

(86) **Date de dépôt PCT/PCT Filing Date:** 2014/07/09
(87) **Date publication PCT/PCT Publication Date:** 2015/01/22
(45) **Date de délivrance/Issue Date:** 2020/04/14
(85) **Entrée phase nationale/National Entry:** 2015/11/10
(86) **N° demande PCT/PCT Application No.:** US 2014/045918
(87) **N° publication PCT/PCT Publication No.:** 2015/009501
(30) **Priorité/Priority:** 2013/07/17 (US13/944,613)

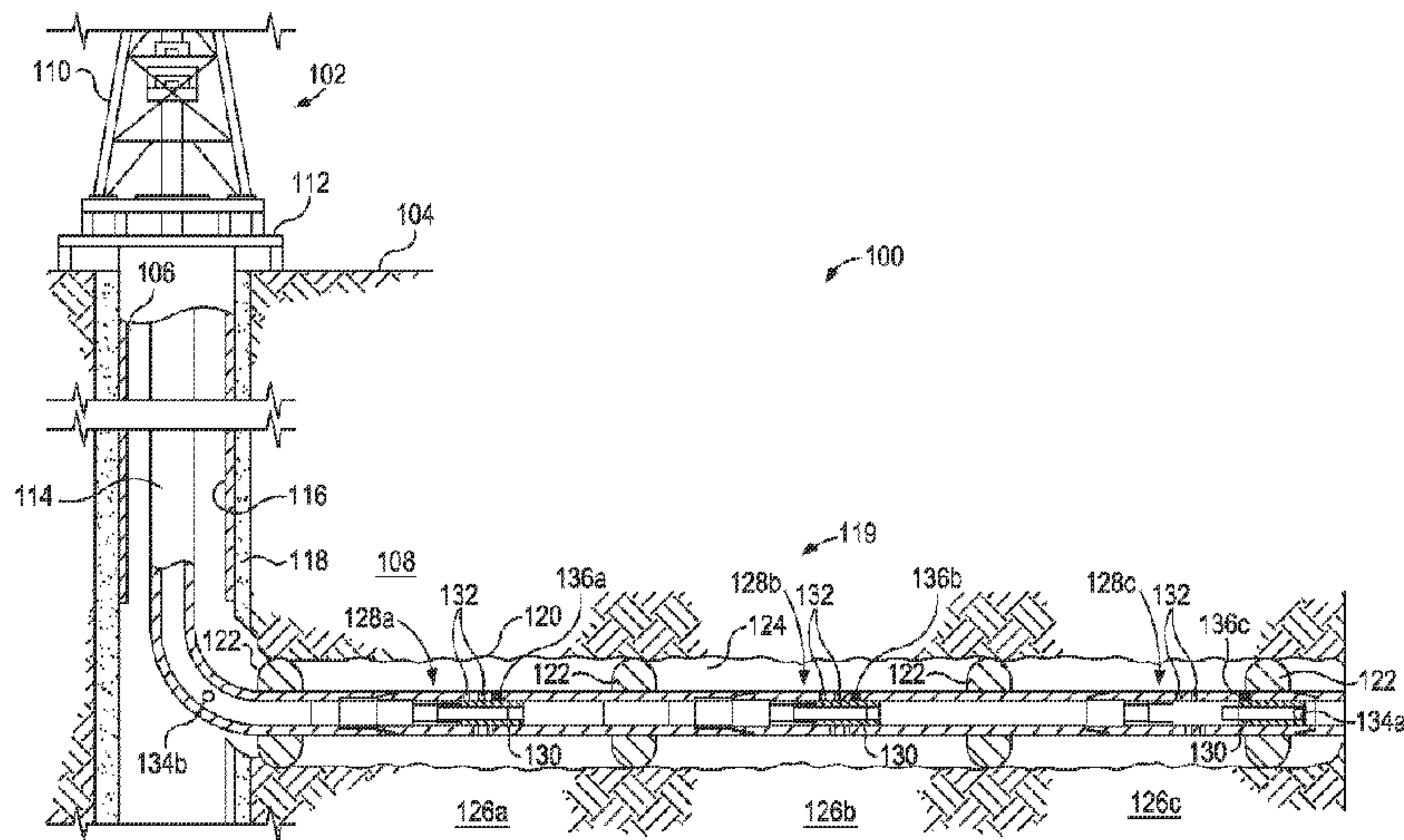
(51) **CI.Int./Int.CI. E21B 43/25** (2006.01),
C09K 8/60 (2006.01), **E21B 43/26** (2006.01)

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(54) **Titre : SYSTEMES ET PROCEDES DE STIMULATION DE PUITS DE FORAGE A INTERVALLES MULTIPLES**
 (54) **Title: MULTIPLE-INTERVAL WELLBORE STIMULATION SYSTEM AND METHOD**



(57) Abrégé/Abstract:

Systems and methods for carrying out multiple-interval stimulation of a wellbore. One disclosed method includes introducing one or more wellbore projectiles into a work string including a completion assembly having a first downhole tool arranged within a first interval, a second downhole tool arranged within a second interval, and a third downhole tool arranged within a third interval that interposes the first and second intervals, detecting the one or more wellbore projectiles with first and second sensors of the first and second downhole tools, opening first and second sliding sleeves arranged within the first and second downhole tools, treating the first and second intervals, sealing the first and second intervals, detecting a wellbore projectile with a third sensor of the third downhole tool, opening a third sliding sleeve arranged within the third downhole tool, and treating the third interval independent of the first and second intervals.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property

Organization

International Bureau

(43) International Publication Date

22 January 2015 (22.01.2015)



(10) International Publication Number

WO 2015/009501 A1

(51) International Patent Classification:

E21B 43/25 (2006.01) C09K 8/60 (2006.01)

E21B 43/26 (2006.01)

(21) International Application Number:

PCT/US2014/045918

(22) International Filing Date:

9 July 2014 (09.07.2014)

(25) Filing Language:

English

(26) Publication Language:

English

(30) Priority Data:

13/944,613

17 July 2013 (17.07.2013)

US

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(81) Designated States (unless otherwise indicated, for every kind of national protection available): AE, AG, AL, AM,

AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Declarations under Rule 4.17:

— as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))

Published:

— with international search report (Art. 21(3))

(54) Title: MULTIPLE-INTERVAL WELLBORE STIMULATION SYSTEM AND METHOD

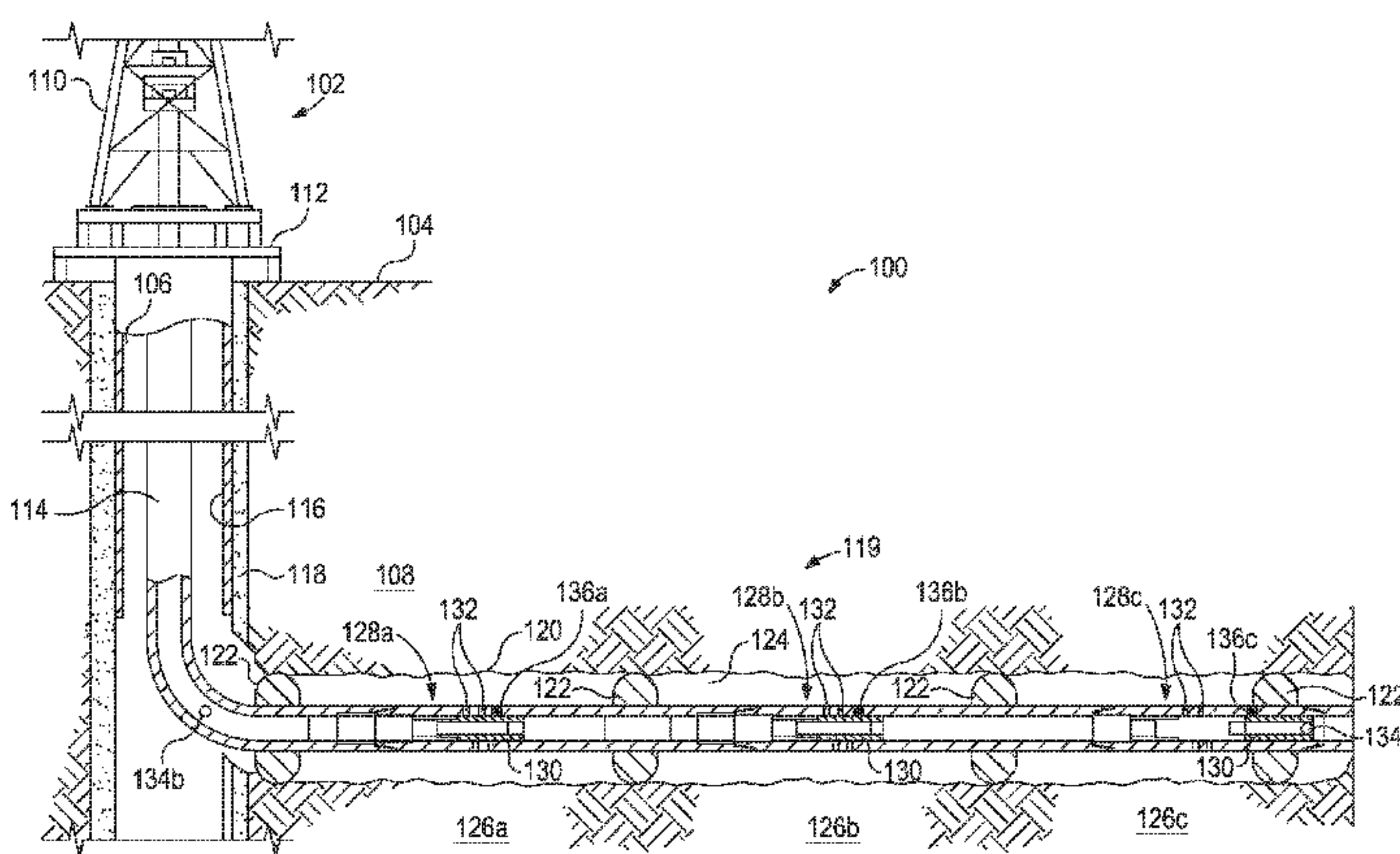


FIG. 1

(57) Abstract: Systems and methods for carrying out multiple-interval stimulation of a wellbore. One disclosed method includes introducing one or more wellbore projectiles into a work string including a completion assembly having a first downhole tool arranged within a first interval, a second downhole tool arranged within a second interval, and a third downhole tool arranged within a third interval that interposes the first and second intervals, detecting the one or more wellbore projectiles with first and second sensors of the first and second downhole tools, opening first and second sliding sleeves arranged within the first and second downhole tools, treating the first and second intervals, sealing the first and second intervals, detecting a wellbore projectile with a third sensor of the third downhole tool, opening a third sliding sleeve arranged within the third downhole tool, and treating the third interval independent of the first and second intervals.

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MULTIPLE-INTERVAL WELLBORE STIMULATION SYSTEM AND METHOD

BACKGROUND

5 **[0001]** The present disclosure relates generally to wellbore operations and, more particularly, to systems and methods for carrying out multiple-interval stimulation of a wellbore.

[0002] Hydrocarbon-producing wells are often stimulated by hydraulic fracturing operations in order to enhance the production of hydrocarbons present
10 in subterranean formations. During a typical fracturing operation, a servicing fluid (*i.e.*, a fracturing fluid or a perforating fluid) may be injected into a subterranean formation penetrated by a wellbore at a hydraulic pressure sufficient to create or enhance fractures within the subterranean formation. The resulting fractures serve to increase the conductivity potential for extracting
15 hydrocarbons from the subterranean formation.

[0003] In some wellbores, it may be desirable to selectively generate multiple fractures along the wellbore at predetermined distances apart from each other, thereby creating multiple-interval “pay zones” in the subterranean formation. Some pay zones may extend a substantial distance along the axial
20 length of the wellbore. In order to adequately fracture the subterranean formation encompassing such zones, it may be advantageous to introduce a stimulation fluid via multiple stimulation assemblies arranged within the wellbore at spaced apart locations on a work string extended therein. Each stimulation assembly may include, for example, a sliding sleeve configured to be opened
25 and shut in order to allow fluid communication between the interior of the work string and the surrounding subterranean formation.

[0004] Alternatively, each interval can be treated using a method known as “plug-and-perf” where charges are run in hole using wireline or coiled tubing. Once downhole, the charges are then fired to create perforations in the
30 casing string. The interval may then be treated by pumping proppant fluids into the interval. A plug is then run on wireline or coiled tubing to seal the wellbore such that the first perforations are then below the plug and therefore sealed from the wellbore above. More perforations are then created using the process previously mentioned, and those perforations are created above the plug. This

interval is then treated, and the process is then repeated as many times as desired moving upwards within the wellbore.

[0005] One method recently implemented for multiple-interval fracturing is the alternate sequence fracturing "ASF" process. One ASF process that is now being used is referred to as the "Texas Two-Step" method. This method involves conventional fracturing of individual intervals in a single well, but with a change in the sequence by which the formation fracturing is undertaken. The method starts at the toe of the well where a first interval is stimulated by hydraulic fracturing. Then, moving upwards within the well towards the heel, a second interval is stimulated such that a degree of interference between the two fractures is generated. A third interval is then stimulated between the first and second previously fractured intervals, thereby taking advantage of the altered stress in the rock by fluidly connecting to stress-relief fractures generated from the first and second fractures.

[0006] The Texas Two-Step method takes advantage of sliding sleeve technology where each interval is defined by at least one sliding sleeve and an annular wellbore isolation device (*e.g.*, wellbore packer) arranged at opposing axial ends of each interval. The process of stimulating each interval using this method, however, can be a time-consuming process requiring multiple trips into the wellbore with wireline and/or coiled tubing tools to accomplish the job. This disadvantage is further exacerbated in wells where multiple Texas Two-Step operations are undertaken. Alternatively, alternating sequence fracturing can be performed by other methods involving coiled tubing. These processes, however, are also time intensive and costly.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] The following figures are included to illustrate certain aspects of the present disclosure, and should not be viewed as exclusive embodiments. The subject matter disclosed is capable of considerable modifications, alterations, combinations, and equivalents in form and function, without departing from the scope of this disclosure.

[0008] FIG. 1 is a schematic of an exemplary well system which can embody or otherwise employ one or more principles of the present disclosure, according to one or more embodiments.

[0009] FIGS. 2A-2D illustrate progressive partial cut-away views of one of the downhole tools of FIG. 1, according to one or more embodiments.

[0010] FIG. 3 illustrates a cross-sectional view of a completion assembly of the well system of FIG. 1 during a first stage of operation, according to one or more embodiments.

[0011] FIG. 4 illustrates a cross-sectional view of a completion assembly of the well system of FIG. 1 during a second stage of operation, according to one or more embodiments.

[0012] FIG. 5 illustrates a cross-sectional view of a completion assembly of the well system of FIG. 1 during a third stage of operation, according to one or more embodiments.

[0013] FIGS. 6A and 6B illustrate separate isometric views of an exemplary wellbore projectile that may be used in the systems described herein, according to one or more embodiments.

[0014] FIG. 7 is a schematic diagram of a method of treating multiple intervals of a formation, according to one or more embodiments disclosed.

DETAILED DESCRIPTION

[0015] The present disclosure relates generally to wellbore operations and, more particularly, to systems and methods for carrying out multiple-interval stimulation of a wellbore.

[0016] The present disclosure provides an improved method and system of stimulating or treating multiple intervals in a wellbore without the need to run into the wellbore multiple times with coiled tubing or wireline. More particularly, the disclosed systems may include at least three sliding sleeve assemblies arranged to treat three corresponding, laterally spaced pay zones or intervals in a subterranean formation. Each assembly may include a sensor configured to detect a wellbore projectile, such as a frac ball, that exhibits magnetic properties. One or more wellbore projectiles may interact with the first and third sliding sleeve assemblies, thereby allowing the first and third intervals to be treated simultaneously while the second interposing interval remains shut. Following stimulation of the first and third intervals, a diverting agent may be used to temporarily seal the first and third intervals.

[0017] A third magnetic wellbore projectile may then be used to interact with the second sliding sleeve assembly, thereby allowing the second

interval to be treated while the first and third intervals are temporarily sealed. Once the diverting agent that sealed first and third intervals degrades, the wellbore projectiles may each be returned to the surface under pressure derived from the various intervals, and production operations may then commence.

5 Advantageously, each of the three intervals may be stimulated and produced without having to run into the wellbore multiple times to shift sleeves using shifting tools coupled to coiled tubing or wireline. As a result, a significant amount of time and cost is saved.

10 **[0018]** Referring to FIG. 1, illustrated is an exemplary well system 100 which can embody or otherwise employ one or more principles of the present disclosure, according to one or more embodiments. As illustrated, the well system 100 may include an oil and gas rig 102 arranged at the Earth's surface 104 and a wellbore 106 extending therefrom and penetrating a subterranean earth formation 108. Even though FIG. 1 depicts a land-based oil and gas rig 15 102, it will be appreciated that the embodiments of the present disclosure are equally well suited for use in other types of rigs, such as offshore platforms, or rigs used in any other geographical location. In other embodiments, the rig 102 may be replaced with a wellhead installation, without departing from the scope of the disclosure.

20 **[0019]** The rig 102 may include a derrick 110 and a rig floor 112, and the derrick 110 may support or otherwise help manipulate the axial position of a work string 114 extended within the wellbore 106 from the rig floor 112. As used herein, the term "work string" refers to one or more types of connected lengths of tubulars such as drill pipe, drill string, landing string, production 25 tubing, coiled tubing combinations thereof, or the like. In exemplary operation, the work string 114 may be utilized in drilling, stimulating, completing, or otherwise servicing the wellbore 106, or various combinations thereof.

30 **[0020]** As illustrated, the wellbore 106 may extend substantially vertically away from the surface 104 over a vertical wellbore portion. In other embodiments, the wellbore 106 may otherwise deviate at any angle from the surface 104 over a deviated or horizontal wellbore portion. In other applications, portions or substantially all of the wellbore 106 may be vertical, deviated, horizontal, and/or curved. Moreover, use of directional terms such as above, below, upper, lower, upward, downward, uphole, downhole, and the like 35 are used in relation to the illustrative embodiments as they are depicted in the

figures, the upward direction being toward the top of the corresponding figure and the downward direction being toward the bottom of the corresponding figure, the uphole direction being toward the heel or surface of the well and the downhole direction being toward the toe or bottom of the well.

5 **[0021]** In an embodiment, the wellbore 106 may be at least partially cased with a casing string 116 or may otherwise remain at least partially uncased. The casing string 116 may be secured within the wellbore 106 using, for example, cement 118. In other embodiments, the casing string 116 may be only partially cemented within the wellbore 106 or, alternatively, the casing
10 string 116 may be entirely un-cemented, without departing from the scope of the disclosure. The work string 114 may be coupled to a completion assembly 119 that extends into a branch or lateral portion 120 of the wellbore 106. As illustrated, the lateral portion 120 may be an uncased or "open hole" section of the wellbore 106. It is noted that although FIG. 1 depicts horizontal and vertical
15 portions of the wellbore 106, the principles of the apparatus, systems, and methods disclosed herein may be similarly applicable to or otherwise suitable for use in wholly horizontal or vertical wellbore configurations. Consequently, the horizontal or vertical nature of the wellbore 106 should not be construed as limiting the present disclosure to any particular wellbore 106 configuration.

20 **[0022]** The completion assembly 119 may be arranged or otherwise seated within the lateral portion 120 of the wellbore 106 using one or more packers 122 or other wellbore isolation devices known to those skilled in the art. The packers 122 may be configured to seal off an annulus 124 defined between the completion assembly 119 and the walls of the wellbore 106. As a result, the
25 subterranean formation 108 may be effectively divided into multiple intervals or "pay zones" 126 (shown as intervals 126a, 126b, and 126c) which may be stimulated and/or produced independently via isolated portions of the annulus 124 defined between adjacent pairs of packers 122. While only three intervals 126a-c are shown in FIG. 1, those skilled in the art will readily recognize that
30 any number of intervals 126a-c may be defined or otherwise used in the well system 100, without departing from the scope of the disclosure.

[0023] The completion assembly 119 may include one or more downhole tools 128 (shown as 128a, 128b, and 128c) arranged in, coupled to, or otherwise forming an integral part of the work string 114. As illustrated, at
35 least one downhole tool 128a-c may be arranged in the completion assembly

119 in each interval 126a-c, but those skilled in the art will readily appreciate that more than one downhole tool 128 may be arranged therein, without departing from the scope of the disclosure. The downhole tools 128a-c may include a variety of tools, devices, or machines known to those skilled in the art
5 used in the preparation, stimulation, and production of the subterranean formation 108.

[0024] In the illustrated embodiment, however, the downhole tool 128a-c in each interval 126a-c may include or otherwise encompass a sliding sleeve assembly that may be actuated in order to provide fluid communication
10 between the interior of the work string 114 and the annulus 124 adjacent each corresponding interval 126a-c. As depicted, each downhole tool 128a-c may include a sliding sleeve 130 that is axially movable to expose one or more ports 132 defined in the corresponding body of the work string 114 or downhole tool 128a-c. Once exposed, the ports 132 may facilitate fluid communication
15 between the annulus 124 and the interior of the work string 114 such that stimulation and production operations may be undertaken in each corresponding interval 126a-c of the formation 108.

[0025] It should be noted that, while the downhole tools 128a-c are shown in FIG. 1 as being employed in an open hole section of the wellbore 106,
20 the principles of the present disclosure are equally applicable to completed or cased sections of the wellbore 106. In such embodiments, the cased wellbore 106 may be perforated at predetermined locations in each interval 126a-c using any known methods (*e.g.*, explosives, hydrazetting, etc.) in the art. Such perforations serve to facilitate fluid conductivity between the interior of the work
25 string 114 and the surrounding intervals 126a-c of the formation 108.

[0026] In order to actuate, trigger, or manipulate the downhole tools 128a-c and thereby expose the corresponding ports 132, one or more wellbore projectiles 134 (shown in FIG. 1 as projectiles 134a and 134b) may be introduced into the wellbore 106 and conveyed to the downhole tools 128a-c to
30 engage or otherwise interact therewith. The wellbore projectiles 134 may include, but are not limited to balls (*e.g.*, “frac” balls), darts, wipers, plugs, or any combination thereof. The wellbore projectiles 134 may be conveyed through the work string 114 and to the completion assembly 119 by any known technique. For example, the wellbore projectiles 134 can be dropped through
35 the work string 114 from the surface 104, pumped by flowing fluid through the

interior of the work string 114, self-propelled, conveyed by wireline, slickline, coiled tubing, etc.

[0027] Each wellbore projectile 134 may further exhibit known magnetic properties, and/or produce a known magnetic field, pattern, or combination of magnetic fields, which is/are detected by one or more sensors 136 (shown as sensors 136a, 136b, and 136c) associated with each downhole tool 128a-c. Each sensor 136a-c can include any type of sensor capable of detecting the presence of the magnetic field(s) produced by the wellbore projectiles 134 and/or one or more other magnetic properties of the wellbore projectiles 134. Suitable sensors 136a-c can include, but are not limited to, magneto-resistive sensors, Hall-effect sensors, conductive coils, combinations thereof, and the like. In some embodiments, permanent magnets can be combined with one or more of the sensors 136a-c in order to create a magnetic field that is disturbed by the wellbore projectiles 134, and a detected change in the magnetic field can be an indication of the presence of the wellbore projectiles 134.

[0028] Each sensor 136a-c may be connected to associated electronic circuitry (not shown in FIG. 1) which determines whether the associated sensor has detected a particular predetermined magnetic field, or pattern or combination of magnetic fields, or other magnetic properties of the wellbore projectiles 134. For example, the electronic circuitry could have the predetermined magnetic field(s) or other magnetic properties programmed into non-volatile memory for comparison to magnetic fields/properties detected by the associated sensor.

[0029] Once a wellbore projectile 134 is detected by the sensors 136a-c, the electronic circuitry may trigger actuation of the corresponding downhole tool 128a-c using one or more associated actuation devices (not shown in FIG. 1). In some embodiments, however, actuation of the associated downhole tool 128a-c may not be triggered until a predetermined number or combination of wellbore projectiles 134 has been detected by the sensor 136a-c. In other embodiments, actuation of the associated downhole tool 128a-c may not be triggered until a predetermined time period has passed following detection of a wellbore projectile 134 or a predetermined number or combination thereof.

[0030] In the illustrated example, a first wellbore projectile 134a has been introduced into the work string 114 and conveyed past each of the sensors

136a-c such that each sensor 136a-c is able to detect and otherwise record its proximity and/or presence. In some embodiments, in response to sensing or otherwise detecting the first wellbore projectile 134a, the third sensor 136c may be configured to trigger actuation of the corresponding third downhole tool 128c.

5 More particularly, once the third sensor 136c detects the first wellbore projectile 134a, associated electronic circuitry may trigger the actuation of a baffle seat (not shown in FIG. 1) arranged within the third downhole tool 128c. As described in greater detail below with reference to FIGS. 2A-2D, the baffle seat of the third downhole tool 128c may be configured to catch and retain a
10 subsequent wellbore projectile 134 (e.g., the second wellbore projectile 134b) conveyed downhole.

[0031] Referring now to FIGS. 2A-2D, with continued reference to FIG. 1, illustrated are progressive partial cut-away views of the third downhole tool 128c, according to one or more embodiments. Similar reference numerals used
15 in FIG. 1 and FIGS. 2A-2D correspond to similar components that will not be described again in detail. The following discussion of the third downhole tool 128c may be generally descriptive also of the second downhole tool 128b, without departing from the scope of the disclosure. As illustrated, the third downhole tool 128c may be coupled at each end to opposing portions of the
20 work string 114. In at least one embodiment, the third downhole tool 128c may be similar in some respects to the injection valves disclosed in co-owned U.S. Patent App. Ser. No. 13/219,790.

[0032] In FIG. 2A, the downhole tool 128c is depicted in a "run-in" or closed configuration, where the sleeve 130 generally occludes the ports 132
25 defined in the body 202 of the tool 128c. The first wellbore projectile 134a is shown in FIG. 2A downhole from the third sensor 136c and proceeding in a downhole direction (e.g., to the right in FIG. 2A). As the first wellbore projectile 134a passes by the third sensor 136c, electronic circuitry 204 associated with the sensor 136c may determine that a predetermined magnetic field(s) or
30 change(s) in magnetic field(s) of the first wellbore projectile 134a has been detected. As a result, the electronic circuitry 204 may be configured to actuate the third downhole tool 128c. In alternative embodiments, as briefly mentioned above, the electronic circuitry 204 may be configured to actuate the third downhole tool 128c following the detection of a predetermined number or
35 combination of wellbore projectiles 134, or following a predetermined time

period after detection of the first wellbore projectile 134a or a predetermined number or combination of wellbore projectiles 134.

[0033] Once the appropriate signal (*e.g.*, magnetic property or properties) has been detected or otherwise sensed, the electronic circuitry 204 may cause that a retractable baffle 206 extend a short distance into the interior of the downhole tool 128c, as depicted in FIG. 2B. This may be accomplished by triggering an actuator 208 associated with the third downhole tool 128c. The actuator 208 may be any mechanical, electro-mechanical, hydraulic, or pneumatic actuation device capable of manipulating the configuration or position of the baffle 206. In at least one embodiment, the actuator 208 may be an electro-hydraulic piston lock similar to the devices disclosed in U.S. Patent App. Ser. No. 13/219,790. Briefly, the actuator 208 may include a piercing member (not shown) configured to pierce a pressure barrier (not shown) that initially isolates first and second chambers (not shown). Once the pressure barrier is pierced, a support fluid flows from the first chamber to the second chamber, thereby generating a pressure differential across the sleeve 130 that displaces the sleeve downward (*e.g.*, to the right in FIGS. 2A-2D).

[0034] Referring to FIG. 2B, as the sleeve 130 moves downward, it engages or otherwise contacts an axial end of the baffle 206, thereby forcing the baffle 206 axially against a baffle containment sleeve 210 arranged on the inner wall of the downhole tool 128c. The baffle 206 may be a retractable landing seat in the form of an expandable ring. As the baffle 206 is forced axially against the baffle containment sleeve 210 by the sleeve 130, the baffle 206 contracts radially and otherwise extends inwardly to a sealing position, as shown in FIG. 2B. In its sealing position, the baffle 206 may be configured to receive and seat a wellbore projectile 134, such as the second wellbore projectile 134b.

[0035] Referring to FIG. 2C, the second wellbore projectile 134b has been introduced into the work string 114, conveyed to the third downhole tool 128c, and subsequently received by the baffle 206 extended into its sealing position. Once seated on the baffle 206, the second wellbore projectile 134b may be configured to substantially seal the interior of the downhole tool 128c such that fluids are generally prevented from passing downhole past that point within the work string 114 (FIG. 1).

[0036] Referring to FIG. 2D, the work string 114 may then be pressurized from the surface 104 (FIG. 1) uphole from the baffle 206 and the

second wellbore projectile 134b. Upon increasing the pressure within the interior of the work string 114, the second wellbore projectile 134b may force the baffle containment sleeve 210 axially downhole a short distance until engaging a shoulder 212 (best seen in FIG. 2C), thereby allowing the sleeve 130 to fully open and expose the ports 132 defined in the body 202. The third downhole tool 128c is shown in FIG. 2D in its open configuration, where the ports 132 are exposed and therefore able to facilitate fluid communication into and out of the work string 114. With the third downhole tool 128c in the open configuration, a fracturing or stimulation fluid may be injected into the surrounding interval 126c (FIG. 1) via the ports 132, as will be discussed below.

[0037] Referring now to FIG. 3, with continued reference to FIG. 1, illustrated is a cross-sectional view of the completion assembly 119 of the well system 100 of FIG. 1 during a first stage of exemplary operation, according to one or more embodiments. As illustrated, the second wellbore projectile 134b is sealingly engaged in the third downhole tool 128c, as generally described above. Upon pressurizing the work string 114, the second wellbore projectile 134b allows the sleeve 130 associated with the third downhole tool 128c to move axially and expose the corresponding ports 132, thereby facilitating fluid communication between the annulus 124 and the interior of the work string 114 such that the third interval 126c of the formation 108 may be treated.

[0038] In some embodiments, the second wellbore projectile 134b may further be configured to trigger actuation of the first downhole tool 128a. More particularly, the first sensor 136a of the first downhole tool 128a may be configured to detect the second wellbore projectile 134b and, upon detection thereof, may be configured to trigger an actuation device (not shown) associated with the first downhole tool 128a. The actuation device of the first downhole tool 128a may be an electromechanical or hydraulic actuation device configured to facilitate axial movement of its associated sleeve 130 to an open configuration. In the open configuration, as shown in FIG. 3, the one or more ports 132 defined in the work string 114 at that point may be exposed, thereby facilitating fluid communication between the annulus 124 and the interior of the work string 114 such that the first interval 126a of the formation 108 may be treated.

[0039] In at least one embodiment, actuation of the first downhole tool 128a may be time delayed. More specifically, the electronic circuitry (not

shown) associated with the first sensor 136a may be configured to delay actuation of the first downhole tool 128a until after a predetermined time period has expired following detection of the second wellbore projectile 134b. The predetermined time period may provide sufficient time to pressurize the work string 114 in order to fully actuate the third downhole tool 128c prior to opening the sleeve 130 of the first downhole tool 128a. The predetermined time period may range from about 2 minutes to about 10 minutes. Those skilled in the art, however, will readily appreciate that the predetermined time delay may be more than 10 minutes, without departing from the scope of the disclosure.

[0040] With the sleeves 130 of each of the first and third downhole tools 128a and 128c in their respective open configurations, the first and third intervals 126a and 126c may be treated. It is noted that at this time the sleeve 130 of the second downhole tool 128b remains in its closed position, thereby occluding the ports 132 of the second downhole tool 128b. Treating the first and third intervals 126a,c may include introducing or otherwise injecting a fracturing fluid 302 into each interval 126a,c via the exposed ports 132 of the first and third downhole tools 128a,c. The fracturing fluid 302 is hydraulically forced into the formation 108 through the ports 132, thereby generating and propagating a network of fractures 304 (shown as fractures 304a and 304c) in each of the first and third intervals 126a,c. In some embodiments, the fracturing fluid 302 may include a proppant slurry or other particulate matter configured to prop open the fractures 304a,c once the hydraulic pressure is reduced.

[0041] As illustrated, the fractures 304a,c may extend generally radially outward from the wellbore 106 and generally within each corresponding interval 126a,c. At least some of the fractures 304a,c, however, may extend laterally into the second interval 126b as a degree of interference between the first and third networks of fractures 304a,c is generated.

[0042] Referring now to FIG. 4, with continued reference to FIG. 3, illustrated is a cross-sectional view of the completion assembly 119 of the well system 100 of FIG. 1 during a second stage of exemplary operation, according to one or more embodiments. Following the stimulation treatment of the first and third intervals 126a,c, a diverting agent 402 may be introduced or otherwise injected into each interval 126a,c via the exposed ports 132 of the first and third downhole tools 128a,c. In other embodiments, the diverting agent 402 may be introduced into each interval 126a,c as an integral part of the stimulation

operation, without departing from the scope of the disclosure. Again, it is noted that the sleeve 130 of the second downhole tool 128b remains in its closed position, thereby occluding the ports 132 of the second downhole tool 128b and preventing the diverting agent 402 from exiting the second downhole tool 128b into the second interval 126b.

[0043] The diverting agent 402, also known as a chemical diverter, may be used to temporarily seal or block off the fractured first and third intervals 126a, c, such that subsequent injections of fracturing fluids may be diverted to other intervals, such as the second interval 126b. When being introduced into the first and third intervals 126a, c, the diverting agent 402 will flow most readily into portions of the first and third intervals 126a, c having the largest pores, fissures, or vugs, until those portions are bridged and sealed, thus diverting the remaining fluid to the next most permeable portion of the formation 108.

[0044] In some embodiments, the diverting agent 402 may be at least partially degradable. In at least one embodiment, the diverting agent 402 may be a diverting agent from the BIOVERT™ series of degradable diverting agents commercially available through Halliburton Energy Services of Houston Texas, USA. Other suitable diverting agents 402 that may be used include, but are not limited to, mineral particles (e.g. , calcium carbonate, magnesium oxide, zinc oxide, zinc carbonate and calcium sulfate), degradable polymers (e.g. , polysaccharides such as dextran or cellulose, chitins, chitosans, proteins, aliphatic polyesters, poly(lactides), poly(glycolides), poly(s-caprolactones), poly(hydroxybutyrates), poly(anhydrides), aliphatic polycarbonates, poly(orthoesters), poly(amino acids), poly(ethylene oxides), and polyphosphazenes), dehydrated compounds (e.g. , solid anhydrous borate material), and combinations thereof.

[0045] Any particulates used in the diverting agent 402 include material particles having the physical shape of platelets, shavings, flakes, ribbons, rods, strips, spheroids, toroids, pellets, tablets or any other physical shape. The size of the particles of the diverting agent used to carry out the method of the invention will vary over a wide range depending upon the formation to be treated . The terms "degrade," "degradation," "degradable," and the like, when used herein refer to both the two relative cases of hydrolytic degradation that the degradable diverting agent 402 may undergo; i. e. , heterogeneous (or bulk erosion) and homogeneous (or surface erosion), and any stage of degradation in

between these two. This degradation can be a result of *inter alia*, a chemical or thermal reaction or a reaction induced by radiation.

[0046] Referring now to FIG. 5, with continued reference to FIGS. 3 and 4, illustrated is a cross-sectional view of the completion assembly 119 of the well system 100 of FIG. 1 during a third stage of exemplary operation, according to one or more embodiments. With the first and third intervals 126a,c successfully treated (e.g., hydraulically fractured) and sealed using the diverting agent 402 (FIG. 4), the second downhole tool 128b may be actuated such that the second interval 126b may also be treated. In some embodiments, the second wellbore projectile 134b may further be configured to trigger actuation of the section downhole tool 128b. More particularly, the second sensor 136b of the second downhole tool 128a may be configured to detect the second wellbore projectile 134b and, upon detection thereof, may be configured to trigger an actuation device (not shown) associated with the second downhole tool 128b.

[0047] As briefly mentioned above, the second downhole tool 128b may be substantially similar to the third downhole tool 128c described above with reference to FIGS. 2A-2D. Accordingly, operation of the second downhole tool 128b may be best understood with reference to FIGS. 2A-2D. More particularly, as the second wellbore projectile 134b passes by the second sensor 136b of the second downhole tool 128b, the associated electronic circuitry may determine that a predetermined magnetic property of the second wellbore projectile 134b has been detected. Alternatively, the associated electronic circuitry may determine that a predetermined number or combination of wellbore projectiles 134 (e.g., first and second projectiles 134a,b) has been affirmatively detected by the second sensor 136b.

[0048] Once the appropriate signal has been detected or otherwise sensed by the second sensor 136b, the associated electronic circuitry may cause that a retractable baffle (similar to the baffle 206 of FIGS. 2A-2D) extend a short distance into the interior of the second downhole tool 128b and otherwise move into its sealing position (similar to FIG. 2B). This may be accomplished by moving the sleeve 130 axially downward, as generally described above with reference to FIGS. 2A-2D. In its sealing position, the baffle of the second downhole tool 128b may be configured to receive and seat a wellbore projectile 134, such as the third wellbore projectile 134c depicted in FIG. 5.

[0049] Once properly seated on the baffle of the second downhole tool 128b, the third wellbore projectile 134c may be configured to substantially seal the interior of the second downhole tool 128b such that fluids are generally prevented from passing downhole past that point within the work string 114.

5 The work string 114 may then be pressurized from the surface 104 (FIG. 1), in order to act on the seated third wellbore projectile 134c and thereby move the sleeve 130 of the second downhole tool 128b axially downhole to its open configuration, as depicted in FIG. 5. In its open configuration, the ports 132 of the second downhole tool 128b may be exposed and otherwise facilitate fluid
10 communication into and out of the work string 114 at that location.

[0050] With the sleeve 130 of the second downhole tool 128b in its open configuration, the second interval 126b may then be treated (*i.e.*, hydraulically fractured). This may be accomplished by introducing or otherwise injecting fracturing fluid 302 into the interval 126b via the exposed ports 132 of
15 the second downhole tool 128b. Since the first interval 126a is substantially sealed with the diverting agent 402 (FIG. 4), the fracturing fluid 302 may generally bypass the ports 132 of the first downhole tool 128a, and instead locate the ports 132 of the second downhole tool 128b. At the second downhole tool 128b, the fracturing fluid 302 is hydraulically forced into the formation 108
20 through the ports 132, thereby generating and propagating a network of fractures 304b in the second interval 126b that extend generally radially outward from the wellbore 106.

[0051] The fractures 304b formed in the second interval 126b may take advantage of the altered stress in the formation rock previously caused by the
25 fracturing of the first and third intervals 126a,c. As illustrated, a portion of the fractures 304b associated with the second interval 126b may extend laterally and potentially overlap with the fractures 304a,c of the first and third intervals 126a,c, respectively. As a result, a highly conductive network of fractures 304a-c is generated and extends across each of the intervals 126a-c. Over time, the
30 diverting agent 402 used to seal the first and third intervals 126a,c may degrade, thereby allowing fluid conductivity once again through each of the fractures 304a,c. Prior to commencing production operations, the wellbore projectiles 134a-c may be returned to the surface 104 (FIG. 1) using, for example, zonal pressure derived from each interval 126a-c.

[0052] Referring additionally now to FIGS. 6A and 6B, illustrated are individual isometric views of an exemplary wellbore projectile 134 that may be used in the system 100 (FIG. 1), according to one or more embodiments. As illustrated, the wellbore projectile 134 is in the general shape of a sphere 602, such as a frac ball known to those skilled in the art. In this example, magnets (not shown in FIGS. 6A and 6B) may be retained in a plurality of recesses 604 defined in the outer surface of the sphere 602. In other embodiments, however, the magnet(s) of the wellbore projectile 134 may be disposed entirely within the center of the sphere 602, without departing from the scope of the disclosure.

[0053] In some embodiments, the recesses 604 may be arranged in a pattern which, in this case, resembles that of stitching on a baseball. More particularly, the pattern shown in FIGS. 6A and 6B encompasses spaced apart positions distributed along a continuous undulating path about the sphere 602. However, it should be clearly understood that any pattern of magnetic field-producing components may be used in the wellbore projectile 134, in keeping with the scope of this disclosure. Indeed, the magnets may be arranged to provide a magnetic field that extends a predetermined distance from the wellbore projectile 134, and to do so no matter the orientation of the sphere 602. The pattern depicted in FIGS. 6A and 6B may be configured to project the produced magnetic field(s) substantially evenly around the sphere 602.

[0054] Referring now to FIG. 7, with continued reference to FIG. 1, illustrated is a schematic diagram of a method 700 of treating multiple intervals of a formation, according to one or more embodiments disclosed. The method 700 may include introducing one or more wellbore projectiles into a work string, as at 702. The work string may be arranged at least partially within a formation 108 and include a completion assembly. The completion assembly may include a first downhole tool 128a arranged adjacent a first interval 126a of the formation 108 and a second downhole tool 128b arranged within a second interval 126c of the formation 108. The completion assembly may further include a third downhole tool 126b arranged adjacent a third interval 126b that interposes the first and second intervals 126a,c.

[0055] The method 700 may further include detecting the one or more wellbore projectiles with a first sensor 136a of the first downhole tool 128a and a second sensor 136c of the second downhole tool 128b, as at 704. First and second sliding sleeves 130 arranged within the first and second downhole tools

128a,c may then be opened following detection of the one or more wellbore projectiles, as at 706. The first and second intervals 126a,c may then be treated, as at 708, and the first and second intervals 126a,c are then sealed, as at 710. In at least one embodiment, this may be done by injecting a diverting agent into the first and second intervals.

[0056] The method 700 may further include detecting the one or more wellbore projectiles with a third sensor 136b of the third downhole tool 128b, as at 712. A third sliding sleeve 130 arranged within the third downhole tool 128b may then be opened following detection of the one or more wellbore projectiles, as at 714. The third interval 126b may then be treated independent of the first and second intervals 126a,c, as at 716.

[0057] Embodiments disclosed herein include:

[0058] Embodiment A. A well system that includes one or more wellbore projectiles introduced into a completion assembly, and a first downhole tool arranged in the completion assembly adjacent a first interval and having a first sensor that triggers actuation of a first sleeve upon detecting the one or more wellbore projectiles. The well system further includes a second downhole tool arranged in the completion assembly downhole from the first downhole tool and adjacent a second interval, the second downhole tool having a second sensor that triggers actuation of a second sleeve upon detecting the one or more wellbore projectiles, and a third downhole tool arranged in the completion assembly downhole from the second downhole tool and adjacent a third interval, the third downhole tool having a third sensor that triggers actuation of a third sleeve upon detecting the one or more wellbore projectiles, wherein actuation of the first and third sleeves is triggered such that the first and third intervals are stimulated simultaneously, and wherein actuation of the second sleeve is triggered such that the second interval is stimulated independent of the first and third intervals.

[0059] Embodiment B. A method is also disclosed. The method may include introducing one or more wellbore projectiles into a work string arranged at least partially within a formation, the work string including a completion assembly having a first downhole tool arranged adjacent a first interval, a second downhole tool arranged adjacent a second interval, and a third downhole tool arranged adjacent a third interval that interposes the first and second intervals, detecting the one or more wellbore projectiles with a first sensor of the

first downhole tool and a second sensor of the second downhole tool, opening first and second sliding sleeves arranged within the first and second downhole tools, respectively, following detection of the one or more wellbore projectiles, treating the first and second intervals, sealing the first and second intervals by
5 injecting a diverting agent into the first and second intervals, detecting the one or more wellbore projectiles with a third sensor of the third downhole tool, opening a third sliding sleeve arranged within the third downhole tool following detection of the one or more wellbore projectiles, and treating the third interval independent of the first and second intervals.

10 **[0060]** Embodiment C. Another method is disclosed. The method may include detecting a first wellbore projectile with a first sensor associated with a first downhole tool arranged adjacent a first interval, detecting a second wellbore projectile with a second sensor associated with a second downhole tool and thereby causing the second downhole tool to actuate, the second downhole
15 tool being arranged adjacent a second interval uphole from the first interval, actuating the first downhole tool by catching the second wellbore projectile on a first baffle associated with the first downhole tool and subsequently pressurizing the work string, detecting the second wellbore projectile with a third sensor associated with a third downhole tool interposing the first and second downhole
20 tools and arranged adjacent a third interval that interposes the first and second intervals, hydraulically fracturing the first and second intervals via the first and second downhole tools, respectively, sealing the first and second intervals by injecting a diverting agent into the first and second intervals, actuating the third downhole tool by catching a third wellbore projectile on a second baffle
25 associated with the third downhole tool and subsequently pressurizing the work string, and hydraulically fracturing the third interval.

[0061] Each of embodiments A, B, and C may have one or more of the following additional elements in any combination: Element 1: wherein the first, second, and third sleeves are movable to expose ports that provide fluid
30 communication into the first, second, and third intervals, respectively. Element 2: wherein the one or more wellbore projectiles are selected from the group comprising balls, darts, wipers, and plugs. Element 3: wherein the one or more wellbore projectiles exhibit known magnetic properties detectable by the first, second, and third sensors. Element 4: further comprising electronic circuitry
35 associated with each of the first, second, and third sensors, the electronic

circuitry being configured to determine whether the corresponding first, second, and third sensors have detected the known magnetic properties of the one or more wellbore projectiles, and one or more actuation devices associated with the electronic circuitry of each of the first, second, and third sensors, the one or more actuation devices being configured to facilitate moving the first, second, and third sleeves from open to closed positions upon being directed by the electronic circuitry. Element 5: further comprising a diverting agent injected into the first and third intervals such that the second interval can be stimulated independent of the first and second intervals following injection of the diverting agent.

[0062] Element 6: wherein detecting the one or more wellbore projectiles with the first sensor of the first downhole tool and the second sensor of the second downhole tool further comprises detecting a magnetic property of the one or more wellbore projectiles with the first and second sensors. Element 7: wherein opening the first and second sliding sleeves comprises exposing a plurality of ports defined in both the first and second downhole tools, and facilitating fluid communication between an interior of the work string and the first and second intervals through the plurality of ports. Element 8: wherein treating the first and second intervals and treating the third interval comprise hydraulically fracturing the first, second, and third intervals. Element 9: wherein detecting the one or more wellbore projectiles with the third sensor of the third downhole tool comprises detecting a magnetic property of the one or more wellbore projectiles with the third sensor. Element 10: opening the third sliding sleeve comprises exposing a plurality of ports defined in the third downhole tool, and facilitating fluid communication between an interior of the work string and the third interval through the plurality of ports. Element 11: further comprising allowing the diverting agent to degrade in the first and second intervals, and producing fluids from the first, second, and third intervals via the first, second, and third downhole tools, respectively.

[0063] Element 12: wherein detecting the first wellbore projectile with the first sensor comprises detecting a magnetic property of the first wellbore projectile with the first sensor, and actuating the first baffle in response to the magnetic property being detected. Element 13: wherein actuating the first downhole tool comprises moving a sliding sleeve from a closed position to an open position where one or more ports are exposed and provide fluid

communication with the first interval. Element 14: wherein detecting the second wellbore projectile with the second sensor comprises detecting a magnetic property of the second wellbore projectile with the second sensor, and moving a sliding sleeve from a closed position to an open position with an actuation device
5 associated with the second downhole tool, wherein, when in the open position, one or more ports are exposed and provide fluid communication with the second interval. Element 15: further comprising actuating the second downhole tool after a predetermined time period expires following detection of the second wellbore projectile by the second sensor. Element 16: wherein detecting the
10 second wellbore projectile with the third sensor associated with the third downhole tool comprises detecting a magnetic property of the second wellbore projectile with the third sensor, and actuating the second baffle in response to the magnetic property being detected. Element 17: further comprising allowing the diverting agent to degrade in the first and second intervals, and producing
15 fluids from the first, second, and third intervals via the first, second, and third downhole tools, respectively.

[0064] Therefore, the disclosed systems and methods are well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the
20 teachings of the present disclosure may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments
25 disclosed above may be altered, combined, or modified and all such variations are considered within the scope of the present disclosure. The systems and methods illustratively disclosed herein may suitably be practiced in the absence of any element that is not specifically disclosed herein and/or any optional element disclosed herein. While compositions and methods are described in
30 terms of "comprising," "containing," or "including" various components or steps, the compositions and methods can also "consist essentially of" or "consist of" the various components and steps. All numbers and ranges disclosed above may vary by some amount. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the
35 range is specifically disclosed. In particular, every range of values (of the form,

“from about a to about b,” or, equivalently, “from approximately a to b,” or, equivalently, “from approximately a-b”) disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values. Also, the terms in the claims have their plain, ordinary meaning unless
5 otherwise explicitly and clearly defined by the patentee. Moreover, the indefinite articles “a” or “an,” as used in the claims, are defined herein to mean one or more than one of the element that it introduces.

CLAIMS

1. A method, comprising:
 - introducing one or more wellbore projectiles into a work string arranged within a wellbore, the work string including a completion assembly having a first downhole tool arranged adjacent a first interval, a second downhole tool arranged adjacent a second interval, and a third downhole tool arranged adjacent a third interval that interposes the first and second intervals, wherein each interval is defined in the wellbore between axially adjacent pairs of packers positioned within an annulus defined between the completion assembly and a wall of the wellbore;
 - detecting the one or more wellbore projectiles with a first sensor of the first downhole tool and a second sensor of the second downhole tool;
 - opening first and second sliding sleeves arranged within the first and second downhole tools, respectively, following detection of the one or more wellbore projectiles, by catching one of the wellbore projectiles on a baffle associated with at least one of the first and second downhole tools;
 - treating the first and second intervals simultaneously;
 - sealing the first and second intervals by injecting a diverting agent into the first and second intervals;
 - detecting the one or more wellbore projectiles with a third sensor of the third downhole tool;
 - opening a third sliding sleeve arranged within the third downhole tool following detection of the one or more wellbore projectiles;
 - treating the third interval independent of the first and second intervals; and
 - actuating the first downhole tool by catching the second wellbore projectile on a first baffle associated with the first downhole tool and subsequently pressurizing the work string.
2. The method of claim 1, wherein detecting the one or more wellbore projectiles with the first sensor of the first downhole tool and the second sensor of the second downhole tool further comprises detecting a magnetic property of the one or more wellbore projectiles with the first and second sensors.

3. The method of claim 1, wherein opening the first and second sliding sleeves comprises:

exposing a plurality of ports defined in both the first and second downhole tools; and

facilitating fluid communication between an interior of the work string and the first and second intervals through the plurality of ports.

4. The method of claim 1, wherein treating the first and second intervals and treating the third interval comprises hydraulically fracturing the first, second, and third intervals.

5. The method of claim 1, wherein detecting the one or more wellbore projectiles with the third sensor of the third downhole tool comprises detecting a magnetic property of the one or more wellbore projectiles with the third sensor.

6. The method of claim 1, wherein opening the third sliding sleeve comprises:

exposing a plurality of ports defined in the third downhole tool; and

facilitating fluid communication between an interior of the work string and the third interval through the plurality of ports.

7. The method of claim 1, further comprising:

allowing the diverting agent to degrade in the first and second intervals; and

producing fluids from the first, second, and third intervals via the first, second, and third downhole tools, respectively.

8. The method of claim 1, wherein opening the first and second sliding sleeves includes displacing at least one of the first and second sleeves against an axial end of the baffle to displace the baffle axially against a baffle containment sleeve.

9. The method of claim 8, wherein displacing the baffle against the baffle containment sleeve includes displacing part of the baffle radially inwardly to a sealing position.

10. The method of claim 9, wherein treating the first and second intervals simultaneously includes catching the one of the wellbore projectiles on the baffle in the sealing position to seal an interior of the work string.

11. A method, comprising:

detecting a first wellbore projectile with a first sensor associated with a first downhole tool arranged adjacent a first interval;

detecting a second wellbore projectile with a second sensor associated with a second downhole tool and thereby causing the second downhole tool to actuate, the second downhole tool being arranged adjacent a second interval uphole from the first interval;

actuating the first downhole tool by catching the second wellbore projectile on a first baffle associated with the first downhole tool and subsequently pressurizing the work string;

detecting the second wellbore projectile with a third sensor associated with a third downhole tool interposing the first and second downhole tools and arranged adjacent a third interval that interposes the first and second intervals;

hydraulically fracturing the first and second intervals simultaneously via the first and second downhole tools, respectively;

sealing the first and second intervals by injecting a diverting agent into the first and second intervals;

actuating the third downhole tool by catching a third wellbore projectile on a second baffle associated with the third downhole tool and subsequently pressurizing the work string; and

hydraulically fracturing the third interval independent of the first and second intervals, wherein each of the first, second, and third intervals is defined in a wellbore between axially adjacent pairs of packers deployed within the wellbore.

12. The method of claim 11, wherein detecting the first wellbore projectile with the first sensor comprises:

detecting a magnetic property of the first wellbore projectile with the first sensor; and

actuating the first baffle in response to the magnetic property being detected.

13. The method of claim 12, wherein actuating the first downhole tool comprises moving a sliding sleeve from a closed position to an open position where one or more ports are exposed and provide fluid communication with the first interval.

14. The method of claim 11, wherein detecting the second wellbore projectile with the second sensor comprises:

detecting a magnetic property of the second wellbore projectile with the second sensor; and

moving a sliding sleeve from a closed position to an open position with an actuation device associated with the second downhole tool, wherein, when in the open position, one or more ports are exposed and provide fluid communication with the second interval.

15. The method of claim 11, further comprising actuating the second downhole tool after a predetermined time period expires following detection of the second wellbore projectile by the second sensor.

16. The method of claim 11, wherein detecting the second wellbore projectile with the third sensor associated with the third downhole tool comprises:

detecting a magnetic property of the second wellbore projectile with the third sensor; and
actuating the second baffle in response to the magnetic property being detected.

17. The method of claim 11, further comprising:
allowing the diverting agent to degrade in the first and second intervals;
and
producing fluids from the first, second, and third intervals via the first, second, and third downhole tools, respectively.

18. The method of claim 11, wherein actuating the first downhole tool by catching the second wellbore projectile on the first baffle includes displacing a sliding sleeve against an axial end of the first baffle to displace the first baffle axially against a baffle containment sleeve.

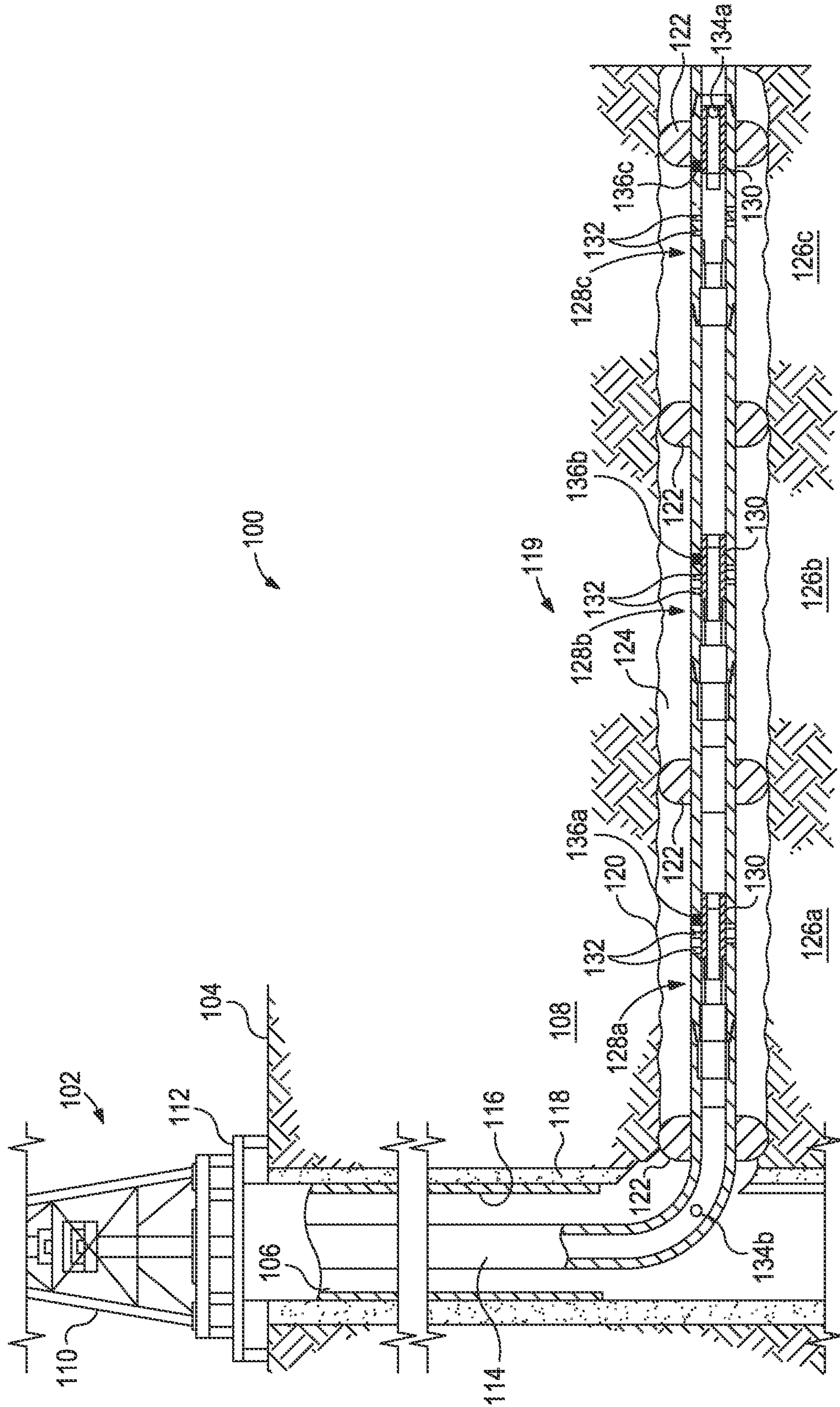
19. The method of claim 18, wherein displacing the first baffle against the baffle containment sleeve includes displacing part of the first baffle radially inwardly to a sealing position.

20. The method of claim 19, wherein pressurizing the work string includes catching the second wellbore projectile on the first baffle in the sealing position to seal an interior of the work string.

21. The method of claim 11, wherein actuating the third downhole tool by catching the third wellbore projectile on the second baffle includes moving a sliding sleeve against an axial end of the second baffle to displace the second baffle axially against a baffle containment sleeve.

22. The method of claim 21, wherein displacing the second baffle against the baffle containment sleeve includes displacing part of the second baffle radially inwardly to a sealing position.

23. The method of claim 22, wherein pressurizing the work string includes catching the third wellbore projectile on the second baffle in the sealing position to seal an interior of the work string.





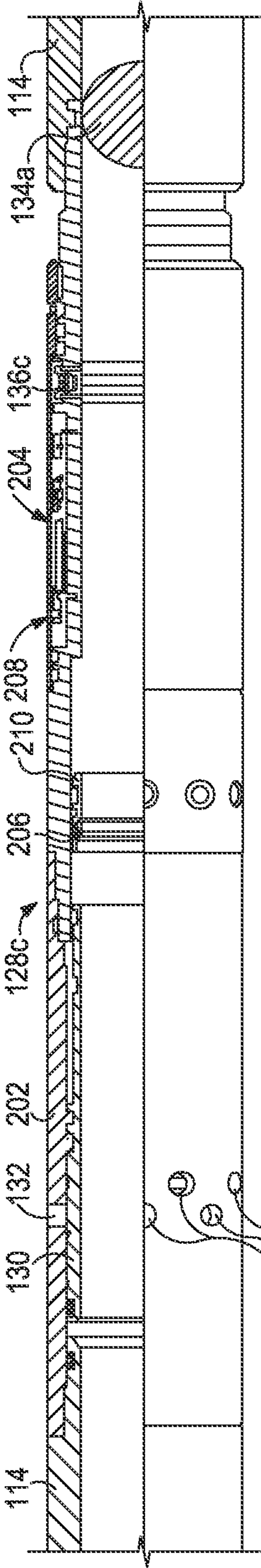


FIG. 2A

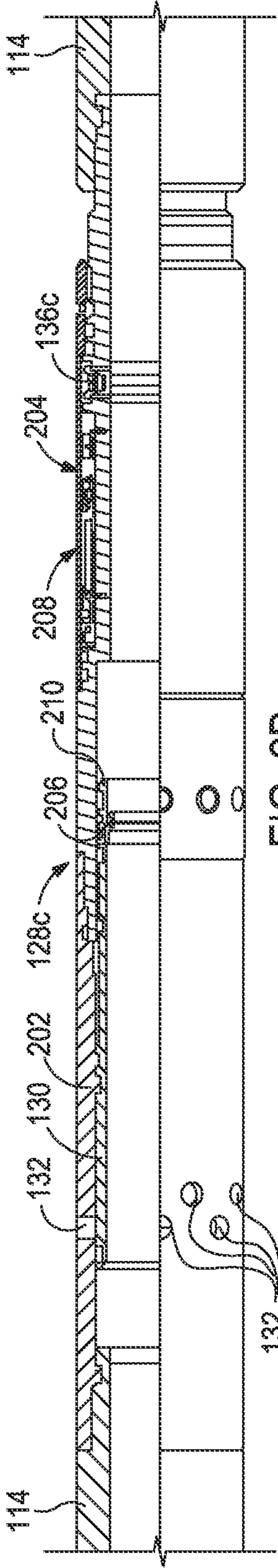


FIG. 2B

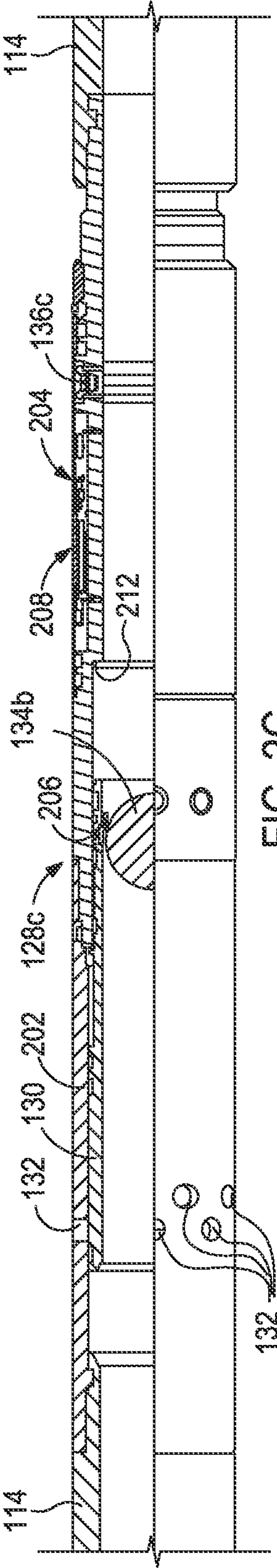


FIG. 2C

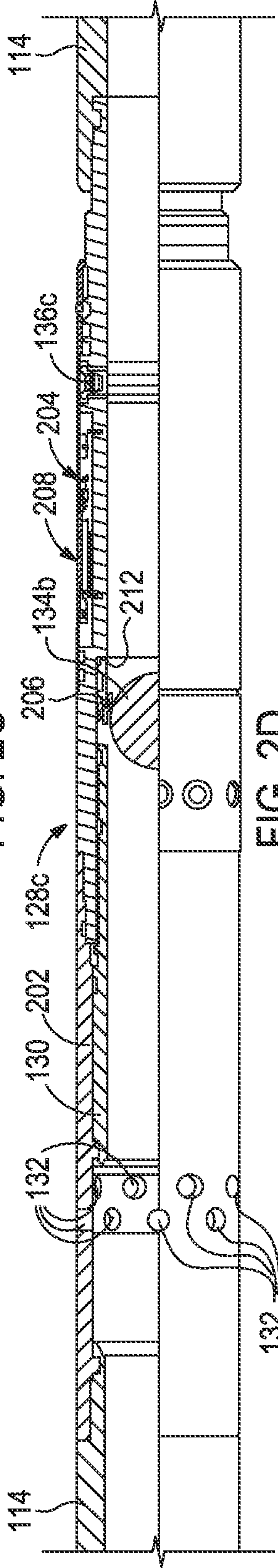


FIG. 2D

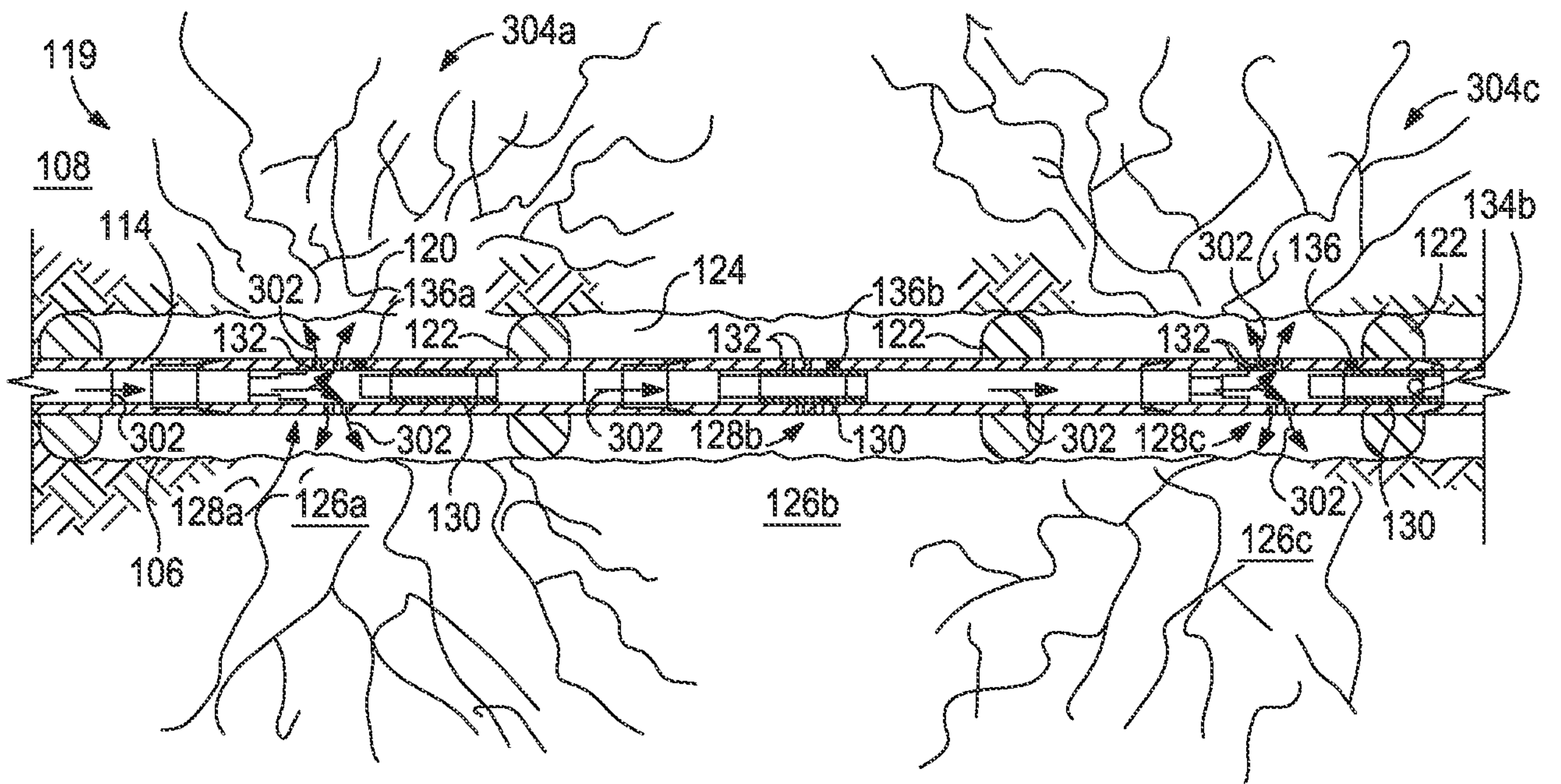


FIG. 3

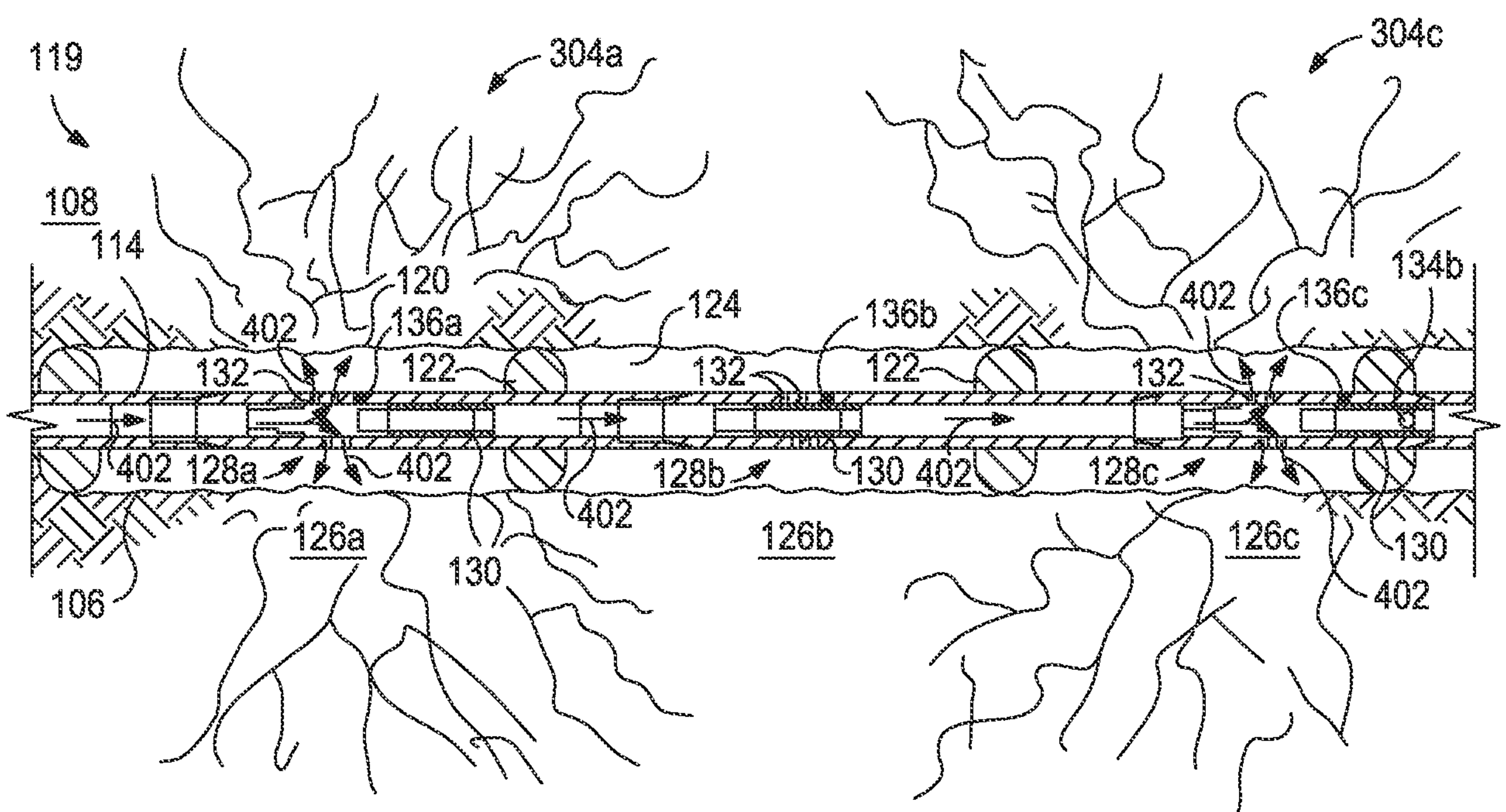


FIG. 4

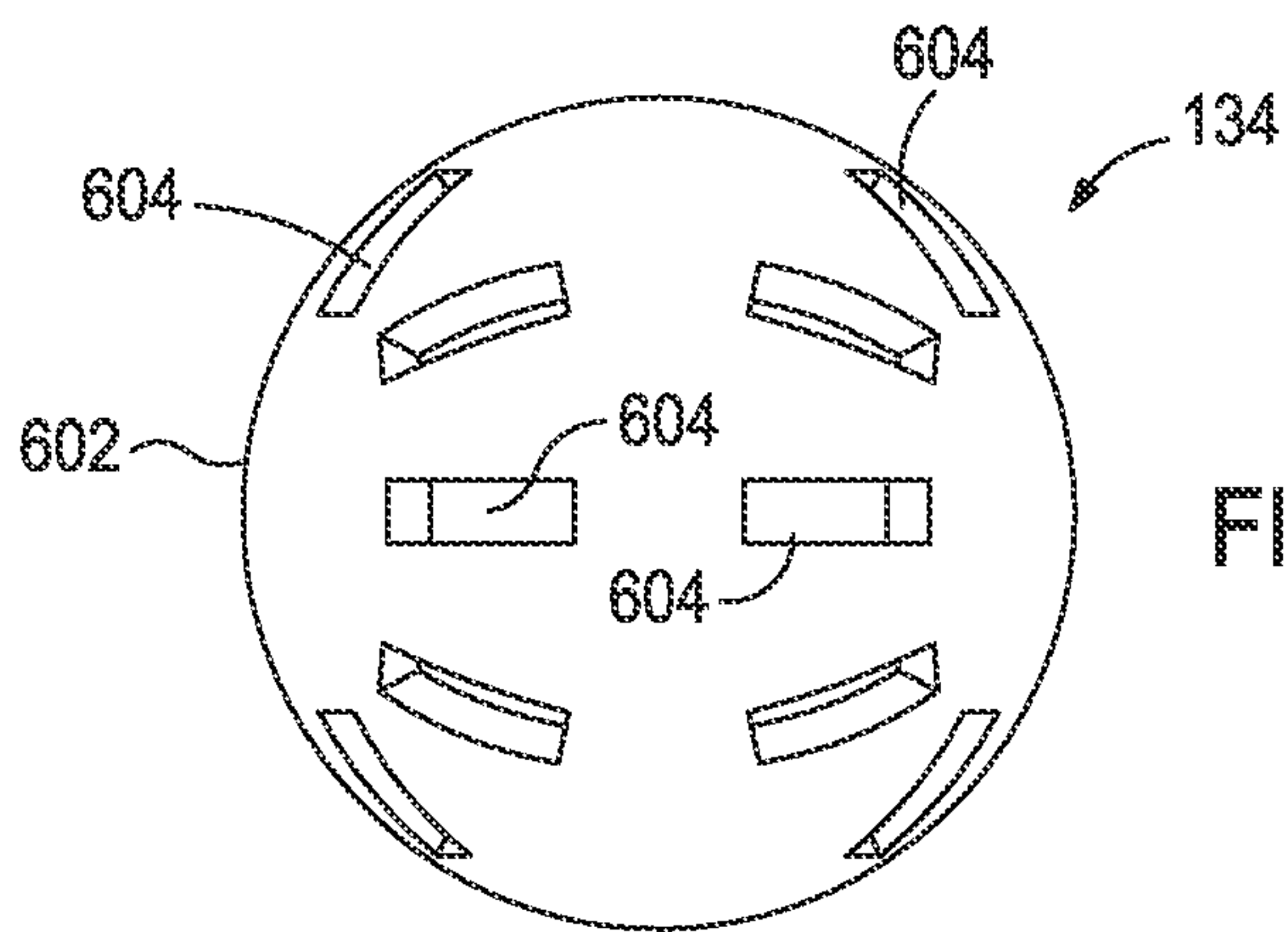
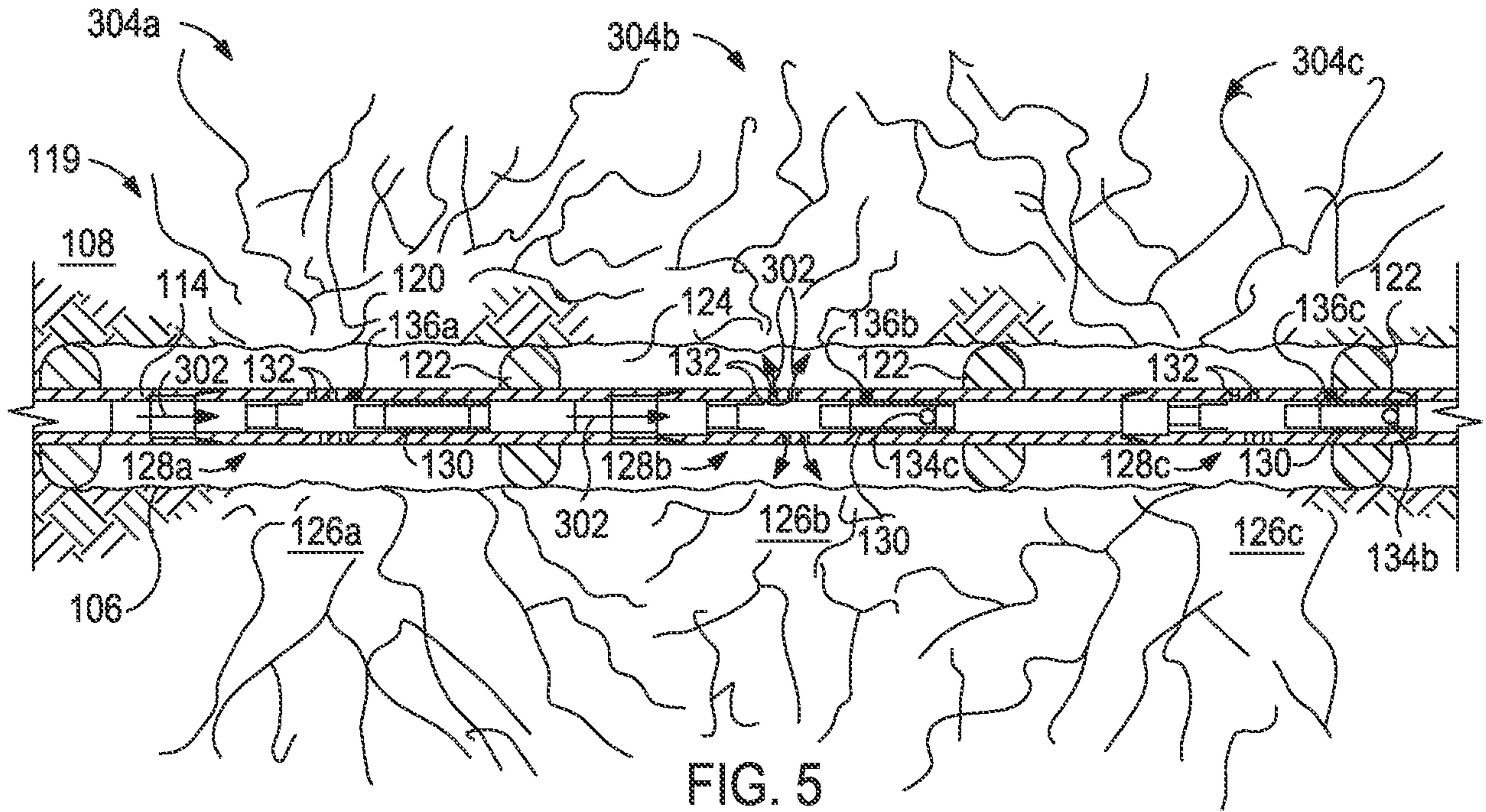
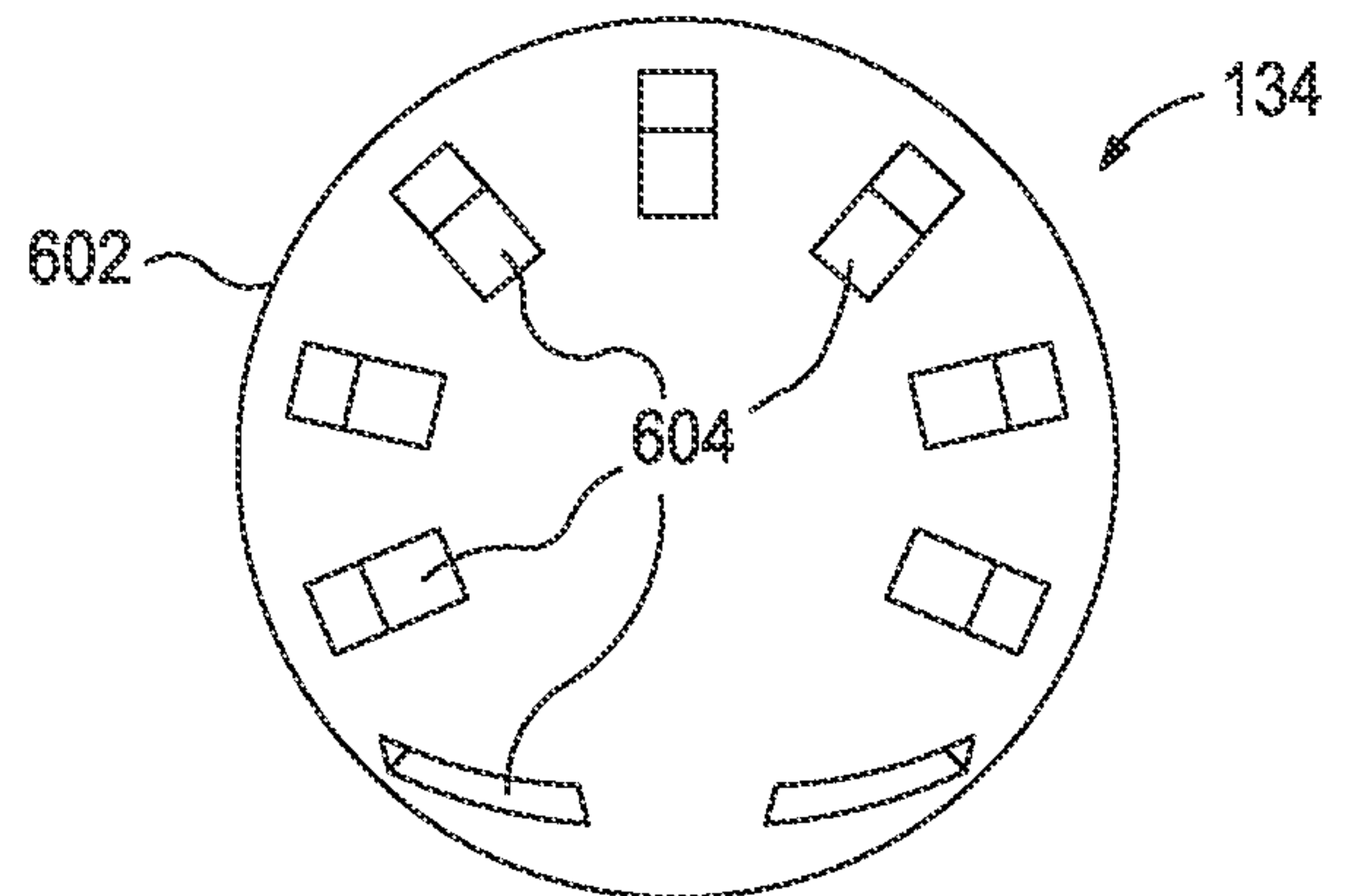


FIG. 6B



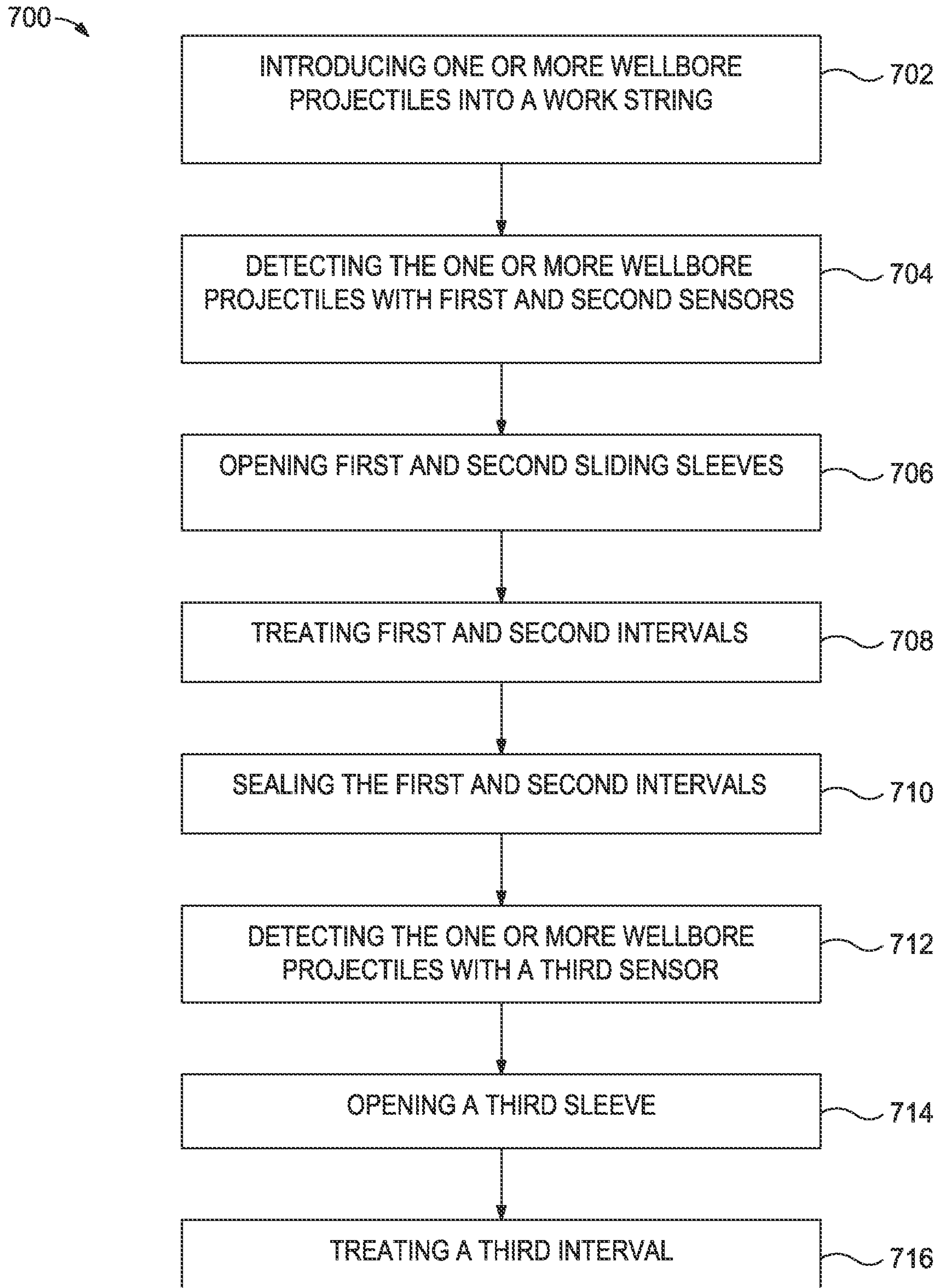


FIG. 7

