate the fluids from the formation by providing sufficient hydrostatic pressure to prevent the ingress of formation fluids into the wellbore, to cool and lubricate the drill string and bit, and/or to maximize penetration rate.

[0005] Wellbore fluids may also be used to provide sufficient hydrostatic pressure in the well to prevent the influx and efflux of formation fluids and wellbore fluids, respectively. When the pore pressure (the pressure in the formation pore space provided by the formation fluids) exceeds the pressure in the open wellbore, the formation fluids tend to flow from the formation into the open wellbore. Therefore, the pressure in the open wellbore is typically maintained at a higher pressure than the pore pressure. While it is highly advantageous to maintain the wellbore pressures above the pore pressure, on the other hand, if the pressure exerted by the wellbore fluids exceeds the fracture resistance of the formation, a formation fracture and thus induced mud losses may occur. Further, with a formation fracture, when the wellbore fluid in the annulus flows into the fracture, the loss of wellbore fluid may cause the hydrostatic pressure in the wellbore to decrease, which may in turn also allow formation fluids to enter the wellbore. As a result, the formation fracture pressure typically defines an upper limit for allowable wellbore pressure in an open wellbore while the pore pressure defines a lower limit. Therefore, a major constraint on well design and selection of drilling fluids is the balance between varying pore pressures and formation fracture pressures or fracture gradients through the depth of the well.

[0006] As stated above, wellbore fluids are circulated downhole to remove rock, as well as deliver agents to combat the variety of issues described above. Fluid compositions may be water- or oil-based and may comprise weighting agents, surfactants, proppants, and polymers. However, for a wellbore fluid to perform all of its functions and allow wellbore operations to continue, the fluid must stay in the borehole. Frequently, undesirable formation conditions are encountered in which substantial amounts or, in some cases, practically all of the wellbore fluid may be lost to the formation. For example, wellbore fluid can leave the borehole through large or small fissures or fractures in the formation or through a highly porous rock matrix surrounding the borehole.

[0007] Lost circulation is a recurring drilling problem, characterized by loss of drilling mud into downhole formations. However, other fluids, besides "drilling fluid" can potentially be lost, including completion, drill-in, production fluid, etc. Lost circulation can occur naturally in formations that are fractured, highly permeable, porous, cavernous, or vugular. These earth formations can include shale, sands, gravel, shell beds, reef deposits, limestone, dolomite, and chalk, among others.

[0008] Lost circulation may also result from induced pressure during drilling. Specifically, induced mud losses may occur when the mud weight, required for well control and to maintain a stable wellbore, exceeds the fracture resistance of the formations. A particularly challenging situation arises in depleted reservoirs, in which the drop in pore pressure weakens hydrocarbon-bearing rocks, but neighboring or inter-bedded low permeability rocks, such as shales, maintain their pore pressure. This can make the drilling of certain depleted zones impossible because the mud weight required to support the shale exceeds the fracture resistance of the sands and silts. Another unintentional method by which lost circulation can result is through the inability to remove low and high gravity solids from fluids. Without being able to remove such solids, the fluid density can increase, thereby increasing the hole pressure, and if such hole pressure exceeds the formation fracture pressure, fractures and fluid loss can result.

[0009] Losing any fluid to the formation, for any reason, can be a costly result for the drilling, completion, or production operation due to the fluid cost as well as the rig downtime and equipment rental. Mechanical and electrical methods exist for determining the location(s) or zone(s) of fluid loss; however, they require specialized equipment and repeated trips in and out of the hole. If such equipment is unavailable, the location of the loss zones may not actually be determined but instead larger than necessary volumes of loss circulation treatments may be pumped into the well with the hope that the treatment will plug the zone where losses are occurring so that that drilling (or other) operations may resume. Because of this inaccuracy, it is typically necessary to repeat loss circulation treatments, further increasing costs and downtime.

[0010] Accordingly, there exists a continuing need for methods by which a loss zone may be easily and more accurately determined without the cost of specialized equipment so that a loss zone may be identified and plugged more quickly and the regular drilling or other operations resumed.

SUMMARY OF INVENTION

[0011] In one aspect, embodiments disclosed herein relate to a method for determining a location of a lost circulation zone in a wellbore having a first wellbore fluid therein that includes allowing loss of the first wellbore fluid to the lost circulation zone to stabilize; adding a volume of a second wellbore fluid having a density less than the first wellbore fluid to the wellbore on top of the first wellbore fluid to a predetermined wellbore depth; determining an average density of the combined first wellbore fluid and second wellbore fluid; mixing the first wellbore fluid and the second wellbore fluid together; pumping a volume of a third wellbore fluid having a density greater the average density of the combined first and second wellbore fluid into the wellbore bottom until fluid loss occurs; and determining the location of the lost circulation zone.

[0012] In another aspect, embodiments disclosed herein relate to a method for minimizing fluid loss to a lost circula-

tion zone in a wellbore having a first wellbore fluid therein that includes allowing loss of the first wellbore fluid to the lost circulation zone to stabilize; adding a volume of a second wellbore fluid having a density less than the first wellbore fluid to the wellbore on top of the first wellbore fluid to a predetermined wellbore depth; determining an average density of the combined first wellbore fluid and second wellbore fluid; and pumping a third wellbore having the determined average density of the combined first and second wellbore fluids into the wellbore to fill the wellbore.

[0013] In yet another aspect, embodiments disclosed herein relate to a method for determining a location of a lost circulation zone in a wellbore having a wellbore fluid therein that includes allowing loss of the wellbore fluid to the lost circulation zone to stabilize; calculating the pressure gradient of the lost circulation zone; increasing the weight of the wellbore fluid in the wellbore from a bottom of the wellbore upwards until fluid loss occurs; and calculating the location of the lost circulation zone.

[0014] Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0015] FIGS. 1 to 6 show schematics of a wellbore having a lost circulation event and subjected to the methods disclosed herein.

DETAILED DESCRIPTION

[0016] Embodiments disclosed herein generally relate to the identification or determination of the location(s) of loss zones in a wellbore. In particular, embodiments disclosed herein relate to determination of a lost circulation zone so that a lost circulation treatment may be more accurately placed in the vicinity of the loss.

[0017] In particular, the method of the present disclosure rely on the principles of pore pressures and pressure gradients within a well to determine the location of a lost circulation zone instead of relying on costly and time-consuming mechanical or electrical equipment to make sure determinations. Specifically, the methods described herein may include determination of pressure gradients to achieve a balanced (or slightly overbalanced) well and then slowing introducing a heavier wellbore fluid at the wellbore bottomhole such that when the heavier fluid reaches the depth of the lost circulation zone, additional fluid loss will occur, indicating the location of the lost circulation zone has been determined.

[0018] Referring to FIGS. 1 to 6, schematic illustrations of a wellbore at incremental stages of the methods disclosed herein are shown. Specifically, as shown in FIG. 1, a wellbore 10 includes a first wellbore fluid 20 therein. Such wellbore fluid 20 may include any type of wellbore fluid, including drilling fluids, completion fluids, drill-in fluids, production fluids, and the like, which may include one or more liquid and/or gas phases. Rather, no limitation is placed on the type of wellbore fluid that may be present in the wellbore when lost circulation occurs, and the present methods may be applied to determine the location of the lost circulation.

[0019] When a lost circulation event occurs, loss of first wellbore fluid 20 to the formation at the lost circulation zone 16 occurs, and is identified, for example, a drop in the fluid level, by constant or periodic make-up volumes, or the inability to maintain circulation of the wellbore fluid. Once a lost

circulation event is detected, in accordance methods disclosed herein, pumping of the first wellbore fluid is stopped, and the fluid level 20a is allowed to decrease or stabilize to an equilibrium static point 12. Stabilization occurs when the formation pressure exerted on the lost circulation zone and the pressure exerted by the fluid in the wellbore are balanced (or at least substantially balanced).

[0020] Upon stabilization of the first wellbore fluid 20, a second wellbore fluid 22 lighter than the first wellbore fluid 20 is added to the casing top (i.e., on top of the first wellbore fluid 20) until the second wellbore fluid level 20a reaches a predetermined wellbore depth (which as shown in FIG. 2, is a depth of zero, at the top of the casing. As mentioned above with respect to first wellbore fluid 20, second wellbore fluid (as well as any other wellbore fluids) may include at least one liquid and/or gaseous component. In a particular embodiment, the second wellbore fluid 26 may be water. The volume of second wellbore fluid 20 added to the wellbore 10 is measured and recorded. When the second wellbore fluid 20 is added to the wellbore 10, the first wellbore fluid level 20a may drop to a greater depth D2 as compared to D1 due to the increased density/fluid pressure added by the second wellbore fluid to obtain a pressure balanced system.

[0021] Upon stabilization of the fluids 20 and 22 within the wellbore and measurement/recordal of the volume of second wellbore fluid 22 added to the well, the average fluid density between the combined first and second wellbore fluids 20 and 22 may be determined. Such determination may be made through calculating the fluid volume fractions, depth fractions well fractions, total pressure within the wellbore, and/or average fluid gradient density. However, one skilled in the art would appreciate that the ultimate determination (average fluid density) may be broken into multiple calculation steps or may be performed as a single long calculation.

[0022] Upon determination of the average density for the balanced wellbore fluid system in the wellbore (layers of wellbore fluids 20 and 22), the fluids may be mixed/homogenized or displaced (with a third wellbore fluid) such that the fluid 24 present in the wellbore 10 is a substantially uniform fluid having a density at the calculated density (of the first and second wellbore fluids 20 and 22) so that the well remains balanced (or even slightly overbalanced for safety concerns). Depending on the intent of the operator, drilling may be continued at this density or the location of the lost circulation zone may be determined. Drilling may be continued without making such determination in such an instance where the operator does not care to determine the location of the lost circulation zone, but instead desires to determine the maximum density of the wellbore fluid that may be used to continue drilling with minimal fluid losses.

[0023] However, if the operator wishes to determine the location of the lost circulation zone, once the well has a fluid density substantially balancing the wellbore's pressure gradient, a fourth wellbore fluid 26 may be pumped into and fill the drill string. Fourth wellbore fluid 26 may have a density slightly greater than the balanced wellbore fluid 24. Such increase in density may be achieved by formulating a fluid 26 having a density greater than the average density of the first and second wellbore fluids 20 and 22 (through general fluid components, including weight material) and/or adding a weight material to the a third displacement fluid 24 (if used). The amount of such increase in density (as compared to balanced fluid 24) may be selected based on the particular well; however, suitable ranges may include an increase of at

least 0.5 ppg in some embodiments and at least 1.0 ppg in other embodiments. However, no limitation is intended on the scope of the present disclosure. Rather other density differentials may be used without departing from the scope of the present disclosure.

[0024] Pumping of fluid **26** out of the drill string and into the wellbore **10** occurs at a slow rate, and by measuring the pump strokes so that the volume of fourth wellbore fluid **26** may be recorded. Additionally, pumping may occur at a slow rate, and with periodic stops so that fluid loss may be detected as soon as possible after occurrence. As shown in FIG. **5**, no fluid loss to the formation **18** has occurred because the density of fluid **24** above the low pressure pore area at the lost circulation zone **16** is the same as the pressure exerted by the fluid above the zone. However, as shown in FIG. **6**, fluid loss occurs because as the volume of fluid **26** pumped into the wellbore increases such that the fluid level **26a** approaches the lost circulation zone **16**, the denser fluid **26** is exerting greater pressure on the lost circulation zone **16** than what the formation is exerting on the wellbore fluid **24**. As soon as fluid loss is detected, the measurement of the volume of fluid **26** pumped into the wellbore (as it is pumped from the bottom of the wellbore up) may be used to determine the depth **D3** or location of lost circulation zone **16** using known wellbore dimensional values.

[0025] However, it is possible that a single wellbore **10** may include multiple lost circulation zones **16**. In such an instance, the lost circulation zones may be determined from the bottom of the well up, repeating the steps described herein until each lost circulation zone is locationally identified and treated.

[0026] Following determination of the location(s) of the lost circulation zone **16**, a lost circulation treatment may be accurately placed proximate the location of the loss zone. Lost circulation treatments fall into two main categories: low fluid loss treatments where the fracture or formation is rapidly plugged and sealed; and high fluid loss treatments where dehydration of the loss prevention material in the fracture or formation with high leak off of a carrier fluid fills a fracture and/or forms a plug that then acts as the foundation for fracture sealing. The mechanism by which fluid loss is controlled, i.e., plugging, bridging, and filling, may be based on the particle size distribution, relative fracture aperture, fluid leak-off through the fracture walls, and fluid loss to the fracture tip. Accurate placement of such materials may allow for less rigdown downtime and more managed use of lost circulation treatments. Selection of lost circulation treatments may be made based on the type quantification, and analysis of losses, formation/fracture type, and pressures within the loss zone, many of which may be quantified during the methods disclosed herein. Selection based on these factors may be described in greater detail in U.S. Patent Application No. 61/024,807, which is assigned to the present assignee and herein incorporated by reference in its entirety.

[0027] Lost circulation treatments may include particulate-and/or settable-based treatments. Particulate-based treatments may include use of particles frequently referred to in the art as bridging materials. For example, such bridging materials may include at least one substantially crush resistant particulate solid such that the bridging material props open and bridges or plugs the fractures (cracks and fissures) that are induced in the wall of the wellbore. Examples of bridging materials suitable for use in the present disclosure include graphite, calcium carbonate (preferably, marble),

dolomite ($\text{MgCO}_3 \cdot \text{CaCO}_3$), celluloses, micas, proppant materials such as sands or ceramic particles and combinations thereof. In addition to such particulate based treatments, depending on the classified severity of loss, a reinforcing plug, including cement- or resin-based plugs, may be necessary to seal off the fracture.

[0028] Settable treatments suitable for use in the methods of the present disclosure include those that may set or solidify upon a period of time. The term “settable fluid” as used herein refers to any suitable liquid material which may be pumped or emplaced downhole, and will harden over time to form a solid or gelatinous structure and become more resistance to mechanical deformation. Examples of compositions that may be included in the carrier fluid to render it settable include cementitious materials, “gunk” and polymeric or chemical resin components.

[0029] Further, while the present disclosure may refer to use of these methods in traditional wellbores and/or traditional drilling operations, the present invention is not so limited. Rather, it is specifically within the scope of the present invention that the methods disclosed herein may be used in any wellbore operations, including, for example, casing drilling, cable drilling, conventional drilling, reverse circulation drilling, and coiled tubing drilling, etc.

Example

[0030] The following example is used to demonstrate the manner in which the depth of a lost circulation zone may be calculated and a treatment more rapidly and accurately spotted into the well.

[0031] For a given well (such as that shown in FIG. **1**) that has an observed fluid loss of an original wellbore fluid (11 ppg), the fluid loss may be allowed to stabilize. Following stabilization, a light density fluid (water, 8.334 ppg) may be added to the top of the well, as shown in FIG. **2**, and the volume of light density fluid added to the well to fill the well to a predetermined depth (i.e., zero depth) is recorded (as shown in Table 1 below). From the volume of lighter density fluid (3400 gallons), the casing and drill pipe diameter, the volume per depth (and depth) of the light density fluid may be calculated. Thus, by knowing the total footage drilled, the well fractions of the original and light density fluid, as well as the total pressure along the wellbore, may be calculated. From this pressure value, the average fluid gradient (10.079 ppg) is calculated.

TABLE 1

Calculate Pressure Gradient as Fluid Weight		
#1	Original Fluid Density*	11 pounds per gallon
#2	Light Density Fluid*	8.334 pounds per gallon
Volume of Light Density Fluid Added #2*		3400 Gallons
Internal Diameter of Casing*		9.625 Inches
External Diameter of Drill Pipe*		3.5 Inches
Casing Volume/depth***		3.2811 gallons per foot
Calculated Depth of Light Fluid Added***		1036.2 Feet of Light Density Fluid
Total Well TVD*		3000 Feet

TABLE 1-continued

Calculate Pressure Gradient as Fluid Weight	
Well Fraction of Original Fluid Density***	1123.3 psi fraction
Well Fraction of Light Density Fluid***	449.07 psi fraction
Total pressure along wellbore***	1572.3 psi at bottom of hole
Average fluid gradient density***	10.079 pounds per gallon

Required

*= Data

***= Calculated Data

[0032] Following mixing of the original and light density fluid to form a homogenous fluid (10.079 ppg a weight material (at +1 ppg) may be added to the fluid to form a heavier fluid. The heavier fluid may be filled into the drill string and slowly pumped at the borehole bottom. Pump strokes may be calculated, and the pumping periodically stopped so that fluid levels may be observed and fluid loss immediately detected. Upon detection of fluid loss, the number of pump strokes and/or volume of fluid pumped into the wellbore may be recorded. From the volume of heavier fluid pumped into the wellbore (as well as drill pipe and bit diameter), the volume per depth, as well as total feet from the bottomhole, of the heavier fluid may be calculated. The lost circulation zone will correspond to the heavier fluid height. From the heavier fluid height, the depth from the surface may be calculated so that a lost circulation treatment may be spotted with relative accuracy.

[0033] Embodiments of the present disclosure may advantageously provide for at least one of the following. Losing any fluid to the formation, for any reason, can be a costly result for the drilling, completion, or production operation due to the fluid cost as well as the rig downtime and equipment rental. Conventional reactions include use of either mechanical and electrical equipment (with repeated trips in and out of the hole) or larger than necessary volumes of loss circulation treatments may be pumped into the well with the hope that the treatment will plug the zone where losses are occurring so that that drilling (or other) operations may resume. Because of this inaccuracy, it is typically necessary to repeat loss circulation treatments, further increasing costs and downtime. However, in accordance with the present disclosure, methods by which a loss zone may be easily and more accurately determined are provided without the cost of specialized equipment so that a loss zone may be identified and plugged more quickly and the regular drilling or other operations resumed.

[0034] While the invention has been described with respect to a limited number of embodiments, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments can be devised which do not depart from the scope of the invention as disclosed herein. Accordingly, the scope of the invention should be limited only by the attached claims.

What is claimed:

1. A method for determining a location of a lost circulation zone in a wellbore having a first wellbore fluid therein, comprising:

allowing loss of the first wellbore fluid to the lost circulation zone to stabilize;

adding a volume of a second wellbore fluid having a density less than the first wellbore fluid to the wellbore on top of the first wellbore fluid to a predetermined wellbore depth;

determining an average density of the combined first wellbore fluid and second wellbore fluid;

mixing the first wellbore fluid and the second wellbore fluid together;

pumping a volume of a third wellbore fluid having a density greater the average density of the combined first and second wellbore fluid into the wellbore bottom until fluid loss occurs; and

determining the location of the lost circulation zone.

2. The method of claim 1, further comprising:

pumping a lost circulation treatment into the determined location of the lost circulation zone.

3. The method of claim 1, wherein the third wellbore fluid has a density of at least 0.5 ppg more than the average density of the combined first and second wellbore fluid.

4. The method of claim 1, wherein the pumping the volume of third wellbore comprises:

pumping the third wellbore fluid to a bottom of a drilling assembly; and

pumping and measuring pump strokes as the third wellbore fluid exits the bottom of the drilling assembly until fluid loss is detected and pumping is halted.

5. The method of claim 1, further comprising:

identifying loss of the first wellbore fluid to the loss circulation zone.

6. The method of claim 5, further comprising:

stopping pumping of the first wellbore fluid into the wellbore.

7. The method of claim 1, further comprising:

determining a location of a second loss circulation zone in the wellbore.

8. The method of claim 1, wherein the mixing comprises forming a homogenous blend of the first and second wellbore fluids.

9. A method for minimizing fluid loss to a lost circulation zone in a wellbore having a first wellbore fluid therein, comprising:

allowing loss of the first wellbore fluid to the lost circulation zone to stabilize;

adding a volume of a second wellbore fluid having a density less than the first wellbore fluid to the wellbore on top of the first wellbore fluid to a predetermined wellbore depth;

determining an average density of the combined first wellbore fluid and second wellbore fluid; and

pumping a third wellbore having the determined average density of the combined first and second wellbore fluids into the wellbore to fill the wellbore.

10. The method of claim 9, further comprising:

drilling with the third wellbore fluid having the determined average density.

11. The method of claim 9, further comprising:

pumping a third wellbore having the average density of the combined first and second wellbore fluids into the wellbore to fill the wellbore;

pumping a volume of fourth wellbore fluid having a density greater the average density of the combined first and second wellbore fluid into the wellbore bottom until fluid loss occurs; and

determining the location of the lost circulation zone.

12. The method of claim 11, further comprising:

pumping a lost circulation treatment into the determined location of the lost circulation zone.

13. The method of claim **11**, wherein the fourth wellbore fluid has a density of at least 0.5 ppg more than the average density of the combined first and second wellbore fluid.

14. The method of claim **11**, wherein the pumping the volume of fourth wellbore comprises:

pumping the fourth wellbore fluid to a bottom of a drilling assembly; and

pumping and measuring pump strokes as the fourth wellbore fluid exits the bottom of the drilling assembly until fluid loss is detected and pumping is halted.

15. The method of claim **9**, further comprising: identifying loss of the first wellbore fluid to the formation.

16. The method of claim **9**, further comprising: stopping pumping of the first wellbore fluid into the wellbore.

17. The method of claim **11**, further comprising: determining a location of a second loss circulation zone in the wellbore.

18. The method of claim **9**, wherein the pumping the third wellbore fluid comprises displacing the first and second wellbore fluids from the wellbore.

19. A method for determining a location of a lost circulation zone in a wellbore having a wellbore fluid therein, comprising:

allowing loss of the wellbore fluid to the lost circulation zone to stabilize;

calculating the pressure gradient of the lost circulation zone;

increasing the weight of the wellbore fluid in the wellbore from a bottom of the wellbore upwards until fluid loss occurs; and

calculating the location of the lost circulation zone.

20. The method of claim **17**, further comprising:

pumping a lost circulation treatment into the determined location of the lost circulation zone.

21. The method of claim **17**, wherein calculating the pressure gradient comprises determining a wellbore fluid density that balances or slightly overbalances the pressure gradient.

22. The method of claim **17**, wherein the fluid loss stabilizes when the pore pressure and the fluid pressure are substantially the same.

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