



(11) **EP 3 201 429 B1**

(12) **EUROPEAN PATENT SPECIFICATION**

(45) Date of publication and mention
of the grant of the patent:
19.12.2018 Bulletin 2018/51

(51) Int Cl.:
E21B 43/267 ^(2006.01) **E21B 34/06** ^(2006.01)
E21B 34/10 ^(2006.01) **E21B 43/116** ^(2006.01)
E21B 43/119 ^(2006.01)

(21) Application number: **15756319.8**

(86) International application number:
PCT/US2015/045988

(22) Date of filing: **20.08.2015**

(87) International publication number:
WO 2016/053497 (07.04.2016 Gazette 2016/14)

(54) **METHOD FOR REMEDIATING A SCREEN-OUT DURING WELL COMPLETION**

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BOHRLOCHKOMPLETTIERUNG

PROCÉDÉ POUR REMÉDIER À UN BOUCHAGE PRÉMATURÉ PENDANT LA COMPLÉTION D'UN
PUITS

(84) Designated Contracting States:
**AL AT BE BG CH CY CZ DE DK EE ES FI FR GB
GR HR HU IE IS IT LI LT LU LV MC MK MT NL NO
PL PT RO RS SE SI SK SM TR**

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(30) Priority: **03.10.2014 US 201462059517 P**
13.02.2015 US 201562116084 P

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(43) Date of publication of application:
09.08.2017 Bulletin 2017/32

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Description

BACKGROUND OF THE INVENTION

[0001] This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

FIELD OF THE INVENTION

[0002] This invention relates generally to the field of wellbore operations. More specifically, the invention relates to completion processes wherein multiple zones of a subsurface formation are fractured in stages.

GENERAL DISCUSSION OF TECHNOLOGY

[0003] In the drilling of oil and gas wells, a wellbore is formed using a drill bit that is urged downwardly at a lower end of a drill string. After drilling to a predetermined bottomhole location, the drill string and bit are removed and the wellbore is lined with a string of casing. An annular area is thus formed between the string of casing and the surrounding formations.

[0004] A cementing operation is typically conducted in order to fill or "squeeze" the annular area with columns of cement. The combination of cement and casing strengthens the wellbore and facilitates the zonal isolation of the formations behind the casing.

[0005] It is common to place several strings of casing having progressively smaller outer diameters into the wellbore. A first string may be referred to as surface casing. The surface casing serves to isolate and protect the shallower, freshwater-bearing aquifers from contamination by any other wellbore fluids. Accordingly, this casing string is almost always cemented entirely back to the surface.

[0006] A process of drilling and then cementing progressively smaller strings of casing is repeated several times below the surface casing until the well has reached total depth. In some instances, the final string of casing is a liner, that is, a string of casing that is not tied back to the surface. The final string of casing, referred to as a production casing, is also typically cemented into place. In some completions, the production casing (or liner) has swell packers or external casing packers spaced across selected productive intervals. This creates compartments between the packers for isolation of zones and specific stimulation treatments. In this instance, the annulus may simply be packed with sand.

[0007] As part of the completion process, the production casing is perforated at a desired level. This means that lateral holes are shot through the casing and the

cement column surrounding the casing. The perforations allow reservoir fluids to flow into the wellbore. In the case of swell packers or individual compartments, the perforating gun penetrates the casing, allowing reservoir fluids to flow from the rock formation into the wellbore along a corresponding zone.

[0008] After perforating, the formation is typically fractured at the corresponding zone. Hydraulic fracturing consists of injecting water with friction reducers or viscous fluids (usually shear thinning, non-Newtonian gels or emulsions) into a formation at such high pressures and rates that the reservoir rock parts and forms a network of fractures. The fracturing fluid is typically mixed with a proppant material such as sand, crushed granite, ceramic beads, or other granular materials. The proppant serves to hold the fracture(s) open after the hydraulic pressures are released. In the case of so-called "tight" or unconventional formations, the combination of fractures and injected proppant substantially increases the flow capacity of the treated reservoir.

[0009] In order to further stimulate the formation and to clean the near-wellbore regions downhole, an operator may choose to "acidize" the formations. This is done by injecting an acid solution down the wellbore and through the perforations. The use of an acidizing solution is particularly beneficial when the formation comprises carbonate rock. In operation, the completion company injects a concentrated formic acid or other acidic composition into the wellbore and directs the fluid into selected zones of interest. The acid helps to dissolve carbonate material, thereby opening up porous channels through which hydrocarbon fluids may flow into the wellbore. In addition, the acid helps to dissolve drilling mud that may have invaded the formation.

[0010] Application of hydraulic fracturing and acid stimulation as described above is a routine part of petroleum industry operations as applied to individual hydrocarbon-producing formations (or "pay zones"). Such pay zones may represent up to about 60 meters (100 feet) of gross, vertical thickness of subterranean formation. More recently, wells are being completed through a hydrocarbon-producing formation horizontally, with the horizontal portion extending possibly 1524, 3048, 4572 m (5,000, 10,000 or even 15,000 feet).

[0011] When there are multiple or layered formations to be hydraulically fractured, or a very thick hydrocarbon-bearing formation (over about 40 meters, or 131 feet), or where an extended-reach horizontal well is being completed, then more complex treatment techniques are required to obtain treatment of the entire target formation. In this respect, the operating company must isolate various zones or sections to ensure that each separate zone is not only perforated, but adequately fractured and treated. In this way, the operator is sure that fracturing fluid and stimulant are being injected through each set of perforations and into each zone of interest to effectively increase the flow capacity at each desired depth.

[0012] The isolation of various zones for pre-product-

tion treatment requires that the intervals be treated in stages. This, in turn, involves the use of so-called diversion methods. In petroleum industry terminology, "diversion" means that injected fluid is diverted from entering one set of perforations so that the fluid primarily enters only one selected zone of interest. Where multiple zones of interest are to be perforated, this requires that multiple stages of diversion be carried out.

[0013] In order to isolate selected zones of interest, various diversion techniques may be employed within the wellbore. In many cases, mechanical devices such as fracturing bridge plugs, down-hole valves, sliding sleeves (known as "frac sleeves"), and baffle/plug combinations are used.

[0014] A problem sometimes encountered during a "perf-and-frac" process is the so-called screen-out. Screen-out occurs when the proppant being injected as part of the fracturing fluid slurry tightly packs the fractures and perforation tunnels near the wellbore. This creates a blockage such that continued injection of the slurry inside the fractures requires pumping pressures in excess of the safe limitations of the wellbore or wellhead equipment. Operationally, this causes a disruption in fracturing operations and requires cessation of pumping and cleaning of the wellbore before resumption of operations. In horizontal well fracturing, screen-outs disrupt well operations and cause cost overruns. As background, the following documents are cited: U.S. Patent Application No. 2004/0084190 (Hill et al.) describes a flow responsive dump valve mechanism for a straddle packer tool and has a valve controlled flow passage from which under-flushed fluid, typically well treatment slurry, in a conveyance and fluid supplying tubing string can be dumped into a well casing; U.S. Patent Application No. 2012/0205120 (Howell) describes a method for individually servicing a plurality of zones of a subterranean formation; U.S. Patent Application No. 2003/0188871 (Dusterhoft et al.) describes a single trip method for selectively fracture packing multiple formations traversed by a wellbore; WO 2015/080754 (Morrow et al.) describes remotely actuated screenout relief valves and systems and methods including the same; U.S. Patent Application No. 2015/0068762 relates to an apparatus and methods for inhibiting a screen-out condition in a subterranean well fracturing operation.

[0015] Where the operator is pumping slurry while a live perforating gun is in the hole, the operator may be able to remedy a screen-out by shooting a new set of perforations during pumping. This may be done where a multi-zone stimulation technique is being employed. In this instance, the operator sends a signal to a bottom hole assembly that includes various perforating guns having associated charges. Examples of multi-zone stimulation techniques using such a bottom hole assembly include the "Just-In-Time Perforating" (JITP) technique and the "ACT Frac" technique. In these processes, a substantially continuous treatment of zones takes place.

[0016] The benefit of the bottom hole assemblies used

for JITP and ACT Frac processes is that they allow the operator to perforate the casing along various zones of interest and then sequentially isolate the respective zones of interest so that fracturing fluid may be injected into several zones of interest in the same trip. Fortuitously, each of these multi-zone stimulation techniques also offers the ability to create, as needed, proppant disposal zones to clean up the wellbore by perforating a new section of rock (JITP) or to simply circulate proppant out of the well using the coil tubing in the wellbore (ACT Frac) in the event of a screen-out. However, in more traditional completions where a single zone stimulation is being conducted or where multiple perforation clusters are being treated at one time, screen-outs can require a change-out of completion equipment at the surface and a considerable delay in operations.

[0017] Recently, a new type of completion procedure has been developed that employs so-called autonomous tools. These are tools that are dropped into the wellbore and which are not controlled from the surface; instead, these tools include one or more sensors (such as a casing collar locator) that interact with a controller on the tool to self-determine location within a wellbore. As the autonomous tool is pumped downhole, the controller ultimately identifies a target depth and sends an actuation signal, causing an action to take place. Where the tool is a bridge plug, the plug is set in the wellbore at a desired depth. Similarly, where the tool is a perforating gun, one or more detonators is fired to send "shots" into the casing and the surrounding subsurface formation. Unfortunately, autonomous perforating guns cannot be pumped into a wellbore when a screen-out occurs; thus, they fall into the class of completions that requires a change-out of completion equipment at the surface during screen-out.

[0018] Additionally, it is observed that even the JITP and ACT-Frac procedures are vulnerable to screen-out complications at the highest zone of a perf-and-frac stage. (This is demonstrated in connection with **Figure 1F**, below.)

[0019] Accordingly, a need exists for a process of remediating a wellbore during a condition of screen-out without interrupting the pumping process. Further, a need exists for a completion technique that enables an autonomous perforating tool to be deployed in a wellbore even during a condition of screen-out.

SUMMARY OF THE INVENTION

[0020] The methods described herein have various benefits in the conducting of oil and gas drilling and completion activities. Specifically, methods for completing a well are provided.

[0021] In one aspect, a method of completing a well first includes forming a wellbore. The wellbore defines a bore that extends into a subsurface formation. The wellbore may be formed as a substantially vertical well; more preferably, the well is formed by drilling a deviated or even a horizontal well.

[0022] The method also includes lining the wellbore with a string of production casing. The production casing is made up of a series of steel pipe joints that are threadedly connected, end-to-end.

[0023] The method further includes placing a valve along the production casing. The valve may be inserted into a casing string or made up integrally with the casing string. The valve creates a removable barrier to fluid flow within the bore. Preferably, the valve is a sliding sleeve having a seat that receives a ball, wherein the ball is dropped from the surface to create a pressure seal on the seat. The sleeve is held in place by shear pins, which are engineered to shear when the pressure above the sleeve exceeds a predetermined set point. This opens the ports for treatment of the zone or stage. If an estimated screen-out pressure is exceeded during treatment, additional shear pins holding the seat will shear, releasing the valve downhole. Other types of valves may also be used as described below.

[0024] The method also comprises perforating the production casing. The casing is perforated along a first zone of interest within the subsurface formation. The first zone of interest resides at or above the valve. The process of perforating involves firing shots into the casing, through a surrounding cement sheath, and into the surrounding rock matrix making up a subsurface formation. This is done by using a perforating gun in the wellbore.

[0025] The method next includes injecting a slurry into the wellbore. The slurry comprises a fracturing proppant, preferably carried in an aqueous medium.

[0026] The method further includes pumping the slurry at a pressure sufficient to move the valve and to overcome the barrier to fluid flow. This is done in response to a condition of screen-out along the first zone of interest created during the slurry injection. Moving the valve exposes ports along the production casing to the subsurface formation at or below the valve.

[0027] The method additionally includes further pumping the slurry through the exposed ports, thereby remediating the condition of screen-out above the valve.

[0028] In one aspect of the method, the valve is a sliding sleeve. In this instance, moving the valve to expose ports along the production casing comprises moving or "sliding" the sleeve to expose one or more ports fabricated in the sliding sleeve. This may include the shearing of set pins.

[0029] In another embodiment, the method further includes placing a fracturing baffle along the production casing. The fracturing baffle resides above the sliding sleeve but at or below the first zone of interest. The fracturing baffle may be part of a sub that is threadedly connected to the production casing proximate the sliding sleeve during initial run-in. A rupture disc is then pumped down the wellbore ahead of the slurry. The disc is pumped to a depth just above the valve until the disc lands on the fracturing baffle. In this embodiment, the rupture disc is designed to rupture at a pressure that is greater than a screen-out pressure, but preferably lower

than the pressure required to move the valve.

[0030] Optionally, the operator may inject a fluid (such as an aqueous fluid) under pressure through the exposed port of the sliding sleeve, thereby creating mini-fractures in the subsurface formation below the first zone of interest. This step is done by the operator before pumping the rupture disc into the wellbore.

[0031] In another embodiment, the valve is a first burst plug. The first burst plug will have a first burst rating. The ports represent perforations that are placed in the production casing in a second zone of interest below the first zone of interest. In this embodiment, moving the valve to expose ports comprises injecting the slurry at a pressure that exceeds the burst rating of the first burst plug. Optionally, in this embodiment, the method further includes placing a second and a third burst plug along the production casing at or below the second zone of interest, creating a domino-effect in the event of multiple screen-outs. The second and third burst plugs will have a burst rating that is equal to or greater than the first burst rating.

[0032] In still another aspect, the valve that is moved is a ball-and-seat valve, while the ports are perforations earlier placed in the production casing in a second zone of interest below the first zone of interest. In this instance, moving the valve to expose ports comprises injecting the slurry at a pressure that causes the ball to lose its pressure seal on the seat. Causing the ball to lose its pressure seal may define causing the ball to shatter, causing the ball to dissolve, or causing the ball to collapse.

[0033] In a preferred embodiment, perforating the production casing comprises pumping an autonomous perforating gun assembly into the wellbore, and autonomously firing the perforating gun along the first zone of interest. The autonomous perforating gun assembly comprises a perforating gun, a depth locator for sensing the location of the assembly within the wellbore, and an on-board controller. "Autonomously firing" means pre-programming the controller to send an actuation signal to the perforating gun to cause one or more detonators to fire when the locator has recognized a selected location of the perforating gun along the wellbore. In one aspect, the depth locator is a casing collar locator and the on-board controller interacts with the casing collar locator to correlate the spacing of casing collars along the wellbore with depth according to an algorithm. The casing collar locator identifies collars by detecting magnetic anomalies along a casing wall.

[0034] It is observed that the perforating gun, the locator, and the on-board controller are together dimensioned and arranged to be deployed in the wellbore as an autonomous unit. In this application, "autonomous unit" means that the assembly is not immediately controlled from the surface. Stated another way, the tool assembly does not rely upon a signal from the surface to know when to activate the tool. Preferably, the tool assembly is released into the wellbore without a working line. The tool assembly either falls gravitationally into the wellbore, or is pumped downhole. However, a non-electric working

line such as slickline may optionally be employed.

[0035] In another aspect, an autonomous perforating gun assembly is deployed in the wellbore after a condition of screen-out has been remediated. The perforating gun assembly is used to fire a new set of perforations along the first zone of interest. In this way, a new fracturing process may be initiated in that zone of interest.

BRIEF DESCRIPTION OF THE DRAWINGS

[0036] So that the present inventions can be better understood, certain drawings, charts, graphs, and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

Figures 1A through 1F present a series of side views of a lower portion of a wellbore. The wellbore is undergoing a completion procedure that uses perforating guns and ball sealers in stages. This is a known procedure.

Figure 1A presents a wellbore having been lined with a string of production casing. Annular packers are placed along the wellbore to isolate selected subsurface zones. The zones are identified as "A," "B" and "C."

Figure 1B illustrates **Zone A** of the wellbore having been perforated. Further, fractures have been formed in the subsurface formation along **Zone A** using any known hydraulic fracturing technique.

Figure 1C illustrates that a plug has been set adjacent a packer intermediate **Zones A** and **B**. Further, a perforating gun is shown forming new perforations along **Zone B**.

Figure 1D illustrates a fracturing fluid, or slurry, being pumped into the wellbore, with artificial fractures being induced in the subsurface formation along **Zone B**.

Figure 1E illustrates that ball sealers have been dropped into the wellbore, thereby sealing perforations along **Zone B**. Further, a perforating gun is now indicated along **Zone C**. The casing along **Zone C** is being perforated.

Figure 1F illustrates fracturing fluid, or slurry, being pumped into the wellbore. Artificial fractures are being induced in the subsurface formation along **Zone C**.

Figures 2A through 2F present a series of side views of a lower portion of a wellbore. The wellbore is undergoing a completion procedure that uses perforating guns and plugs in stages. This is a known procedure.

Figure 2A presents a wellbore having been lined with a string of production casing. Annular packers are placed along the wellbore to isolate selected subsurface zones. The zones are identified as "A," "B"

and "C."

Figure 2B illustrates **Zone A** of the wellbore having been perforated using a perforating gun. A plug has been run into the wellbore with the perforating gun.

Figure 2C illustrates that fractures have been formed in the subsurface formation along **Zone A** using a fracturing fluid. Proppant is seen residing now in an annular region along **Zone A**.

Figure 2D illustrates that a second plug has been set adjacent a packer intermediate **Zones B** and **C**. Further, a perforating gun is shown forming perforations along **Zone B**.

Figure 2E illustrates that fracturing fluid is being pumped into the wellbore, with artificial fractures being induced in the subsurface formation along **Zone B**.

Figure 2F illustrates that a third plug has been set adjacent a packer intermediate **Zones B** and **C**. Further, a perforating gun is shown forming perforations along **Zone C**.

Figures 3A through 3F present a series of side views of a lower portion of a wellbore. The wellbore is undergoing a completion procedure that uses perforating guns, fracturing sleeves and dropped balls, in stages. This is a known procedure.

Figure 3A presents a wellbore having been lined with a string of production casing. Annular packers are placed along the wellbore to isolate selected subsurface zones. The zones are identified as "A," "B" and "C."

Figure 3B illustrates that a ball has been dropped onto a fracturing sleeve in **Zone A**.

Figure 3C illustrates that hydraulic pressure has been applied to open the fracturing sleeve in **Zone A** by pumping a fracturing fluid into the wellbore. Further, fractures are being induced in the subsurface formation along **Zone A**. Proppant is seen residing now in an annular region along **Zone A**.

Figure 3D illustrates that a second ball has been dropped. The ball has landed on a fracturing sleeve in **Zone B**.

Figure 3E illustrates that hydraulic pressure has been applied to open the fracturing sleeve in **Zone B** by pumping a fracturing fluid into the wellbore. Further, fractures are being induced in the subsurface formation along **Zone B**. Proppant is seen residing now in an annular region along **Zone B**.

Figure 3F illustrates that a third ball has been dropped. The ball has landed on a fracturing sleeve in **Zone C**. **Zone C** is ready for treatment.

Figures 4A through 4F present a series of side views of a lower portion of a wellbore. The wellbore is undergoing a completion procedure that uses a valve, wherein actuating or moving the valve exposes a port along the production casing in a novel application.

Figure 4A presents the wellbore with a sliding sleeve threadedly connected in line with a string of produc-

tion casing. A ball is being pumped into the wellbore to actuate the sliding sleeve.

Figure 4B illustrates that the ball has landed onto a seat of the sliding sleeve. The sleeve has been actuated, exposing a port. In addition, a hydraulic fluid has been pumped into the wellbore to open small fractures.

Figure 4C is another view of the wellbore of **Figure 4A**. Here, a rupture disc is being pumped down the wellbore.

Figure 4D illustrates that the rupture disc has landed on a baffle seat. The seat is upstream from the sliding sleeve. In addition, the production casing has been perforated above the baffle seat.

Figure 4E is another view of the wellbore of **Figure 4A**. Here, a fracturing fluid is being pumped down the wellbore and through the perforations. Fractures are being formed in the subsurface formation.

Figure 4F illustrates that the fracturing fluid continues to be pumped down the wellbore in response to a condition of screen-out at the perforations. Pumping pressure has caused the rupture disc to be breached, allowing slurry to move down the wellbore and towards the exposed ports.

Figures 5A and 5B illustrate an alternate completion method for a perforated wellbore. Here, a rupture disc is again landed on a baffle seat. However, rather than using a sliding sleeve, the wellbore is separately perforated below the rupture disc.

Figure 5A presents the wellbore with a rupture disc landed on a baffle seat. The wellbore has received perforations both above and below the baffle seat. The subsurface formation is being fractured through the upper perforations.

Figure 5B is another view of the wellbore of **Figure 5A**. Fracturing fluid continues to be pumped down the wellbore in response to a condition of screen-out at the upper perforations. Pumping pressure has caused the rupture disc to be breached, allowing slurry to move down the wellbore and towards the lower perforations.

Figure 5C presents the wellbore with a ball landed in a frac plug. The wellbore has received perforations both above and below the frac plug. The subsurface formation is being fractured through the upper perforations.

Figure 5D is another view of the wellbore of **Figure 5C**. Fracturing fluid continues to be pumped down the wellbore in response to a condition of screen-out at the upper perforations. Pumping pressure has caused a seat along the frac plug to be sheared off, allowing slurry to move down the wellbore and towards the lower perforations.

Figures 6A and 6B illustrate another alternate completion method for a perforated wellbore. Here, a rupture disc is again landed on a baffle seat. Additionally, a second lower rupture disc is landed on a baffle seat below a lower set of perforations.

Figure 6A presents the wellbore with an upper rupture disc landed on an upper baffle seat. The wellbore has received perforations both above and below the upper baffle seat. The subsurface formation is being fractured through the upper perforations.

Figure 6B is another view of the wellbore of **Figure 6A**. Fracturing fluid continues to be pumped down the wellbore in response to a condition of screen-out at the upper perforations. Pumping pressure has caused the upper rupture disc to be breached, allowing slurry to move down the wellbore and towards the lower perforations.

Figures 7A and 7B illustrate an alternate completion method for a perforated wellbore. Here, a ball-and-seat valve is used in the wellbore. The wellbore is separately perforated below the valve.

Figure 7A presents the wellbore with a collapsible ball landed on the seat. The wellbore has received perforations both above and below the seat. The subsurface formation is being fractured through the upper perforations.

Figure 7B is another view of the wellbore of **Figure 7A**. Fracturing fluid continues to be pumped down the wellbore in response to a condition of screen-out at the upper perforations. Pumping pressure has caused the ball to collapse, allowing slurry to move down the wellbore and towards the lower perforations.

Figure 8 is a flow chart illustrating steps for a method of completing a well, in one embodiment. The method uses a valve that may be actuated to expose a set of ports below perforations, thereby remediating a condition of screen-out.

DETAILED DESCRIPTION OF CERTAIN EMBODIMENTS

Definitions

[0037] As used herein, the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons generally fall into two classes: aliphatic, or straight chain, hydrocarbons; and cyclic, or closed ring, hydrocarbons, including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

[0038] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions, or at ambient conditions (15° C to 20° C and 1 atm pressure). Hydrocarbon fluids may include, for example, oil, natural gas, coalbed methane,

shale oil, pyrolysis oil, pyrolysis gas, a pyrolysis product of coal, and other hydrocarbons that are in a gaseous or liquid state.

[0039] As used herein, the terms "produced fluids" and "production fluids" refer to liquids and/or gases removed from a subsurface formation, including, for example, an organic-rich rock formation. Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids. Production fluids may include, but are not limited to, oil, natural gas, pyrolyzed shale oil, synthesis gas, a pyrolysis product of coal, carbon dioxide, hydrogen sulfide, and water (including steam).

[0040] As used herein, the term "fluid" refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, combinations of liquids and solids, and combinations of gases, liquids, and solids.

[0041] As used herein, the term "gas" refers to a fluid that is in its vapor phase at 1 atm and 15° C.

[0042] As used herein, the term "oil" refers to a hydrocarbon fluid containing primarily a mixture of condensable hydrocarbons.

[0043] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[0044] As used herein, the term "formation" refers to any definable subsurface region. The formation may contain one or more hydrocarbon-containing layers, one or more non-hydrocarbon containing layers, an overburden, and/or an underburden of any geologic formation.

[0045] The terms "zone" or "zone of interest" refer to a portion of a formation containing hydrocarbons. Alternatively, the formation may be a water-bearing interval.

[0046] For purposes of the present application, the term "production casing" includes a liner string or any other tubular body fixed in a wellbore along a zone of interest, which may or may not extend to the surface.

[0047] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shapes. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

Description of Selected Specific Embodiments

[0048] The inventions are described herein in connection with certain specific embodiments. However, to the extent that the following detailed description is specific to a particular embodiment or a particular use, such is intended to be illustrative only and is not to be construed as limiting the scope of the inventions.

[0049] Certain aspects of the inventions are also described in connection with various figures. In certain of the figures, the top of the drawing page is intended to be toward the surface, and the bottom of the drawing page toward the well bottom. While wells historically have been completed in substantially vertical orientation, it is under-

stood that wells now are frequently inclined and/or even horizontally completed. When the descriptive terms "up" and "down" or "upper" and "lower" or similar terms are used in reference to a drawing or in the claims, they are intended to indicate relative location on the drawing page or with respect to claim terms, and not necessarily orientation in the ground, as the present inventions have utility no matter how the wellbore is orientated.

[0050] Wellbore completions in unconventional reservoirs are increasing in length. Whether such wellbores are vertical or horizontal, such wells require the placement of multiple perforation sets and multiple fractures. Known completions, in turn, require the addition of down-hole hardware which increases the expense, complexity, and risk of such completions.

[0051] Several techniques are known for fracturing multiple zones along an extended wellbore incident to hydrocarbon production operations. One such technique involves the use of perforating guns and ball sealers run in stages.

[0052] Figures 1A through 1F present a series of side views of a lower portion of an extended wellbore 100. The wellbore 100 is undergoing a completion procedure that uses perforating guns 150 and ball sealers 160 in stages.

[0053] First, Figure 1A introduces the wellbore 100. The wellbore 100 is lined with a string of production casing 120. The production casing 120 defines a long series of pipe joints that are threadedly coupled, end-to-end. The production casing 120 provides a bore 105 for the transport of fluids into the wellbore 100 and out of the wellbore 100.

[0054] The production casing 120 resides within a surrounding subsurface formation 110. Annular packers are placed along the casing 120 to isolate selected subsurface zones. Three illustrative zones are shown in the Figure 1 series, identified as "A," "B" and "C." The packers, in turn, are designated as 115A, 115B, 115C, and 115D, and are generally placed intermediate the zones.

[0055] It is desirable to perforate and fracture the formation along each of Zones A, B and C. Figure 1B illustrates Zone A having been perforated. Perforations 125A are placed by detonating charges associated with a perforating gun 150. Further, fractures 128A have been formed in the subsurface formation 110 along Zone A. The fractures 128A are formed using any known hydraulic fracturing technique.

[0056] It is observed that in connection with the formation of the fractures 128A, a hydraulic fluid 145 having a proppant is used. The proppant is typically sand and is used to keep the fractures 128A open after hydraulic pressure is released from the formation 110. It is also observed that after the injection of the hydraulic fluid 145, a thin annular gravel pack is left in the region formed between the casing 120 and the surrounding formation 110. This is seen between packers 115A and 115B. The gravel pack beneficially supports the surrounding formation 110 and helps keeps fines from invading the bore

105.

[0057] As a next step, **Zone B** is fractured. This is shown in **Figure 1C**. **Figure 1C** illustrates that a plug **140** has been set adjacent the packer **115B** intermediate **Zones A** and **B**. Further, the perforating gun **150** has been placed along **Zone B**. Additional charges associated with the perforating gun **150** are detonated, producing perforations **125B**.

[0058] Next, **Figure 1D** illustrates that a fracturing fluid **145** is being pumped into the bore **105**. Artificial fractures **128B** are being formed in the subsurface formation **110** along **Zone B**. In addition, a new perforating gun **150** has been lowered into the wellbore **100** and placed along **Zone C**. Ball sealers **160** have been dropped into the wellbore.

[0059] **Figure 1E** illustrates a next step in the completion of the multi-zone wellbore **100**. In **Figure 1E**, the ball sealers **160** have fallen in the bore **105** and have landed along **Zone B**. The ball sealers **160** seal the perforations **125B**.

[0060] It is also observed in **Figure 1E** that the perforating gun **150** has been raised in the wellbore **100** up to **Zone C**. Remaining charges associated with the perforating gun **150** are detonated, producing new perforations **125C**. After perforating, a fracturing fluid **145** is pumped into the bore **105** behind the perforating gun **150**.

[0061] Finally, **Figure 1F** illustrates the fracturing fluid **145** being pumped further into the wellbore **100**. Specifically, the fracturing fluid **145** is pumped through the new perforations **125C** along **Zone C**. Artificial fractures **128C** have been induced in the subsurface formation **120** along **Zone C**. The firing charges in the perforating gun **150** are now spent and the gun is pulled out of the wellbore **100**.

[0062] The multi-zone completion procedure of **Figures 1A** through **1F** is known as the "Just-In-Time Perforating" (JITP) process. The JITP process represents a highly efficient method in that a fracturing fluid may be run into the wellbore with a perforating gun in the hole. As soon as the perfs are shot and fractures are formed, ball sealers are dropped. When the ball sealers seat on the perforations, a gun is shot at the next zone. These steps are repeated for multiple zones until all guns are spent. A new plug **140** is then set and the process begins again.

[0063] The JITP process requires low flush volumes and offers the ability to manage screen-outs along the zones. However, it does require that multiple plugs be drilled out in an extended well. In addition, even this procedure is vulnerable to screen-out at the highest zone of a multi-zone stage. In this respect, if a screen-out occurs along illustrative **Zone C** during pumping, clean-out operations will need to be conducted. This is because the slurry **145** cannot be completely pumped through the perforations **125C** and into the formation, due to the presence of the ball sealers **160** along **Zone B** and the bridge plug **140** above **Zone A**.

[0064] An alternate completion procedure that has

been used is the traditional "Plug and Perf" technique. This is illustrated in **Figures 2A** through **2F**. The **Figure 2** drawings present a series of side views of a lower portion of a wellbore **200**. The wellbore **200** is undergoing a completion procedure that uses perforating plugs **240** and guns **250** in stages.

[0065] **Figure 2A** presents a wellbore **200** that has been lined with a string of production casing **220**. The wellbore **200** is identical to the wellbore **100** of **Figure 1A**. The wellbore **200** is lined with a string of production casing **220**. The production casing **220** provides a bore **205** for the transport of fluids into the wellbore **200** and out of the wellbore **200**. The production casing **220** resides within a surrounding subsurface formation **210**.

[0066] Annular packers are again placed along the casing **220** to isolate selected subsurface zones, identified as "**A**," "**B**" and "**C**." The packers, in turn, are designated as **215A**, **215B**, **215C**, and **215D**.

[0067] In order to complete the wellbore **200**, **Zones A**, **B**, and **C** are each perforated. In **Figure 2B**, a perforating gun **250** has been run into the bore **205**. The gun **250** has been placed along **Zone A**. Perforations **225A** have been formed in the production casing **120** by detonating charges associated with the perforating gun **250**.

[0068] Along with the perforating gun **250**, a plug **240A** has been set. In practice, the plug **240A** is typically run into the bore **205** at the lower end of the perforating gun on the wireline **255**. In other words, the plug **240A** and the gun **250** are run into the wellbore **200** together before the charges are detonated.

[0069] Next, a fracturing fluid **245** is injected into the newly-formed perforations **225A**. The fracturing fluid **245**, with proppant, is injected under pressure in order to flow through the perforations **225A** and into the formation **210**. In this way, artificial fractures **228A** are formed.

[0070] **Figure 2C** illustrates that fractures **228A** have been formed in the subsurface formation **210** along **Zone A**. Proppant is now seen residing in an annular region along **Zone A**. Thus, something of a gravel pack is formed.

[0071] In the completion method of the **Figure 2** series of drawings, the process of perforating and fracturing along **Zone A** is repeated in connection with **Zones B** and **C**. **Figure 2D** illustrates that a second perforating gun **250** and a second plug **240B** having been run into the wellbore **200**. The gun **250** is placed along **Zone B** while the plug **240B** is set adjacent packer **215B**. Further, charges associated with the perforating gun **250** have been detonated, forming new perforations **225B** along **Zone B**.

[0072] Next, a fracturing fluid **245** is injected into the newly-formed perforations **225B**. The fracturing fluid **245**, with proppant, is injected under pressure in order to flow through the perforations **225B** and into the formation **210**. In this way, and as shown in **Figure 2E**, new artificial fractures **228A** are formed.

[0073] The "Plug and Perf" process is repeated for **Zone C**. **Figure 2F** illustrates that a third perforating gun

250 has been lowered into the bore **205** adjacent **Zone C**, and a third plug **240C** has been set adjacent a packer intermediate **Zones B and C**. Further, the perforating gun **250** is shown forming perforations along **Zone C**. It is understood that fractures (not shown) are then created in the subsurface formation **210** along **Zone C** using a fracturing fluid (also not shown).

[0074] In order to perforate multiple zones, the "Plug and Perf" process requires the use of many separate plugs. Those plugs, in turn, must be drilled out before production operations may commence. Further, the "Plug and Perf" process requires large flush volumes and is also vulnerable to screen-out. In this respect, if a screen-out occurs along any zone during pumping, clean-out operations will need to be conducted. This is because the slurry cannot be completely pumped through the perforations and into the formation, or further down the wellbore, due to the presence of the bridge plug (such as plug **240C**) immediately below the target zone.

[0075] Yet another completion procedure that has been used involves the placement of multiple fracturing sleeves (or "frac sleeves") along the production casing. This is known as "Ball and Sleeve" completion. The Ball and Sleeve technique is illustrated in **Figures 3A through 3F**. The **Figure 3** drawings present a series of side views of a lower portion of a wellbore **300**. The wellbore **300** is undergoing a completion procedure that uses frac sleeves **321** in stages.

[0076] First, **Figure 3A** introduces the wellbore **300**. The wellbore **300** is identical to the wellbore **100** of **Figure 1A**. The wellbore **300** is lined with a string of production casing **320** that provides a bore **305** for the transport of fluids into and out of the wellbore **300**. Annular packers **315A, 315B, 315C, 315D** are placed along the casing **320** to isolate selected subsurface zones. The zones are identified as "A," "B" and "C."

[0077] In the completion processes shown in the **Figure 1** and the **Figure 2** series, each of **Zones A, B, and C** is sequentially perforated. However, in the completion process of the **Figure 3** series, frac sleeves **321A, 321B, 321C** are used. The frac sleeves **321A, 321B, 321C** are sequentially opened using balls **323A, 323B, 323C**. This causes ports to be exposed along the production casing **320**.

[0078] Looking now at **Figure 3B**, it can be seen that frac sleeve **321A** has been placed along **Zone A**. A ball **323A** has been dropped into the wellbore **300** and landed onto a seat associated with the frac sleeve **321A**.

[0079] **Figure 3C** illustrates that hydraulic pressure has been applied to open the fracturing sleeve **321A**. This is done by pumping a fracturing fluid **345** into the bore **305**. As shown in **Figure 3C**, the fracturing fluid **345** flows through the frac sleeve **321A**, into the annular region between the production casing **320** and the surrounding subsurface formation **310**, and into the formation **310** itself. Fractures **328A** are being induced in the subsurface formation **310** along **Zone A**. Additionally, proppant is seen now residing in the annular region along

Zone A.

[0080] In the completion method of the **Figure 3** series of drawings, the process of opening a sleeve and fracturing along **Zone A** is repeated in connection with **Zones B and C**. **Figure 3D** illustrates that a second ball **323B** has been dropped into the wellbore **300** and landed on a sleeve **321B**. The sleeve **321B** resides along **Zone B**.

[0081] **Figure 3E** illustrates that hydraulic pressure has been applied to open the fracturing sleeve **321B**. This is done by pumping a fracturing fluid **345** into the wellbore **300**. Fractures are being induced in the subsurface formation **310** along **Zone B**. Proppant is seen residing now in an annular region along **Zone B**.

[0082] The "Ball and Sleeve" process is repeated for **Zone C**. **Figure 3F** illustrates that a third ball **323C** has been dropped into the bore **305**. The ball **323C** has landed onto the frac sleeve **321C** adjacent **Zone C**. It is understood that fractures (not shown) are then created in the subsurface formation **310** along **Zone C**.

[0083] The use of the sleeves **321A, 321B, 321C** as shown in the **Figure 3** series reduces the flush volumes needed for completion. This, in turn, reduces the environmental impact. At the same time, the use of multiple sleeves creates a higher hardware risk and a higher risk of screen-out. If a screen-out occurs along any zone during pumping, clean-out operations will need to be conducted. This is because the slurry cannot be completely pumped through the perforations and into the formation, due to the presence of the sealed sleeve.

[0084] As the need for "pinpoint stimulation" has gained recognition, the number of stages may increase in the future for a given well length. However, experience with single zone stimulation has shown that as the wellbore is divided into smaller treated segments, the risk of screen-out increases. This means that the chance of pumping into easily treatable rock decreases. Recovery from screen-out upset for a frac-sleeve-only completion is very costly and usually involves well intervention and removal (i.e., destruction) of the hardware placed in the well during drilling operations.

[0085] For these and perhaps other reasons, it is desirable to modify the procedures presented in the processes of the **Figure 1** series, the **Figure 2** series, and the **Figure 3** series. Specifically, it is desirable to replace the wellbore plugs and sleeves with a valve that creates a fluid barrier, but wherein the fluid barrier can be selectively removed using increased pumping pressures to expose a port through the production casing. In this way, the slurry may be pumped through the then-exposed port. This enables the continuous pumping of fracturing fluids in the wellbore even when a screen-out occurs.

[0086] Various methods for providing a valve in the wellbore that removes the barrier to fluid flow downhole are provided and are described below.

[0087] **Figures 4A through 4F** present a series of side views of a lower portion of a wellbore **400**. The wellbore **400** is undergoing a completion procedure that includes perforation and fracturing of at least one zone of interest.

The wellbore **400** defines a bore **405** that has been formed through a subsurface formation **410**. In the illustrative **Figure 4** series, the wellbore **400** is being completed in a horizontal orientation.

[0088] **Figure 4A** introduces the wellbore **400**. The wellbore **400** is being completed with a string of production casing **420**. The production casing **420** represents a series of steel pipe joints threadedly connected, end-to-end. The production casing **420** provides path for fluids into and out of the wellbore **400**.

[0089] An annular region **415** resides between the production casing **420** and the surrounding rock matrix of the subsurface formation **410**. The annular region **415** is filled with cement as is known in the art of drilling and completions. Where so-called swell-packers are used in the annular region **415** (see, for example, packers **115A**, **115B**, **115C**, and **115D** of the **Figure 1** set of drawings), the annular region **415** would not be cemented.

[0090] A frac sleeve **440** has been placed along the production casing **420**. The frac sleeve **440** defines a hydraulically-actuated valve. This may be, for example, the Falcon Hydraulic-Actuated Valve of Schlumberger limited, of Sugar Land, Texas. The frac sleeve **440** includes a seat **442**. The seat **442** which is dimensioned to receive a ball **450**. In the view of **Figure 4A**, the ball **450** has been dropped and is traveling down the wellbore **400**, as indicated by **Arrow B**, towards the seat **442**. Upon landing on the seat **442**, the ball **450** will seal a through-opening **445** in the sleeve **440**.

[0091] As shown in **Figure 4A**, the wellbore **400** also includes a baffle seat **462**. The baffle seat **462** defines a sub that is threadedly connected in-line with the production casing **420**. The baffle seat **462** is dimensioned to receive a rupture disc, shown in **Figures 4C** and **4D** at **460**.

[0092] **Figure 4B** presents a next view of the wellbore **400**. Here, the ball **450** has landed on the seat **442** of the frac sleeve **440**. The ball **450** provides a substantial pressure seal, creating a fluid barrier in the bore **405**.

[0093] **Figure 4B** also illustrates that the frac sleeve **440** has been moved. This means that pressure has been applied by the ball **450** against the seat **462**, causing the sleeve **440** to shift, thereby exposing one or more ports **455**. Pressure is applied by the injection of fluid into the wellbore and the application of fluid pressure using pumps (not shown) at the surface.

[0094] It can also be seen that some degree of fracturing has taken place. At least one small fracture **458**, or "mini-fracture," has been created in the subsurface formation **410** as a result of the injection of fluids under pressure. Preferably, the fluid is a brine or other aqueous fluid that invades the near-wellbore region.

[0095] Referring now to **Figures 4C** and **4D** together, **Figure 4C** illustrates the placement of a rupture disc **460** in the bore **405**. The rupture disc **460** is being pumped downhole as indicated by **Arrow D**. In **Figure 4D**, the rupture disc **460** has landed on the baffle seat **462**. The baffle seat **462** resides proximate the frac sleeve **440** and

just above the newly-exposed flow ports **455**.

[0096] The rupture disc **460** includes a diaphragm or other pressure-sensitive device. The pressure device has a burst rating. When the pressure in the bore **405** goes above the burst rating, the disc **460** will rupture, permitting a flow of fluids there through. Until bursting, the disc **460** creates a barrier to fluid flow through the bore **405**.

[0097] Also seen in **Figure 4D** is a new set of perforations **478**. The perforations **478** have been formed through the casing **420** and into the subsurface formation **410**. The perforations were shot using a perforating gun (not shown). The perforating gun may be a select fire gun that fires, for example, 16 shots. The gun has associated charges that detonate in order to cause shots to be fired from the gun and into the surrounding production casing **420**. Typically, the perforating gun **420** contains a string of shaped charges distributed along the length of the gun **420** and oriented according to desired specifications.

[0098] Alternatively, the perforating gun may be part of an autonomous perforating gun assembly, such as that described in U.S. Patent Publ. No. 2013/0062055. The autonomous perforating gun assembly is designed to be released into the wellbore **400** and to be self-actuating. In this respect, the assembly does not require a wireline and need not otherwise be mechanically tethered or electronically connected to equipment external to the wellbore. The delivery method may include gravity, pumping, or tractor delivery.

[0099] The autonomous perforating gun assembly generally includes a perforating gun, a depth locator, and an on-board controller. The depth locator may be, for example, a casing collar locator that measures magnetic flux as the assembly falls through the wellbore. Anomalies in magnetic flux are interpreted as casing collars residing along the length of the casing string. The assembly is aware of its location in the wellbore by counting collars along the casing string as the assembly moves downward through the wellbore.

[0100] The on-board controller is programmed to send an actuation signal. The signal is sent to the perforating gun when the assembly has reached a selected location along the wellbore. In the case of **Figure 4B**, that location is a depth that is above the frac sleeve **440** and along a zone of interest. To confirm location, the controller may be pre-programmed with a known casing or formation log. The controller compares readings taken in real time by the casing collar locator or other logging tool with the pre-loaded log.

[0101] The autonomous assembly may also include a power supply. The power supply may be, for example, one or more lithium batteries, or battery pack. The power supply will reside in a housing along with the on-board controller. The perforating gun, the location device, the on-board controller, and the battery pack are together dimensioned and arranged to be deployed in a wellbore as an autonomous unit.

[0102] The autonomous assembly defines an elongat-

ed body. The assembly is preferably fabricated from a material that is frangible or "friable." In this respect, it is designed to disintegrate when charges associated with the perforating gun are detonated.

[0103] The completion assembly is preferably equipped with a special tool-locating algorithm. The algorithm allows the tool to accurately track casing collars en route to a selected location downhole. U.S. Patent Appl. No. 13/989,726, filed on 24 May 24 2013, discloses a method of actuating a downhole tool in a wellbore. That patent application is entitled "Method for Automatic Control and Positioning of Autonomous Downhole Tools." The application was published as U.S. Patent Publ. No. 2013/0255939.

[0104] According to that U.S. Patent Publ. No. 2013/0255939, the operator will first acquire a CCL data set from the wellbore. This is preferably done using a traditional casing collar locator. The casing collar locator is run into a wellbore on a wireline or electric line to detect magnetic anomalies along the casing string. The CCL data set correlates continuously recorded magnetic signals with measured depth. More specifically, the depths of casing collars may be determined based on the length and speed of the wireline pulling a CCL logging device. In this way, a first CCL log for the wellbore is formed.

[0105] In practice, the first CCL log is downloaded into a processor which is part of the on-board controller. The on-board controller processes the depth signals generated by the casing collar locator. In one aspect, the on-board controller compares the generated signals from the position locator with a pre-determined physical signature obtained for wellbore objects from the prior CCL log.

[0106] The on-board controller is programmed to continuously record magnetic signals as the autonomous tool traverses the casing collars. In this way, a second CCL log is formed. The processor, or on-board controller, transforms the recorded magnetic signals of the second CCL log by applying a moving windowed statistical analysis. Further, the processor incrementally compares the transformed second CCL log with the first CCL log during deployment of the downhole tool to correlate values indicative of casing collar locations. This is preferably done through a pattern matching algorithm. The algorithm correlates individual peaks or even groups of peaks representing casing collar locations. In addition, the processor is programmed to recognize the selected location in the wellbore, and then send an activation signal to the actuable wellbore device or tool when the processor has recognized the selected location.

[0107] In some instances, the operator may have access to a wellbore diagram providing exact information concerning the spacing of downhole markers such as the casing collars. The on-board controller may then be programmed to count the casing collars, thereby determining the location of the tool as it moves downwardly in the wellbore.

[0108] In some instances, the production casing may

be pre-designed to have so-called short joints, that is, selected joints that are only, for example, 4.5 or 6 m (15 or 20 feet) in length, as opposed to the "standard" length selected by the operator for completing a well, such as 9.1 m (30 feet). In this event, the on-board controller may use the non-uniform spacing provided by the short joints as a means of checking or confirming a location in the wellbore as the completion assembly moves through the casing.

[0109] In one embodiment, the method further comprises transforming the CCL data set for the first CCL log. This also is done by applying a moving windowed statistical analysis. The first CCL log is downloaded into the processor as a first transformed CCL log. In this embodiment, the processor incrementally compares the second transformed CCL log with the first transformed CCL log to correlate values indicative of casing collar locations.

[0110] It is understood that the depth locator may be any other logging tool. For example, the on-board depth locator may be a gamma ray log, a density log, a neutron log, or other formation log. In this instance, the controller is comparing readings in real time from the logging tool with a pre-loaded gamma ray or neutron log. Alternatively, the depth locator may be a location sensor (such as IR reader) that senses markers placed along the casing (such as an IR transceiver). The on-board controller sends the actuation signal to the perforating gun when the location sensor has recognized one or more selected markers along the casing.

[0111] In one embodiment, the algorithm interacts with an on-board accelerometer. An accelerometer is a device that measures acceleration experienced during a freefall. An accelerometer may include multi-axis capability to detect magnitude and direction of the acceleration as a vector quantity. When in communication with analytical software, the accelerometer allows the position of an object to be confirmed.

[0112] Additional details for the tool-locating algorithm are disclosed in U.S. Patent Publ. No. 2013/0255939.

[0113] In order to prevent premature actuation, a series of gates is provided. U.S. Patent Appl. No. 14/005,166 describes a perforating gun assembly being released from a wellhead. That application was filed on 13 September 2013, and is entitled "Safety System for Autonomous Downhole Tool." The application was published as U.S. Patent Publ. No. 2013/0248174. Figure 8 and the corresponding discussion of the gates in that published application are incorporated herein by reference.

[0114] After perforations are shot, the operator begins a formation fracturing operation. **Figure 4E** demonstrates the movement of slurry **470** through the bore **405**. Slurry is pumped downhole as indicated by **Arrows S**. As the slurry **470** reaches the perforations, the slurry invades the subsurface formation **410**, creating tunnels and tiny fractures **478** in the rock.

[0115] It is observed that slurry is prevented from moving down to the flow ports **458** in the frac sleeve **440** by

the rupture disc **460**. Of importance, the rupture disc **460** is designed to have a burst rating that is higher than an estimated formation parting pressure. Ideally, the operator or a completions engineer will pre-determine an anticipated formation parting pressure based on geo-mechanical modeling, field data, and/or previous experiences in the same field. A rupture disc having a burst rating sufficiently above the formation parting pressure is selected to avoid accidental break-through during pumping.

[0116] Finally, **Figure 4F** illustrates that a condition of screen-out has occurred. Sand or other proppant material has become tightly packed in the perforations **475** and fractures **478**, even to the point where additional slurry can no longer be pumped. This occurs when the aqueous (or other) carrier medium leaks off into the formation, leaving sand particles in place.

[0117] The operator at the surface will recognize that a condition of screen-out has occurred by observing the surface pumps. In this respect, pressure will quickly build in the wellbore, producing rapidly climbing pressure readings at the surface. Under conventional operations, the operator will need to back off the pump rate to prevent wellbore pressures from exceeding the burst ratings and maximum hoop and tensile stresses of the casing, and to prevent damage to surface valves. The operator may then hope flow back the well, using bottom hole pressure to try and push the proppant-laden slurry back out of the well and to the surface. In known procedures, if the velocity is not sufficient, the proppant will drop out in the casing and across the heel of the well, creating a bridge of proppant that must be removed mechanically before operations can continue. On the other hand, if the pressure is reduced too quickly at the surface, the high flow rate of proppant can cause significant abrasive damage to valves and piping as it flows through significantly smaller pipe.

[0118] In the novel method demonstrated by the **Figure 4** series of drawings, the problem of screen-out is self-remediating. In this respect, the excess pressure created by the pumping and by the hydrostatic head of the proppant-laden slurry during screen-out will prompt the diaphragm in the rupture disc **460** to burst. This fortuitous event has occurred in **Figure 4F**.

[0119] It can be seen in **Figure 4F** that a through-opening **465** has been created through the rupture disc **460**. Slurry **470** remaining in the wellbore is now moving through the through-opening **465**. Further, the slurry **470** is moving through the flow ports **455** of the frac sleeve **440**. In this way, the problem of screen-out is remediated.

[0120] In the method of the **Figure 4** series of drawings, the rupture disc **460** serves as a valve. The valve "opens" in response to a wellbore pressure encountered during the screen-out. When the valve **460** opens, the barrier to fluid flow down the wellbore is removed, exposing the flow ports **455**. This, in turn, relieves the excess wellbore pressure.

[0121] It is noted that the rupture disc **460** is actually an optional feature in the method of the **Figure 4** series.

The method may be modified by removing the rupture disc **460** and just using the frac sleeve **440** as the valve that is opened. In this instance, the sleeve **440** is maintained in its closed position during the perf-and-frac operation, and only opens if higher wellbore pressures indicative of a screen-out occur. The result is that the flow ports **455** open in the step of **Figure 4E** rather than in **Figure 4B**.

[0122] In another embodiment, a rupture disc is used without a frac sleeve. **Figures 5A** and **5B** demonstrate such a method.

[0123] First, **Figure 5A** illustrates a wellbore **500** undergoing completion. The wellbore **500** is being completed in a horizontal orientation. The completion of wellbore **500** includes a string of production casing **520** cemented in place within a surrounding subsurface formation **510**. Optional cement is shown in an annular area **515** around the casing **520**.

[0124] In this view, the wellbore **500** has been completed along two zones of interest, indicated by separate perforations at **575'** and **575"**. The lower zone of interest, indicated by perforations at **575'**, has been fractured. Fractures are shown somewhat schematically at **578'**. The upper zone of interest, indicated by perforations **575"**, has also been fractured. Fractures are shown there at **578"**.

[0125] In **Figure 5A**, a rupture disc **560** has been pumped down into the bore **505**. The disc **560** has landed on a baffle seat **562**. The baffle seat **562** is located above the lower zone of interest and the corresponding perforations **575'**. In this way, the rupture disc **560** resides between the lower **575'** and the upper **575"** sets of perforations.

[0126] The rupture disc **560** includes a pressure diaphragm **564**. The diaphragm **564** has a burst pressure that is higher than an anticipated formation fracturing pressure for the upper perforations **575"**. Specifically, the disc **560** is designed to rupture in the event of a screen-out during fracturing of the upper perforations **575"**. Thus, the burst rating for the rupture disc **560** and its diaphragm **564** is designed to approximate a pressure that would be experienced in the wellbore **500** in the event of a screen-out.

[0127] **Figure 5B** demonstrates that a condition of screen-out has arisen. It can be seen that slurry **570** has moved past the upper perforations **575** and has moved down the bore **505** towards the lower set of perforations **575'**. A buildup of pressure due to screen-out has caused the pressure diaphragm **564** to rupture, creating a new through-opening **565** in the rupture disc **560**. Slurry **570** will proceed to the lower set of perforations **575'**, as indicated by **Arrows S**. Thus, the rupture disc **560** serves essentially as a relief valve.

[0128] In another embodiment, a frac plug is used that may shear off in response to a condition of screen-out. **Figures 5C** and **5D** demonstrate such a method.

[0129] First, **Figure 5C** illustrates the same wellbore **500** as in **Figure 5A** undergoing completion. The well-

bore 500 is being completed in a horizontal orientation. The completion of wellbore 500 includes a string of production casing 520 cemented in place within a surrounding subsurface formation 510. Optional cement is shown in an annular area 515 around the casing 520.

[0130] In Figure 5C, a frac plug 580 has been placed along the casing 520. The frac plug 580 may be, for example, Halliburton's composite frac plug with caged ball and seat. The frac plug 580 includes a seat 584 dimensioned to receive a ball 550. A ball 550 has landed on the seat 584 above the lower zone of interest and the corresponding perforations 575'. In this way, the ball 550 resides between the lower 575' and the upper 575" sets of perforations.

[0131] The frac plug 580 includes shear pins 582 designed to release in response to a fluid pressure within the bore 505 that is greater than a screen-out pressure during fracturing of the upper perforations 575". This is a pressure that is higher than an anticipated formation fracturing pressure for the upper perforations 575". The seat 584 is held with shear pins which release the valve (ball 550 and seat 584) when the designed pressure differential is exceeded, most likely caused by screen-out of proppant into the upper formation 575".

[0132] Figure 5D demonstrates that a condition of screen-out has arisen. It can be seen that slurry 570 has moved past the upper perforations 575" and has moved down the bore 505 towards the lower set of perforations 575'. A build-up of pressure due to screen-out has caused the pins 582 along the frac plug 580 to shear, allowing slurry 570 to proceed to the lower set of perforations 575', as indicated by Arrows S. The ball 550 and seat 584 are falling in the wellbore 500. Thus, the ball-and-seat arrangement of the releasable frac plug 580 serves essentially as a relief valve.

[0133] In another embodiment, two rupture discs are used between the upper and lower zones of interest, without a frac sleeve. Figures 6A and 6B demonstrate such a method.

[0134] First, Figure 6A illustrates a wellbore 600 undergoing completion. The wellbore 600 is being completed in a horizontal orientation. The completion of wellbore 600 includes a string of production casing 620 cemented in place within a surrounding subsurface formation 610. Optional cement is shown in an annular area 615 around the casing 620.

[0135] In Figure 6A, the wellbore 600 has been completed along two zones of interest, indicated by separate perforations at 675' and 675". The lower zone of interest, indicated by perforations at 675', has been fractured. Fractures are shown somewhat schematically at 678'. The upper zone of interest, indicated by perforations 675", has also been fractured. Fractures are shown there at 678".

[0136] In Figure 6A, an upper rupture disc 660" has been pumped down into the bore 605. The disc 660" has landed on an upper baffle seat 662". The upper baffle seat 662" is located above the lower zone of interest and

the corresponding perforations 675'. In this way, the rupture disc 660" resides between the upper 675" and the lower 675' sets of perforations.

[0137] The upper rupture disc 660" includes a pressure diaphragm 664". The diaphragm 664" has a burst pressure that is higher than an anticipated formation fracturing pressure for the formation 610. Specifically, the disc 660" is designed to rupture in the event of a screen-out during fracturing of the upper perforations 675". Thus, the burst rating for the rupture disc 660" and its diaphragm 664" is designed to approximate a pressure that would be experienced in the wellbore 600 in the event of a screen-out.

[0138] The wellbore 600 also includes a lower rupture disc 660'. The lower rupture disc 660' has been previously pumped down into the bore 605 ahead of the upper rupture disc 660". The lower rupture disc 660' is dimensioned to pass through the upper baffle seat 662" and land on a lower baffle seat 662'. The lower baffle seat 662' is located below the lower zone of interest and the corresponding perforations 675'.

[0139] The lower rupture disc 660' also includes a pressure diaphragm 664'. The diaphragm 664' has a burst pressure that is higher than the burst rating for the upper rupture disc 660". Specifically, the disc 660' is designed to withstand even an anticipated screen-out during fracturing of the upper perforations 675".

[0140] Figure 6B demonstrates that a condition of screen-out has arisen. It can be seen that slurry 670 has moved past the upper perforations 675" and has moved down the bore 605 towards the lower set of perforations 675'. A buildup of pressure due to screen-out has caused the pressure diaphragm 664' in the upper rupture disc 660" to rupture, creating a new through-opening 665" in the rupture disc 660". The lower rupture disc 660' remains in-tact, and forces the slurry 670 to enter the lower set of perforations 675', as indicated by Arrows S.

[0141] As can be seen, the first rupture disc 660" again serves essentially as a relief valve.

[0142] In another embodiment, a frac plug having a removable ball is used without a frac sleeve. Figures 7A and 7B demonstrate such a method.

[0143] First, Figure 7A illustrates another wellbore 700 undergoing completion procedures. The wellbore 700 is being completed in a horizontal orientation. The completion of wellbore 700 includes a string of production casing 720 cemented in place within a surrounding subsurface formation 710. Optional cement is shown in an annular area 715 around the casing 720.

[0144] In the view of Figure 7A, the wellbore 700 is again being completed along two zones of interest, indicated by separate perforations at 775' and 775". The lower zone of interest, indicated by perforations at 775', has been fractured. Fractures are shown somewhat schematically at 778'. The upper zone of interest, indicated by perforations 775", has also been fractured. Fractures are shown there at 778".

[0145] In Figure 7A, a ball-and-seat valve 760 has

been placed along the subsurface formation **710**. The valve **760** comprises a sub that is threadedly connected in-line with the production casing **720**. The valve **760** has a seat **762** that is dimensioned to receive a ball **750**. It can be seen in **Figure 7A** that a ball **750** been dropped into the bore **705** and has landed on the seat **762**, thereby creating a pressure seal that prevents fluid flow further down the bore **705**.

[0146] The ball-and-seat valve **760** is located above the lower zone of interest and the corresponding perforations **775'**. At the same time, the valve **760** resides below the upper zone of interest and the corresponding perforations **775"**.

[0147] The ball **750** is uniquely fabricated from a material than collapses in response to pressure. Rather than having a burst pressure, it has a collapse pressure. The collapse pressure is the pressure at which the ball **750** will collapse or break or dissolve. In the arrangement of **Figures 7A** and **7B**, this pressure is higher than an anticipated formation fracturing pressure for the subsurface formation **710**. Specifically, the ball **750** is designed to collapse in the event of a screen-out during fracturing of the upper perforations **775"**. Thus, the collapse rating for the ball **750** is designed to approximate a pressure that would be experienced in the wellbore **700** in the event of a screen-out.

[0148] In **Figure 7A**, a slurry **770** is being pumped down the bore **705**. This forms the upper set of fractures **778"**. However, **Figure 7B** demonstrates that a condition of screen-out has arisen at the level of these fractures **778"**. It can be seen that slurry **770** has moved past the upper perforations **775"** and has moved down the bore **705** towards the lower set of perforations **775'**. A buildup of pressure due to screen-out has caused the ball (**750**) to collapse, crumble, disintegrate, and/or dissolve, creating a new through-opening **765** in seat **762**. Slurry **770** will proceed to the lower set of perforations **775'** as indicated by **Arrows S**. Thus, the ball-and-seat valve **760** serves essentially as a relief valve.

[0149] Beneficially for this embodiment, the downstream pressure need not be known by the completions engineer (or operator) in order to define the optimal pressure to create the leak path. The treatment pressure acts only on the pressure internal to the ball **750**, which causes it to collapse or destruct. This, in turn, allows fluids to bypass the collapsed ball **750**.

[0150] The methods of the present invention can be presented in flow chart form. **Figure 8** represents a flow chart showing steps for a method **800** of completing a well, in one embodiment. In connection with the method, a condition of screen-out along the wellbore is remediated.

[0151] The method **800** first includes forming a wellbore. This is shown at **Box 810**. The wellbore defines a bore that extends into a subsurface formation. The wellbore may be formed as a substantially vertical well; more preferably, the well is drilled as a deviated well or, even more preferably, a horizontal well.

[0152] The method **800** also includes lining at least a lower portion of the wellbore with a string of production casing. This is provided at **Box 820**. The production casing is made up of a series of steel pipe joints that are threadedly connected, end-to-end.

[0153] The method **800** further includes placing a valve along the production casing. This is indicated at **Box 840**. The valve creates a removable barrier to fluid flow within the bore. Preferably, the valve is a sliding sleeve having a seat that receives a ball, wherein the ball is dropped from the surface to create a pressure seal on the seat. Other types of valves may also be used as noted below.

[0154] The method **800** also comprises perforating the production casing. This is shown at **Box 850**. The casing is perforated along a first zone of interest within the subsurface formation. The first zone of interest resides at or above the valve. The process of perforating involves firing shots into the casing, through a surrounding annular region (that may or may not have a cement sheath), and into the surrounding rock matrix making up a subsurface formation. This is done by using a perforating gun in the wellbore.

[0155] The method **800** next includes injecting a slurry into the wellbore. This is provided at **Box 860**. The slurry comprises a proppant, preferably carried in an aqueous medium. The slurry is injected in sufficient volumes and at sufficient pressures as to form fractures in the subsurface formation along the zone of interest.

[0156] The method **800** further includes pumping the slurry at a pressure sufficient to move the valve and to overcome the barrier to fluid flow. This is seen at **Box 870**. The pumping is done in response to a condition of screen-out along the first zone of interest created during the slurry injection. Moving the valve exposes ports along the production casing to the subsurface formation at or below the valve.

[0157] In one aspect of the method, the valve is a sliding sleeve. In this instance, moving the valve to expose ports along the production casing comprises moving or "sliding" the sleeve to expose one or more ports fabricated in the sliding sleeve. Optionally, the operator may inject a fluid (such as an aqueous fluid) under pressure through the exposed port before perforating the casing. This creates mini-fractures in the subsurface formation below the first zone of interest adjacent the sliding sleeve. In this instance, the operator will then place a rupture disc on top of the sliding sleeve to seal the bore to slurry during fracturing.

[0158] In another embodiment, the method **800** further includes placing a fracturing baffle along the production casing. The fracturing baffle resides above the frac valve but at or below the first zone of interest. The fracturing baffle may be part of a sub that is threadedly connected to the production casing proximate the valve during initial run-in. A rupture disc is then pumped down the wellbore ahead of the slurry. The disc is pumped to a depth just above the valve until the disc lands on the fracturing baffle. In this embodiment, the rupture disc is designed to

rupture at a pressure that is greater than a screen-out pressure, but lower than the pressure required to move the valve.

[0159] In an alternative arrangement, the rupture disc itself is the valve. In this arrangement, the fracturing valve is not used; instead, a second rupture seat is placed below the lower zone of interest. Thus, the rupture disc that serves as the valve is an upper burst plug, while the other rupture disc is a lower burst plug.

[0160] In another embodiment, the valve is a first burst plug. The first burst plug will have a first burst rating. The ports represent perforations that are placed in the production casing in a second zone of interest below the first zone of interest. In this embodiment, moving the valve to expose ports comprises injecting the slurry at a pressure that exceeds the burst rating of the first burst plug. Optionally, in this embodiment the method further includes placing a second and a third burst plug along the production casing at or below the second zone of interest, creating a domino-effect in the event of multiple screen-outs. The second and third burst plugs will have a second burst rating that is equal to or greater than the first burst rating. When a burst plug is ruptured, a new through-opening is created through the burst plug, wherein the barrier to fluid flow has been removed.

[0161] In still another aspect, the valve that is moved is a ball-and-seat valve, while the ports are perforations earlier placed in the production casing in a second zone of interest below the first zone of interest and below the valve. In this instance, moving the valve to expose ports comprises injecting the slurry at a pressure that causes the ball to lose its pressure seal on the seat. Causing the ball to lose its pressure seal may define causing the ball to shatter, causing the ball to dissolve, or causing the ball to collapse.

[0162] The method **800** additionally includes further pumping the slurry through the exposed ports. This is shown at **Box 880**. In this way, the condition of screen-out is remediated. Stated another way, the "screened out" slurry is disposed of downhole in a "proppant disposal zone."

[0163] Preferably, the method **800** also includes the step of estimating a screen-out pressure along the zone of interest. This is provided at **Box 830**. This determining step is preferably done before the valve is placed along the production casing in the step of **Box 840**. The reason is so that the operator knows what type of valve to use and what pressure rating or burst rating is needed for the valve.

[0164] In a preferred embodiment of the method **800**, the step of **Box 850**, which involves perforating the production casing, comprises pumping an autonomous perforating gun assembly into the wellbore and autonomously firing the perforating gun along the first zone of interest. The autonomous perforating gun assembly comprises a perforating gun, a depth locator for sensing the location of the assembly within the wellbore, and an on-board controller. "Autonomously firing" means pre-program-

ming the controller to send an actuation signal to the perforating gun to cause one or more detonators to fire when the locator has recognized a selected location of the perforating gun along the wellbore. In one aspect, the depth locator is a casing collar locator and the on-board controller interacts with the casing collar locator to correlate the spacing of casing collars along the wellbore with depth. The casing collar locator identifies collars by detecting magnetic anomalies along a casing wall.

[0165] In another aspect, the on-board depth locator is a formation log such as a gamma ray log, a density log, or a neutron log. In this instance, the controller is comparing readings in real time from the logging tool with a pre-loaded formation log. Alternatively, the depth locator may be a location sensor (such as an IR reader) that senses markers placed along the casing (such as an IR transceiver). The on-board controller sends the actuation signal to the perforating gun when the location sensor has recognized one or more selected markers along the casing.

[0166] It is observed that the perforating gun, the locator, and the on-board controller are together dimensioned and arranged to be deployed in the wellbore as an autonomous unit. In this application, "autonomous unit" means that the assembly is not immediately controlled from the surface. Stated another way, the tool assembly does not rely upon a signal from the surface to know when to activate the tool. Preferably, the tool assembly is released into the wellbore without a working line. The tool assembly either falls gravitationally into the wellbore or is pumped downhole. However, a non-electric working line, such as slickline, may optionally be employed to retrieve the autonomous tool.

[0167] It is preferred that the location sensor and the on-board controller operate with software in accordance with the locating algorithm discussed above. Specifically, the algorithm preferably employs a windowed statistical analysis for interpreting and converting magnetic signals generated by the casing collar locator (or, alternatively, a formation log). In one aspect, the on-board controller compares the generated signals with a pre-determined physical signature obtained for the wellbore objects. For example, a log may be run before deploying the autonomous tool in order to determine the spacing of the casing collars or the location of formation features. The corresponding depths of the casing collars or formation features may be determined based on the speed of the wireline that pulled the logging device.

[0168] When an autonomous perforating gun assembly is used for completing a horizontal wellbore, the operator may install a hydraulically-actuated valve at the toe of the well. The hydraulically-actuated valve may be installed, for example, just upstream from a frac baffle ball-and-seat device. Additional seats or frac baffle rings, etc., may be installed further upstream of the hydraulically-actuated valve in progressively smaller sizes from top to bottom.

[0169] Preparation of the well for treatment begins by

pumping down a first ball. The ball seats on the lowest, or deepest, seat below the hydraulically-actuated valve. Once seated, the casing is pressured up to a "designed" set point. For example, a 68.9 MPa (10,000 psi) surface pressure may be reached by pumping an aqueous fluid. This pressure (acting on a ball landed on the seat) causes the hydraulically-actuated valve to open, exposing one or more ports along the casing. Once the ports are exposed, hydrostatic and pumping pressures cause a small opening to be formed in the subsurface formation adjacent the valve. Fresh water continues to be pumped to create a "mini" fracture in the formation. Such a fracture is shown at 458 in Figure 4B.

[0170] It is noted that the process of forming the "mini" fracture 458 affords the operator with a real-time opportunity to evaluate the rock mechanics of the subsurface formation. Specifically, the operator is able to determine a level of pressure generally needed to initiate fractures. This may be used as part of the "estimating" step of Box 830 described above. The operator will understand that the screen-out pressure will be somewhere significantly above this initial formation-parting pressure. The operator may then select a proper sealing device, such as the rupture disc 460 of Figure 4C or the collapsible ball 750 of Figure 7A, for use in the well.

[0171] The sealing device is pumped down the wellbore until it is seated on the seat (or baffle ring) 462 just above the open hydraulically-actuated valve. In this condition, the sealing device creates a barrier to fluid flow through the bore of the well. At the same time, and as described above, the sealing device creates a "relief valve" that may be opened by the pressure and "fluid hammer" of a screen-out condition.

[0172] When a condition of screen-out occurs, the hydraulically-actuated valve may be self-actuated. The valve opens to provide a path for the proppant-laden fluid in the wellbore to be swept from the wellbore. The slurry flows through the ports, through the mini fracture, and into the subsurface formation at fracture treatment rates. A new autonomous perforating gun assembly may then be placed in the wellbore, pumped down, and then used to re-perforate the trouble zone. Alternatively, the new autonomous perforating gun assembly may be pumped downhole to a new zone of interest for the creation of perforations along the new zone.

[0173] Once the new zone is perforated, the well is ready for the next stage of fracture treatment. This is accomplished by then pumping down another removable sealing device and placing it in a seat upstream of the hydraulically-actuated valve. Placement of the sealing device will force fluids into the new set of perforations.

[0174] It is observed that the wellbore may be designed with more than one seat. Each seat resides above a different set of perforations, or above an open sleeve. Multiple sealing devices, or plugs, may be landed on the seats, in succession, with each having a progressively higher pressure rating. The multiple plugs are capable of "domino-ing" if needed during upset conditions. This

also creates a large number of available slurry disposal zones, allowing autonomous perforating gun assemblies to be pumped into the wellbore for the perforating of the sequential zones without the need of wireline tractors or coiled tubing operations.

[0175] As can be seen, improved methods for remediating a condition of screen-out are provided herein.

10 Claims

1. A method (800) of completing a well, comprising:

forming (810) a wellbore, the wellbore comprising a bore extending into a subsurface formation;
lining (820) at least a lower portion of the wellbore with a string of production casing;
placing (840) a valve along the production casing, the valve creating a removable barrier to fluid flow within the bore;
perforating (850) the production casing along a first zone of interest within the subsurface formation, the first zone of interest residing at or above the valve;
injecting (860) a slurry into the wellbore, the slurry comprising a fracturing proppant;
in response to a condition of screen-out along the first zone of interest during the injecting, pumping (870) the slurry at a pressure sufficient to move the valve and overcome the barrier to fluid flow, thereby exposing ports along the production casing to the subsurface formation at or below the valve; and
further pumping (880) the slurry through the exposed ports, thereby remediating the condition of screen-out.

2. The method of claim 1, wherein the wellbore is completed along the subsurface formation in a horizontal orientation.

3. The method of either of claims 1 or 2, wherein the valve is a ball-and-seat valve or a ball-and-cage valve.

4. The method of either of claims 1 or 2, wherein:

the valve is a sliding sleeve; and
moving the valve to expose ports along the production casing comprises moving the sliding sleeve to expose one or more ports fabricated in the sliding sleeve.

5. The method of either of claims 1 or 2, wherein:

the valve is a rupture disc;
the ports reside adjacent a sliding sleeve below

the first zone of interest; and
the method further comprises:

pumping an aqueous fluid down the wellbore to move the sliding sleeve, thereby exposing the ports along the production casing; 5

before injecting the slurry, further injecting the aqueous fluid under pressure through the exposed ports, thereby creating fractures in the subsurface formation below the first zone of interest adjacent the sliding sleeve for receiving the slurry; 10

placing a baffle seat along the production casing, the seat residing above the sliding sleeve but at or below the first zone of interest; 15

pumping the rupture disc down the wellbore ahead of the slurry to a depth proximate the valve; and 20

landing the rupture disc on the baffle seat, thereby creating the barrier to fluid flow; and

moving the valve comprises bursting the rupture disc, wherein the rupture disc is designed to rupture at a pressure that is greater than a screen-out pressure. 25

6. The method of either of claims 1 or 2, wherein: 30

the valve is a first burst plug having a first burst rating; 35

the ports are perforations placed in the production casing in a second zone of interest below the first zone of interest; and

moving the valve to expose ports comprises injecting the slurry at a pressure that exceeds the burst rating of the first burst plug. 40

7. The method of claim 6, further comprising: 45

placing a second burst plug along the production casing at or below the second zone of interest, the second burst plug having a second burst rating.

8. The method of claim 7, wherein the second burst rating is equal to or greater than the first burst rating. 50

9. The method of either of claims 1 or 2, wherein: 55

the valve is a ball-and-seat valve;

the ports are perforations placed in the production casing in a second zone of interest below the first zone of interest; and

moving the valve to expose ports comprises injecting the slurry at a pressure that causes the ball to lose its pressure seal on the seat, or shearing pins to cause the seat to shear off and move lower in the wellbore below the ports. 55

10. The method of claim 9, wherein causing the ball to lose its pressure seal comprises causing the ball to shatter, causing the ball to dissolve, or causing the ball to collapse.

11. The method of any of claims 1-10, further comprising: estimating (830) a screen-out pressure along the first zone of interest prior to placing the valve along the production casing.

12. The method of claim 1, further comprising:

placing a valve along the production casing along a second zone of interest below the first zone of interest, the valve along the second zone of interest also creating a removable barrier to fluid flow within the bore; and

in response to the condition of screen-out along the first zone of interest during the injecting, pumping the slurry at a pressure sufficient to move the valve along the second zone of interest and overcome the barrier to fluid flow, thereby exposing ports along the production casing to the subsurface formation at or below the valve along the second zone of interest; and wherein further pumping the slurry through the exposed ports, thereby remediating the condition of screen-out, comprises pumping the slurry through exposed ports along the second zone of interest.

13. The method of any of the claims 9-12, wherein:

the valve is a first burst plug having a first burst rating;

the ports are perforations placed in the production casing below the zone of interest; and moving the valve to expose ports comprises injecting the slurry at a pressure that exceeds the burst rating of the first burst plug, thereby allowing the slurry to bypass the first burst plug and invade the subsurface formation through the perforations; and

the method further comprises placing a second burst plug along the production casing below the perforations, the second burst plug having a second burst rating that is equal to or greater than the first burst rating.

14. The method of any of the preceding claims, wherein:

the valve is a frac plug having a seat configured to receive a ball;

the ports are perforations placed in the production casing below the zone of interest; and moving the valve to expose ports comprises: dropping a ball onto the seat before formation

fracturing begins;
 injecting the slurry at a pressure that exceeds the shear rating of pins along the frac plug in response to a condition of screen-out, thereby allowing the ball and seat to shear off of the frac plug and move lower in the wellbore below the perforations residing below the zone of interest.

Patentansprüche

1. Verfahren (800) zum Komplettieren einer Bohrung, bei dem:

ein Bohrloch gebildet (810) wird, das eine Bohrung umfasst, die sich in eine unterirdische Formation erstreckt;
 mindestens ein unterer Abschnitt des Bohrlochs mit einem Strang von Produktionsbohrfutter ausgekleidet (820) wird;
 ein Ventil entlang des Produktionsbohrfutters platziert (840) wird, wobei das Ventil eine entfernbare Barriere gegen Fluidfluss innerhalb der Bohrung erzeugt;
 das Produktionsbohrfutter entlang einer ersten interessierenden Zone innerhalb der unterirdischen Formation perforiert (850) wird, wobei die erste interessierende Zone am Ventil oder oberhalb des Ventils liegt;
 eine Aufschlämmung in das Bohrloch injiziert (860) wird, wobei die Aufschlämmung ein Fracturing-Stützmittel umfasst;
 die Aufschlämmung in Reaktion auf einen Zustand des Screenouts entlang der ersten interessierenden Zone während der Injektion mit einem ausreichenden Druck gepumpt (870) wird, um das Ventil zu bewegen und die Barriere gegen Fluidfluss zu überwinden, wodurch Öffnungen entlang des Produktionsfutterrohrs zu der unterirdischen Formation an oder unterhalb des Ventils freigelegt werden; und
 die Aufschlämmung ferner durch die freiliegenden Öffnungen gepumpt (880) wird, wodurch der Zustand des Screenouts saniert wird.

2. Verfahren nach Anspruch 1, bei dem das Bohrloch entlang der unterirdischen Formation in einer horizontalen Orientierung komplettiert wird.

3. Verfahren nach Anspruch 1 oder 2, bei dem das Ventil ein Kugel- und Sitzventil oder ein Kugel- und Käfig-Ventil ist.

4. Verfahren nach einem der Ansprüche 1 oder 2, bei dem das Ventil eine Schiebehülse ist; und das Bewegen des Ventils, um Öffnungen entlang des Produktionsfutterrohrs freizulegen, Bewegen

der Schiebehülse umfasst, um eine oder mehrere Öffnungen freizulegen, die in der Schiebehülse gefertigt sind.

5. Verfahren nach Anspruch 1 oder 2, bei dem das Ventil eine Berstscheibe ist; die Öffnungen neben einer Schiebehülse unter der ersten interessierenden Zone liegen; und bei dem Verfahren ferner ein wässriges Fluid herunter in das Bohrloch gepumpt wird, um die Schiebehülse zu bewegen, wodurch die Öffnungen entlang des Produktionsfutterrohrs freigelegt werden; vor dem Injizieren der Aufschlämmung ferner das wässrige Fluid unter Druck durch die freiliegenden Öffnungen injiziert wird, wodurch Brüche in der unterirdischen Formation unter der ersten interessierenden Zone neben der Schiebehülse erzeugt werden, um die Aufschlämmung aufzunehmen; ein Prallsitz entlang des Produktionsfutterrohrs platziert wird, wobei der Sitz sich oberhalb der Schiebehülse befindet, jedoch an oder unterhalb der ersten interessierenden Zone; die Berstscheibe vor der Aufschlämmung in dem Bohrloch auf eine Tiefe in der Nähe des Ventils nach unten gepumpt wird; und die Berstscheibe auf dem Prallsitz landen gelassen wird, wodurch die Barriere gegen Fluidfluss erzeugt wird; und Bewegen des Ventils Berstenlassen der Berstscheibe umfasst, wobei die Berstscheibe konzipiert ist, um bei einem Druck zu bersten, der größer als ein Screenout-Druck ist.

6. Verfahren nach einem der Ansprüche 1 und 2, bei dem das Ventil ein erster Berststopfen mit einem ersten Berstnennwert ist; die Öffnungen Perforationen sind, die in dem Produktionsfutterrohr in einer zweiten interessierenden Zone unterhalb der ersten interessierenden Zone platziert sind; und Bewegen des Ventils, um Öffnungen freizulegen, Injizieren der Aufschlämmung mit einem Druck umfasst, der den Berstnennwert des ersten Berststopfens übersteigt.

7. Verfahren nach Anspruch 6, bei dem ferner ein zweiter Berststopfen entlang des Produktionsfutterrohrs an oder unterhalb der zweiten interessierenden Zone platziert wird, wobei der zweite Berststopfen einen zweiten Berstnennwert aufweist.

8. Verfahren nach Anspruch 7, bei dem der zweite Berstnennwert gleich oder größer als der erste Berstnennwert ist.

9. Verfahren nach Anspruch 1 oder 2, bei dem das Ventil ein Kugel- und Sitz-Ventil ist; die Öffnungen Perforationen sind, die in dem Produktionsfutterrohr in einer zweiten interessierenden

- Zone unterhalb der ersten interessierenden Zone platziert sind; und Bewegen des Ventils, um Öffnungen freizulegen, Injizieren der Aufschlammung mit einem Druck, der bewirkt, dass die Kugel ihre Druckdichtung auf dem Sitz verliert, oder Scheren von Stiften umfasst, um zu bewirken, dass der Sitz abscher und sich tiefer in das Bohrloch unterhalb der Öffnungen bewegt.
10. Verfahren nach Anspruch 9, bei dem Bewirken, dass die Kugel ihre Druckdichtung verliert, umfasst, dass Zerschneiden der Kugel bewirkt wird, Auflösen der Kugel bewirkt wird, oder Zusammenfallen der Kugel bewirkt wird.
11. Verfahren nach einem der Ansprüche 1 bis 10, bei dem ferner ein Screenout-Druck entlang der ersten interessierenden Zone geschätzt (830) wird, bevor das Ventil entlang des Produktionsfutterrohrs platziert wird.
12. Verfahren nach Anspruch 1, bei dem ferner ein Ventil entlang des Produktionsfutterrohrs entlang einer zweiten interessierenden Zone unterhalb der ersten interessierenden Zone platziert wird, wobei das Ventil entlang der zweiten interessierenden Zone auch eine entfernbare Barriere gegen Fluidfluss innerhalb der Bohrung erzeugt; und die Aufschlammung in Reaktion auf den Zustand des Screenouts entlang der ersten interessierenden Zone während der Injektion mit einem ausreichenden Druck gepumpt wird, um das Ventil entlang der zweiten interessierenden Zone zu bewegen und die Barriere gegen Fluidfluss zu überwinden, wodurch Öffnungen entlang des Produktionsfutterrohrs zu der unterirdischen Formation an dem Ventil oder unterhalb des Ventils entlang der zweiten interessierenden Zone freigelegt werden; und wobei ferner Pumpen der Aufschlammung durch die freiliegenden Öffnungen, damit der Zustand des Screenouts saniert wird, Pumpen der Aufschlammung durch freigelegte Öffnungen entlang der zweiten interessierenden Zone umfasst.
13. Verfahren nach einem der Ansprüche 9 bis 12, bei dem das Ventil ein erster Berststopfen mit einem ersten Berstnennwert ist; die Öffnungen Perforationen sind, die in dem Produktionsfutterrohr unterhalb der interessierenden Zone platziert sind; und das Bewegen des Ventils, um Öffnungen freizulegen, Injizieren der Aufschlammung mit einem Druck umfasst, der den Berstnennwert des ersten Berststopfens übersteigt, wodurch die Aufschlammung den ersten Berststopfen umgehen kann und durch die Perforationen hindurch in die unterirdische Formation eindringen kann; und

das Verfahren ferner Platzieren eines zweiten Berststopfens entlang des Produktionsfutterrohrs unterhalb der Perforationen umfasst, wobei der zweite Berststopfen einen zweiten Berstnennwert aufweist, der gleich dem ersten Berstnennwert oder größer als dieser ist.

14. Verfahren nach einem der vorhergehenden Ansprüche, bei dem das Ventil ein Frac-Stopfen mit einem Sitz ist, der ausgestaltet ist, um eine Kugel aufzunehmen; die Öffnungen Perforationen sind, die in dem Produktionsfutterrohr unterhalb der interessierenden Zone platziert sind; und Bewegen des Ventils, um Öffnungen freizulegen, umfasst: Fallenlassen einer Kugel auf den Sitz, bevor das Fracturing der Formation beginnt; die Aufschlammung in Reaktion auf einen Zustand des Screenouts mit einem Druck injiziert wird, der den Scherungsnennwert der Stifte entlang des Frac-Stopfens übersteigt, wodurch die Kugel und der Sitz von dem Frac-Stopfen abscheren gelassen werden und sich tiefer in das Bohrloch hinein unterhalb der Perforationen bewegen, die unter der interessierenden Zone liegen.

Revendications

1. Procédé (800) de complétion d'un puits consistant :
- à former (810) un puits de forage, le puits de forage comprenant un alésage s'étendant dans une formation souterraine ;
 - à doubler (820) au moins une partie inférieure du puits de forage avec une rame de tubage de production ;
 - à placer (840) une vanne le long du tubage de production, la vanne créant une barrière amovible à un écoulement de fluide à l'intérieur de l'alésage ;
 - à perforer (850) le tubage de production le long d'une première zone digne d'intérêt dans la formation souterraine, la première zone digne d'intérêt se trouvant au niveau de la vanne ou au-dessus de cette dernière ;
 - à injecter (860) une suspension épaisse dans le puits de forage, la suspension épaisse comprenant un agent de soutènement de fracturation ; en réponse à un état de bouchage prématuré le long de la première zone digne d'intérêt pendant l'injection, à pomper (870) la suspension épaisse à une pression suffisante pour déplacer la vanne et vaincre la barrière à un écoulement de fluide, ce qui permet d'exposer des orifices le long du tubage de production à la formation souterraine au niveau de la vanne ou en dessous de cette dernière ; et

à pomper davantage (880) la suspension épaisse par les orifices exposés, ce qui permet de remédier à l'état de bouchage prématuré.

2. Procédé selon la revendication 1, dans lequel le puits de forage est achevé le long de la formation souterraine dans une orientation horizontale. 5
3. Procédé selon l'une ou l'autre des revendications 1 et 2, dans lequel la vanne est une vanne à bille et à siège ou une vanne à bille et à cage. 10
4. Procédé selon l'une ou l'autre des revendications 1 et 2, dans lequel : 15

la vanne est un manchon coulissant ; et
le déplacement de la vanne pour exposer des orifices le long du tubage de production consiste à déplacer le manchon coulissant pour exposer un ou plusieurs orifices fabriqués dans le manchon coulissant. 20
5. Procédé selon l'une ou l'autre des revendications 1 et 2, dans lequel : 25

la vanne est un disque de rupture ;
les orifices se trouvent adjacents à un manchon coulissant en dessous de la première zone digne d'intérêt ; et
le procédé consiste en outre : 30

à pomper un fluide aqueux vers le bas du puits de forage pour déplacer le manchon coulissant, ce qui permet d'exposer les orifices le long du tubage de production ; 35
avant d'injecter la suspension épaisse, à injecter en outre le fluide aqueux sous pression par les orifices exposés, ce qui permet de créer des fractures dans la formation souterraine en dessous de la première zone digne d'intérêt adjacente au manchon coulissant pour recevoir la suspension épaisse ; 40
à placer un siège de déflecteur le long du tubage de production, le siège se trouvant au-dessus du manchon coulissant mais au niveau de la première zone digne d'intérêt ou en dessous de cette dernière ;
à pomper le disque de rupture vers le bas du puits de forage devant la suspension épaisse jusqu'à une certaine profondeur à proximité de la vanne ; et
à poser le disque de rupture sur le siège de déflecteur, ce qui permet de créer la barrière à un écoulement de fluide ; et 50 55

le déplacement de la vanne consiste à éclater le disque de rupture, dans lequel le disque de

rupture est conçu pour rompre à une pression qui est supérieure à une pression de bouchage prématuré.

6. Procédé selon l'une ou l'autre des revendications 1 et 2, dans lequel :

la vanne est un premier bouchon de rupture ayant une première valeur nominale de rupture ; les orifices sont des perforations placées dans le tubage de production dans une seconde zone digne d'intérêt en dessous de la première zone digne d'intérêt ; et
le déplacement de la vanne pour exposer des orifices consiste à injecter la suspension épaisse à une pression qui dépasse la valeur nominale de rupture du premier bouchon de rupture.
7. Procédé selon la revendication 6, consistant en outre :

à placer un second bouchon de rupture le long du tubage de production au niveau de la seconde zone digne d'intérêt ou en dessous de cette dernière, le second bouchon de rupture ayant une seconde valeur nominale de rupture.
8. Procédé selon la revendication 7, dans lequel la seconde valeur nominale de rupture est égale ou supérieure à la première valeur nominale de rupture.
9. Procédé selon l'une ou l'autre des revendications 1 et 2, dans lequel :

la vanne est une vanne à bille et à siège ; les orifices sont des perforations placées dans le tubage de production dans une seconde zone digne d'intérêt en dessous de la première zone digne d'intérêt ; et
le déplacement de la vanne pour exposer des orifices consiste à injecter la suspension épaisse à une pression qui contraint la bille à perdre son joint d'étanchéité sur le siège ou à cisailer des broches pour contraindre le siège à se détacher et à se déplacer plus bas dans le puits de forage en dessous des orifices.
10. Procédé selon la revendication 9, dans lequel le fait de contraindre la bille à perdre son joint d'étanchéité consiste à provoquer l'éclatement de la bille, provoquant la dissolution de la bille ou provoquant la chute de la bille.
11. Procédé selon l'une quelconque des revendications 1 à 10, consistant en outre :

à estimer (830) une pression de bouchage prématuré le long de la première zone digne d'intérêt avant de placer la vanne le long du tubage de production.

12. Procédé selon la revendication 1, consistant en outre :

à placer une vanne le long du tubage de production le long d'une seconde zone digne d'intérêt en dessous de la première zone digne d'intérêt, la vanne le long de la seconde zone digne d'intérêt créant également une barrière amovible à un écoulement de fluide dans l'alésage ; et
 5
 10
 en réponse à l'état de bouchage prématuré le long de la première zone digne d'intérêt pendant l'injection, à pomper la suspension épaisse à une pression suffisante pour déplacer la vanne le long de la seconde zone digne d'intérêt et vaincre la barrière à un écoulement de fluide, ce qui permet d'exposer des orifices le long du tubage de production à la formation souterraine au niveau de la vanne ou en dessous de cette dernière le long de la seconde zone digne d'intérêt ; et
 15
 20
 dans lequel le pompage supplémentaire de la suspension épaisse par les orifices exposés, ce qui permet de remédier à l'état de bouchage prématuré, consiste à pomper la suspension épaisse par des orifices exposés le long de la seconde zone digne d'intérêt.
 25

13. Procédé selon l'une quelconque des revendications 9 à 12, dans lequel :

la vanne est un premier bouchon de rupture ayant une première valeur nominale de rupture ; les orifices sont des perforations placées dans le tubage de production en dessous de la zone digne d'intérêt ; et
 30
 35
 le déplacement de la vanne pour exposer des orifices consiste à injecter la suspension épaisse à une pression qui dépasse la valeur nominale de rupture du premier bouchon de rupture, ce qui permet à la suspension épaisse de contourner le premier bouchon de rupture et d'envahir la formation souterraine par les perforations ; et
 40
 le procédé consiste en outre à placer un second bouchon de rupture le long du tubage de production en dessous des perforations, le second bouchon de rupture ayant une seconde valeur nominale de rupture qui est égale ou supérieure à la première valeur nominale de rupture.
 45
 50

14. Procédé selon l'une quelconque des revendications précédentes, dans lequel :

la vanne est un bouchon de fracturation ayant un siège configuré pour recevoir une bille ;
 55
 les orifices sont des perforations placées dans le tubage de productions en dessous de la zone digne d'intérêt ; et

le déplacement de la vanne pour exposer des orifices consiste :

à faire tomber une bille sur le siège avant que la fracturation de la formation ne commence ;
 à injecter la suspension épaisse à une pression qui dépasse la valeur nominale de cisaillement de broches le long du bouchon de fracturation en réponse à un état de bouchage prématuré, ce qui permet à la bille et au siège de cisailer le bouchon de fracturation et de se déplacer plus bas dans le puits de forage en dessous des perforations se trouvant en dessous de la zone digne d'intérêt.

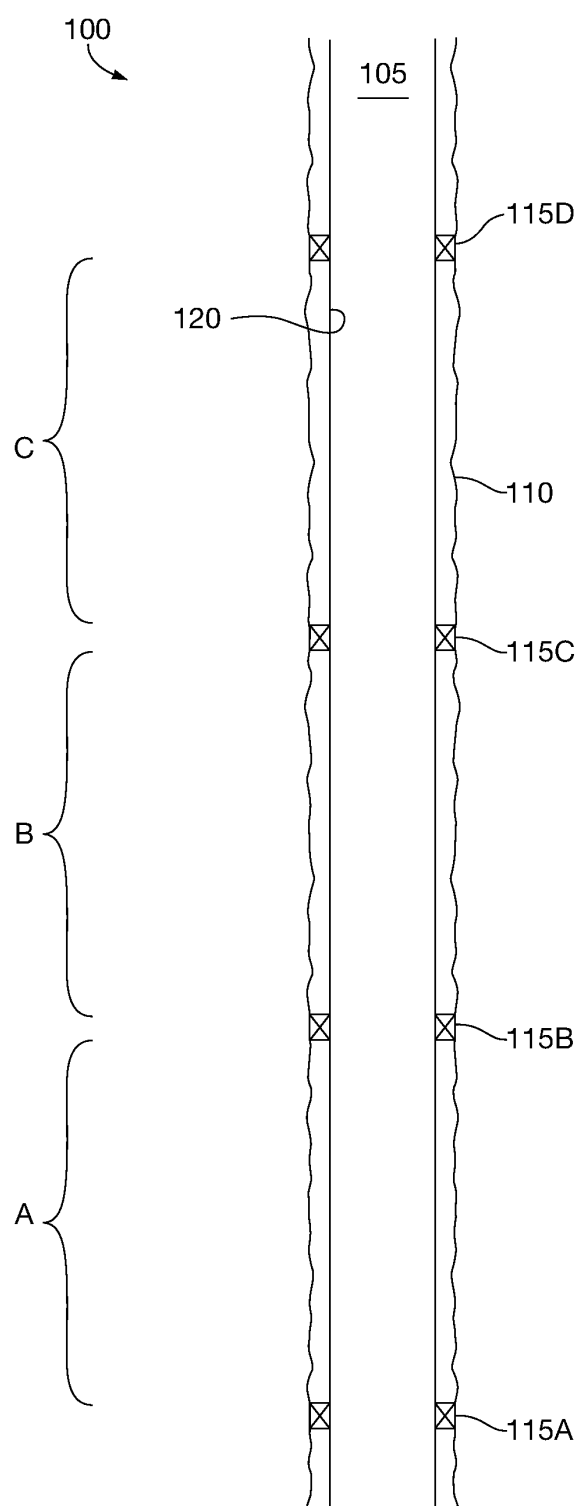


FIG. 1A

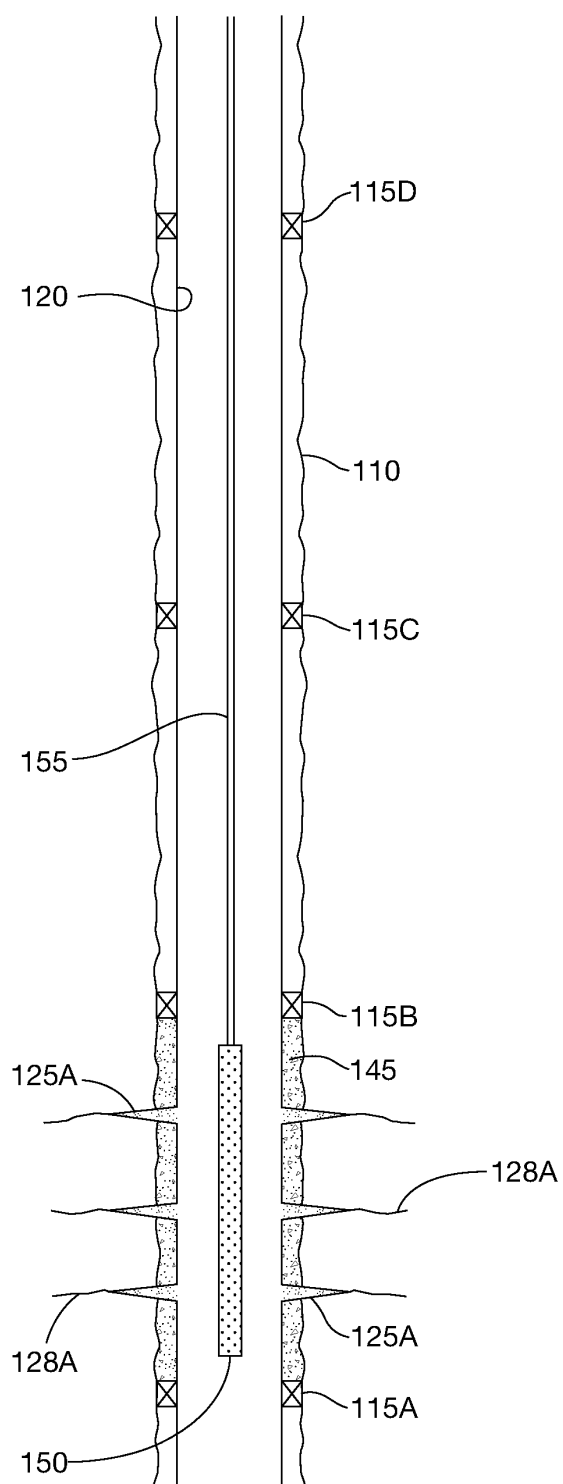


FIG. 1B

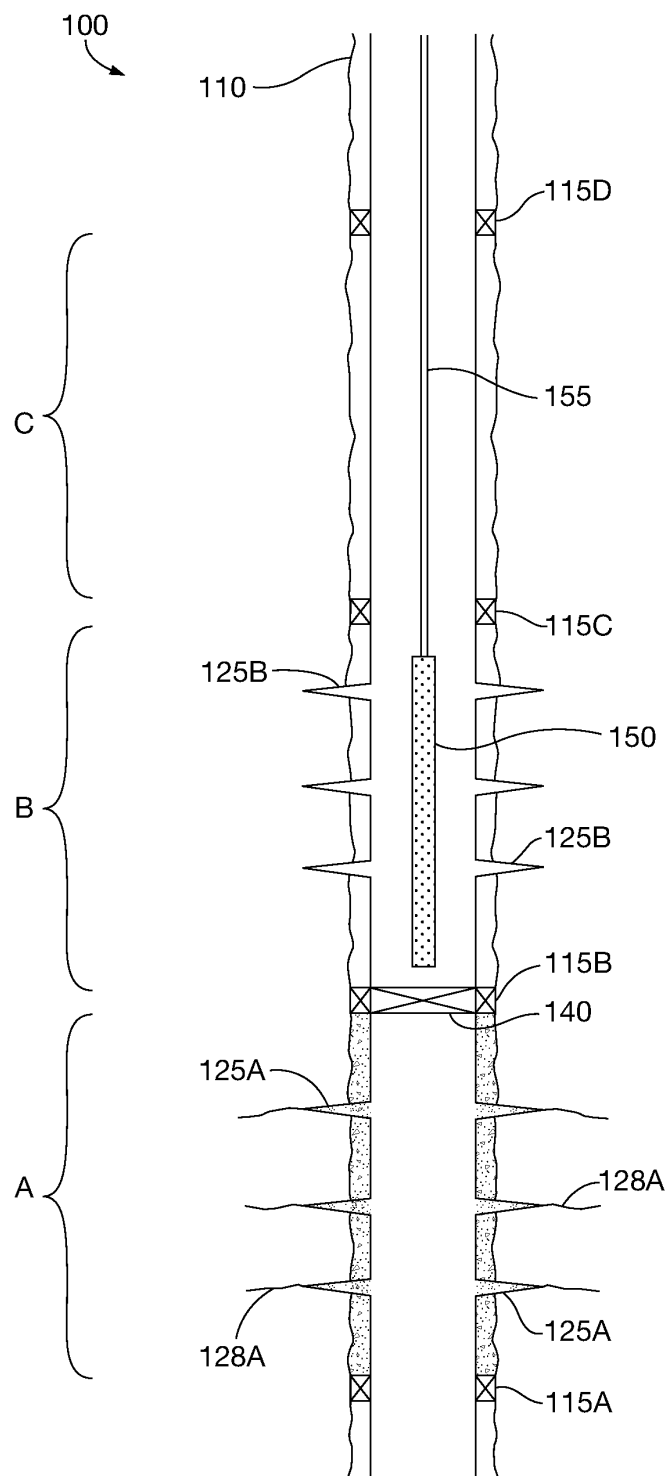


FIG. 1C

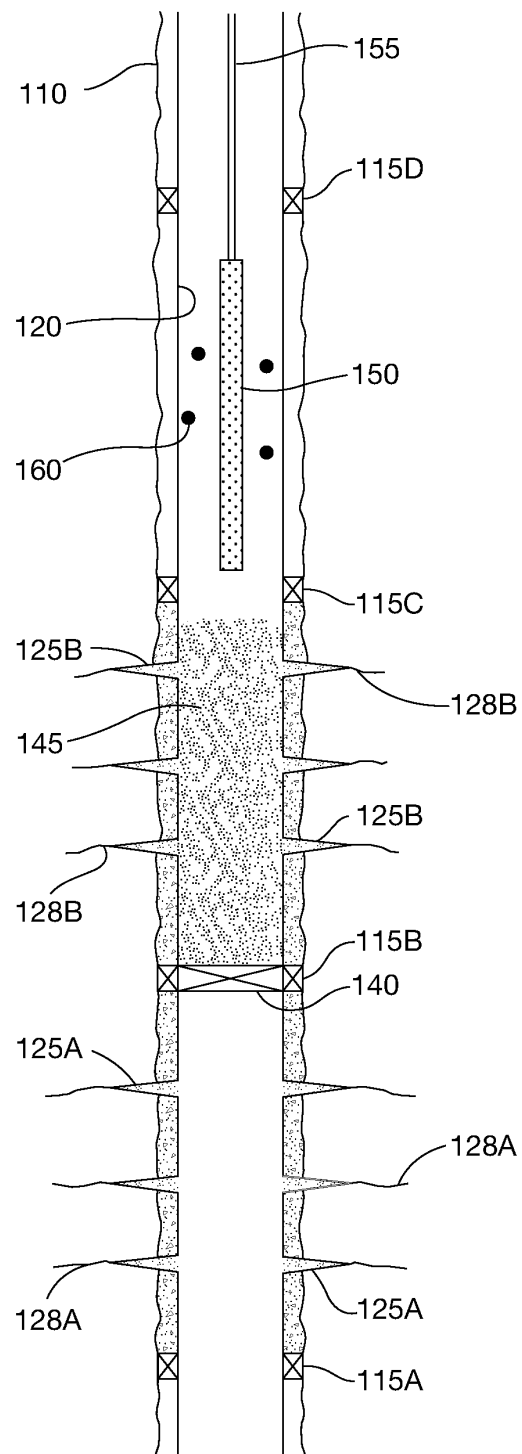


FIG. 1D

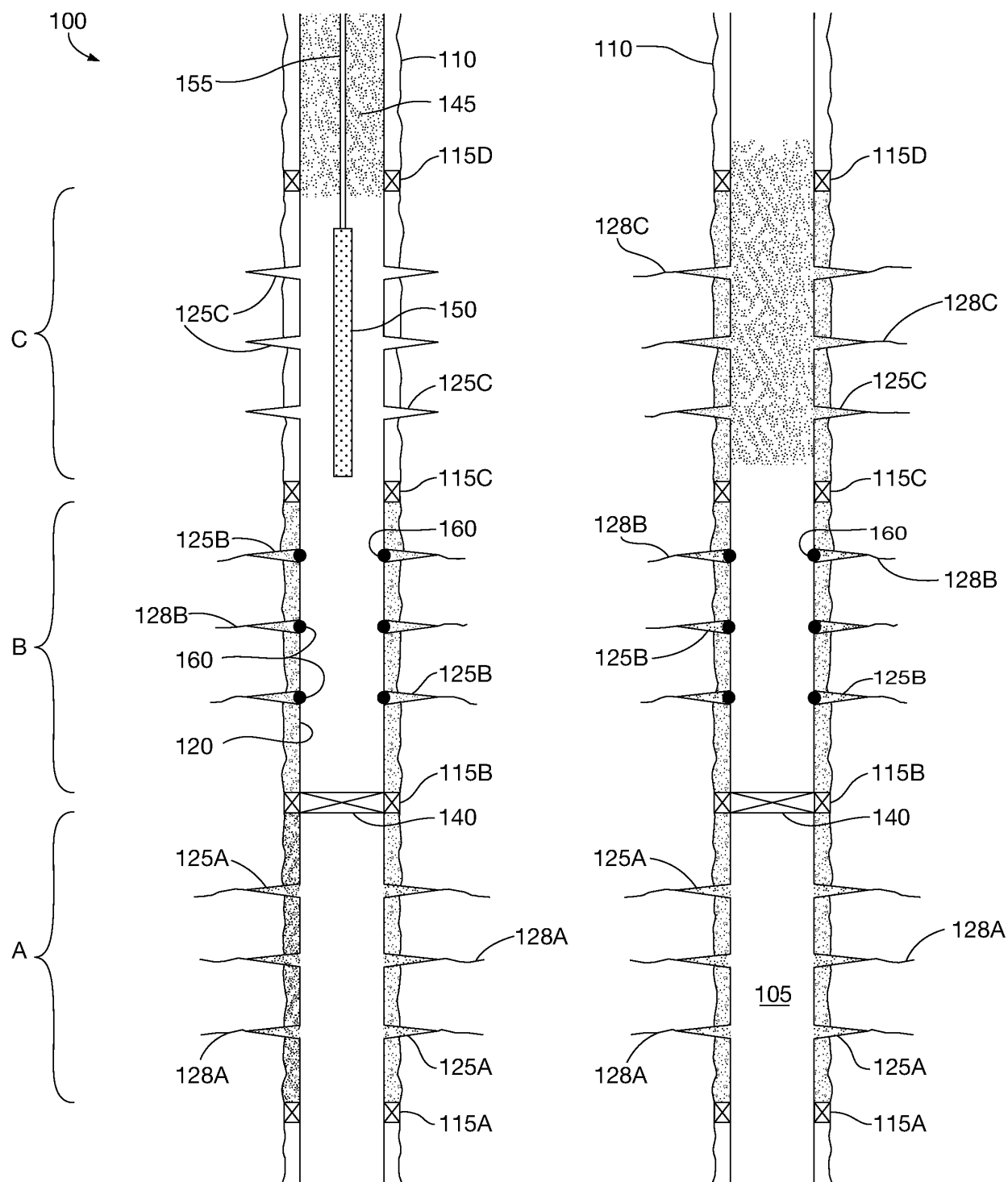


FIG. 1E

FIG. 1F

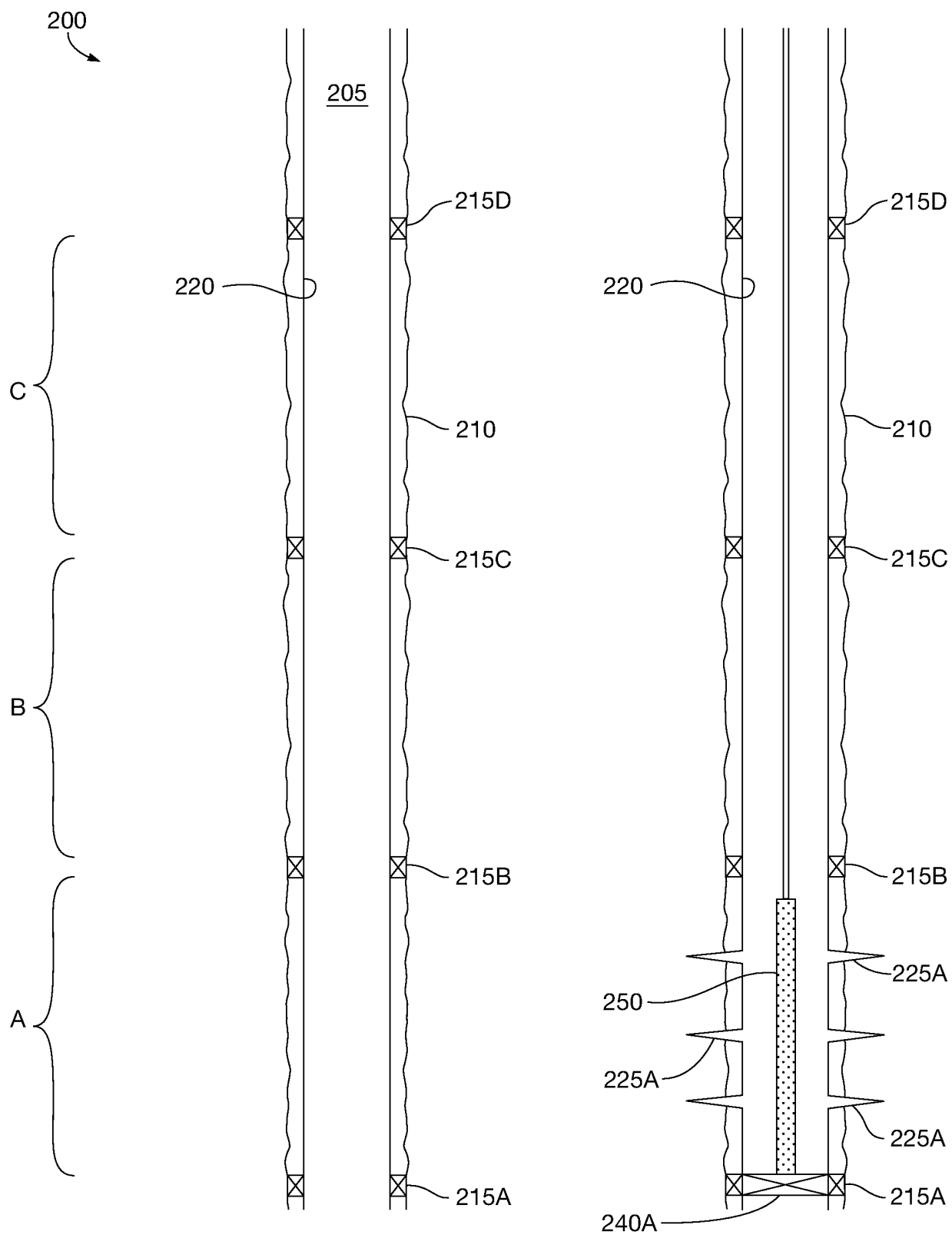


FIG. 2A

FIG. 2B

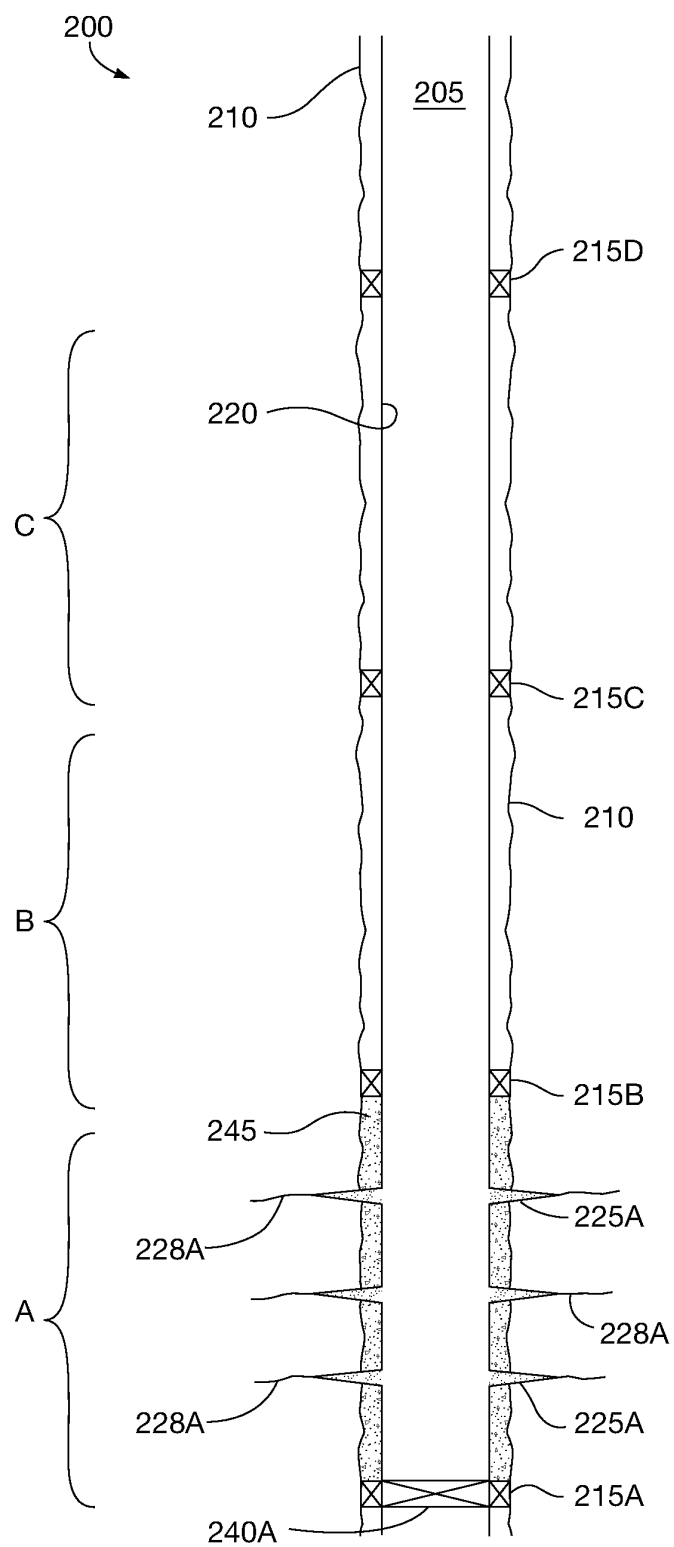


FIG. 2C

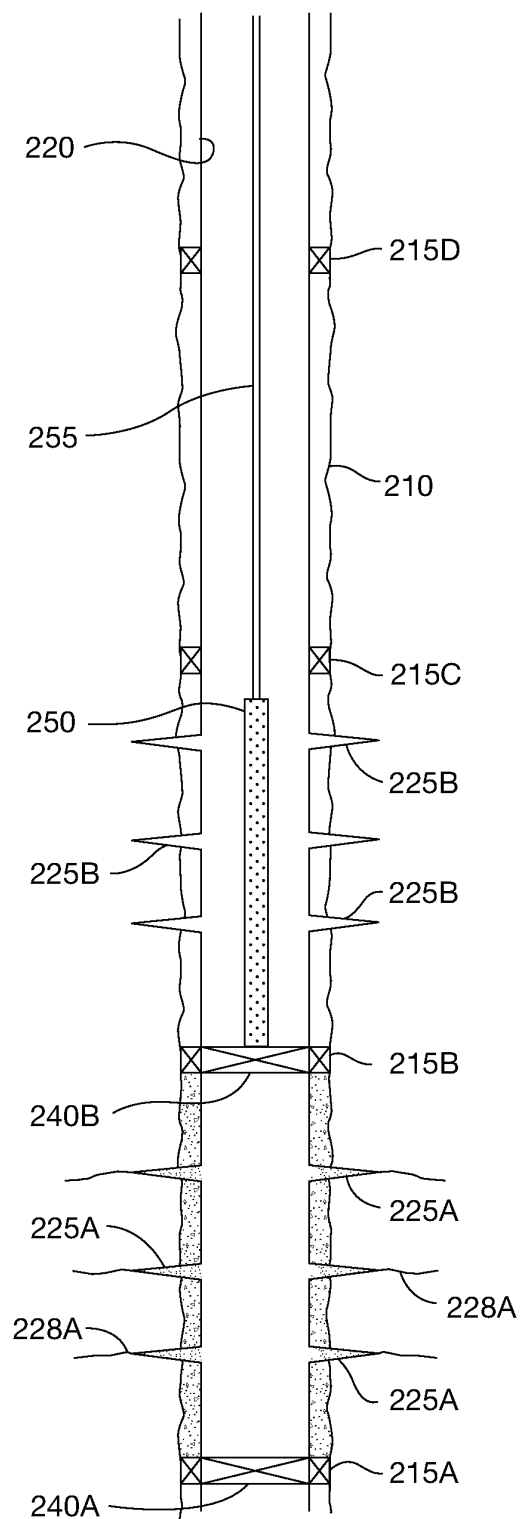


FIG. 2D

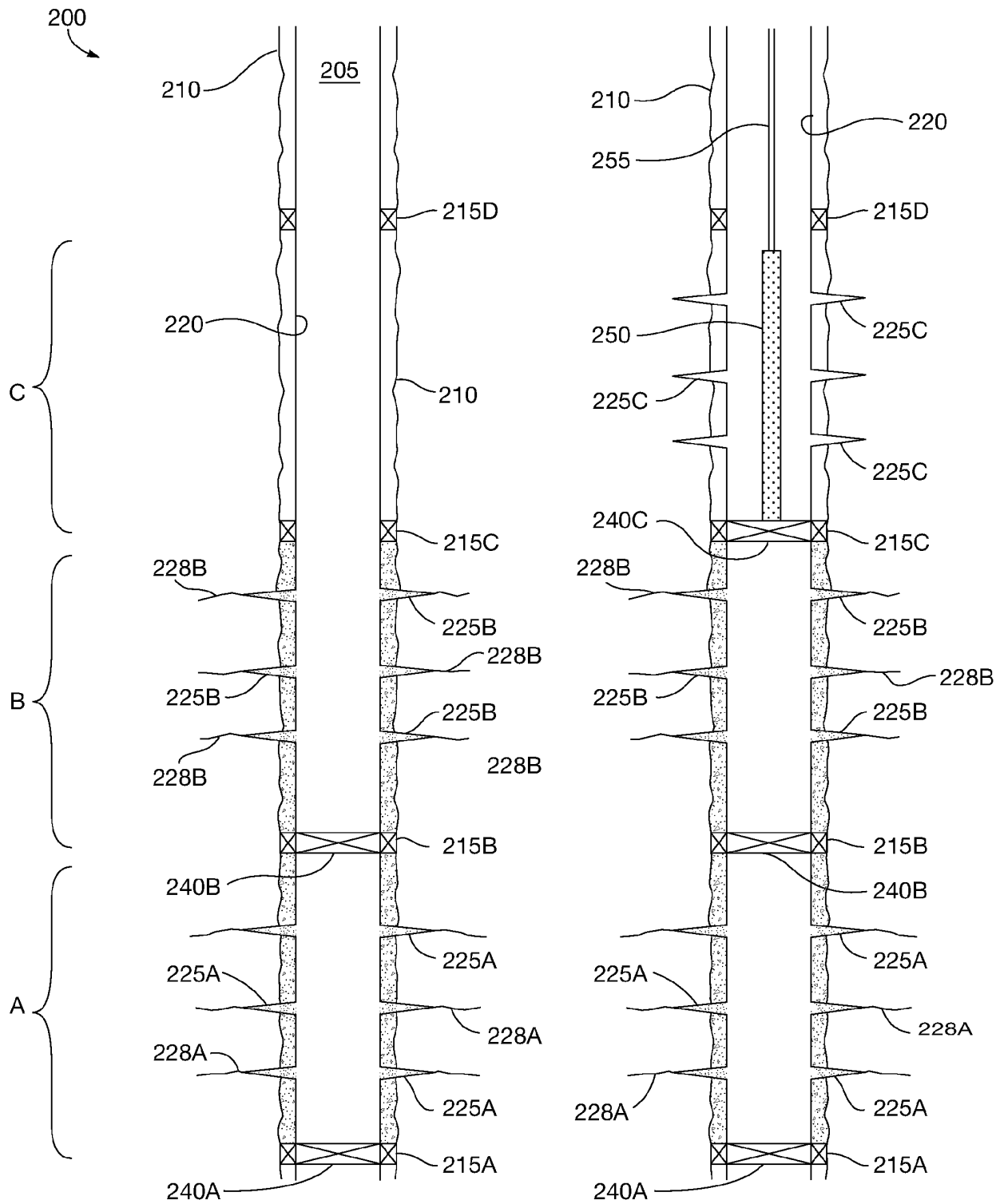


FIG. 2E

FIG. 2F

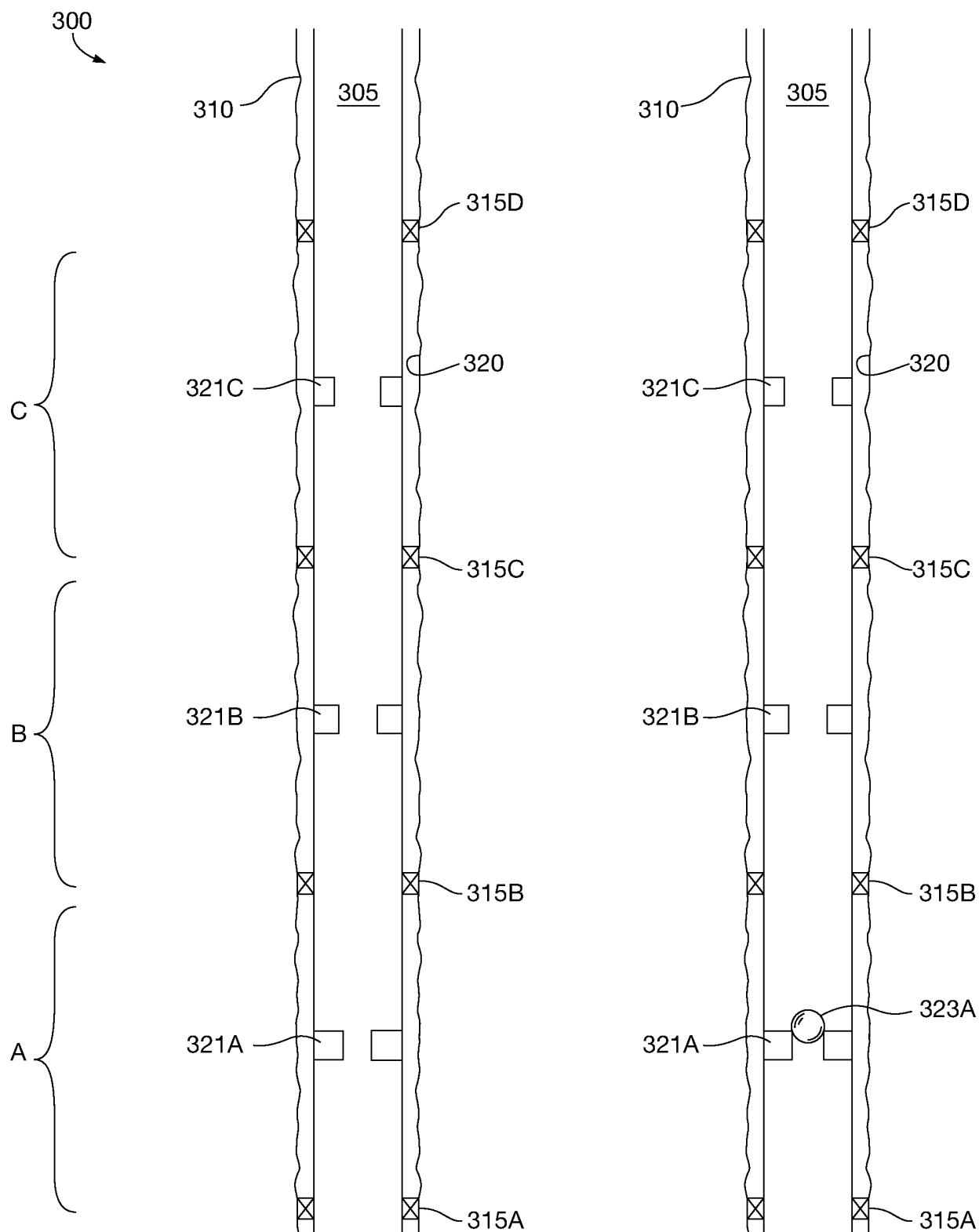


FIG. 3A

FIG. 3B

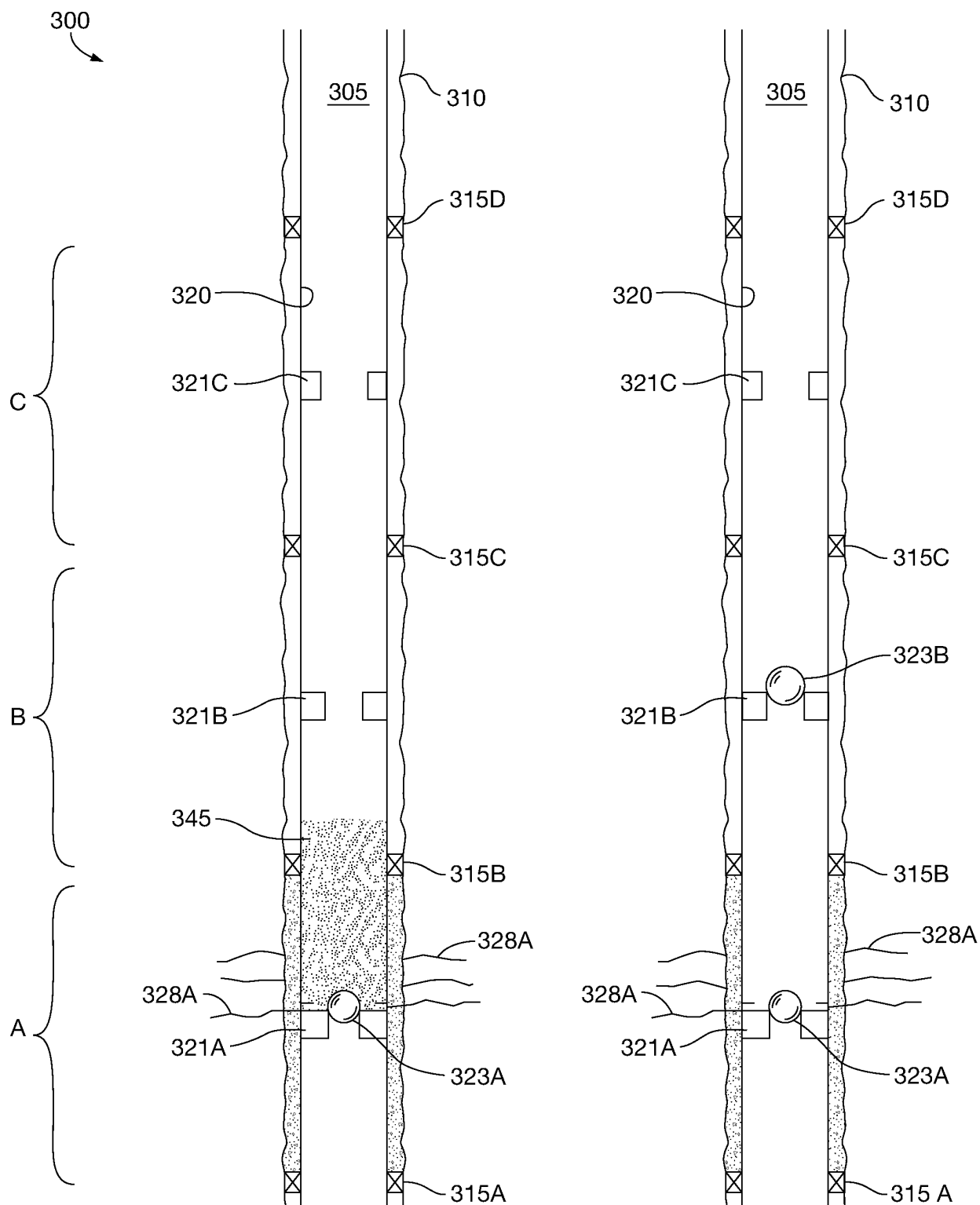


FIG. 3C

FIG. 3D

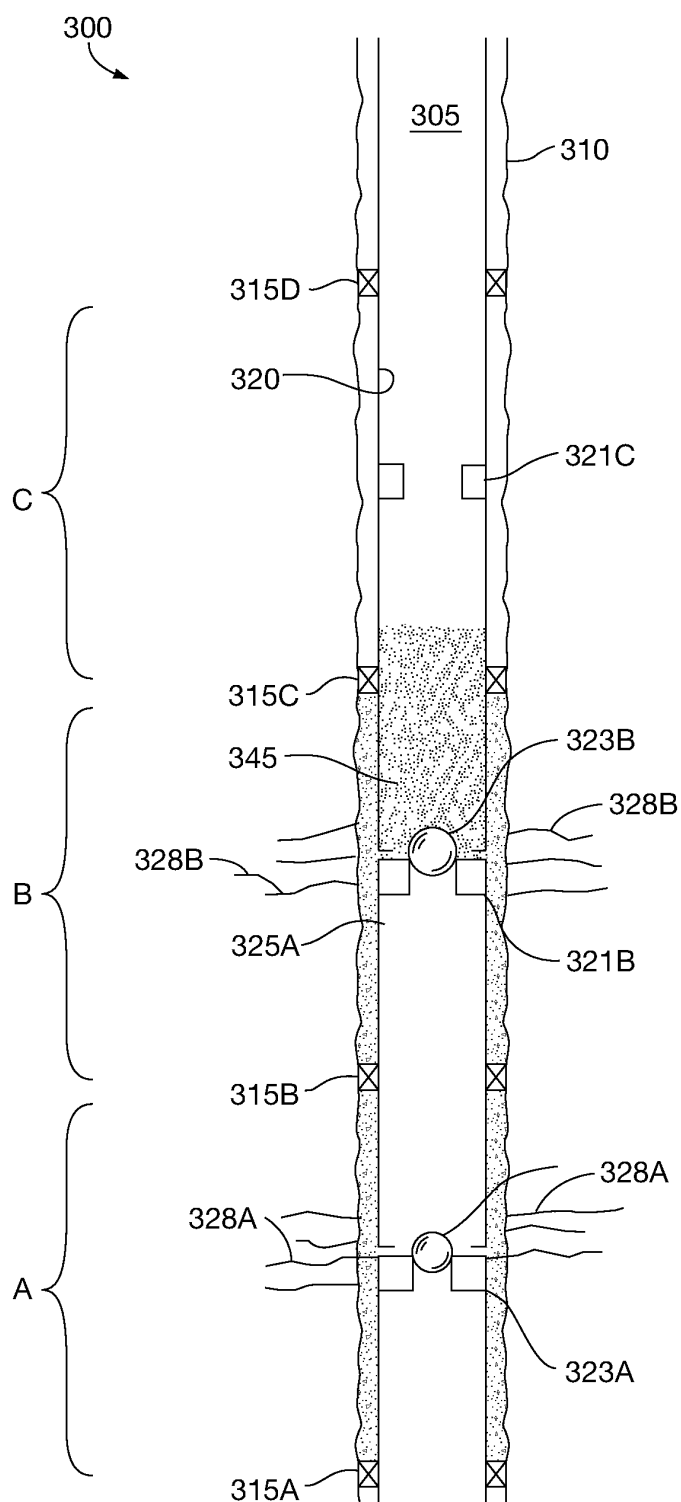


FIG. 3E

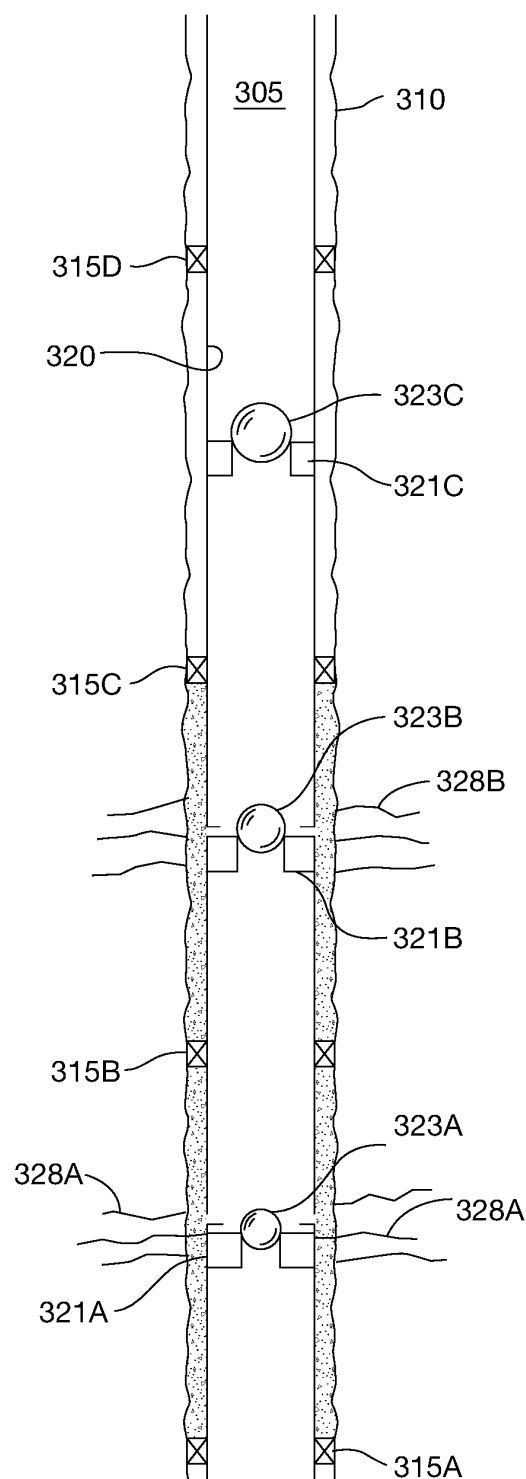


FIG. 3F

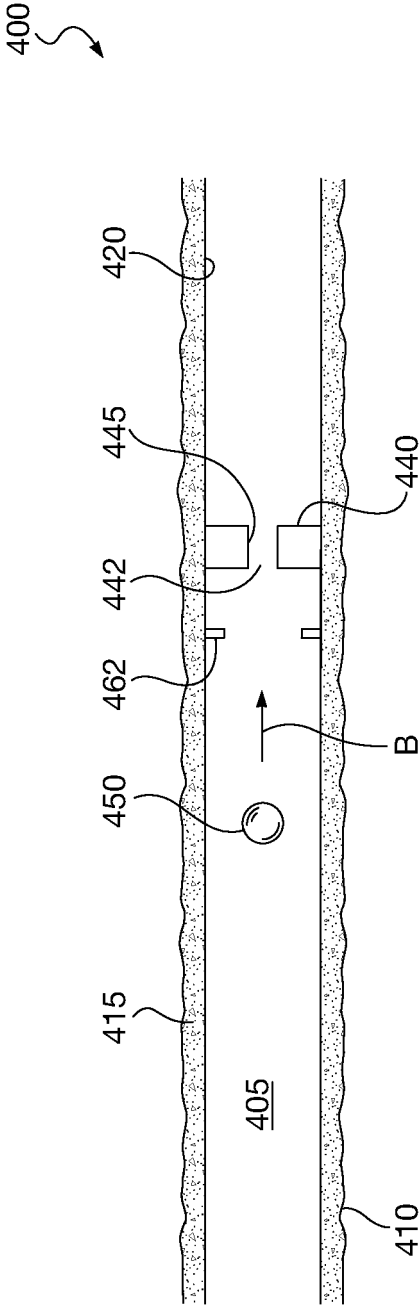


FIG. 4A

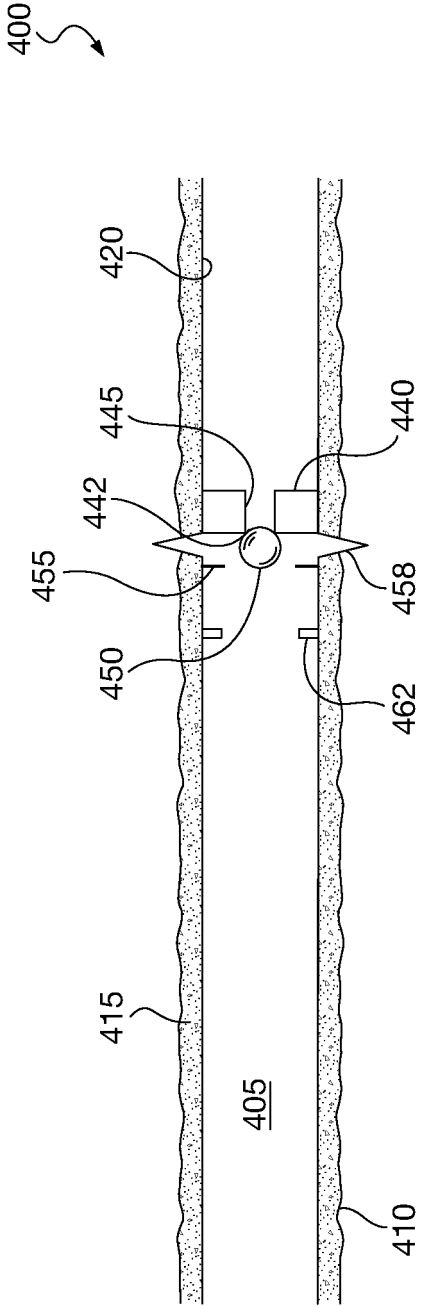


FIG. 4B

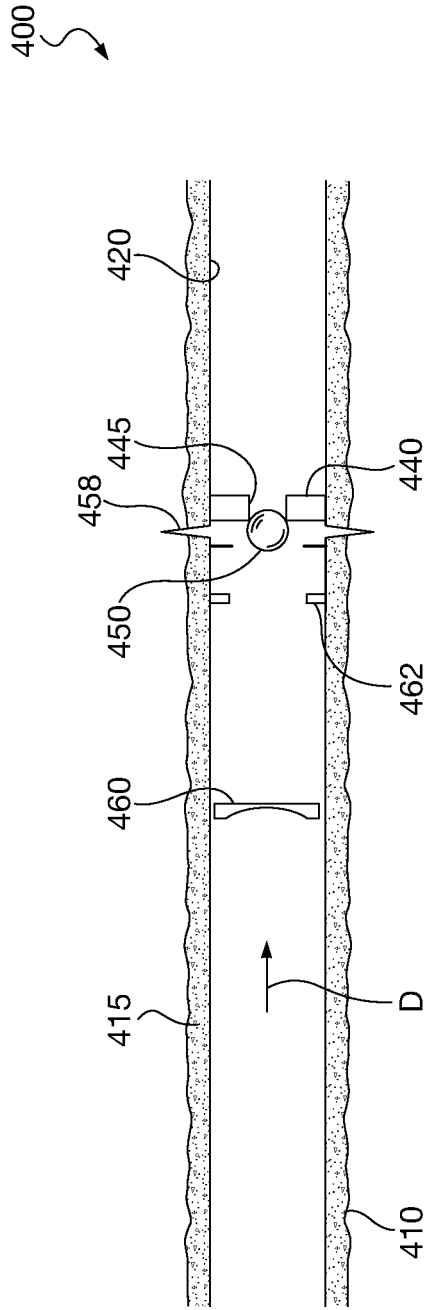


FIG. 4C

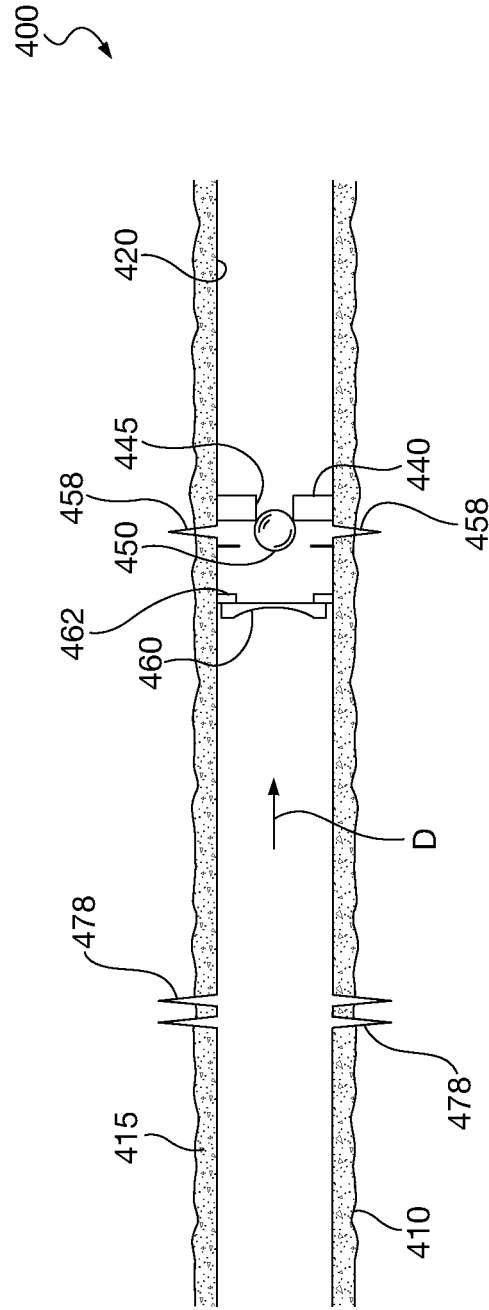


FIG. 4D

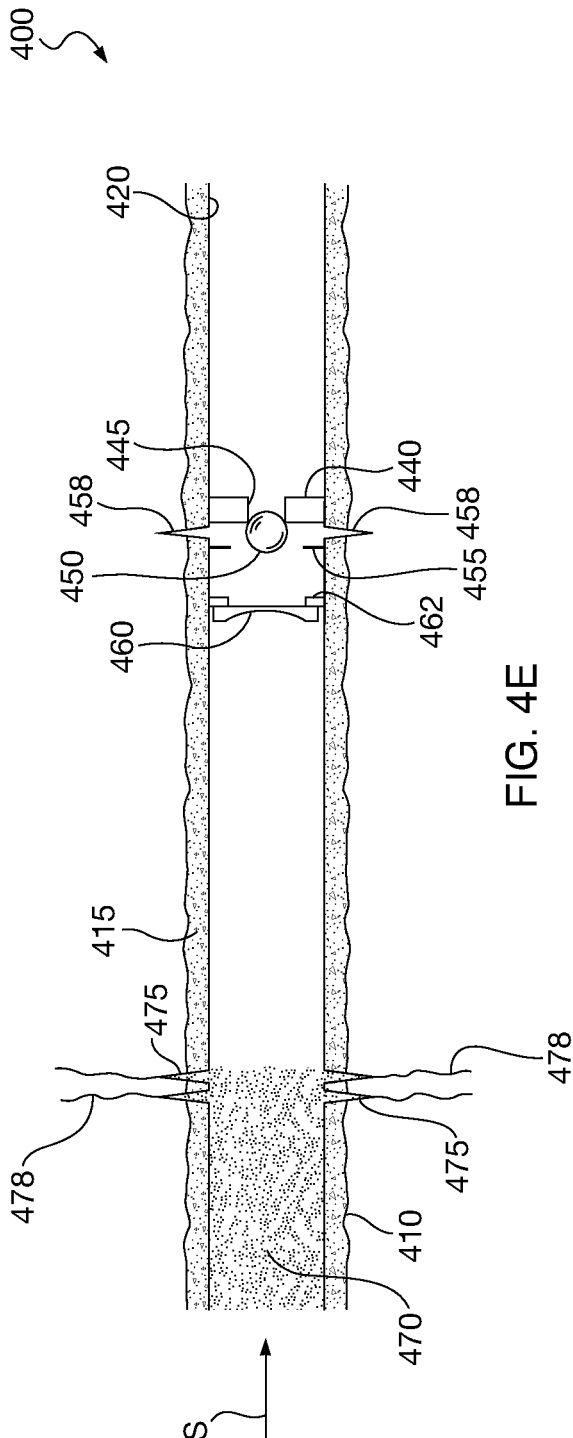


FIG. 4E

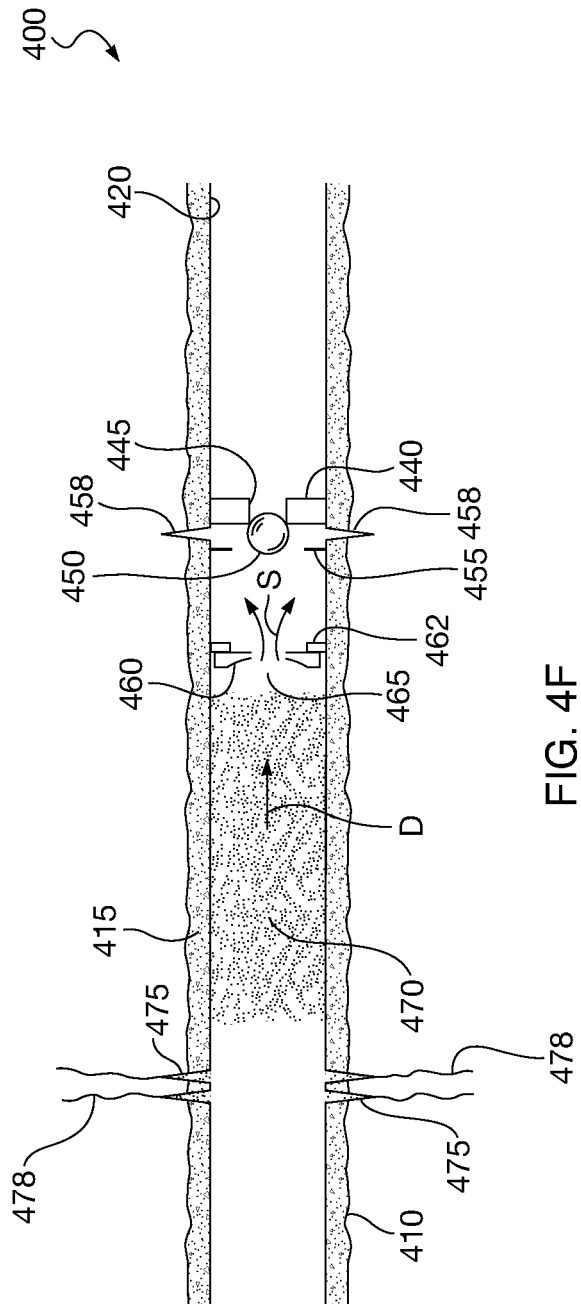
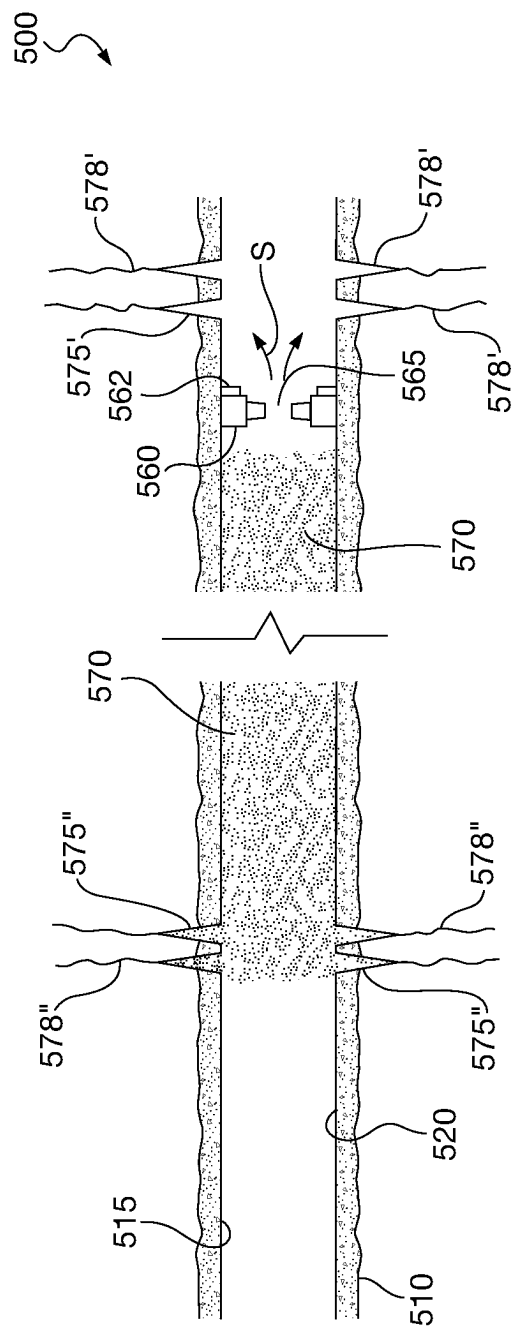
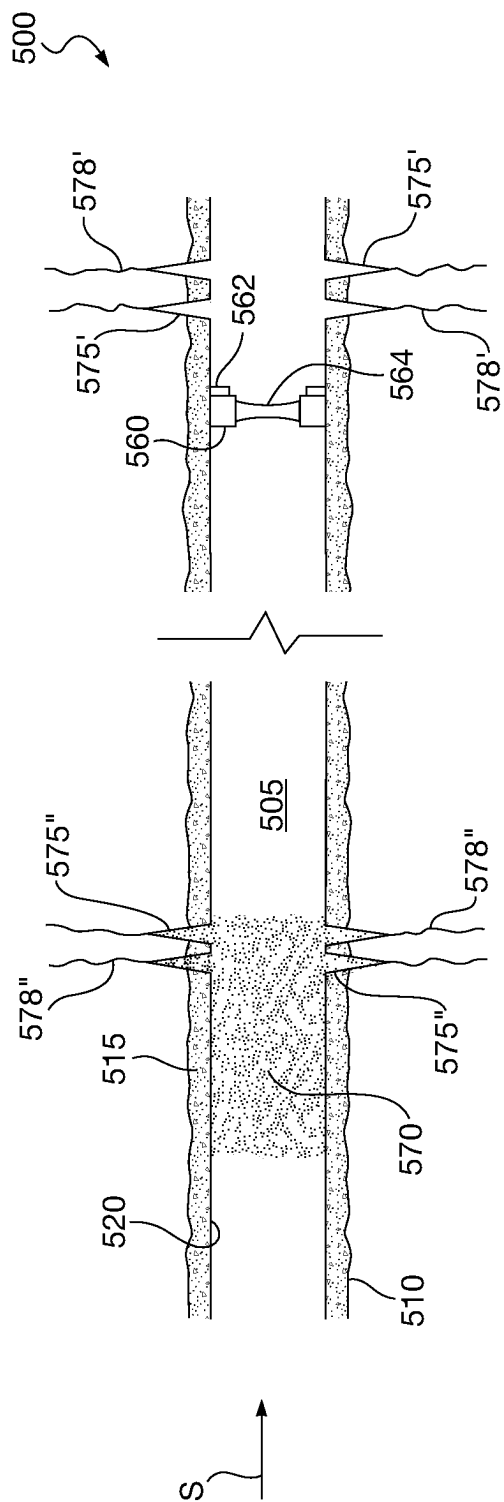


FIG. 4F



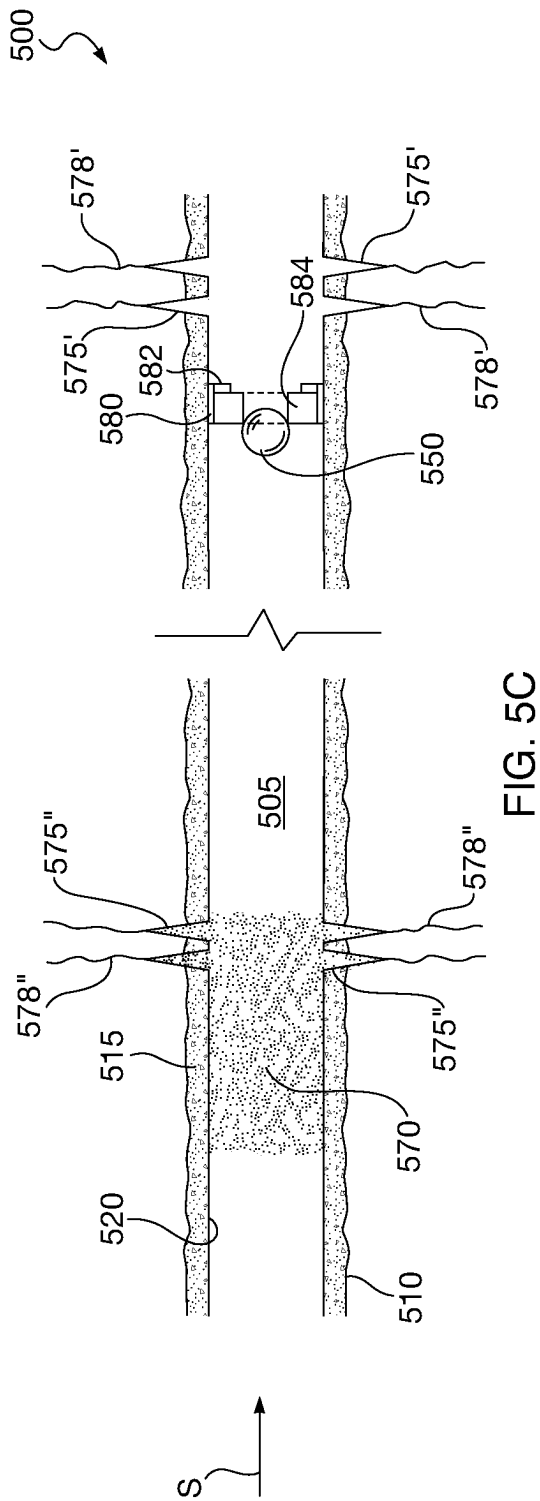


FIG. 5C

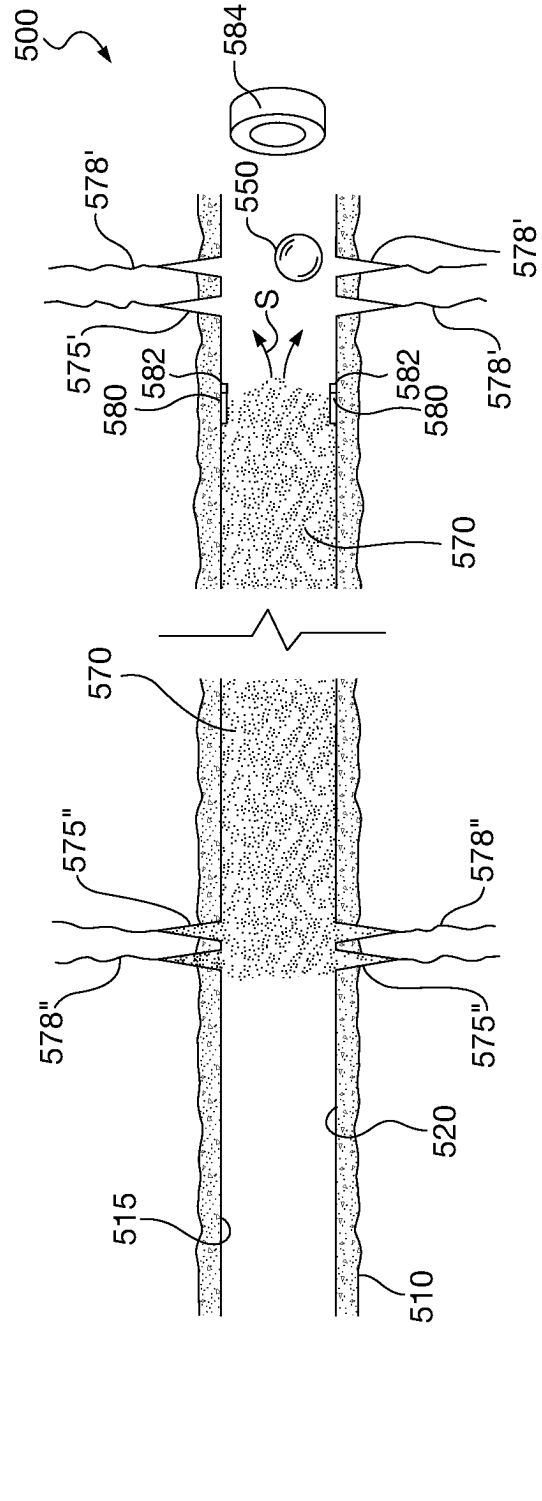


FIG. 5D

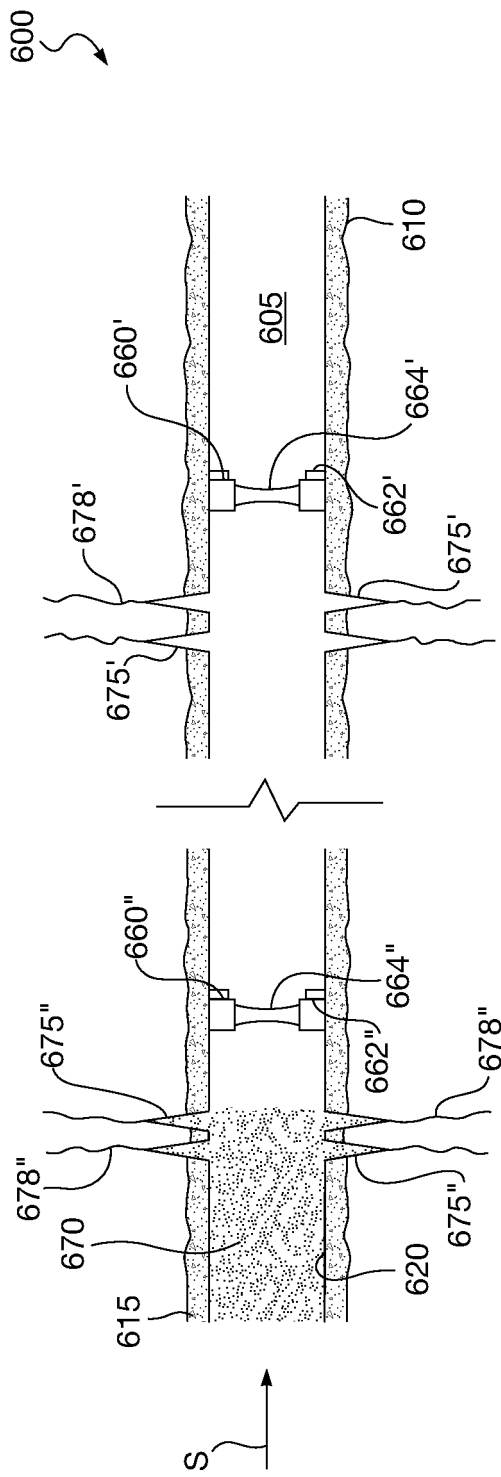


FIG. 6A

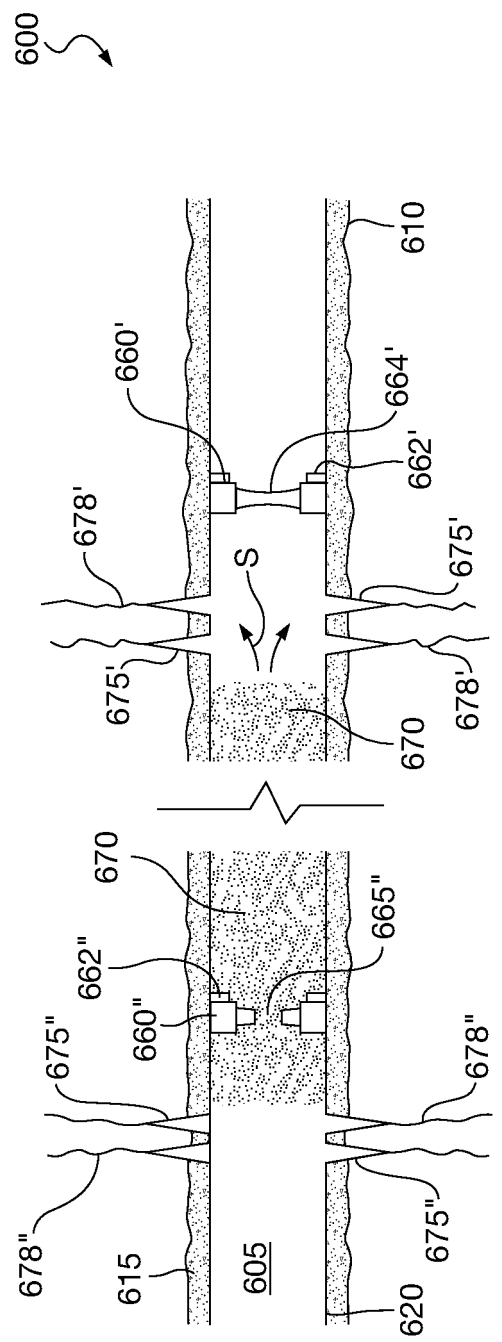


FIG. 6B

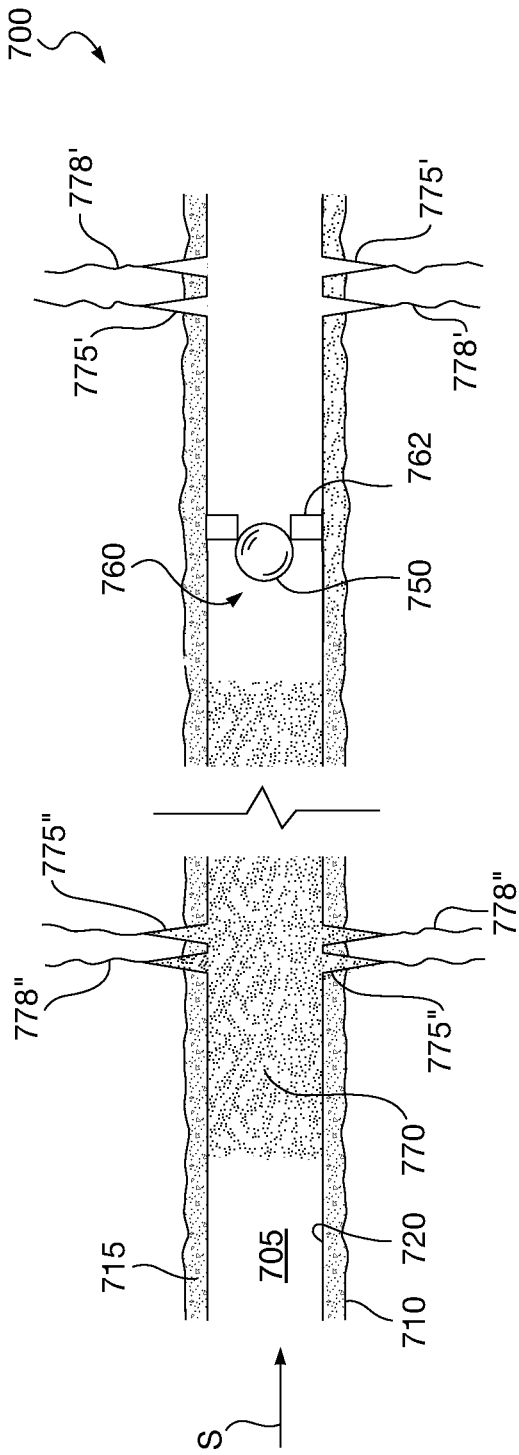


FIG. 7A

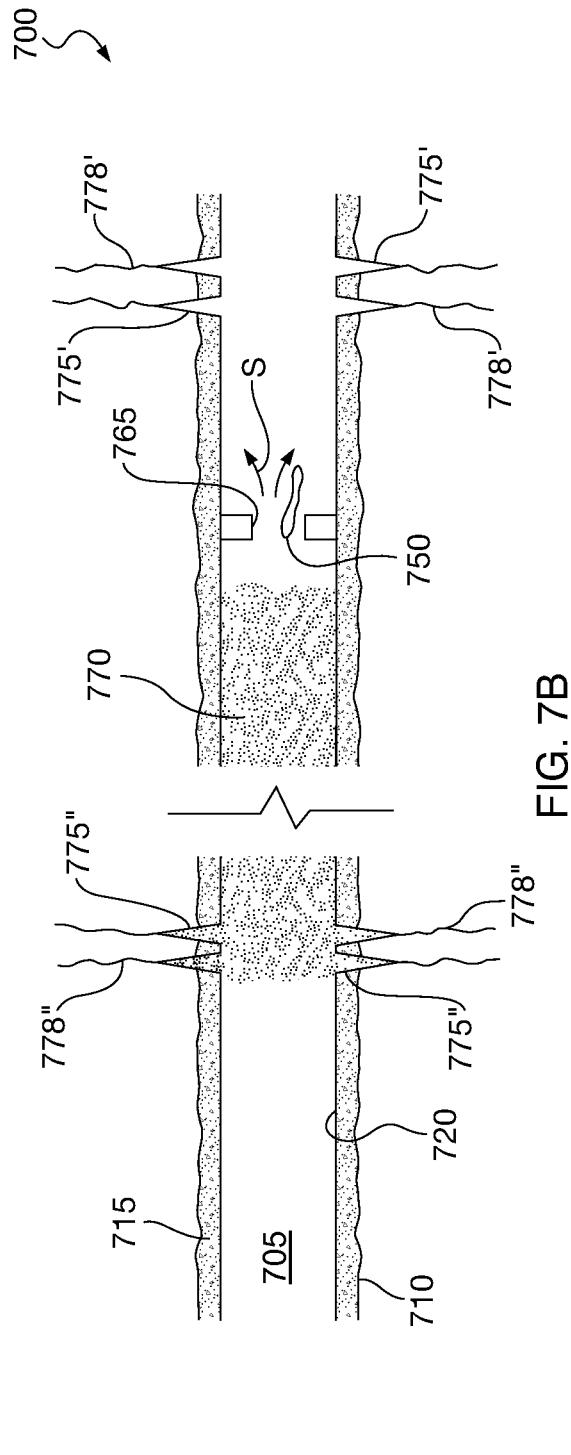


FIG. 7B

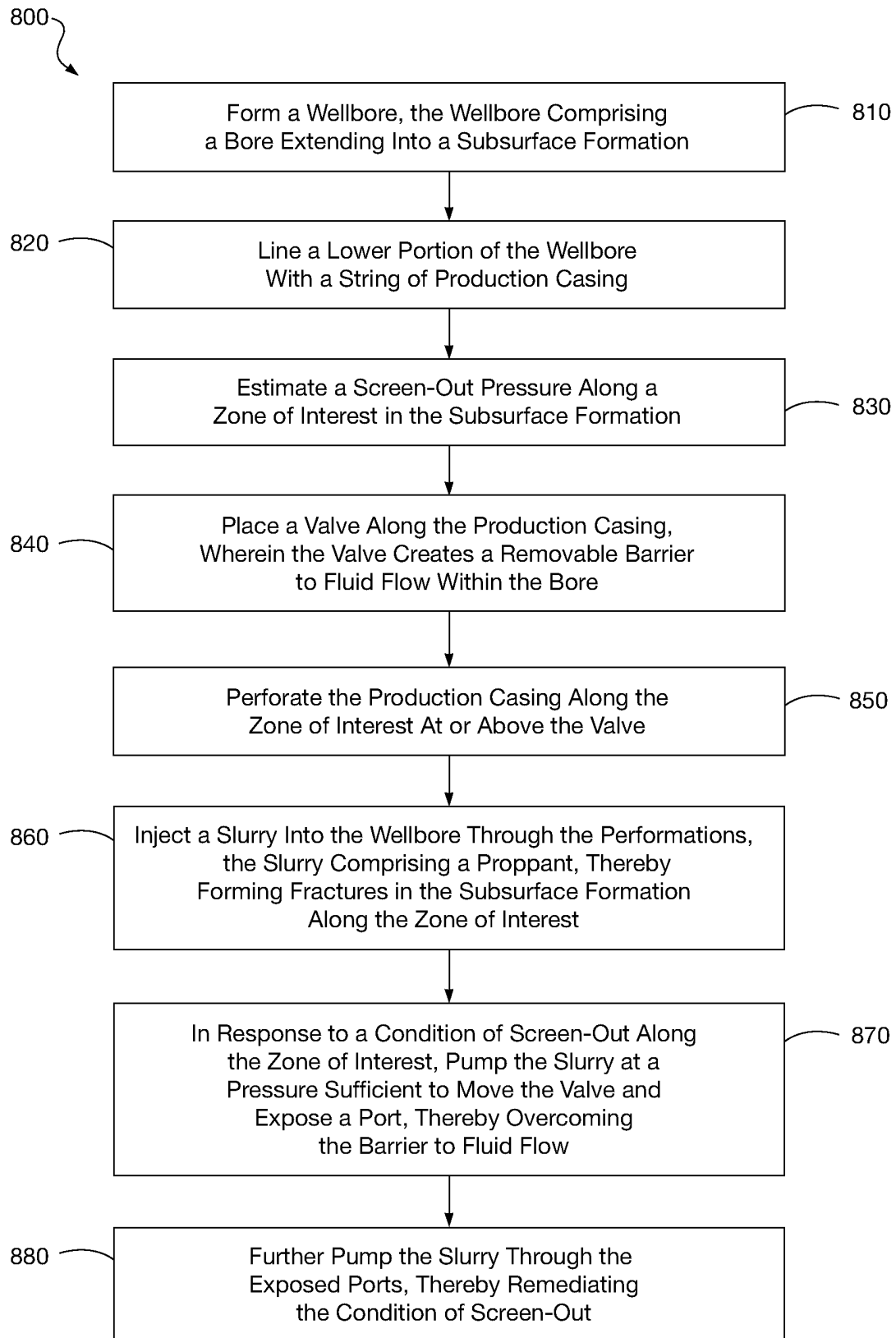


FIG. 8

REFERENCES CITED IN THE DESCRIPTION

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