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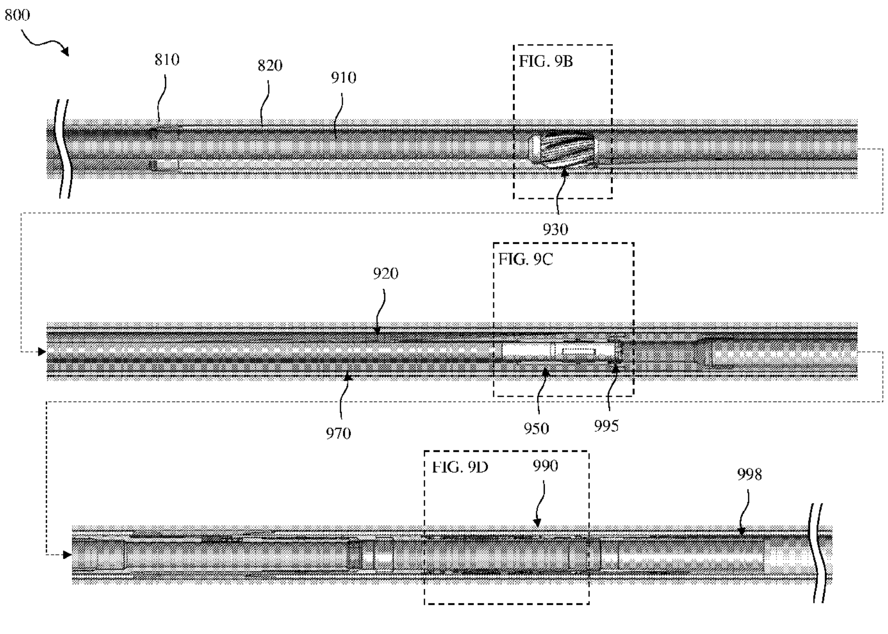

FIG. 9A

(57) Abstract: Provided is a downhole tool, a well system, and a method for forming a well system. The downhole tool, in at least one aspect, includes a two part drilling and running tool, the two part drilling and running tool including a conveyance, a smaller assembly coupled to an end of the conveyance, and a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly. The downhole tool, in accordance with this aspect, further includes a whipstock assembly coupled to the two part drilling and running tool using a coupling mechanism, and a hydraulically actuated anchoring assembly coupled to a downhole end of the whipstock assembly.

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MULTI PASS TWO-PART DRILLING/RUNNING AND ACTIVATION TOOL

REFERENCE TO RELATED APPLICATION

[0001] This application claims priority to U.S. Application Serial No. 18/083,888, filed on December 19, 2022, entitled "MULTI PASS TWO-PART DRILLING/RUNNING AND ACTIVATION TOOL," which claims the benefit of U.S. Provisional Application Serial No. 63/311,502, filed on February 18, 2022, entitled "MULTI PASS TWO-PART DRILLING/RUNNING AND ACTIVATION TOOL," commonly assigned with this application and incorporated herein by reference in their entirety.

BACKGROUND

[0002] The unconventional market is very competitive. The market is trending towards longer horizontal wells to increase reservoir contact. Multilateral wells offer an alternative approach to maximize reservoir contact. Multilateral wells include one or more lateral wellbores (e.g., secondary wellbores) extending from a main wellbore (e.g., primary wellbore). A lateral wellbore is a wellbore that is diverted from the main wellbore or another lateral wellbore.

[0003] Lateral wellbores are typically formed by positioning one or more deflector assemblies (e.g., whipstock assemblies) at desired locations in the main wellbore (e.g., an open hole section or cased hole section) with a running tool. The deflector assemblies are often laterally and rotationally fixed within the primary wellbore using a wellbore anchor.

BRIEF DESCRIPTION

[0004] Reference is now made to the following descriptions taken in conjunction with the accompanying drawings, in which:

[0005] FIG. 1A illustrates a schematic view of a well system designed, manufactured and operated according to one or more embodiments disclosed herein;

[0006] FIGs. 1B through 1G illustrate various different views of one embodiment of the anchoring assembly designed, manufactured and operated according to one or more embodiments of the disclosure at different operational states;

[0007] FIGs. 2A through 7B illustrate various different views of a two part milling and running tool designed, manufactured and operated according to one or more embodiments of the disclosure; and

[0008] FIGs. 8 through 19 illustrate various different views of a well system, the well system employing a two part drilling and running tool, for example to form a lateral wellbore therein.

DETAILED DESCRIPTION

[0009] In the drawings and descriptions that follow, like parts are typically marked throughout the specification and drawings with the same reference numerals, respectively. The drawn figures are not necessarily to scale. Certain features of the disclosure may be shown exaggerated in scale or in somewhat schematic form and some details of certain elements may not be shown in the interest of clarity and conciseness. The present disclosure may be implemented in embodiments of different forms.

[0010] Specific embodiments are described in detail and are shown in the drawings, with the understanding that the present disclosure is to be considered an exemplification of the principles of the disclosure, and is not intended to limit the disclosure to that illustrated and described herein. It is to be fully recognized that the different teachings of the embodiments discussed herein may be employed separately or in any suitable combination to produce desired results.

[0011] Unless otherwise specified, use of the terms “connect,” “engage,” “couple,” “attach,” or any other like term describing an interaction between elements is not meant to limit the interaction to direct interaction between the elements and may also include indirect interaction between the elements described. Unless otherwise specified, use of the terms “up,” “upper,” “upward,” “uphole,” “upstream,” or other like terms shall be construed as generally away from the bottom, terminal end of a well; likewise, use of the terms “down,” “lower,” “downward,” “downhole,” “downstream,” or other like terms shall be construed as generally toward the bottom, terminal end of a well, regardless of the wellbore orientation. Use of any one or more of the foregoing terms shall not be construed as denoting positions along a perfectly vertical axis. Unless otherwise specified, use of the term “subterranean formation” shall be construed as encompassing both areas below exposed earth and areas below earth covered by water, such as ocean or fresh water.

[0012] The disclosure addresses the challenge of running a whipstock assembly on a mill, for example in an effort to reduce trip count. Current designs for shear bolting a whipstock assembly to a mill leave the shear bolt vulnerable to combined loading, which can cause unreliable shear values. Also, current shear bolts are unsuitable for deploying whipstock assembly in extremely deep wells because of the low shear ratings. In addition, the disclosure allows for certain tools to be activated with pressure or flow, further improving efficiencies in the construction of a multilateral junction.

[0013] With this in mind, the present disclosure provides a two part drilling and running tool (e.g., two-part lead bit assembly) that can be used to run a whipstock assembly downhole. In at least one embodiment, the smaller assembly (e.g., downhole/smaller bit assembly) is connected to the whipstock assembly and functions as a running tool. The smaller assembly, in certain embodiments, also seals into the whipstock assembly allowing pressure or flow, or a combination thereof, to be used to activate or otherwise interact with one or more tools below the whipstock assembly. Once released, the smaller assembly pulls back and connects to a larger bit assembly (e.g., uphole/larger bit assembly) thereby forming a new combined bit assembly (e.g., that looks and functions like a conventional lead mill). For purposes of the present disclosure, the term bit assembly is intended to encompass both mill assemblies and drill bit assemblies. Following the successful creation of the exit and the drilling of the lateral, the lateral completion could be installed and then tied together with the main bore by installing a level 5 junction. To accomplish this, in at least one embodiment, the whipstock assembly is actually a hybrid whipstock that incorporates features of a conventional completion deflector, such as seals.

[0014] Heretofore, a two part drilling and running tool consisting of two independent assemblies (e.g., two independent bit assemblies) has not been used, and particularly where the smaller assembly (e.g., smaller bit assembly) can function as a running tool for a whipstock assembly. The two part drilling and running tool described herein ensures reliable deployment of a whipstock assembly. Also, it greatly increases the mechanical ratings that can be achieved while running in hole, thereby allowing the whipstock assembly to be deployed into deeper or highly deviated wells. It would also be feasible to connect more components to the whipstock assembly without risking premature shearing of the shear bolt.

[0015] Additionally, for a reentry well where an anchoring assembly needs to be set first, the ability to apply pressure down the tool string would save a further trip by combining the anchoring assembly setting and first pass milling operations into one trip. Moreover, an additional trip is saved, in one or more embodiments, by being able to land the junction into the hybrid whipstock assembly/deflector.

[0016] One embodiment of the disclosure would feature a smaller assembly and a larger bit assembly. In accordance with at least one embodiment of the disclosure, the smaller assembly is a smaller bit assembly having one or more cutting features (e.g., teeth, blades, etc.) thereon. The smaller assembly, in one embodiment, would be connected to a tubular that extends through the larger bit assembly and is then connected to the rest of the drill string, or perhaps to a downhole motor directly. In at least one embodiment, the smaller assembly is sized such that it can wholly or partially fit into the bore of the whipstock assembly, such that in one embodiment it may connect to the whipstock assembly. Many different connection methods can be used, perhaps the simplest being a shear feature such as a shear bolt.

[0017] The smaller assembly, in one or more embodiments, would also feature the ability to seal into the whipstock assembly. In one simple embodiment, the smaller assembly would have a seal surface that stabs into a seal in the whipstock assembly. Once the whipstock assembly has been positioned in the well, pressure could be applied to activate an anchoring assembly. In reentry or open hole applications this is often a requirement, as there would not be a preposition datum in the well such as a latch coupling. In yet another embodiment, the smaller assembly would have a seal that stabs into a seal surface of the whipstock assembly.

[0018] In at least one embodiment, the whipstock assembly would be run in hole to the depth datum in the well and then latched in. One possible embodiment of this would be a multilateral latch coupling, or another similar latch. Unlike existing shear bolt designs, here the shear bolts of certain embodiments herein would be protected from combined loading. For example, different (e.g., simple) profiles can be included into the design of the smaller assembly and the bore of the whipstock assembly to ensure that the shear bolt will only shear under a single loading condition, such as for example only one of compression, tension, or torque.

[0019] In one or more embodiments, a bolt action profile is employed, whereby the shear features are sheared with a single hand torque (e.g., right hand torque). When locked in, the smaller assembly is trapped in tension and compression transmitting all loads directly to the whipstock assembly bypassing the shear bolts completely. In at least this embodiment, right hand rotation shears the shear features and moves the raised profiles on the OD of the smaller assembly into a channel that allows the smaller assembly to be pulled out of the whipstock assembly.

[0020] In at least one second embodiment, a no-go and splines are used, such that the shear features would be isolated from all compressive loads and all torque, only allowing the shear features to shear in response to tensile loads. In at least one third embodiment, a third profile is possible that isolates the shear bolts from tensile and torque loads and shears the smaller assembly with a compressive load. This profile could be described as a J-slot, where down movement and then rotation releases the smaller assembly from the whipstock assembly. The three simple profiles described could all be different options offered depending on the particular requirements of the well.

[0021] Accordingly, as described above, the smaller assembly can be designed to shear only if supplied a specific one of compression, tension or torque, and not shear if supplied the other two of compression, tension or torque. In contrast, currently a shear bolt connecting a lead mill to the tip of the whipstock assembly may shear if supplied two or more, if not any one, of compression, tension or torque, as well as a collection of these three, contributing to fatigue and cyclical loading.

[0022] In at least one embodiment, the larger bit assembly, is also secured to the tip of the whipstock assembly. Those familiar with multilateral shear bolt systems will recognize this as the traditional placement of a shear bolted mill. Nevertheless, since the larger bit assembly is not used for running the whipstock assembly, a robust connection at the larger bit assembly is not required in certain embodiments, and thus may be dispensed with.

[0023] The larger bit assembly, in at least one embodiment, only needs to remain stationary relative to the smaller assembly as the smaller assembly is being pulled back (e.g., uphole). Therefore, many different methods may be used to hold the larger bit assembly stationary. Several other non-limiting examples are listed below. As the smaller assembly is pulled back, it mostly enters the larger bit assembly. At this point, the external appearance of the two bit assemblies put together would very closely resemble that of a conventional multilateral lead mill in one or more embodiments. Since existing lead mills have been developed over many years it is presumed that this shape is optimized for the task of creating an exit from the main bore of a well. However, variations may be possible, either to incorporate the two-part design or to keep up with latest designs in conventional single part mills.

[0024] Once the smaller assembly has been fully retracted into the larger bit assembly it can be secured to the larger bit assembly for the milling operation. In at least one embodiment, a simple snap ring falls into a groove in the smaller assembly, thereby securing (e.g., laterally securing) the smaller assembly within the larger bit assembly. Many alternate methods are obviously possible, such as spring-loaded pins, a thread, or an interference fit between the two bit assemblies. In at least one embodiment, an external profile on the smaller assembly could mate with an internal profile in the larger bit assembly to lock the two bit assemblies together (e.g., torsionally securing the smaller assembly and the larger bit assembly).

[0025] At this point the larger bit assembly may be disconnected from the whipstock assembly tip and a normal window can be milled in the casing and/or formation as is current industry practice. As is sometimes the practice with milling windows, secondary mills may be added to follow the lead mill to ensure proper window geometry. Likewise multiple trips may be required to successfully mill a window. In those cases, extra mills or trips could be performed as is done today. Thereafter, the remainder of the multilateral construction may be completed, for example including placing a multilateral junction including a mainbore leg and a lateral bore leg at the junction between the main wellbore and the lateral wellbore.

[0026] Up to this point, the use of a two part drilling and running tool has been discussed for creating an exit window from a cased mainbore. An alternate use for this new technology is to sidetrack from an open-hole main bore. In this alternate use, the bit assembly would be more appropriately called a drill bit, as it would be drilling formation to exit the main bore rather milling casing. This would be useful for simple sidetracking where the main bore may need to be abandoned, or it may be used during the construction of an open-hole multilateral junction. In this use, the smaller assembly and larger bit assembly would be designed differently than what is shown here to closely resemble a drill bit instead of a mill bit. This would necessitate certain changes to the external cutting features, which should be understood to not deviate from the core features described herein.

[0027] While the previously mentioned seal surface and seal set up is workable, it could be reversed with the seal instead attached to the mill and a seal bore in the whipstock assembly. It is also understood that there are other methods to affect a seal between two parts that could work here as well. Or it is also conceivable that for some applications a perfect “pressure tight” seal might not be needed at all, and simply having the smaller assembly and whipstock assembly in very close contact is enough to allow enough pressure or flow to be conveyed to achieve the desired effect on the tool below the whipstock assembly.

[0028] Another possible deviation is that the smaller assembly may be secured to the whipstock assembly with different methods known to the industry. For example, the smaller assembly could be secured to the whipstock assembly using various different running, retrieving, and/or shifting tools. Nevertheless, the shear feature concept presented here is thought to be perhaps the simplest, most robust, and predictable of the different methods.

[0029] In at least one embodiment, the smaller assembly may feature one of several different mechanical movements or a combination thereof that connect it to the whipstock assembly. For example, the smaller assembly could include radially extending dogs to transmit all, or some of the mechanical loads (e.g., compression, tension, or torsion) to the whipstock assembly. Another method is to use a collet that locks the smaller assembly into the whipstock assembly axially in combination with a profile to hold torque. The smaller assembly may also be simply threaded into the whipstock assembly, and then once the whipstock assembly is positioned and locked into the mainbore it is unthreaded. The threads could also be used in combination with the above discussed locking methods to ensure it does not unthread prematurely.

[0030] Alternatively, the above concepts could be incorporated into the body of the whipstock assembly instead. Meaning for example the radial dogs extend inward into the smaller assembly and then retract to release. As should be understood from the many examples, many different mechanisms for securing and releasing the smaller assembly and the whipstock assembly together may be used. As such, the present disclosure should not be limited to one specific securing and releasing mechanism, as there are many others that can be substituted without deviating from the core idea of the two-part mill.

[0031] Similarly, the larger bit assembly may be secured to the whipstock assembly in many ways. Since the larger bit assembly is not used as the running tool in one or more embodiments, the connection need not be robust. In fact, the larger bit assembly may simply be loose and rely upon friction between it and the casing or open hole to remain stationary as the smaller assembly is pulled back. While the sole use of friction is unlikely, it is included to illustrate that there is great flexibility in securing the larger bit assembly with the whipstock assembly.

[0032] As mentioned above, there are many different methods and mechanisms known to the industry for securing tubular tools to each other. This also applies when it comes to securing the smaller assembly to the larger bit assembly in preparation for milling. For applications where the whipstock assembly needs to be removed following the drilling of the short rat hole, the present concept may be set up to allow the smaller assembly to disconnect from the whipstock assembly, connect to the larger bit assembly, and then following the completion of the milling/drilling, disconnect from the larger bit assembly again and then again reconnect to the whipstock assembly for its retrieval.

[0033] In at least one embodiment, the two part drilling and running tool can drill a lateral section on its own without the need for dedicated drill out run. Incorporating one of the mechanical movements described above into the smaller assembly would allow for this functionality.

[0034] Additionally, there are many anchoring assembly mechanisms (e.g., within Halliburton multilateral technology alone there are 4 different anchoring assembly mechanisms) for providing the datum for the construction of a multilateral junction. The latch coupling discussed herein is just one, but based on the particular well and requirements, any of the other methods would work just as well and not impact the use of the two part drilling and running tool presented here. For example, other hydraulic actuated anchor assemblies, including traditional anchor assemblies and screen based anchor assemblies, could be used as the anchoring assembly mechanism.

[0035] One or more hydraulic actuated anchoring assemblies designed according to the present disclosure may have a setting range of 15% or more of the run-in-hole diameter. For example, if the wellbore anchoring assembly were to have a diameter (x) when run in hole, the expanded diameter (x') could be 1.15x or more (e.g., 8.5" to 10" or more). Washed out / caved in areas or uneven ID in general is often seen when surveying a drilled section and finding a suitable location/depth for an open hole anchoring assembly can thus be difficult. Furthermore, the traditional open hole wellbore anchoring assembly relies on a certain formation strength of the rock in order to hold the required axial and torsional loads.

[0036] There are no other open hole wellbore anchoring assemblies that offer the same wellbore contact (contact area) or setting range as envisaged with the disclosed wellbore anchoring assembly. The contact area is believed to provide superior axial and torsional ratings. Since the disclosed wellbore anchoring assembly, in at least one embodiment, is activated by pressurized fluid in two or more separate chambers that spans several meters or more across the length of the anchoring assembly, it is believed to conform to any irregularities in the wellbore and is thus less sensitive to an even internal diameter (ID) in the setting area. Furthermore, by design the disclosed wellbore anchoring assembly will help support and stabilize the formation by exerting pressure against the wellbore ID, thereby making it less sensitive to weaker formations compared to a mechanical anchoring assembly, which to a larger degree relies on a competent formation. A wellbore anchoring assembly according to the present disclosure provides the ability to have communication from tubing to annulus, if required, even after being set, which is not known in the art. This feature offers the ability to perform circulation of fluid and/or a return path for pumping cement operation.

[0037] FIG. 1A is a schematic view of a well system 100 designed, manufactured and operated according to one or more embodiments disclosed herein. The well system 100 includes a platform 120 positioned over a subterranean formation 110 located below the earth's surface 115. The platform 120, in at least one embodiment, has a hoisting apparatus 125 and a derrick 130 for raising and lowering one or more downhole tools including pipe strings, such as a drill string 140. Although a land-based oil and gas platform 120 is illustrated in FIG. 1A, the scope of this disclosure is not thereby limited, and thus could potentially apply to offshore applications. The teachings of this disclosure may also be applied to other land-based and/or water-based well systems different from that illustrated.

[0038] As shown, a main wellbore 150 has been drilled through the various earth strata, including the subterranean formation 110. The term "main" wellbore is used herein to designate a primary wellbore from which another secondary wellbore is drilled. It is to be noted, however, that a main wellbore 150 does not necessarily extend directly to the earth's surface, but could instead be a branch of yet another lateral wellbore. A casing string 160 may be at least partially cemented within the main wellbore 150. The term "casing" is used herein to designate a tubular string used to line a wellbore. Casing may actually be of the type known to those skilled in the art as a "liner" and may be made of any material, such as steel or composite material and may be segmented or continuous, such as coiled tubing. The term "lateral" wellbore is used herein to designate a wellbore that is drilled outwardly from its intersection with another wellbore, such as a main wellbore. Moreover, a lateral wellbore may have another lateral wellbore drilled outwardly therefrom.

[0039] A whipstock assembly 170 according to one or more embodiments of the present disclosure may be positioned at a location in the main wellbore 150. Specifically, the whipstock assembly 170 could be placed at a location in the main wellbore 150 where it is desirable for a lateral wellbore 180 to exit. Accordingly, the whipstock assembly 170 may be used to support a drilling/milling tool used to penetrate a window in the main wellbore 150. In at least one embodiment, once the window has been milled and a lateral wellbore 180 formed, the whipstock assembly 170 may be retrieved and returned uphole by a retrieval tool, in some embodiments in only a single trip.

[0040] In some embodiments, an anchoring assembly 190 may be placed downhole in the wellbore 150 to support and anchor downhole tools, such as the whipstock assembly 170, for maintaining the whipstock assembly 170 in place while milling the casing 160 and/or drilling the lateral wellbore 180. The anchoring assembly 190, in accordance with the disclosure, may be employed in a cased section of the main wellbore 150, or may be located in an open-hole section of the main wellbore 150, as is shown. As such, the anchoring assembly 190 in at least one embodiment may be configured to resist at least 6,750 newton meters (Nm) (e.g., about 5,000 lb-ft) of torque. In yet another embodiment, the anchoring assembly 190 may be configured to resist at least 13,500 newton meters (Nm) (e.g., about 10,000 lb-ft) of torque, and in yet another embodiment configured to resist at least 20,250 newton meters (Nm) (e.g., about 15,000 lb-ft) of torque. Similarly, the anchoring assembly 190 may be configured to resist at least 1814 kg (e.g., about 4,000 lb) of axial force. In yet another embodiment, the anchoring assembly 190 may be configured to resist at least 4536 kg (e.g., about 10,000 lb) of axial force, and in yet another embodiment the anchoring assembly 190 may be configured to resist at least 6804 kg (e.g., about 15,000 lb) of axial force.

[0041] In the illustrated embodiment, the anchoring assembly 190 may be a hydraulically activated anchoring assembly. In this embodiment, once the anchoring assembly 190 reaches a desired location in the main wellbore 150, fluid pressure may be applied to set the hydraulic anchoring assembly. In at least one embodiment, the hydraulically activated anchoring assembly includes two or more hydraulic activation chambers, and the activation fluid is supplied to the two or more hydraulic activation chambers (e.g., through a two-part milling assembly coupled to the whipstock assembly 170) to move the two or more hydraulic activation chambers from the first collapsed state to the second activated state and engage a wall of the main wellbore 150. The anchoring assembly 190 may also include, in some embodiments, an expandable medium positioned radially about the two or more hydraulic activation chambers. In some aspects, the expandable medium may be configured to grip and engage the wall of the main wellbore 150 when the two or more hydraulic activation chambers are in the second activated state. Notwithstanding, other fluid activated anchoring assemblies (e.g., other than those having two or more hydraulic activation chambers) may be used and remain within the scope of the disclosure. In at least one other embodiment, the hydraulically activated anchoring assembly includes one or more hydraulic activation slips, and the activation fluid is supplied to the one or more hydraulic activation slips (e.g., through a two-part milling assembly coupled to the whipstock assembly 170) to move the one or more hydraulic activation slips from the first collapsed state to the second activated state and engage the wall of the main wellbore 150.

[0042] In yet other embodiments, the anchoring assembly 190 is a latch coupling. In this embodiment, the latch coupling (e.g., a profile in the casing engages with a reciprocal profile in the whipstock assembly 170) anchors the whipstock assembly 170, and any other features hanging there below (e.g., screens, valves, etc.) in the casing string 160. Once the anchoring assembly 190 reaches a desired location in the main wellbore 150, the reciprocal profile in the whipstock assembly 170 may be activated to engage with the latch coupling profile in the casing string 160, thereby setting the anchoring assembly 190. In at least one embodiment, the anchoring assembly is not hydraulically activated, but is mechanically activated.

[0043] Turning now to FIGs. 1B through 1G, illustrated are various different views of one embodiment of the anchoring assembly 190A designed, manufactured and operated according to one or more embodiments of the disclosure at different operational states. The anchoring assembly 190A, in at least one embodiment, could be used as the anchoring assembly 190 of FIG. 1A. FIGs. 1B and 1C illustrate a partial sectional view and a cross-sectional view, respectively, of the anchoring assembly 190A at a run-in hole state, FIGs. 1D and 1E illustrate a partial sectional view and a cross-sectional view, respectively, of the anchoring assembly 190A when a first plurality of openings is in fluid communication with the two or more hydraulic activation chambers, and FIGs. 1F and 1G illustrate a partial sectional view and a cross-sectional view, respectively, of the anchoring assembly 190A when a second plurality of openings are in fluid communication with an annulus surrounding the base pipe.

[0044] The anchoring assembly 190A illustrated in FIGs. 1B through 1G initially includes a base pipe 191, and two or more hydraulic activation chambers 192 (e.g., at least four hydraulic activation chambers in one embodiment) disposed radially about the base pipe 191, the two or more hydraulic activation chambers 192 configured to move from a first collapsed state (e.g., the radially collapsed state as shown in FIGs. 1B and 1C) to a second activated state (e.g., radially expanded state as shown in FIGs. 1D through 1G) to engage with a wall of a wellbore and laterally and rotationally fix a downhole tool coupled to the base pipe 191 within the wellbore. In the illustrated embodiment, the base pipe 191 has a length (l_{bp}) at least 10 times a diameter (d) of the base pipe 191, and the two or more hydraulic activation chambers extend along at least a portion of the length (l_{bp}). In yet another embodiment, the length (l_{bp}) of the base pipe 191 is at least 2 meters long and a length (l_{ac}) of the two or more hydraulic activation chambers 192 is at least 1.5 meters long. In at least one other embodiment, the length (l_{bp}) of the base pipe 191 is at least 4 meters long and the length (l_{ac}) of the two or more hydraulic activation chambers 192 is at least 3 meters long. In yet another embodiment, the length (l_{bp}) of the base pipe 191 is at least 10 meters long and the length (l_{ac}) of the two or more hydraulic activation chambers 192 is at least 7.5 meters long.

[0045] The base pipe 191, in at least one embodiment, includes a first plurality of openings 193, the first plurality of openings 193 configured to provide fluid communication between the base pipe 191 and the two or more hydraulic activation chambers 192 to move the two or more hydraulic activation chambers 192 from the first collapsed state (e.g., shown in FIGs. 1B and 1C) to the second activated state (e.g., shown in FIGs. 1D through 1E). The base pipe, in at least one other embodiment, includes a second plurality of openings 194, the second plurality of openings 194 configured to provide fluid communication between the base pipe 191 and an annulus 195 surrounding the base pipe 191 when the two or more hydraulic activation chambers 192 are in the second activated state.

[0046] In the illustrated embodiment of FIGs. 1B through 1G, the anchor assembly 190A additionally includes a valve 196 coupled to the base pipe 191. The valve 196, in one or more embodiments, includes a first setting that closes fluid communication to the first plurality of openings 193 and the second plurality of openings 194, a second setting that only opens fluid communication to the first plurality of openings 193, and a third setting that only opens fluid communication to the second plurality of openings 194. While the valve 196 has been illustrated as a sliding sleeve valve in FIGs. 1B through 1G, other types of valves may be used and remain within the scope of the disclosure.

[0047] With reference to FIGs. 1B and 1C, the valve 196 is at the first setting, wherein fluid communication to the first plurality of openings 193 and the second plurality of openings 194 is closed, and thus fluid 197 may bypass the anchor assembly 190. Accordingly, the two or more hydraulic activation chambers 192 remain in the first collapsed state.

[0048] With reference to FIGs. 1D and 1E, the valve 196 is at the second setting, wherein fluid communication is only open to the first plurality of openings 193. Accordingly, fluid 198 may enter the two or more hydraulic activation chambers 192 and move them to the second activated state. In at least one embodiment, the fluid 198 plastically deforms the two or more hydraulic activation chambers 192, such that they may remain in the second activated state regardless of the setting of the valve 196. In yet another embodiment, the valve 196 moves from the second state to either of the first state or the third state while the two or more hydraulic activation chambers 192 are under pressure. Accordingly, the pressurized fluid 198 may be trapped within the two or more hydraulic activation chambers 192, thereby keeping them in the second activated state.

[0049] With reference to FIGs. 1F and 1G, the valve 196 is at the third setting, wherein fluid communication is only open to the second plurality of openings 194. Accordingly, fluid 199 may move between the base pipe 191 and the annulus 195 surrounding the base pipe 191 when the two or more hydraulic activation chambers 192 are in the second activated state.

[0050] Returning to FIG. 1A, in at least one embodiment, a multilateral junction is positioned at an intersection between the resulting main wellbore 150 and the resulting lateral wellbore 180. In accordance with one embodiment, the multilateral junction might include a main bore leg forming a first pressure tight seal with the main bore completion and a lateral bore leg forming a second pressure tight seal with the lateral bore completion, such that the main bore completion and the lateral bore completion are hydraulically isolated from one another. What results, in one or more embodiments, is an open hole TAML Level 5 pressure tight junction.

[0051] Turning to FIG. 2A, illustrated is a side view of a two part milling and running tool 200 designed, manufactured and operated according to one or more embodiments of the disclosure. The two part milling and running tool 200, in the illustrated embodiment, includes a conveyance 210 having a larger bit assembly 220 and a smaller assembly 250 coupled thereto. The phrase "bit assembly," as used herein, is intended to include both milling assemblies (e.g., as might be used to mill through casing) and drill bit assemblies (e.g., as might be used to drill through formation), as well as any combination of the two. As discussed above, and shown in many FIGs., the smaller assembly 250 may be a smaller bit assembly, and thus may contain one or more different types of cutting features along a downhole face thereof.

[0052] The conveyance 210, in at least one embodiment, is a tubular, such as jointed pipe or coiled tubing. In the illustrated embodiment of FIG. 2A, the smaller assembly 250 is coupled to a downhole end of the conveyance 210, whereas the larger bit assembly 220 is in sliding engagement with the conveyance 210. Accordingly, assuming that something (e.g., friction, a shear feature, etc.) is holding the larger bit assembly 220 in place, as the conveyance 210 is moved the smaller assembly 250 may slide relative to the larger bit assembly 220. For instance, if the conveyance 210 were withdrawn uphole, the larger bit assembly 220 would slide along the conveyance 210, thereby allowing the smaller assembly 250 to slide toward the larger bit assembly 220. As will be discussed in greater detail below, the two part milling and running tool 200 may be used to deploy a whipstock assembly, and thus be coupled to the whipstock assembly when running downhole. The coupling of the milling and running tool 200 to the whipstock assembly, in at least one embodiment, would prevent the smaller assembly 250 from sliding toward the larger bit assembly 220 during the run-in-hole phase. Only when the coupling is removed or broken (e.g., sheared) would the smaller assembly 250 be allowed to slide toward the larger bit assembly 220.

[0053] In the illustrated embodiment of FIG. 2A, the two part milling and running tool 200 is positioned in the run-in-hole position. In this run-in-hole position, the larger bit assembly 220 would be spaced apart from the smaller assembly 250 by a distance (D_0). In at least one embodiment, the distance (D_0) approximates the length of the whipstock assembly that the two part milling and running tool 200 is coupled to. According to this embodiment, the smaller assembly 250 might couple proximate a downhole end of the whipstock assembly, whereas the larger bit assembly 220 might couple proximate an uphole end of the whipstock assembly. Thus, in at least one embodiment, the distance (D_0) is at least 2 meters. In yet another embodiment, the distance (D_0) is at least 4 meters, and in even another embodiment the distance (D_0) is at least 5 meters.

[0054] Turning now to FIG. 2B, illustrated is an enlarged side view of the larger bit assembly 220 of FIG. 2A. As is evident in FIG. 2B, the larger bit assembly 220 may have one or more blades 222 and/or one or more cutting features 224 thereon. While specific blades 222 and cutting features 224 are illustrated in FIG. 2B, any currently known or hereafter discovered blades and cutting features may be used and remain within the scope of the disclosure. The larger bit assembly 220, in the illustrated embodiment, includes a cutting diameter (d_l). In at least one embodiment, the cutting diameter (d_l) approximates the size of an opening (e.g., in the casing and/or formation) forming a lateral wellbore.

[0055] Turning now to FIG. 2C, illustrated is an isometric view of one embodiment of an internal profile of the larger bit assembly 220 of FIG. 2A. In the illustrated embodiment of FIG. 2C, the larger bit assembly 220 additionally includes one or more internal profiles 226. In at least one embodiment, the internal profiles 226 are configured to engage with external profiles of the smaller assembly 250 when the smaller assembly 250 has slid relative and proximate to the larger bit assembly 220. Furthermore, in at least one embodiment, the larger bit assembly 220 may include a lock ring profile 228, which may be configured to hold a lock ring (not shown) that could ultimately engage with an associated lock ring profile in the smaller assembly 250, or vice versa.

[0056] Turning now to FIG. 2D, illustrated is an enlarged side view of the smaller assembly 250 of FIG. 2A. As is evident in FIG. 2D, the smaller assembly 250 may have one or more blades 252 and one or more cutting features 254 thereon, thereby making the smaller assembly 240 a smaller bit assembly. While specific blades 252 and cutting features 254 are illustrated in FIG. 2D, any currently known or hereafter discovered blades and cutting features may be used and remain within the scope of the disclosure. The smaller assembly 250, in the illustrated embodiment, includes a cutting diameter (d_s). In at least one embodiment, the cutting diameter (d_s) is at least 10 percent less than the cutting diameter (d_l). In at least one embodiment, the cutting diameter (d_s) is at least 25 percent less than the cutting diameter (d_l), in yet another embodiment at least 50 percent less than the cutting diameter (d_l), in yet another embodiment at least 75 percent less than the cutting diameter (d_l), and in yet another embodiment at least 90 percent less than the cutting diameter (d_l).

[0057] The smaller assembly 250, as shown in FIG. 2D, may additionally include one or more external profiles 256. In at least one embodiment, not only are the one or more external profiles 256 configured to engage with the one or more internal profiles 226 of the larger bit assembly 220, the one or more external profiles 256 may be configured to engage with associated internal profiles in the whipstock assembly that the smaller assembly 250 is originally engaged with. In the illustrated embodiment of FIG. 2D, the one or more external profiles 256 have a length (l_s) and a width (w_s). The length (l_s) and the width (w_s) may be used to limit the compression forces, tension forces, and/or torque forces that may exist between the smaller assembly 250 and the whipstock assembly (not shown) when the two are coupled.

[0058] The smaller assembly 250, in the illustrated embodiment, may further include an associated lock ring profile 258. Accordingly, the lock ring profile 258, as well as the associated lock ring profile 228 and lock ring (not shown) of the larger bit assembly 220, may be used to linearly fix the larger bit assembly 220 and the smaller assembly 250. Additionally, the one or more external profiles 256, as well as the one or more internal profiles 226 of the larger bit assembly 220, may be used to rotationally fix the larger bit assembly 220 and the smaller assembly 250.

[0059] Turning now to FIG. 2E, illustrated is an isometric view of one embodiment of the smaller assembly 250 of FIG. 2A. In the illustrated embodiment of FIG. 2E, the smaller assembly 250 additionally includes one or more shear profiles 260, as well as one or more fluid ports 262. In at least one embodiment, the one or more shear profiles 260 house one or more shear features (not shown), the one or more shear features removably coupling the smaller assembly 250 to the whipstock assembly. In one embodiment, the one or more shear features are one or more shear pins and/or shear bolts. Nevertheless, other coupling mechanisms are within the scope of the present disclosure. The one or more fluid ports 262, in the illustrated embodiment, provide fluid access past the smaller assembly 250, to help cool the bit/mill, lubricate and remove cuttings. In yet another embodiment, the one or more fluid ports 262, provide fluid access past the smaller assembly 250, particularly, when the smaller assembly 250 is coupled to and sealed with the whipstock assembly. For example, the one or more fluid ports 262 may be fluidly coupled with a through bore in the whipstock assembly, and thus may be used to activate a hydraulic wellbore anchoring assembly, among other downhole features.

[0060] Turning to FIG. 3A, illustrated is a cross-sectional side view of the two part milling and running tool 200 of FIG. 2A.

[0061] Turning now to FIG. 3B, illustrated is an enlarged side view of the larger bit assembly 220 of FIG. 3A. As can be shown in FIG. 3B, a lock ring 230 may be positioned within the lock ring profile 228, and surrounding the conveyance 210. As the conveyance 210 does not have a corresponding lock ring profile in the embodiment shown, the larger bit assembly 220 is allowed to slide along the conveyance 210 freely.

[0062] Turning now to FIG. 3C, illustrated is an enlarged side view of the smaller assembly 250 of FIG. 3A.

[0063] Turning to FIG. 4, illustrated is a side view of a two part milling and running tool 200 of FIGs. 2A and 3A, after the conveyance 210 has been pulled partially uphole, thereby sliding the smaller assembly 250 toward the larger bit assembly 220. In the illustrated embodiment, it is assumed that the larger bit assembly 220 is fixed in location, and that the smaller assembly 220 is sliding toward the fixed larger bit assembly 220. Such would be the case if the larger bit assembly 220 were still fixed (e.g., via friction, a shear feature, etc.) relative to the whipstock assembly. In this partially slid position, the larger bit assembly 220 would be spaced apart from the smaller assembly 250 by a distance (D_1). In at least one embodiment, the distance (D_1) is at least 50 percent less than the distance (D_0).

[0064] Turning to FIG. 5, illustrated is a cross-sectional side view of the two part milling and running tool 200 of FIG. 4.

[0065] Turning to FIG. 6A, illustrated is a side view of a two part milling and running tool 200 of FIGs. 4 and 5, after the conveyance 210 has been pulled fully uphole, thereby sliding the smaller assembly 250 into engagement with the larger bit assembly 220, and thus forming a combined bit assembly 600.

[0066] Turning now to FIG. 6B, illustrated is an enlarged side view of the combined bit assembly 600 of FIG. 6A. As shown, the smaller assembly 250 is engaged with the larger bit assembly 220. Furthermore, with the smaller assembly 250 engaged with the larger bit assembly 220, the combined bit assembly 600 may now approximate the shape of bit assemblies currently existing in the art.

[0067] Turning now to FIG. 6C, illustrated is an isometric enlarged side view of the combined bit assembly 600 of FIG. 6A.

[0068] Turning to FIG. 7A, illustrated is a cross-sectional side view of a two part milling and running tool 200 of FIGs. 4 and 5, after the conveyance 210 has been pulled fully uphole, thereby sliding the smaller assembly 250 into engagement with the larger bit assembly 220, thereby forming the combined bit assembly 600.

[0069] Turning now to FIG. 7B, illustrated is an enlarged cross-sectional side view of the combined bit assembly 600 of FIG. 7A. As shown in FIG. 7B, the lock ring 230 may snap into the associated lock ring profile 258 in the smaller assembly 250, and thus axially fix the smaller assembly 250 relative to the larger bit assembly 220.

[0070] Turning now to FIGs. 8 through 17B, illustrated are different views of a well system 800, the well system 800 employing a two part drilling and running tool, for example to form a lateral wellbore therein.

[0071] With initial reference to FIG. 8, the well system 800 initially includes a main wellbore 810. As indicated above, the main wellbore 810 may be a primary wellbore extending from the surface, or a secondary wellbore already extending from a primary wellbore. Located in the main wellbore 810 is tubing string 820, such as casing string. In certain embodiment, while not shown, cement may be positioned between the main wellbore 810 and the tubing string 820.

[0072] Turning now to FIG. 9A, illustrated is the well system 800 of FIG. 8 after employing a conveyance 910 and a two part drilling and running tool 920 to run a whipstock assembly 970 within the main wellbore 810. In at least one embodiment, the whipstock assembly 970 is coupled to an anchoring assembly 990 and a seal assembly 995 (e.g., smaller bit assembly sealing assembly), and thus the two part drilling and running tool 920 also runs the anchoring assembly 990 and the seal assembly 995 within the wellbore. In at least one embodiment, fluid supplied through the conveyance 910 and through the whipstock assembly 970 acts upon the anchoring assembly 990 to move it from a first collapsed state to a second activated state, and thus secure the whipstock assembly 970 within the main wellbore 810.

[0073] In yet another embodiment, a lower mainbore completion assembly 998 is coupled to a downhole end of the anchoring assembly 990. The lower mainbore completion assembly 998, in at least one embodiment, might include one or more screens, one or more control valves, etc.

[0074] The two part drilling and running tool 920 may be similar to the two part drilling and running tool discussed above. Accordingly, the two part drilling and running tool 920 may include a larger bit assembly 930 and a smaller assembly 950. As shown in the embodiment of FIG. 9A, the smaller assembly 950 is coupled to a downhole end of the conveyance 910, and extends at least partially within a through bore of the whipstock assembly 970.

[0075] Turning now to FIG. 9B, illustrated is an enlarged side view of the larger bit assembly 930 of FIG. 9A. In the illustrated embodiment of FIG. 9B, the larger bit assembly 930 is coupled proximate an uphole end of the whipstock assembly 970. For example, a coupling mechanism 935 (e.g., shear feature) may be employed to couple the larger bit assembly 930 to the whipstock assembly 970. While a shear feature has been illustrated, other coupling mechanisms 935 could also be used. Moreover, as has been discussed above, the coupling mechanism 935 is not necessary in all embodiments.

[0076] Turning now to FIG. 9C, illustrated is an enlarged side view of the smaller assembly 950 and seal assembly 995 of FIG. 9A. In the illustrated embodiment of FIG. 9C, the smaller assembly 950 is coupled proximate a downhole end of the whipstock assembly 970. For example, a coupling mechanism 955 (e.g., shear feature) has been employed to couple the smaller assembly 950 to the whipstock assembly 970. While a shear feature has been illustrated, other coupling mechanisms 955 could also be used.

[0077] In at least one embodiment, the coupling mechanism 955 is coupled within a bottom 40 percent of the whipstock assembly 970. In yet another embodiment, the coupling mechanism 955 is coupled within a bottom 20 percent of the whipstock assembly 970. In even another embodiment, the coupling mechanism 955 is coupled within a bottom 10 percent, if not bottom 5 percent, of the whipstock assembly 970. The smaller assembly 950, in the illustrated embodiment, additionally extends within a through bore 980 of the whipstock assembly 970.

[0078] As indicated above, the smaller assembly 950 may have one or more external profiles 960 that engage with one or more internal profiles 985 of the whipstock assembly 970. Accordingly, a combination of the coupling mechanism 955, the one or more external profiles 960, and the one or more internal profiles 985, may isolate the force (e.g., to only one of tension, compression or torsion) required to shear the coupling mechanism 955.

[0079] As further shown, the seal assembly 995 includes one or more seals 996 configured to provide a seal between itself and the smaller assembly 950. In the illustrated embodiment of FIG. 9C, the one or more seals 996 are located in the seal assembly 995 itself, and thus seal against a polished bore surface of the smaller assembly 950 to provide a fluid tight seal. In other embodiments, however, the one or more seals 996 could be located on the smaller assembly 950, and thus seal against a polished bore surface of the seal assembly 995. Those skilled in the art understand the various different seals that might be used and remain within the scope of the present disclosure.

[0080] Turning now to FIG. 9D, illustrated is an enlarged side view of the anchoring assembly 990. In the illustrated embodiment, the anchoring assembly is a hydraulically actuated anchoring assembly. For example, the anchoring assembly 990 of FIG. 9D employs one or more hydraulically actuated slips 991 that may move from the first collapsed state to the second activated state to engage with the main wellbore. In at least one embodiment, the fluid would enter through fluid inlet 992 and act upon slip piston 993 to move the one or more hydraulically actuated slips 991 from the first collapsed state to the second activated state. While the anchoring assembly 990 employs the one or more hydraulically actuated slips 991 in the embodiment of FIG. 9D, in at least one other embodiment an anchoring assembly similar to the anchoring assembly 190 illustrated in FIGs. 1B through 1G could be used.

[0081] Turning to FIG. 10A, illustrated is a cross-sectional side view of the well system 800 of FIG. 9A.

[0082] Turning now to FIG. 10B, illustrated is an enlarged cross-sectional side view of the larger bit assembly 930 of FIG. 10A. As can be seen in FIG. 10B, a lock ring 1010 may be positioned within a lock ring profile 1020 in the larger bit assembly 930. As the conveyance 910 does not have a corresponding lock ring profile in the embodiment shown, but for the coupling mechanism 935, the larger bit assembly 930 would be allowed to slide along the conveyance 910 freely. Nevertheless, the coupling mechanism 935 is preventing the larger bit assembly 930 from moving in the embodiment of FIG. 10B.

[0083] Turning now to FIG. 10C, illustrated is an enlarged cross-sectional side view of the smaller assembly 950 of FIG. 10A.

[0084] Turning now to FIG. 11A, illustrated is the well system 800 of FIG. 10A after generating enough force with the conveyance 910 to shear the coupling mechanism 955 fixing the smaller assembly 950 to the whipstock assembly 970. Again, in at least one embodiment and depending on the design, only a single type of force (e.g., tension, compression, torsion) would (or even could) shear the coupling mechanism 955. In the illustrated embodiment, the force required to shear the coupling mechanism is torsional force, but in other designs it could be either tension force or compression force.

[0085] In the illustrated embodiment, the coupling mechanism 955 has sheared due to the torsion force, and the smaller assembly 950 has subsequently been withdrawn a small distance uphole. Given the sliding relationship between the smaller assembly 950 and the larger bit assembly 930, and the fact that the larger bit assembly 930 is fixed relative to the whipstock assembly 970, the conveyance 910 slides within an inside diameter of the larger bit assembly 930.

[0086] As shown, the conveyance 910 has been pulled uphole, thereby sliding the smaller assembly 950 into engagement with the larger bit assembly 930, and thus forming a combined bit assembly 1110.

[0087] Turning now to FIG. 11B, illustrated is an enlarged side view of the combined bit assembly 1110 of FIG. 11A. As shown, the smaller assembly 950 is engaged with the larger bit assembly 930. Furthermore, with the smaller assembly 950 engaged with the larger bit assembly 930, the combined bit assembly 1110 may now approximate the shape of bit assemblies currently existing in the art.

[0088] Turning now to FIG. 11C, illustrated is an enlarged side view of the whipstock assembly 970. As shown, the whipstock assembly 970 has the one or more internal profiles 985 that were previously engaged with the one or more external profiles 960 of the smaller assembly 950.

[0089] Turning to FIG. 12A, illustrated is a cross-sectional side view of the well system 800 of FIG. 11A.

[0090] Turning now to FIG. 12B, illustrated is an enlarged cross-sectional side view of the combined bit assembly 1110 of FIG. 12A. As shown in FIG. 12B, the lock ring 1010 may snap into the associated lock ring profile 1210 in the smaller assembly 950, and thus axially fix the smaller assembly 950 relative to the larger bit assembly 930. As discussed above, the one or more external profiles 960 in the smaller assembly 950 may engage with the one or more internal profiles of the larger bit assembly 930 to rotationally fix the smaller assembly 950 relative to the larger bit assembly 930.

[0091] Turning to FIG. 13A, illustrated is a side view of a well system 800 of FIG. 12A, after the coupling mechanism 935 has sheared and the conveyance 910 has been pulled further uphole. In at least one embodiment, any one of a compressive force, tensile force or torsional force may shear the coupling mechanism 935. Accordingly, at this stage, the combined bit assembly 1110 is no longer axially or rotationally fixed to the whipstock assembly 970, but the whipstock assembly remains fixed within the wellbore.

[0092] Turning now to FIG. 13B, illustrated is an enlarged side view of the combined bit assembly 1110 of FIG. 13A after it is no longer coupled to the whipstock assembly 970.

[0093] Turning to FIG. 14A, illustrated is a side view of a well system 800 of FIG. 13A, after the conveyance 910 and combined bit assembly 1110 are being pushed back downhole to mill at least a portion of the tubing string 820 to form an exit therein. At the stage illustrated in FIG.

14A, the conveyance 910 and combined bit assembly 1110 have finished forming the exit in the tubing string 820 and have formed a lateral wellbore 1410 (e.g., starting with an initial rat hole) in the subterranean formation.

[0094] Turning now to FIG. 14B, illustrated is an enlarged side view of the combined bit assembly 1110 of FIG. 14A after forming the lateral wellbore 1410 in the subterranean formation.

[0095] Turning to FIG. 15, illustrated is a side view of a well system 800 of FIG. 14A, after the conveyance 910 and combined bit assembly 1110 have been pulled from the lateral wellbore 1410 and the main wellbore 810.

[0096] Turning to FIG. 16A, illustrated is a side view of a well system 800 of FIG. 15, after the whipstock assembly 970 has been removed from the main wellbore 810. While the embodiment of FIGs. 15 and 16A illustrate that the removal of the combined bit assembly 1110 and the whipstock assembly 970 are two separate trips, certain embodiments may exist wherein a single trip is employed to remove both the combined bit assembly 1110 and the whipstock assembly. What remains is a deflector alignment assembly 1610 (e.g., including a slotted muleshoe in one embodiment).

[0097] Turning now to FIG. 16B, illustrated is an enlarged side view of the well system 800 of FIG. 16A including the deflector alignment assembly 1610 in the main wellbore 810.

[0098] Turning to FIG. 17A, illustrated is a side view of a well system 800 of FIG. 16A, after a deflector assembly 1710 has been positioned within the main wellbore 810 and appropriately located and aligned (e.g., both laterally and rotationally), for example using the deflector alignment assembly 1610.

[0099] Turning now to FIG. 17B, illustrated is an enlarged side view of the well system 800 of FIG. 17A including the deflector assembly 1710 in the main wellbore 810.

[00100] Turning to FIG. 18, illustrated is a side view of a well system 800 of FIG. 17A, after a multilateral junction assembly 1810 has been positioned within the main wellbore 810 and the lateral wellbore 1410. In the illustrated embodiment, the multilateral junction assembly 1810 includes a main bore leg 1820 that remains within the main wellbore 810 and a lateral bore leg 1830 that deflects out of the main wellbore 810 and into the lateral wellbore 1410.

[00101] Turning to FIG. 19, illustrated is a cross-sectional side view of the well system 800 of FIG. 18.

[00102] Aspects disclosed herein include:

A. A downhole tool, the downhole tool including: 1) a two part drilling and running tool, the two part drilling and running tool including: a) a conveyance; b) a smaller assembly coupled to an end of the conveyance; and c) a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly; 2) a whipstock assembly coupled to the two part drilling and running tool using a coupling mechanism; and 3) a hydraulically actuated anchoring assembly coupled to a downhole end of the whipstock assembly.

B. A well system, the well system including: 1) a main wellbore located within a subterranean formation; 2) a two part drilling and running tool positioned within the main wellbore, the two part drilling and running tool including: a) a conveyance; b) a smaller assembly coupled to an end of the conveyance; and c) a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly; 3) a whipstock assembly coupled to the two part drilling and running tool using a coupling mechanism; and 4) a hydraulically actuated anchoring assembly coupled to a downhole end of the whipstock assembly.

C. A method for forming a well system, the method including: 1) forming a main wellbore within a subterranean formation; 2) positioning a two part drilling and running tool within the main wellbore, the two part drilling and running tool coupled to a whipstock assembly using a coupling mechanism, the whipstock assembly having a hydraulically actuated anchoring assembly coupled to a downhole end thereof, the two part drilling and running tool including: a) a conveyance; b) a smaller assembly coupled to an end of the conveyance; and c) a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly; and 3) applying fluid pressure to the hydraulically actuated anchoring assembly to set the hydraulically actuated anchoring assembly in the main wellbore.

[00103] Aspects A, B, and C may have one or more of the following additional elements in combination: Element 1: wherein the smaller assembly is a smaller bit assembly. Element 2: wherein the smaller bit assembly includes one or more first profiles and the larger bit assembly includes one or more second profiles, and further wherein the one or more first profiles are configured to engage with the one or more second profiles to rotationally fix the smaller bit assembly with the larger bit assembly when the two are slidingly engaged together. Element 3: wherein the one or more first profiles are one or more external profiles and the one or more second profiles are one or more internal profiles. Element 4: wherein the smaller bit assembly includes one of a lock ring profile or a lock ring, and the larger bit assembly includes an other of the lock ring or the lock ring profile, the lock ring profile and lock ring configured to engage with one another to slidingly fix the smaller bit assembly with the larger bit assembly when the two are slidingly engaged together. Element 5: wherein the smaller bit assembly includes the lock ring profile and the larger bit assembly includes the lock ring. Element 6: wherein the smaller bit assembly includes one or more fluid ports, the one or more fluid ports configured to hydraulically actuate the anchoring assembly. Element 7: wherein the hydraulically actuated anchoring assembly is an expandable screen based anchoring assembly including two or more hydraulic activation chambers. Element 8: further including a seal assembly coupled between the whipstock assembly and the hydraulically actuated anchoring assembly. Element 9: wherein the seal assembly includes one or more seals configured to seal against the smaller bit assembly. Element 10: wherein the hydraulically actuated anchoring assembly is in a radially collapsed state. Element 11: wherein the hydraulically actuated anchoring assembly is in a radially expanded state engaged with a wall of the main wellbore. Element 12: wherein the hydraulically actuated anchoring assembly is an expandable screen based anchoring assembly including two or more hydraulic activation chambers. Element 13: further including applying force to the smaller bit assembly to shear the coupling mechanism after applying the fluid pressure, and then sliding the smaller bit assembly relative to the larger bit assembly to form a combined bit assembly. Element 14: further including milling casing located within the main wellbore using the combined bit assembly. Element 15: further including drilling a lateral wellbore off of the main wellbore using the combined bit assembly. Element 16: wherein the smaller bit assembly and the whipstock assembly are coupled together such that only one of compression, tension or torque may be used to disengage the coupling mechanism. Element 17: wherein only torque may be used to disengage the coupling mechanism.

[00104] Those skilled in the art to which this application relates will appreciate that other and further additions, deletions, substitutions and modifications may be made to the described embodiments.

WHAT IS CLAIMED IS:

1. A downhole tool, comprising:

a two part drilling and running tool, the two part drilling and running tool including:

a conveyance;

a smaller assembly coupled to an end of the conveyance; and

a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly;

a whipstock assembly coupled to the two part drilling and running tool using a coupling mechanism; and

a hydraulically actuated anchoring assembly coupled to a downhole end of the whipstock assembly.

2. The downhole tool as recited in Claim 1, wherein the smaller assembly is a smaller bit assembly.

3. The downhole tool as recited in Claim 2, wherein the smaller bit assembly includes one or more first profiles and the larger bit assembly includes one or more second profiles, and further wherein the one or more first profiles are configured to engage with the one or more second profiles to rotationally fix the smaller bit assembly with the larger bit assembly when the two are slidingly engaged together.

4. The downhole tool as recited in Claim 3, wherein the one or more first profiles are one or more external profiles and the one or more second profiles are one or more internal profiles.

5. The downhole tool as recited in Claim 2, wherein the smaller bit assembly includes one of a lock ring profile or a lock ring, and the larger bit assembly includes an other of the lock ring or the lock ring profile, the lock ring profile and lock ring configured to engage with one another to slidingly fix the smaller bit assembly with the larger bit assembly when the two are slidingly engaged together.

6. The downhole tool as recited in Claim 5, wherein the smaller bit assembly includes the lock ring profile and the larger bit assembly includes the lock ring.

7. The downhole tool as recited in Claim 2, wherein the smaller bit assembly includes one or more fluid ports, the one or more fluid ports configured to hydraulically actuate the anchoring assembly.

8. The downhole tool as recited in Claim 7, wherein the hydraulically actuated anchoring assembly is an expandable screen based anchoring assembly including two or more hydraulic activation chambers.

9. The downhole tool as recited in Claim 7, further including a seal assembly coupled between the whipstock assembly and the hydraulically actuated anchoring assembly.

10. The downhole tool as recited in Claim 9, wherein the seal assembly includes one or more seals configured to seal against the smaller bit assembly.

11. A well system, comprising:

a main wellbore located within a subterranean formation;

a two part drilling and running tool positioned within the main wellbore, the two part drilling and running tool including:

a conveyance;

a smaller assembly coupled to an end of the conveyance; and

a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly;

a whipstock assembly coupled to the two part drilling and running tool using a coupling mechanism; and

a hydraulically actuated anchoring assembly coupled to a downhole end of the whipstock assembly.

12. The well system as recited in Claim 11, wherein the hydraulically actuated anchoring assembly is in a radially collapsed state.

13. The well system as recited in Claim 11, wherein the hydraulically actuated anchoring assembly is in a radially expanded state engaged with a wall of the main wellbore.

14. The well system as recited in Claim 11, wherein the hydraulically actuated anchoring assembly is an expandable screen based anchoring assembly including two or more hydraulic activation chambers.

15. The well system as recited in Claim 11, wherein the smaller assembly is a smaller bit assembly.

16. The well system as recited in Claim 15, wherein the smaller bit assembly includes one or more first profiles and the larger bit assembly includes one or more second profiles, and further wherein the one or more first profiles are configured to engage with the one or more second profiles to rotationally fix the smaller bit assembly with the larger bit assembly when the two are slidingly engaged together.

17. The well system as recited in Claim 16, wherein the one or more first profiles are one or more external profiles and the one or more second profiles are one or more internal profiles.

18. The well system as recited in Claim 15, wherein the smaller bit assembly includes one of a lock ring profile or a lock ring, and the larger bit assembly includes an other of the lock ring or the lock ring profile, the lock ring profile and lock ring configured to engage with one another to slidingly fix the smaller bit assembly with the larger bit assembly when the two are slidingly engaged together.

19. The well system as recited in Claim 18, wherein the smaller bit assembly includes the lock ring profile and the larger bit assembly includes the lock ring.

20. The well system as recited in Claim 15, wherein the smaller bit assembly includes one or more fluid ports, the one or more fluid ports configured to hydraulically actuate the anchoring assembly.

21. The well system as recited in Claim 15, further including a seal assembly coupled between the whipstock assembly and the hydraulically actuated anchoring assembly.

22. The well system as recited in Claim 21, wherein the seal assembly includes one or more seals configured to seal against the smaller bit assembly.

23. A method for forming a well system, comprising:

forming a main wellbore within a subterranean formation;

positioning a two part drilling and running tool within the main wellbore, the two part drilling and running tool coupled to a whipstock assembly using a coupling mechanism, the whipstock assembly having a hydraulically actuated anchoring assembly coupled to a downhole end thereof, the two part drilling and running tool including:

a conveyance;

a smaller assembly coupled to an end of the conveyance; and

a larger bit assembly slidably coupled to the conveyance, the smaller assembly and larger bit assembly configured to slidingly engage one another downhole to form a combined bit assembly; and

applying fluid pressure to the hydraulically actuated anchoring assembly to set the hydraulically actuated anchoring assembly in the main wellbore.

24. The method as recited in Claim 23, further including applying force to the smaller bit assembly to shear the coupling mechanism after applying the fluid pressure, and then sliding the smaller bit assembly relative to the larger bit assembly to form a combined bit assembly.

25. The method as recited in Claim 24, further including milling casing located within the main wellbore using the combined bit assembly.

26. The method as recited in Claim 24, further including drilling a lateral wellbore off of the main wellbore using the combined bit assembly.

27. The method as recited in Claim 23, wherein the smaller assembly is a smaller bit assembly.

28. The method as recited in Claim 27, wherein the smaller bit assembly is coupled to the whipstock assembly using the coupling mechanism.

29. The method as recited in Claim 28, wherein the smaller bit assembly and the whipstock assembly are coupled together such that only one of compression, tension or torque may be used to disengage the coupling mechanism.

30. The method as recited in Claim 29, wherein only torque may be used to disengage the coupling mechanism.

31. The method as recited in Claim 23, further including a seal assembly coupled between the whipstock assembly and the hydraulically actuated anchoring assembly.

32. The method as recited in Claim 31, wherein the seal assembly includes one or more seals configured to seal against the smaller bit assembly.

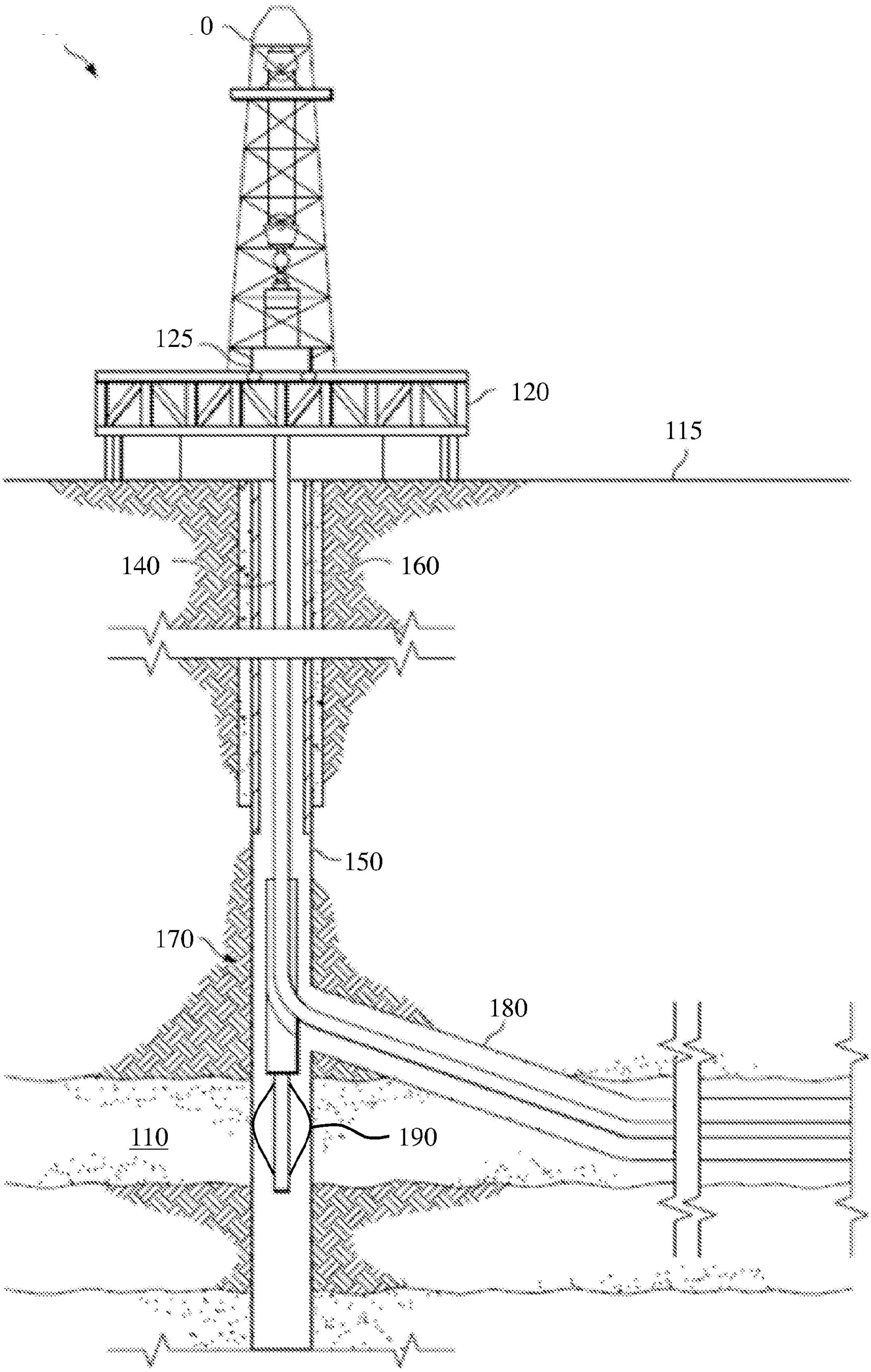

FIG. 1A

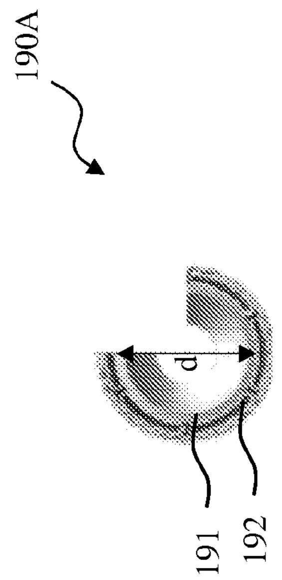

FIG. 1C

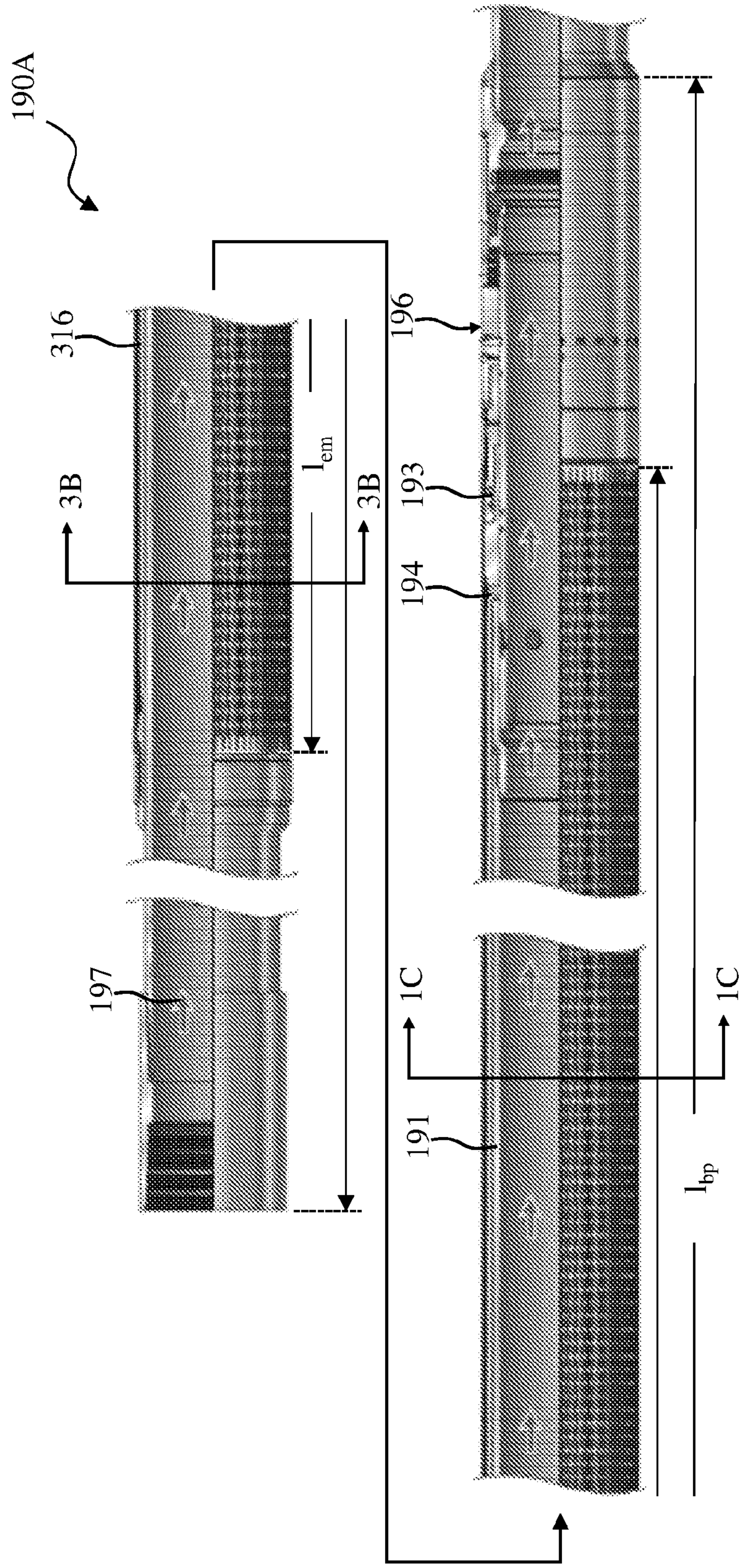

FIG. 1B

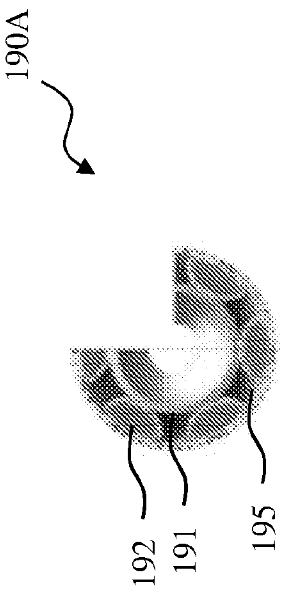

FIG. 1E

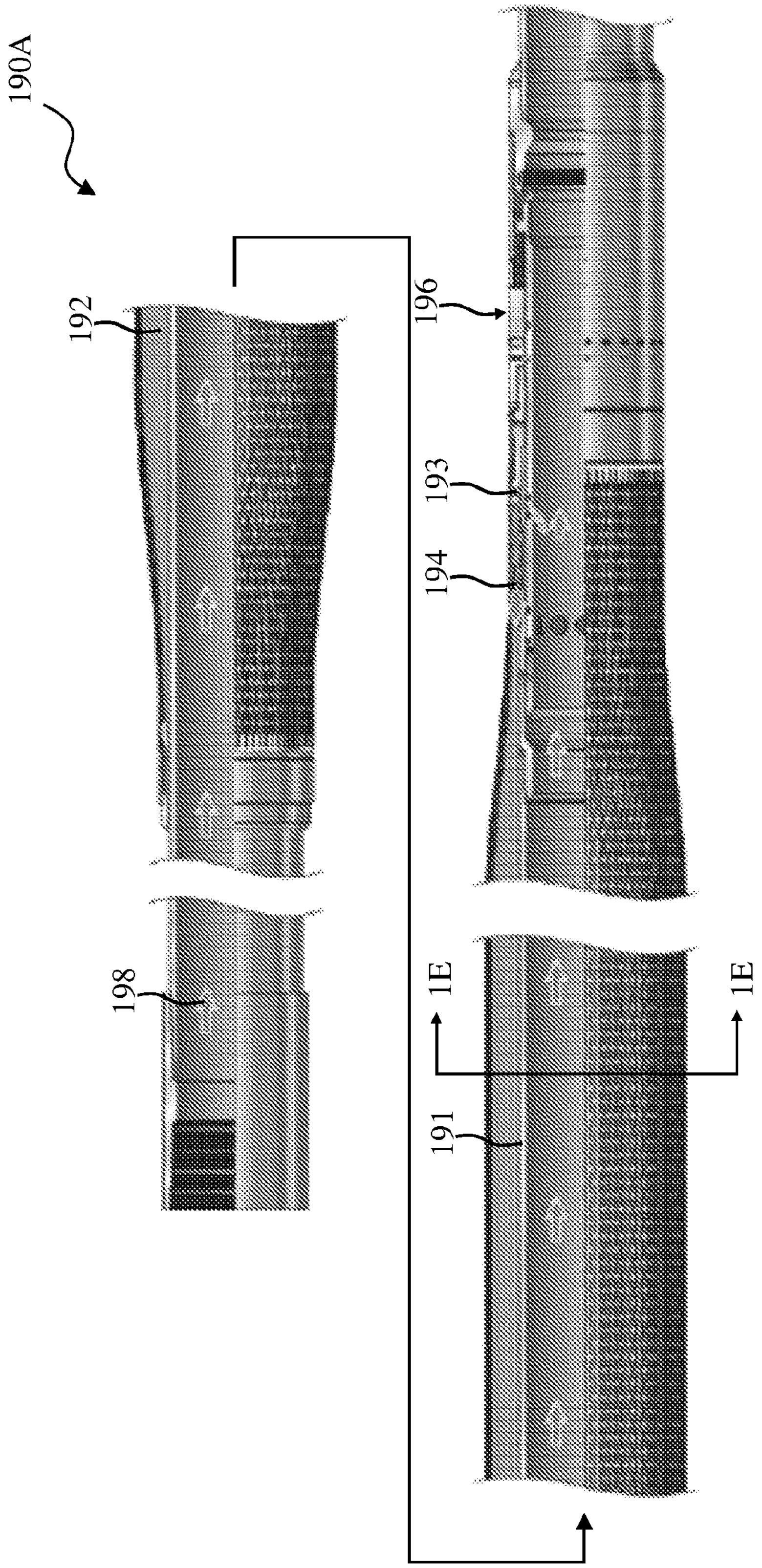

FIG. 1D

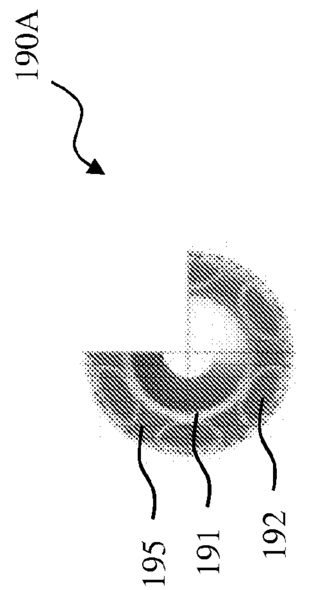

FIG. 1G

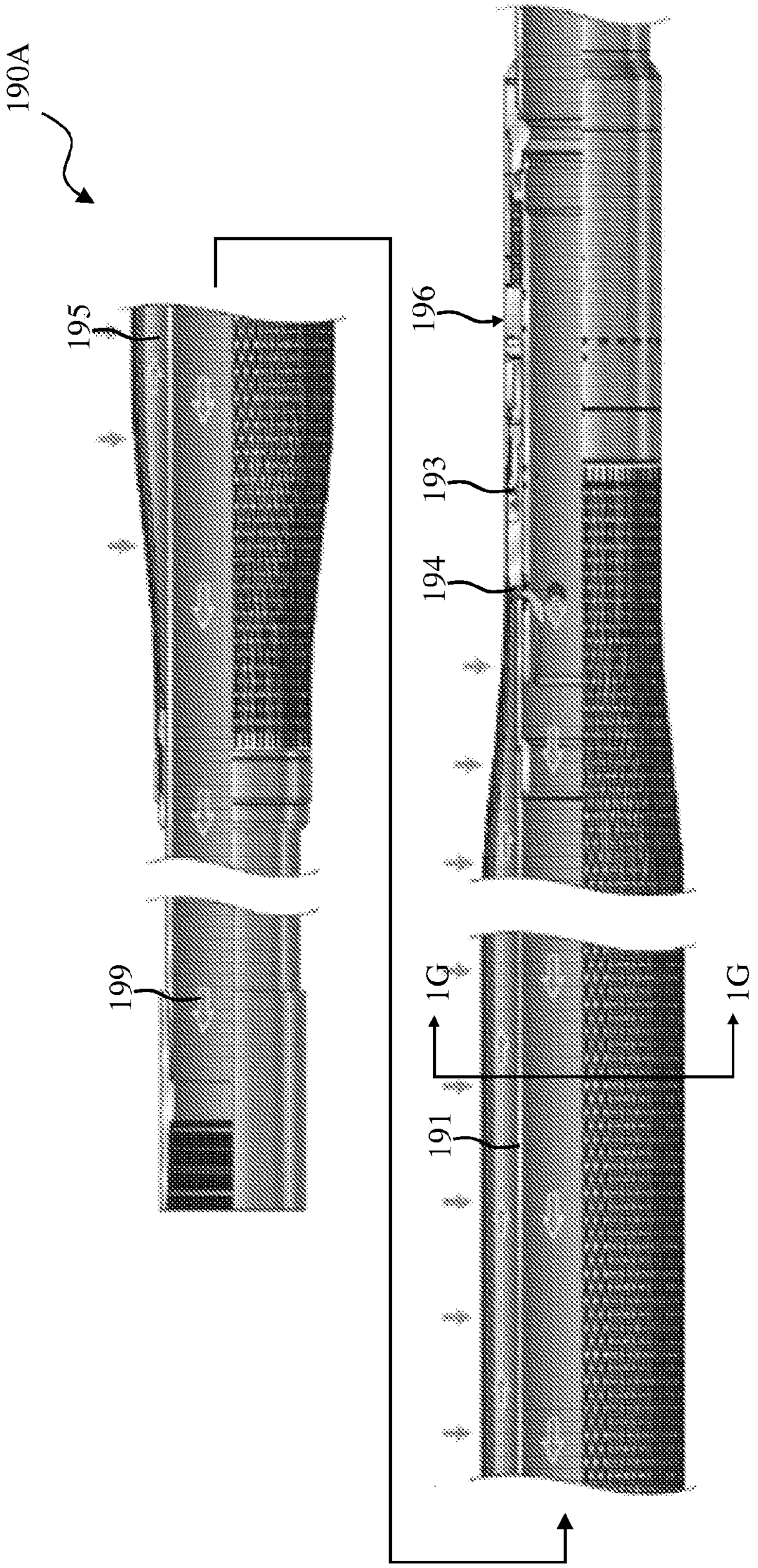

FIG. 1F

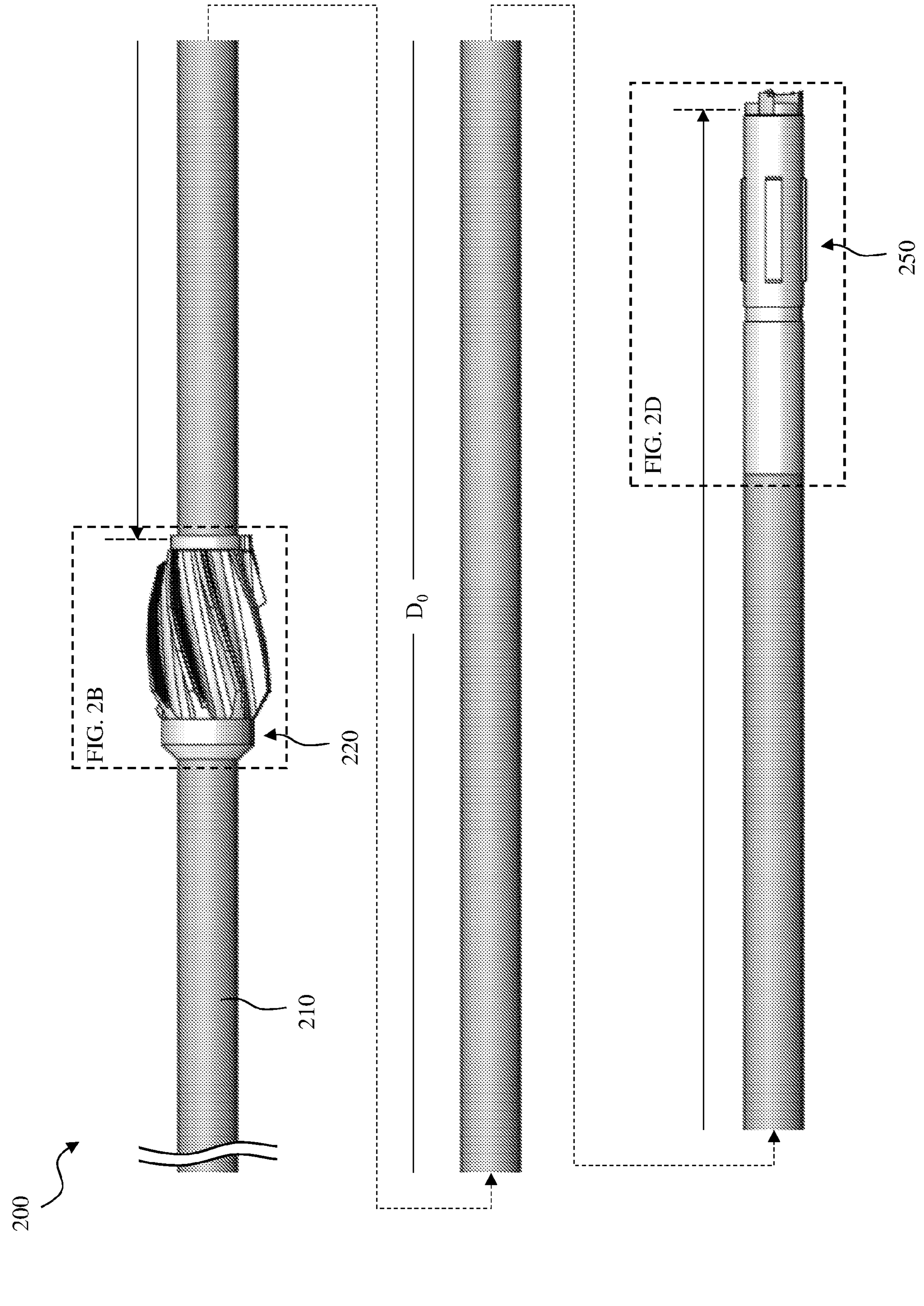

FIG. 2A

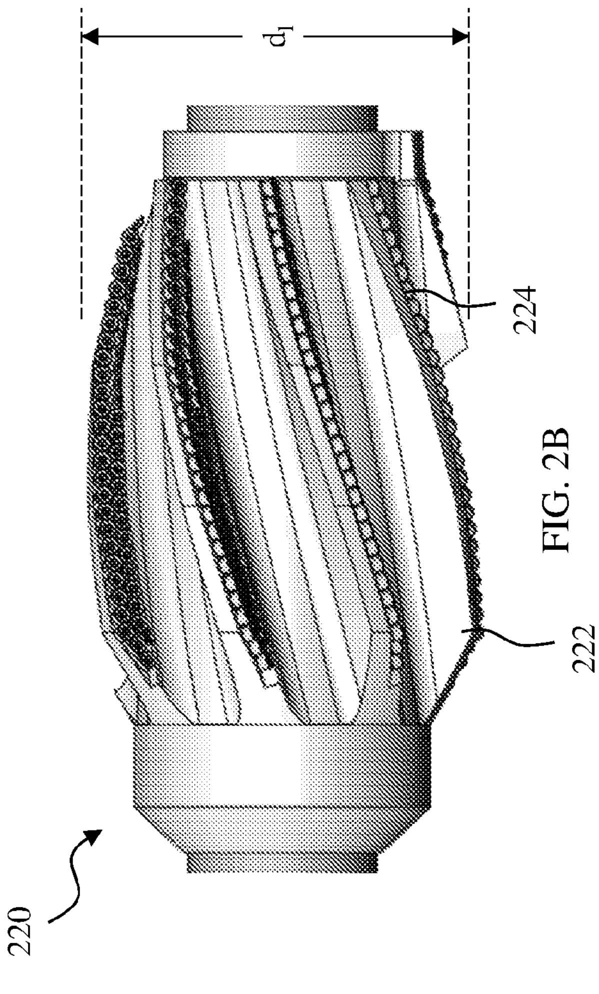

FIG. 2B

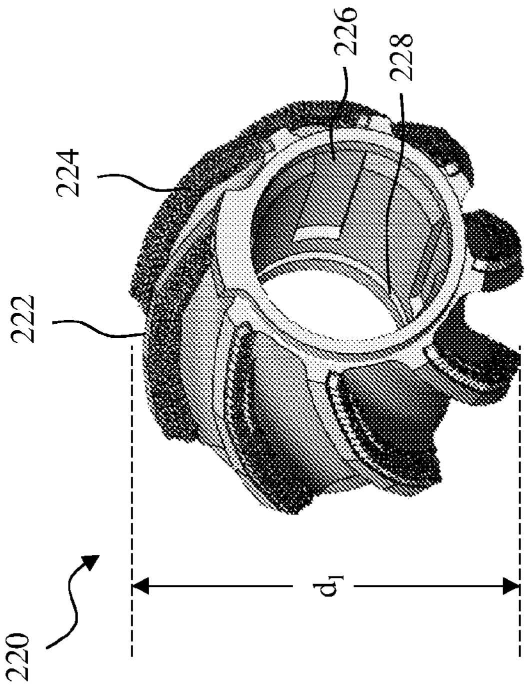

FIG. 2C

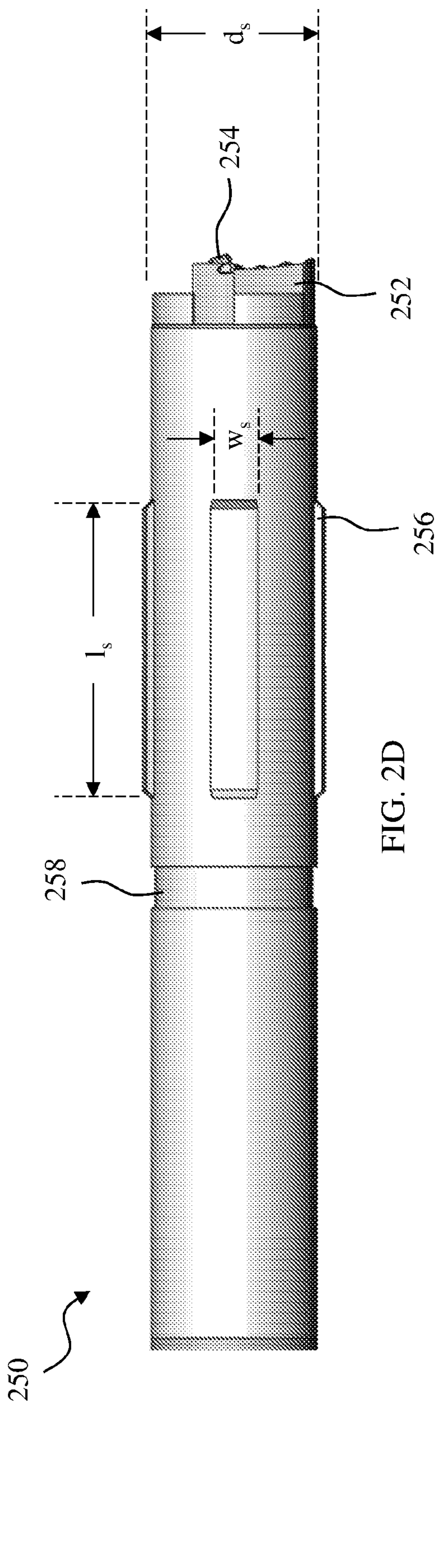

FIG. 2D

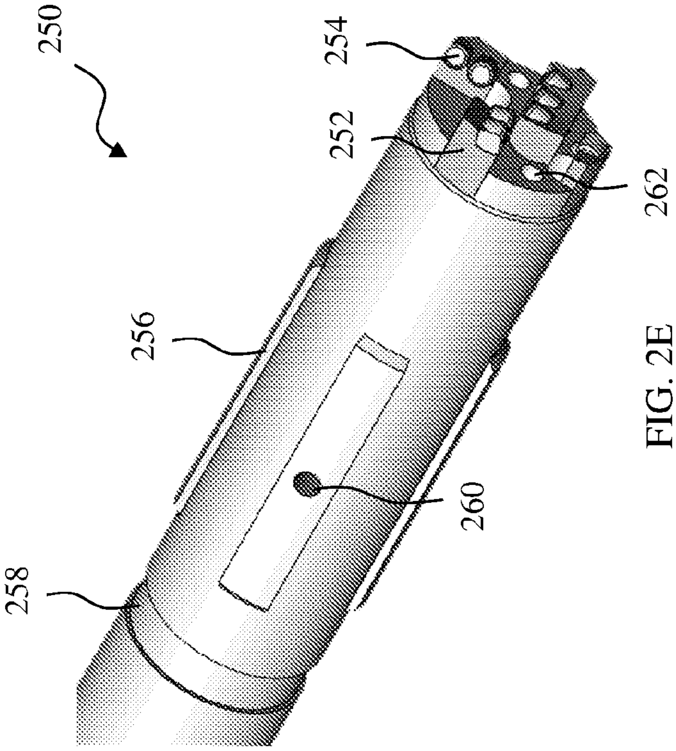

FIG. 2E

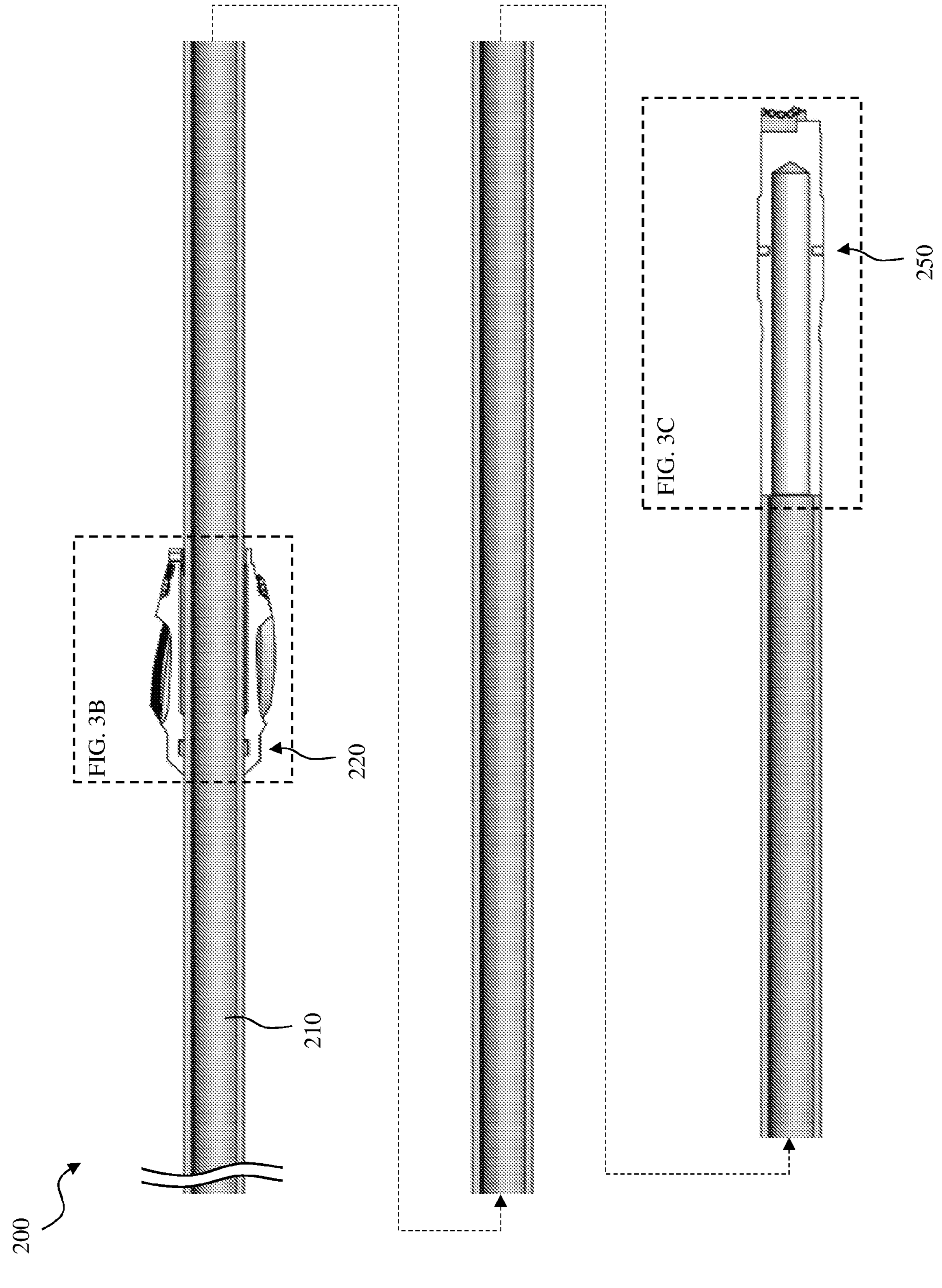

FIG. 3A

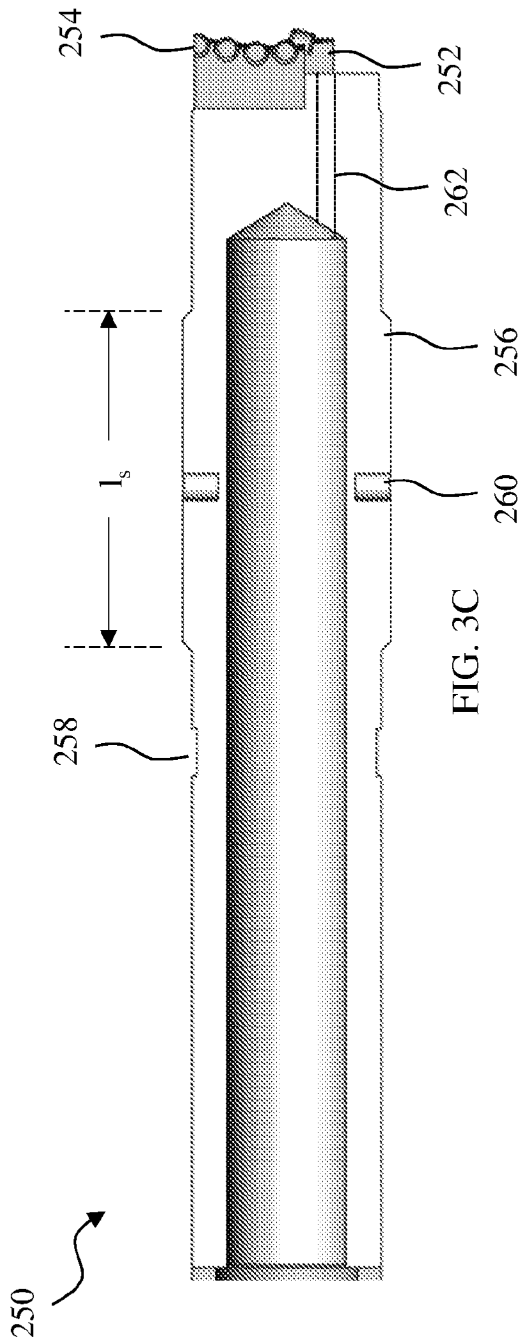

FIG. 3C

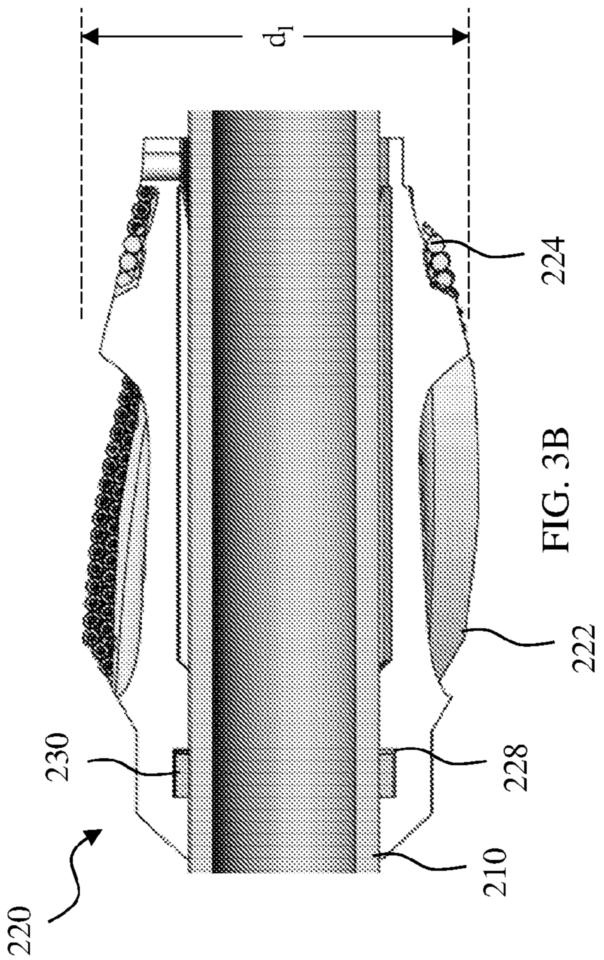

FIG. 3B

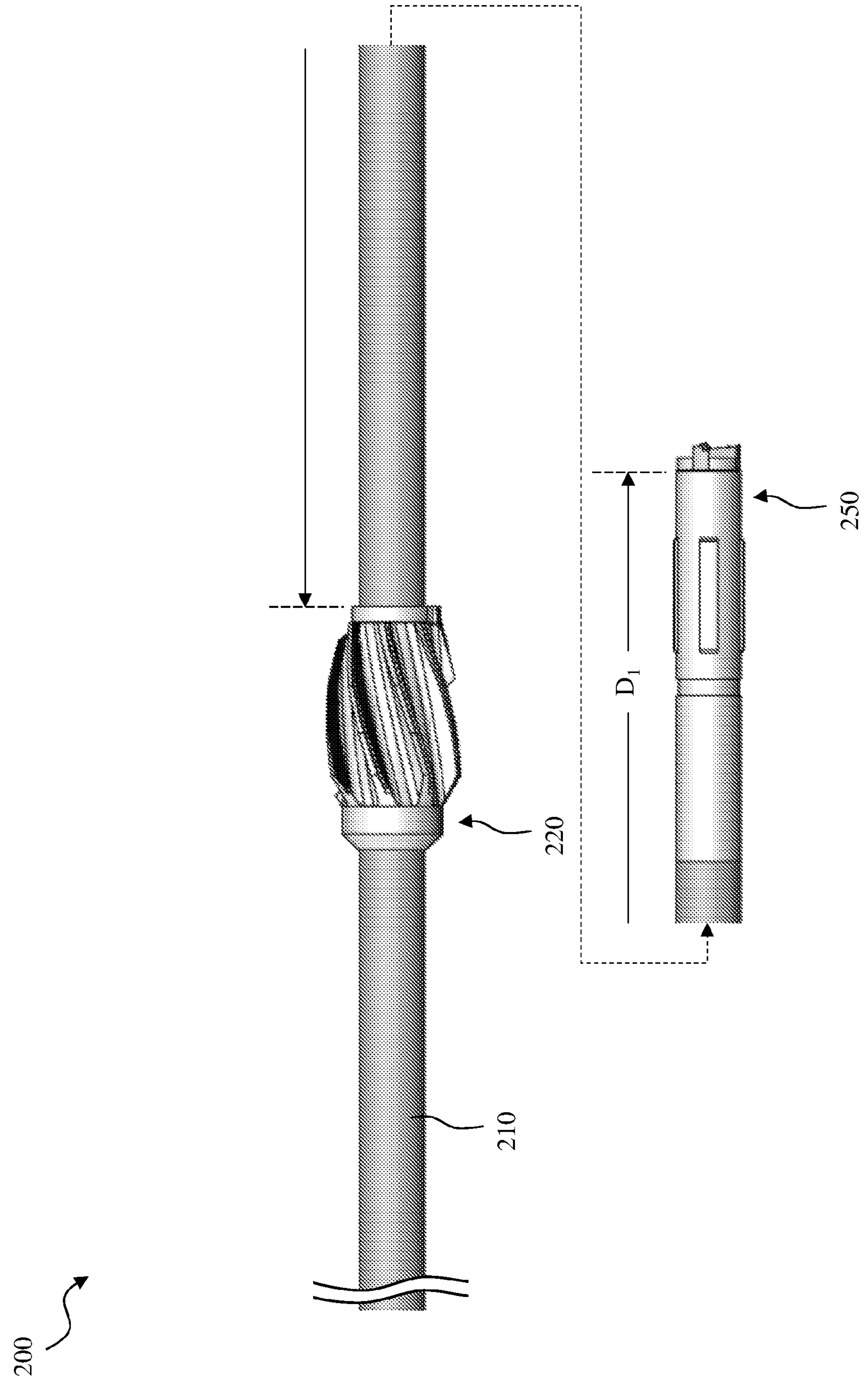

FIG. 4

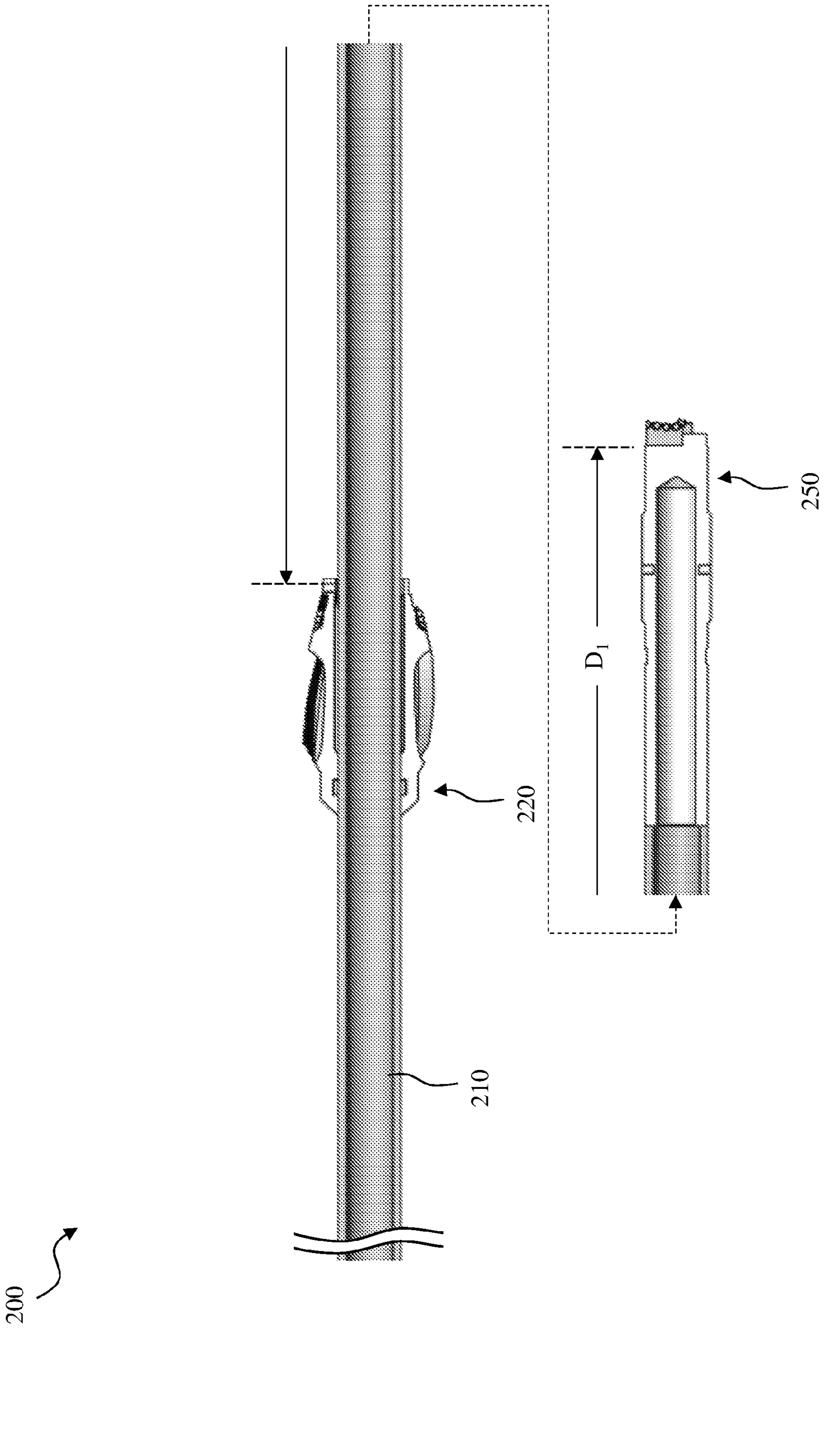

FIG. 5

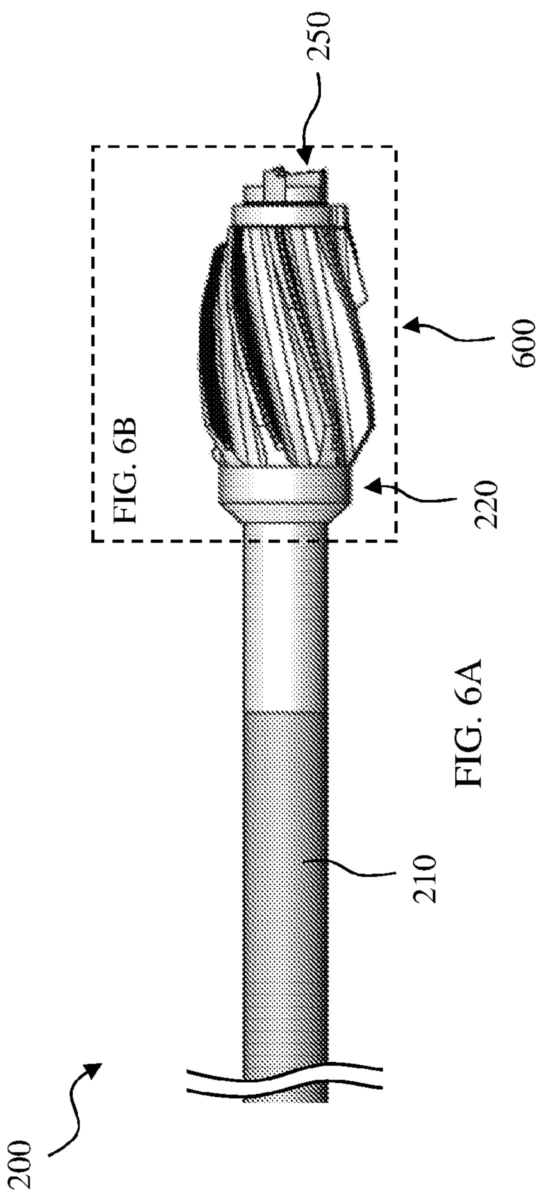

FIG. 6A

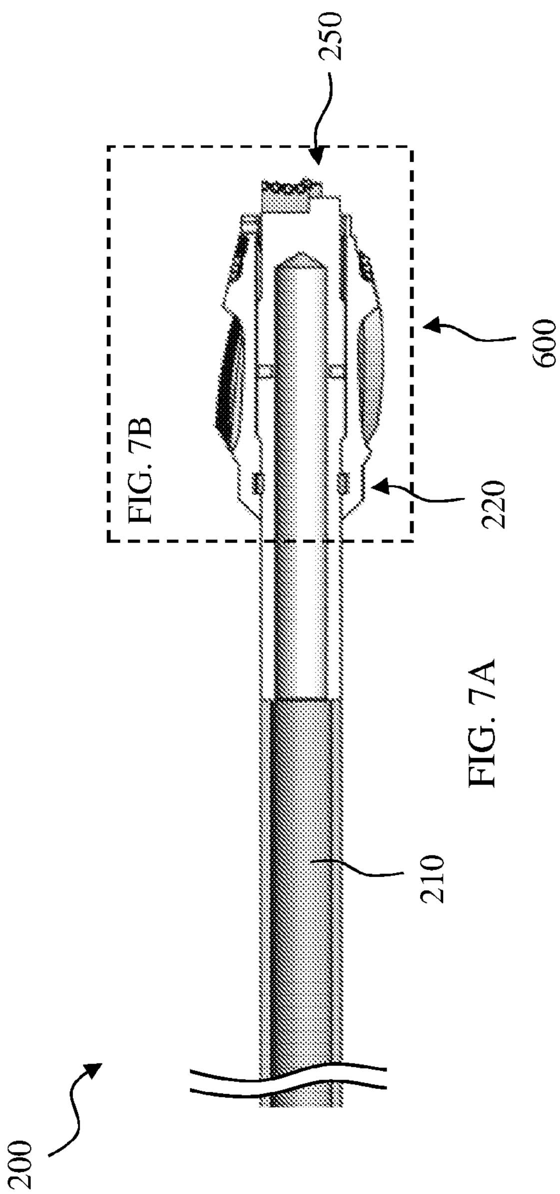

FIG. 7A

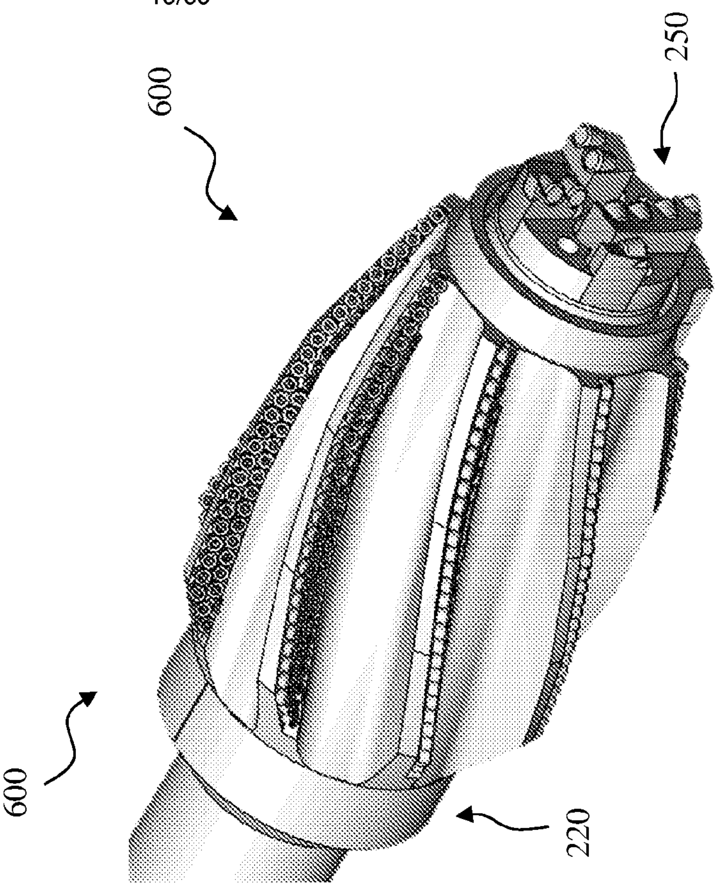

FIG. 6C

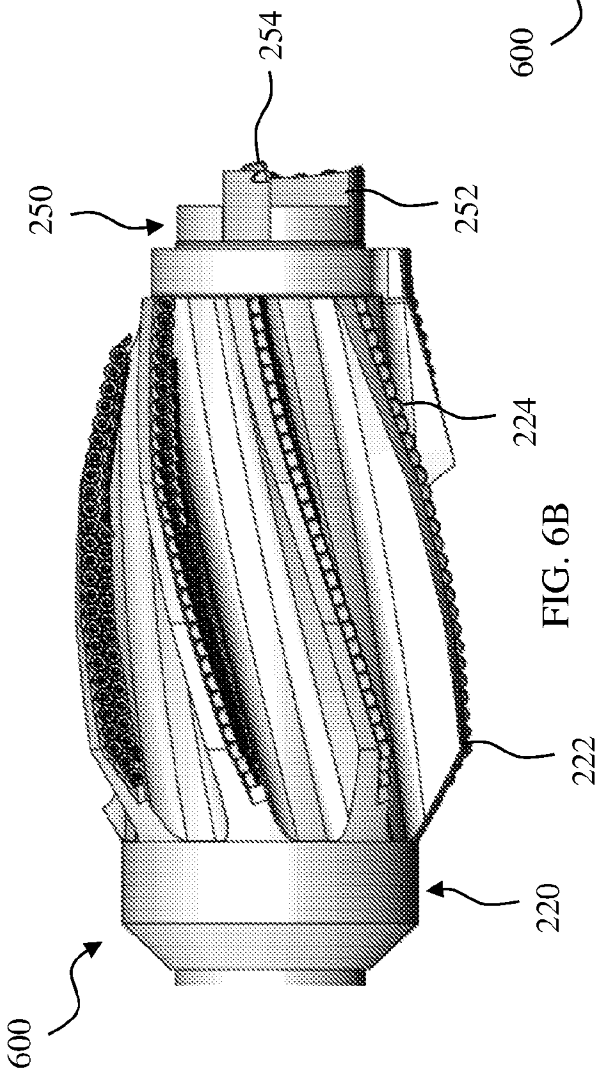

FIG. 6B

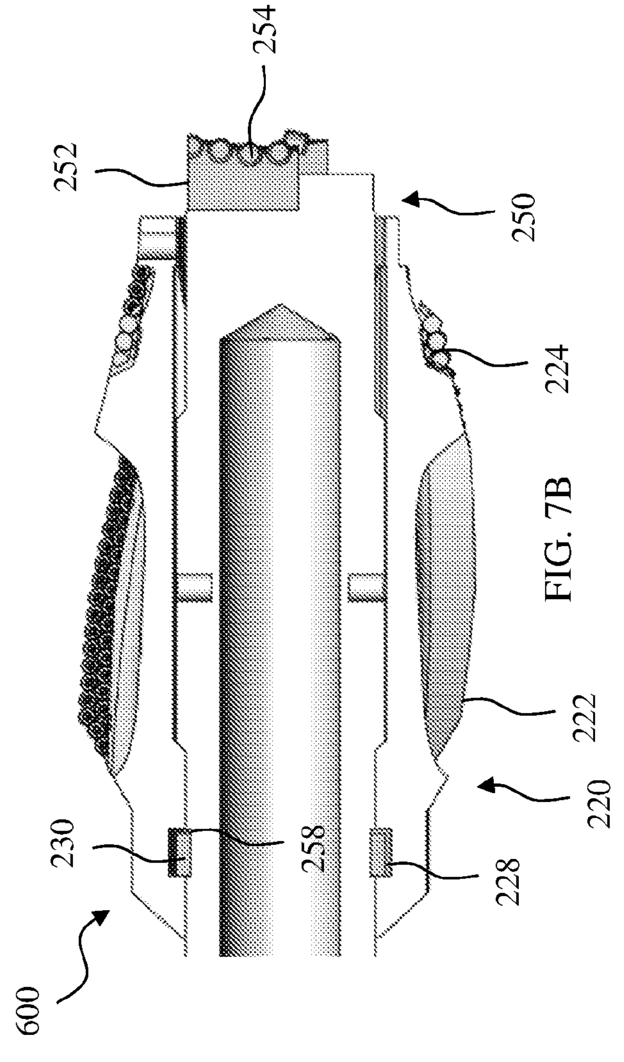

FIG. 7B

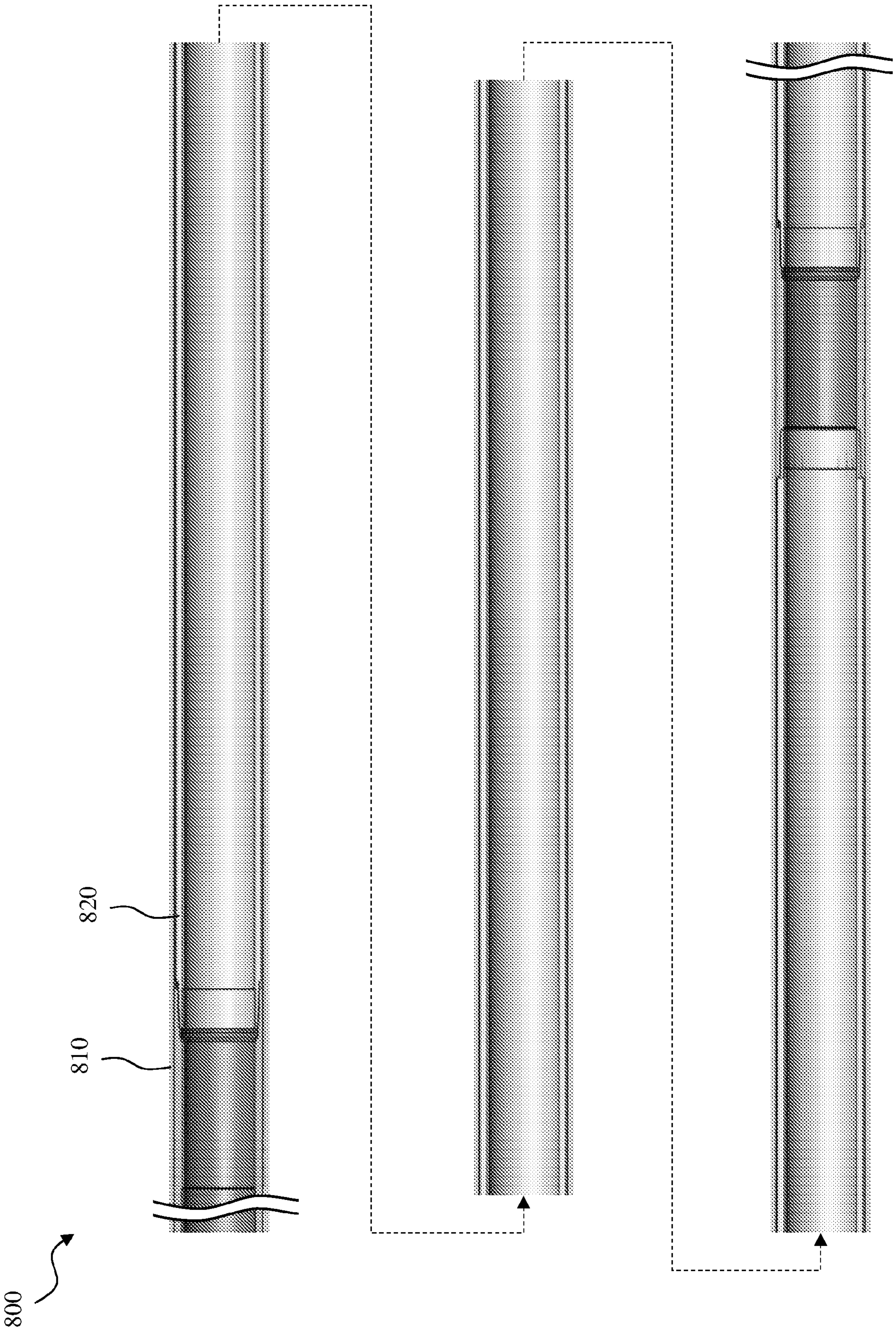

FIG. 8

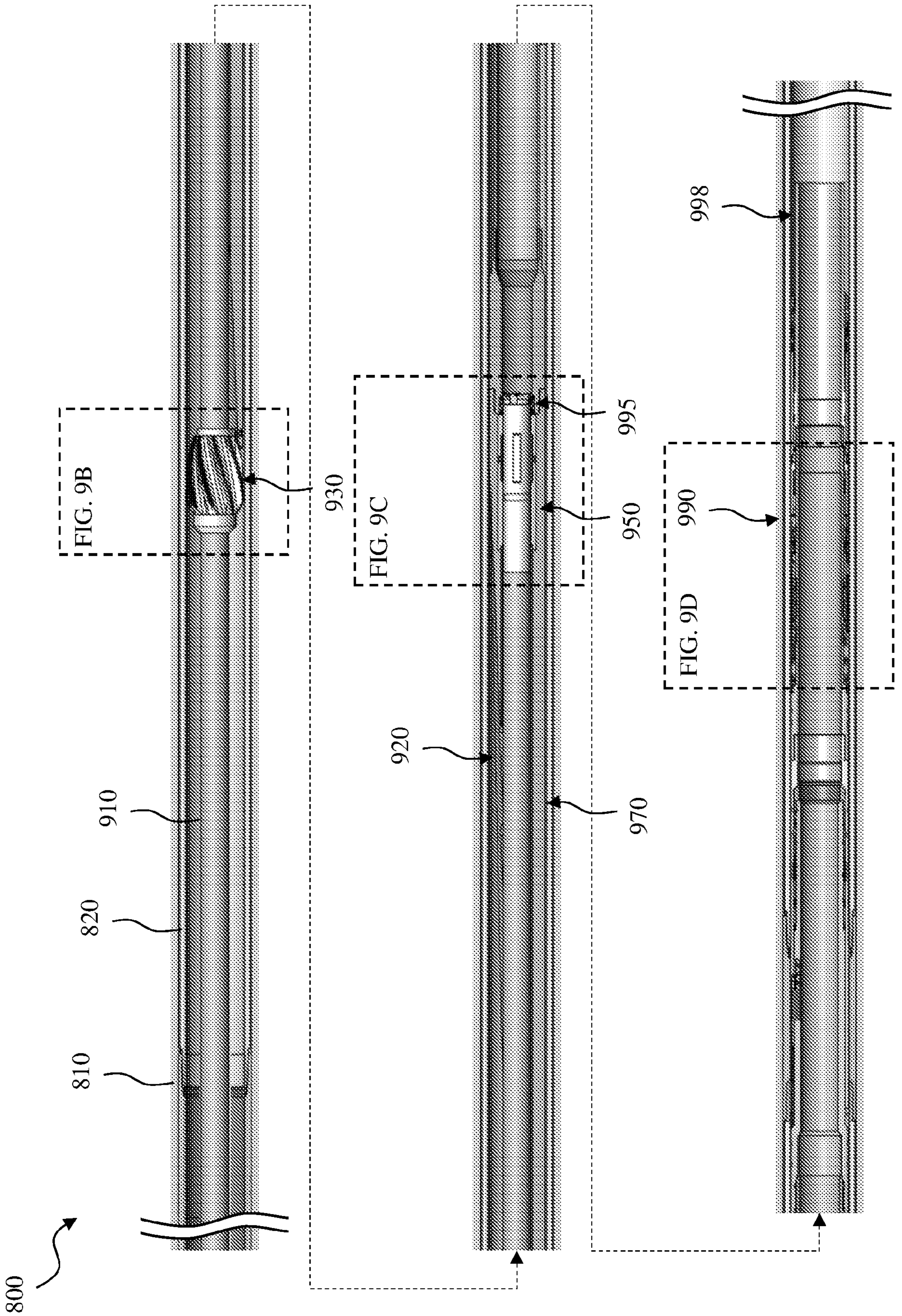

FIG. 9A

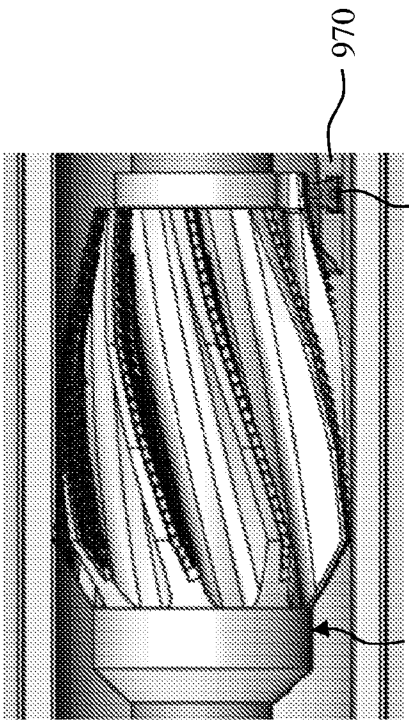

FIG. 9B

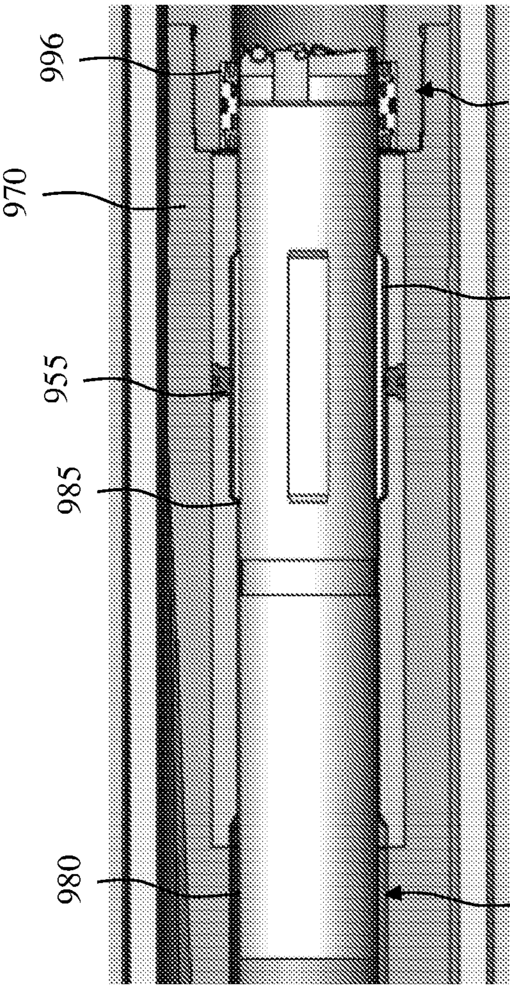

FIG. 9C

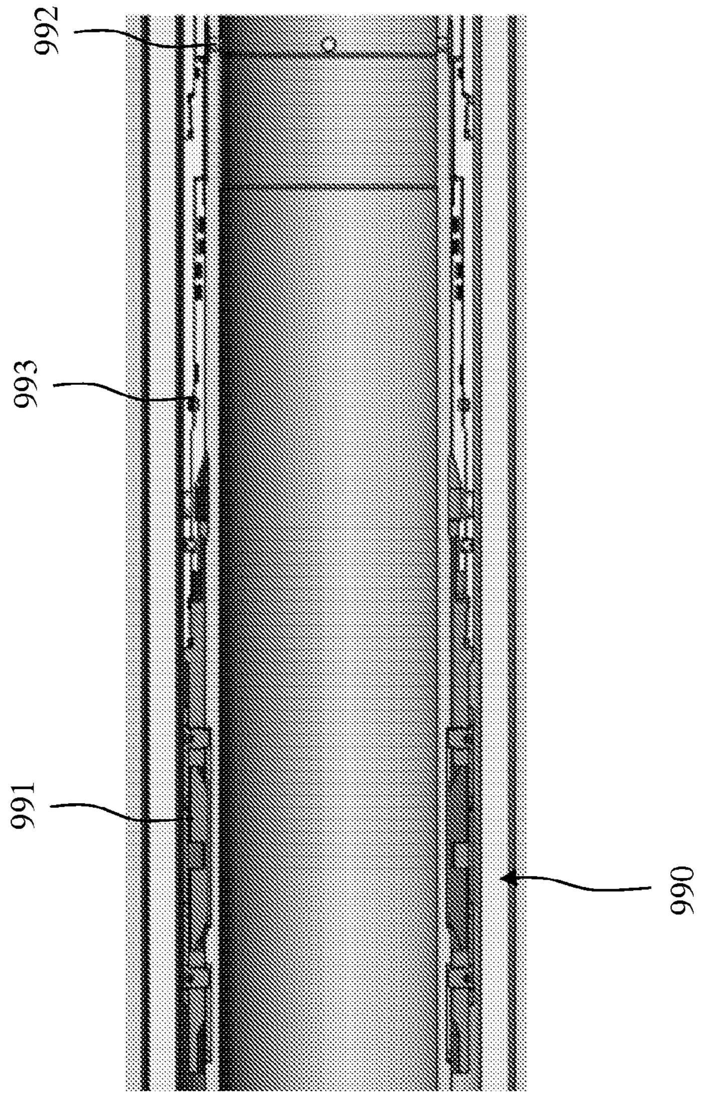

FIG. 9D

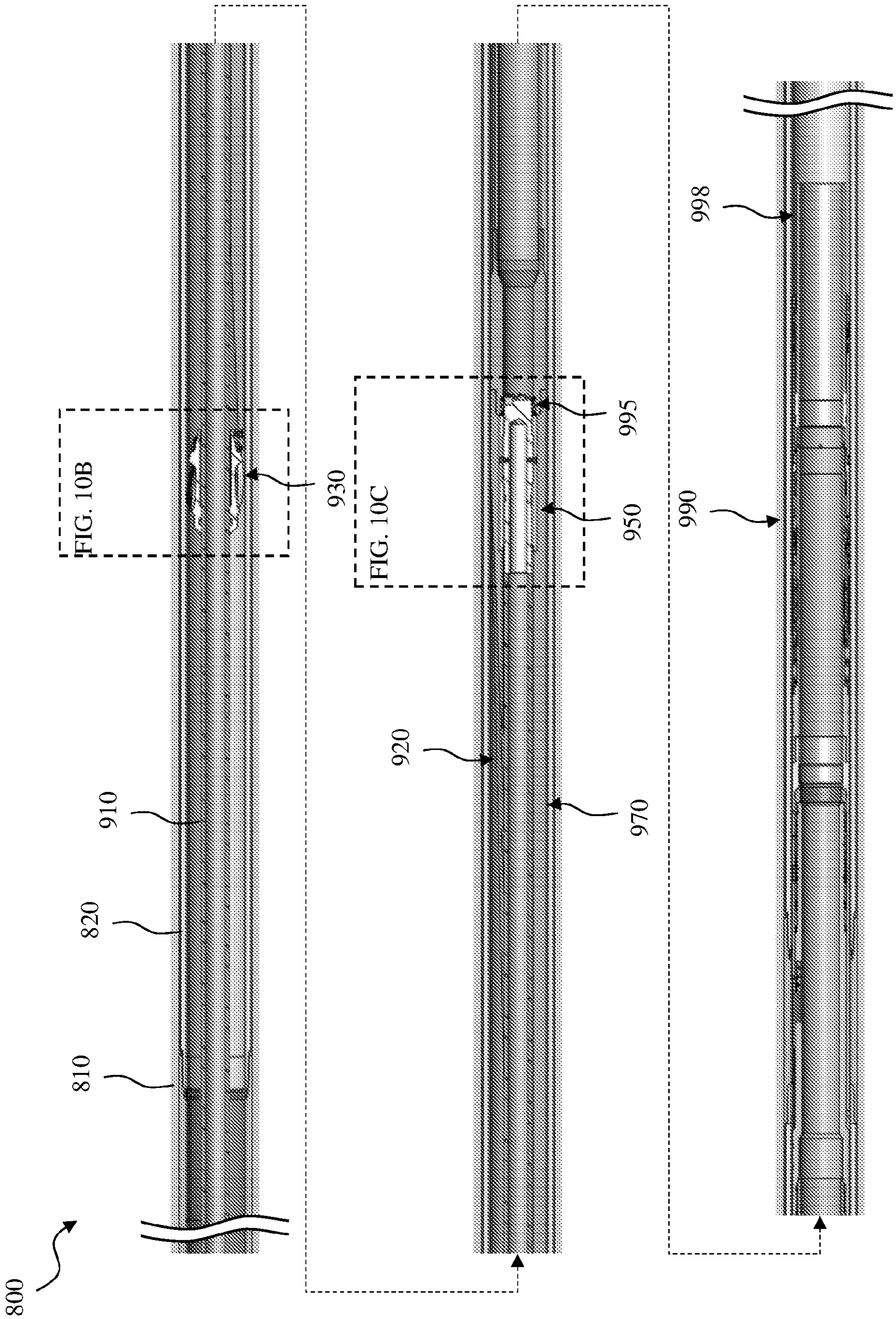

FIG. 10A

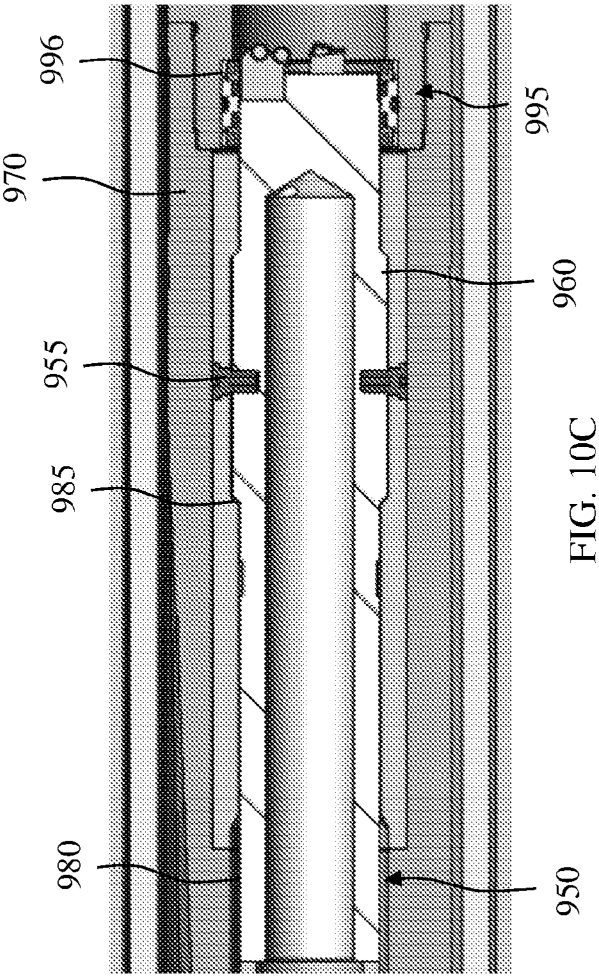

FIG. 10C

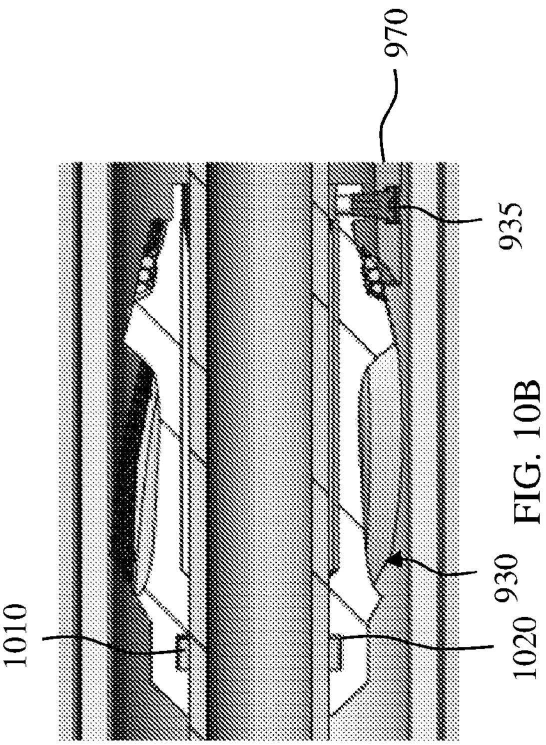

FIG. 10B

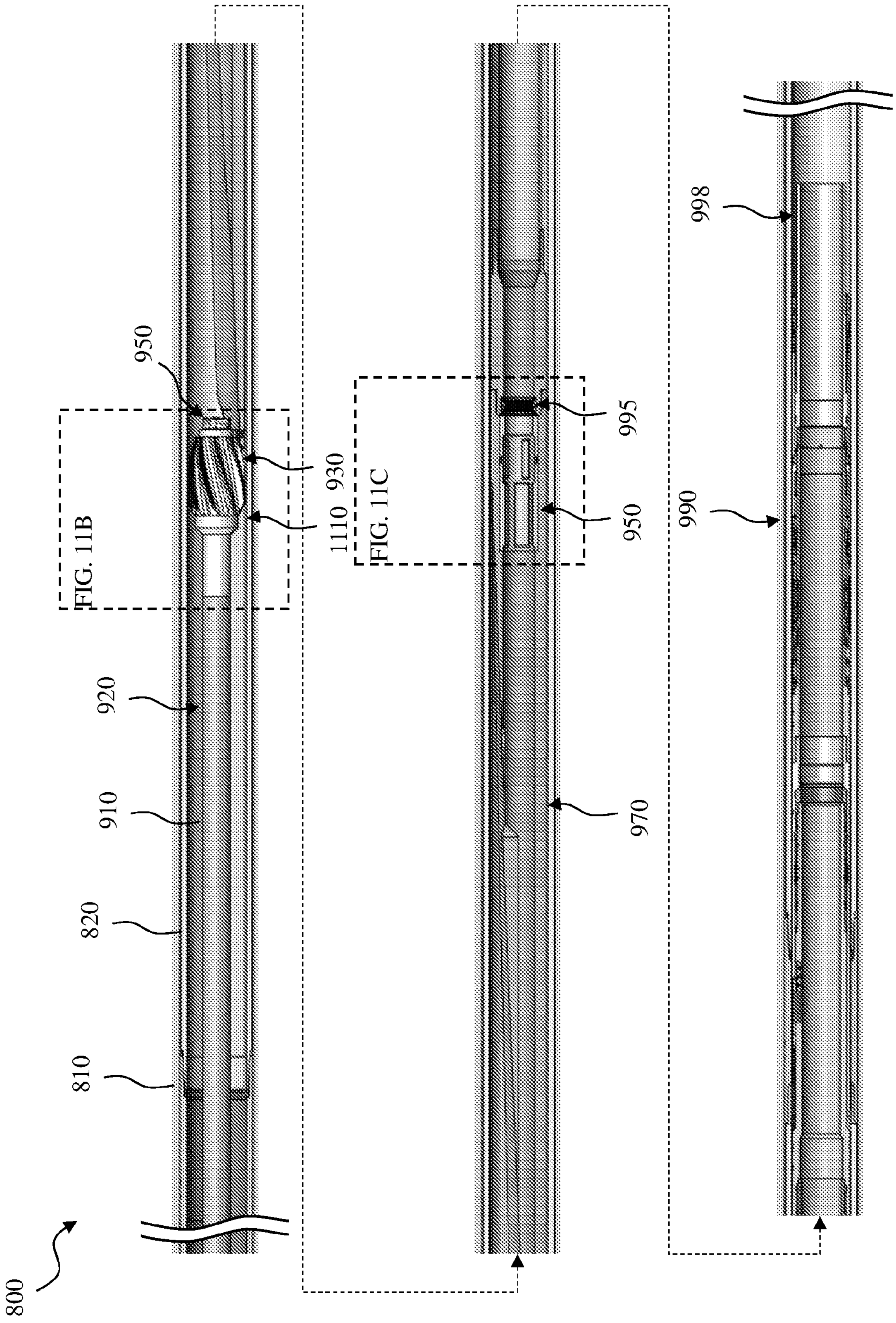
800
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FIG. 11B
FIG. 11C
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FIG. 11A

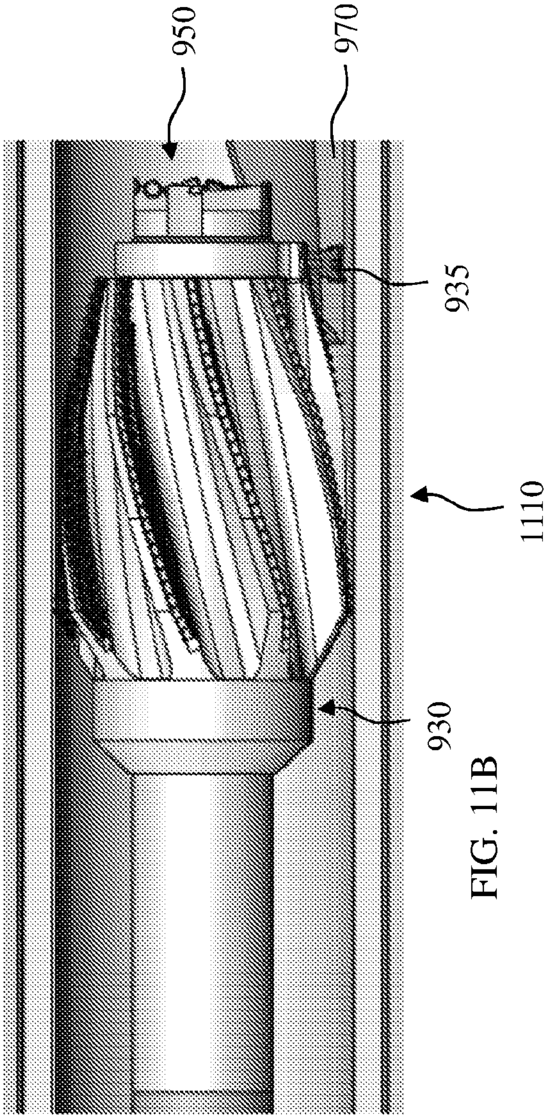

FIG. 11B

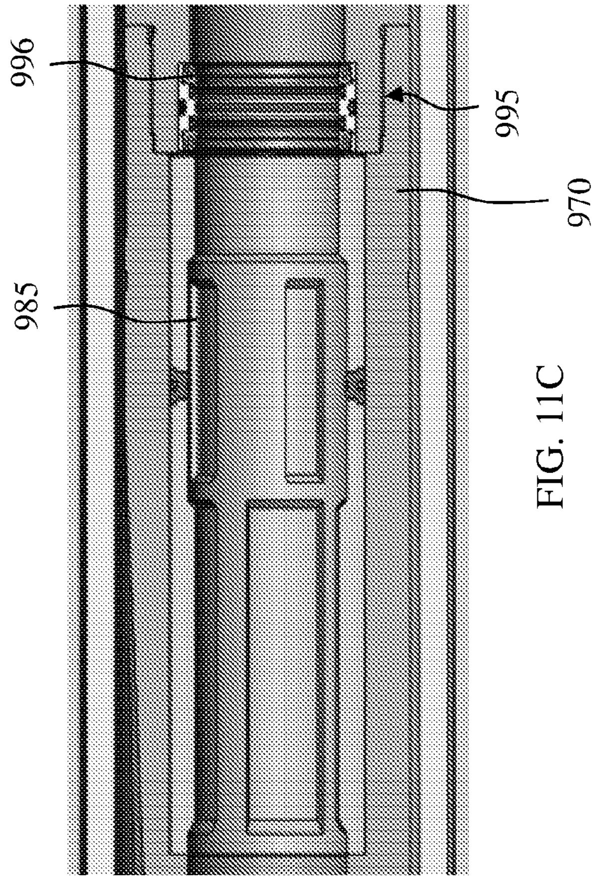

FIG. 11C

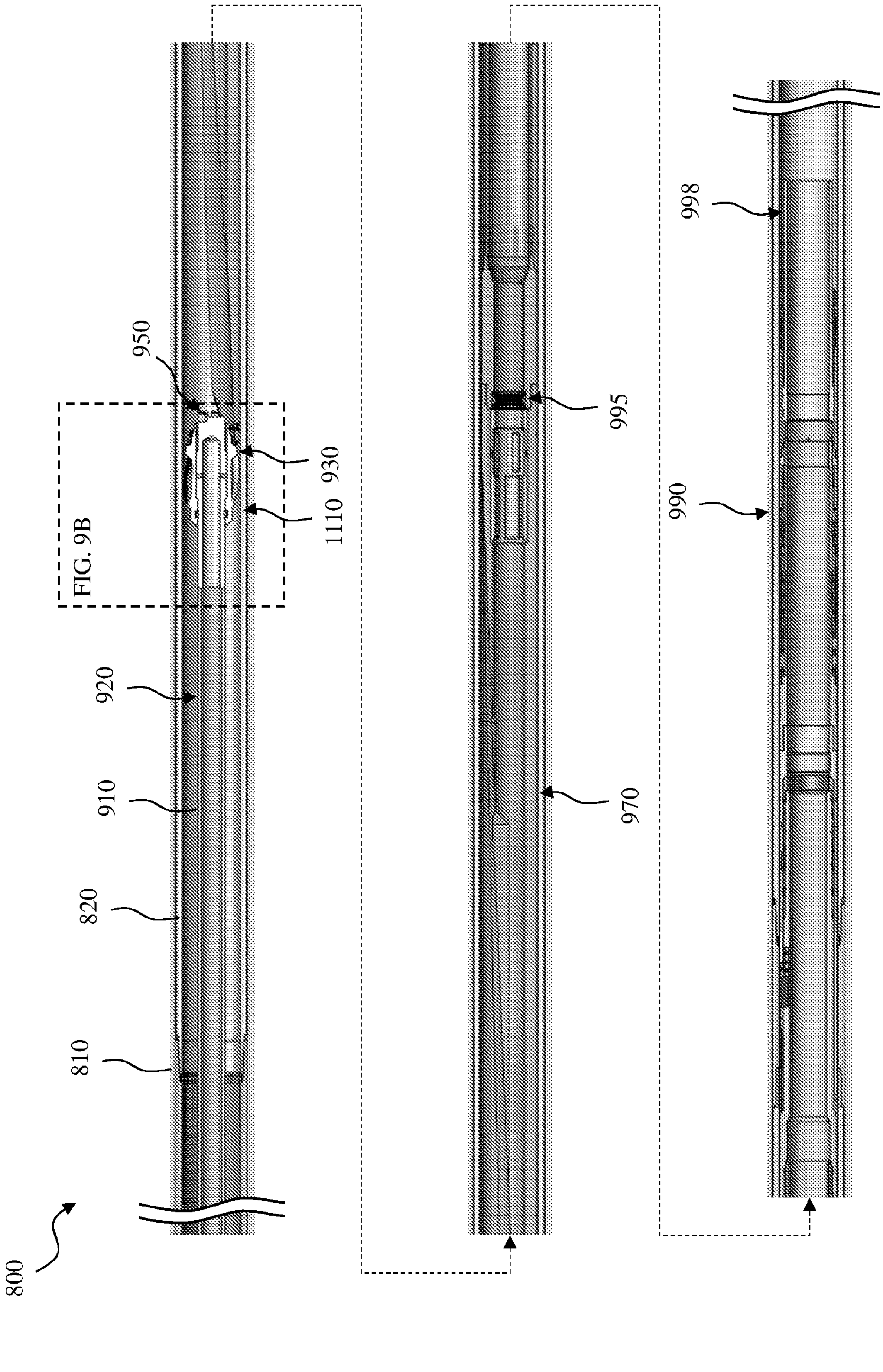

FIG. 12A

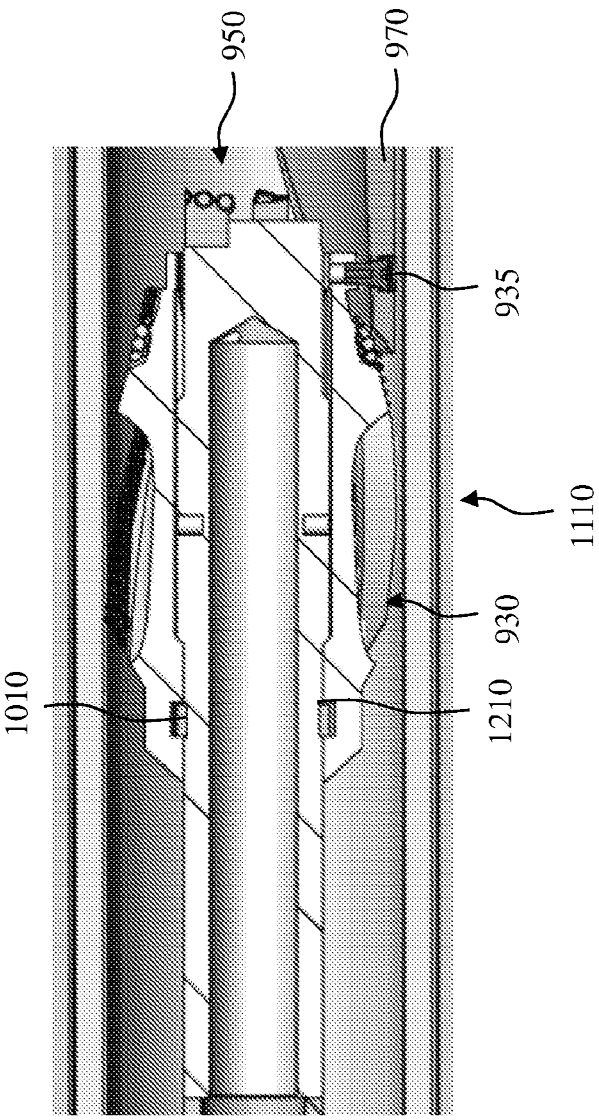

FIG. 12B

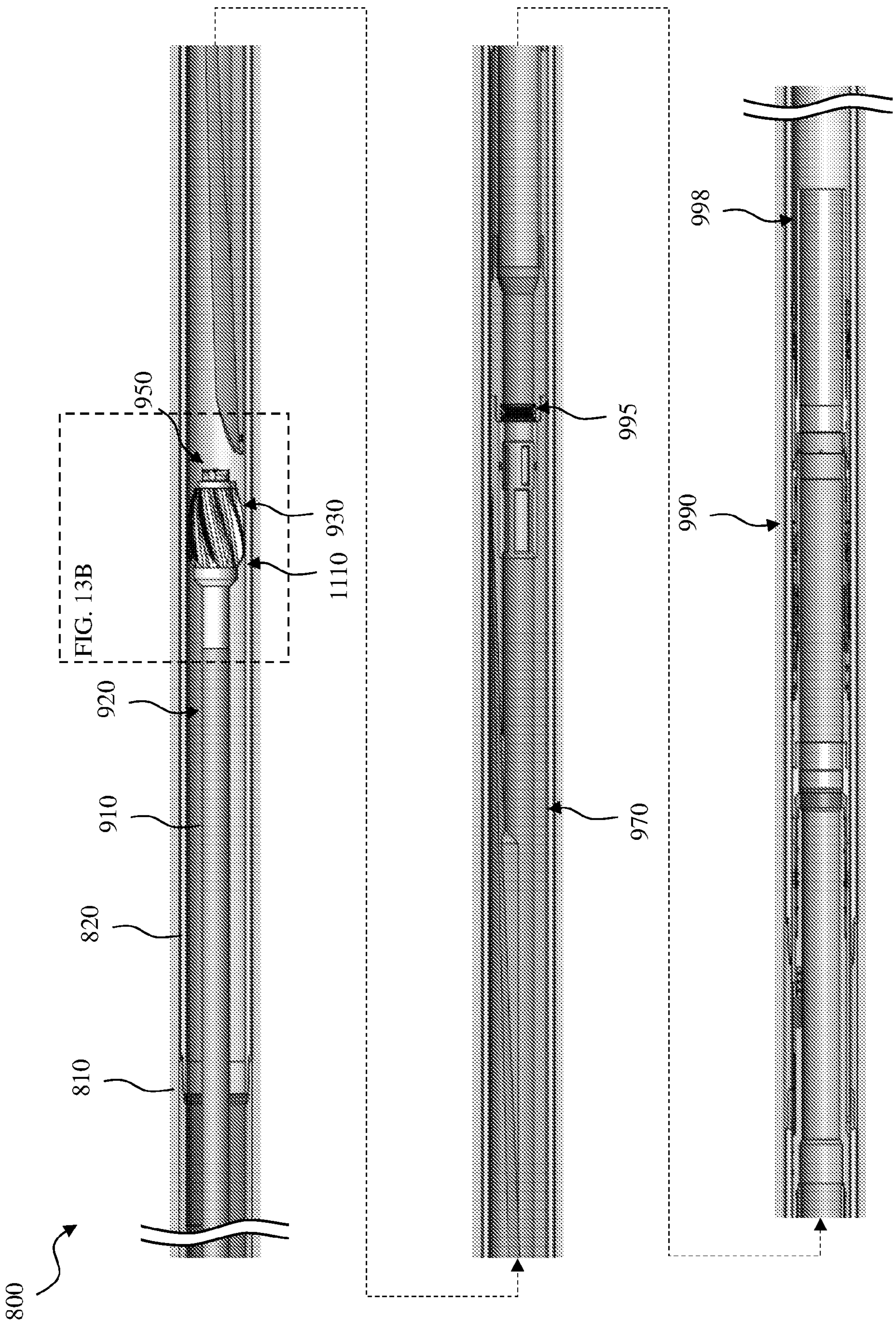

FIG. 13A

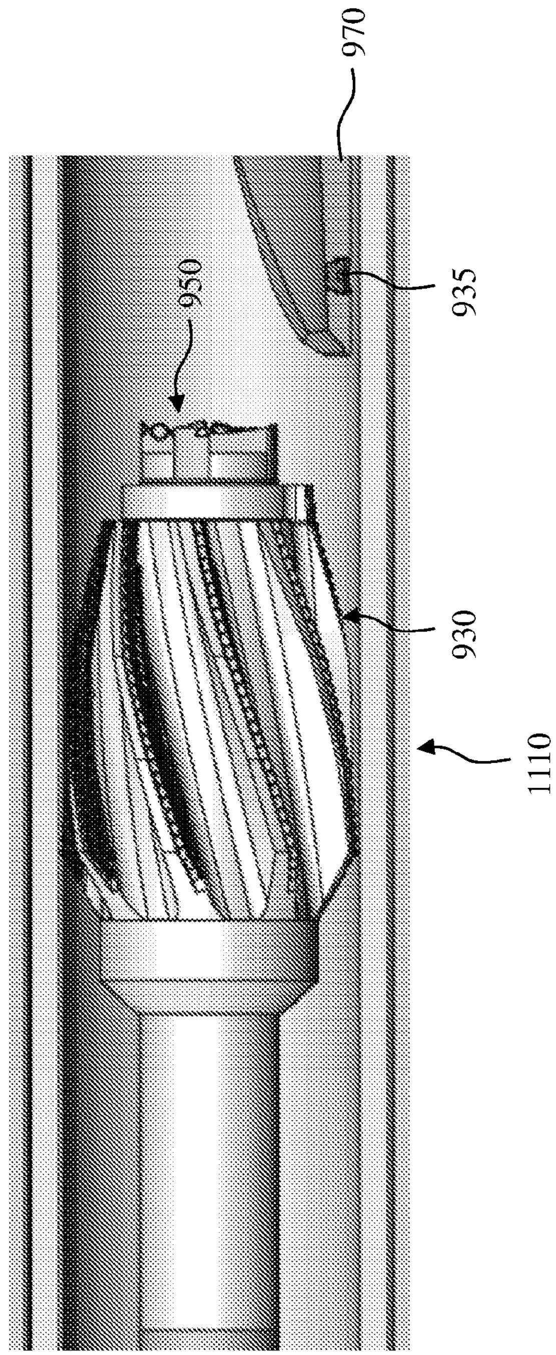

FIG. 13B

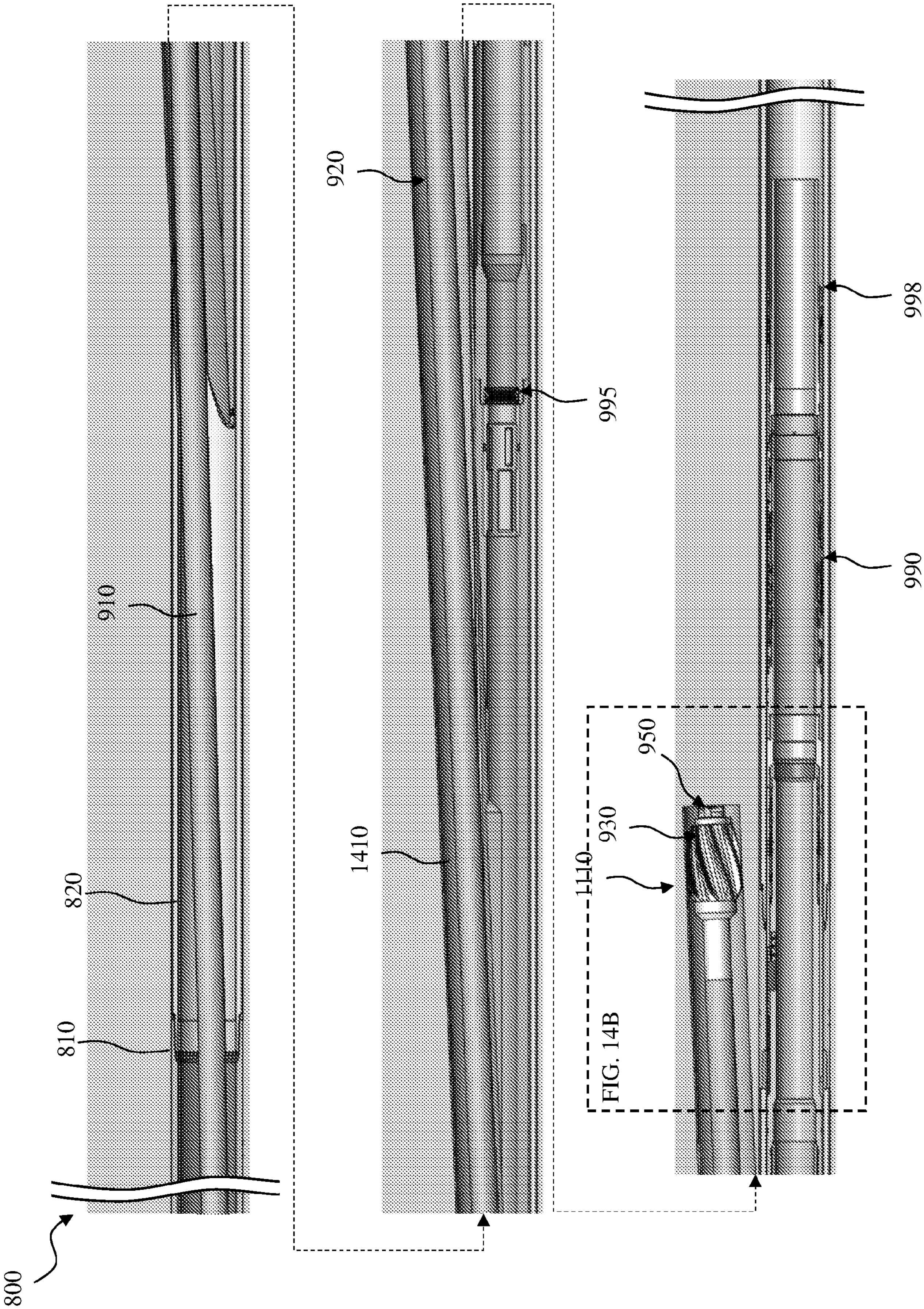

FIG. 14A

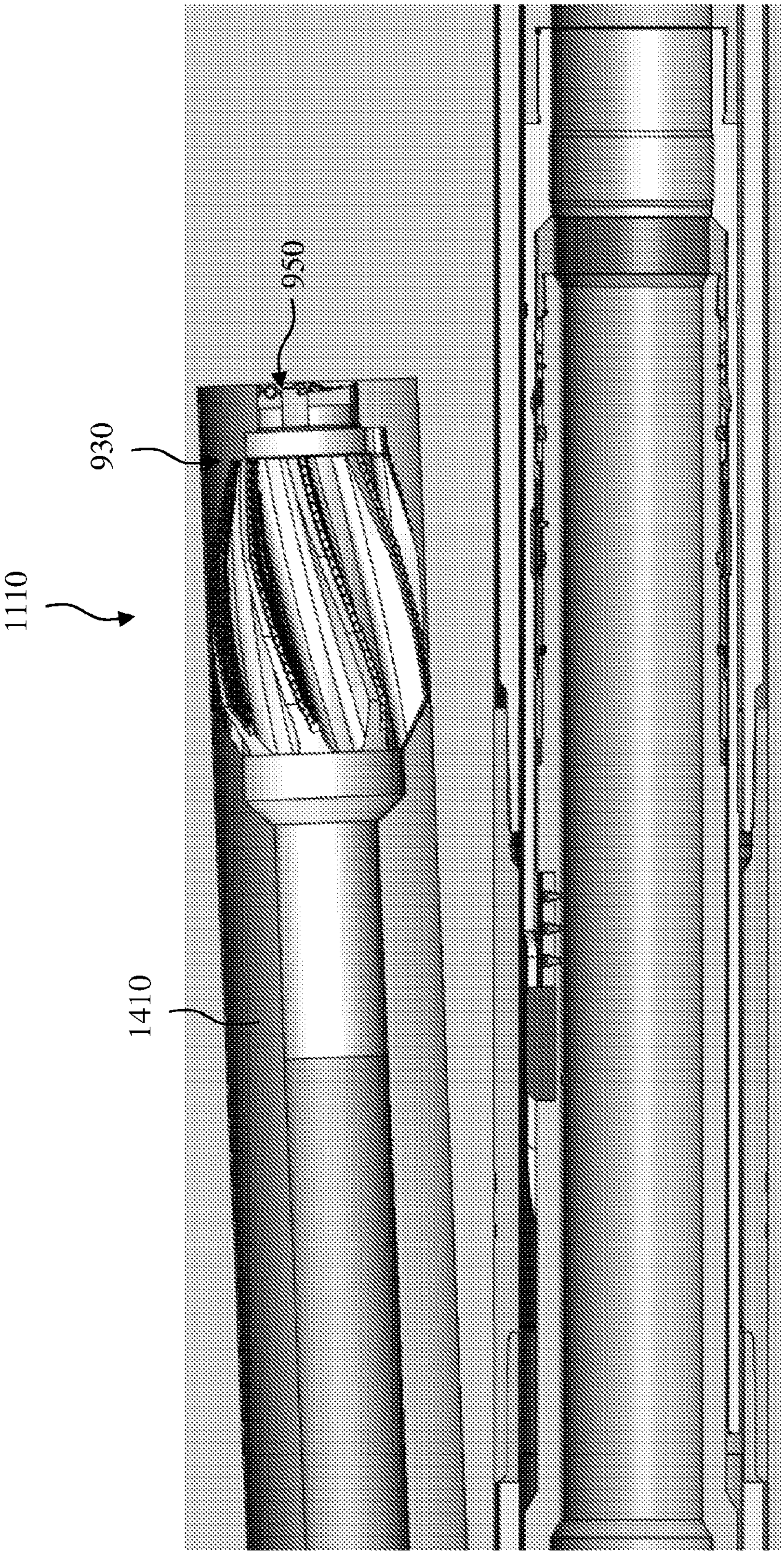

FIG. 14B

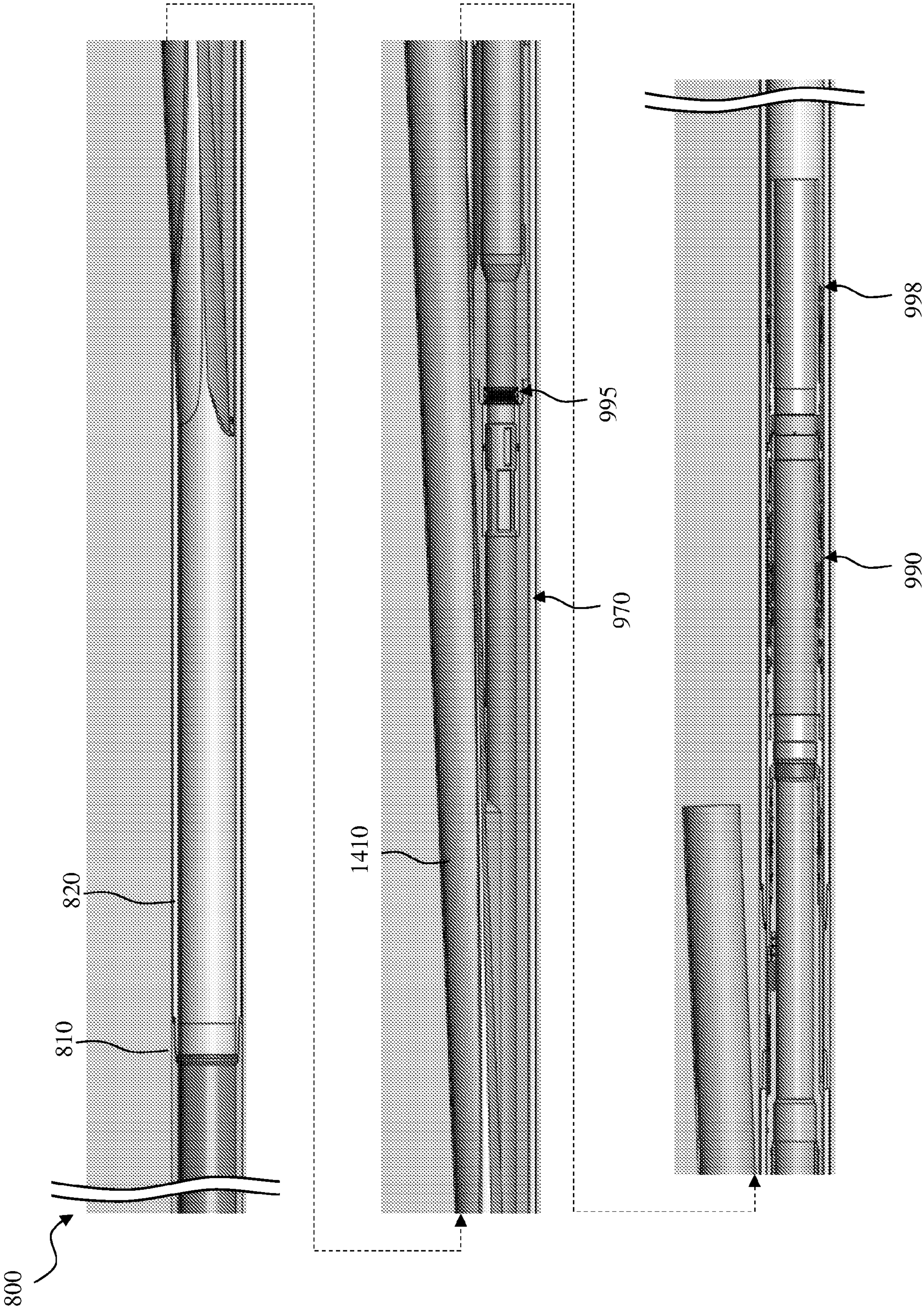

FIG. 15

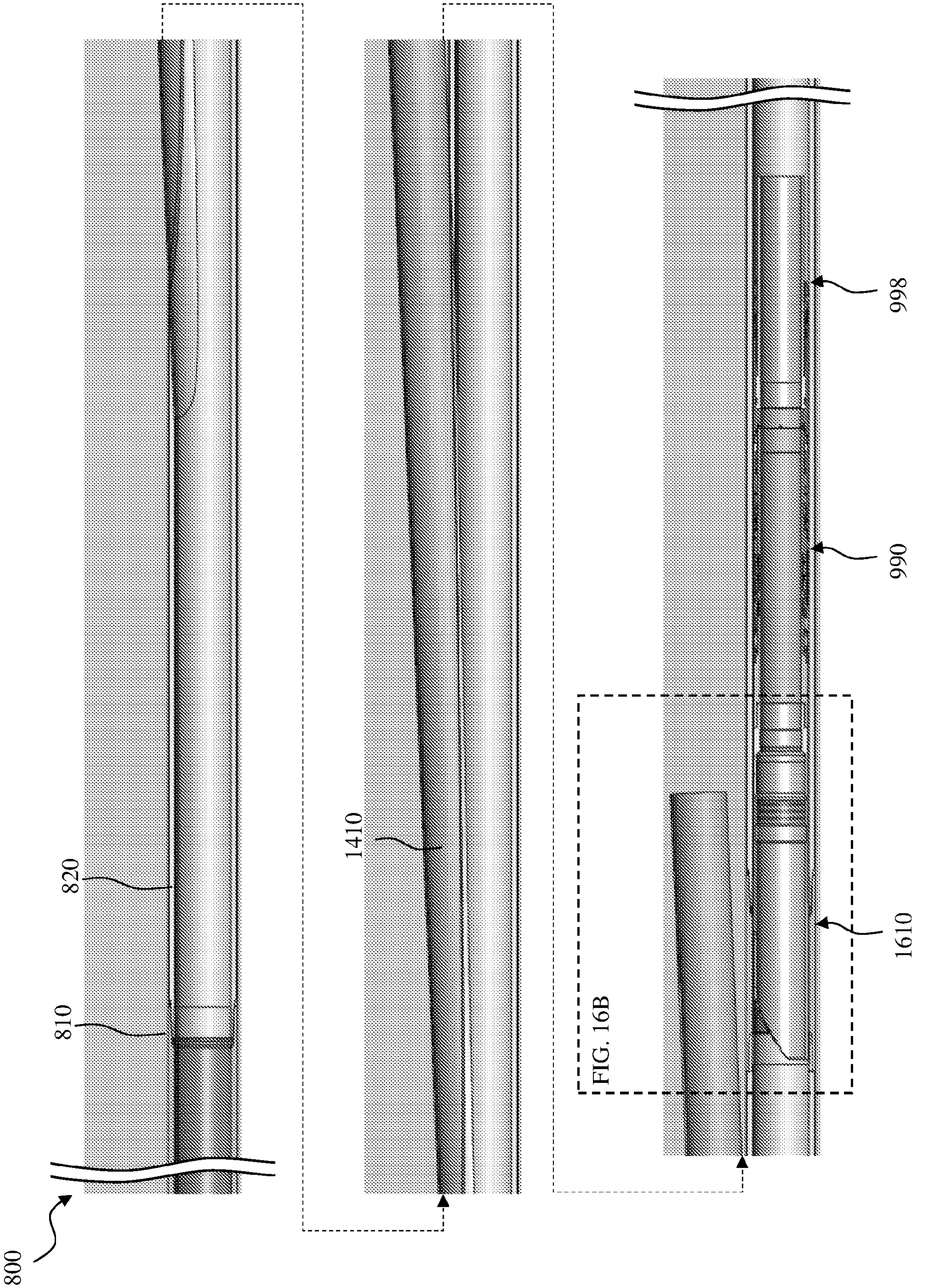

FIG. 16A

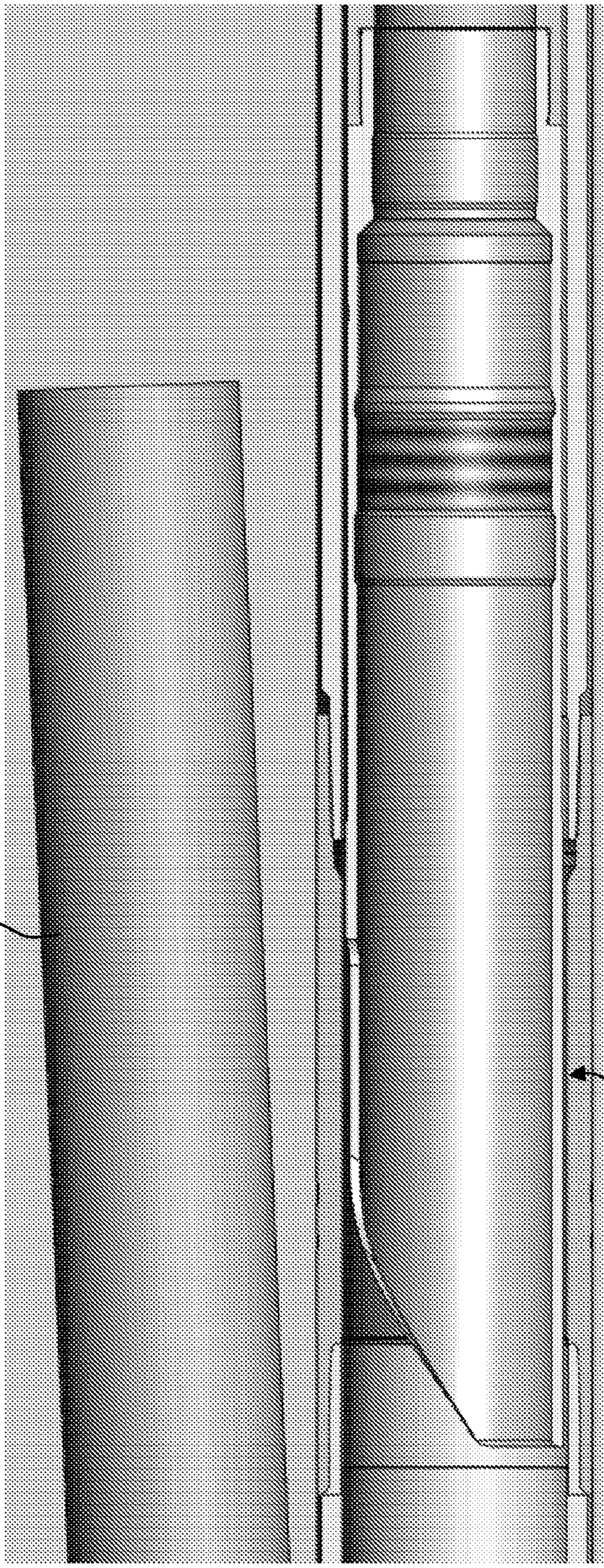

FIG. 16B

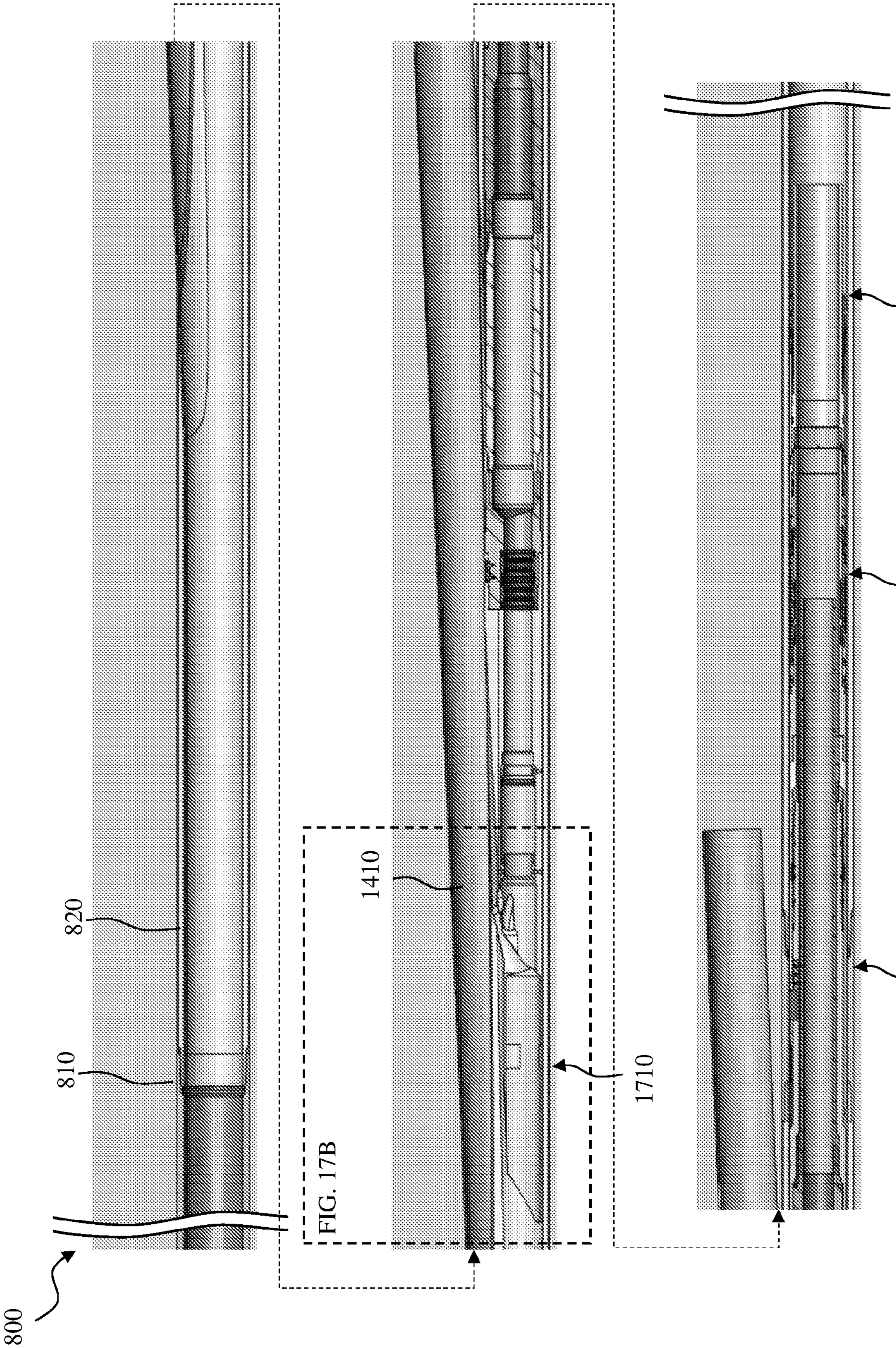

FIG. 17A

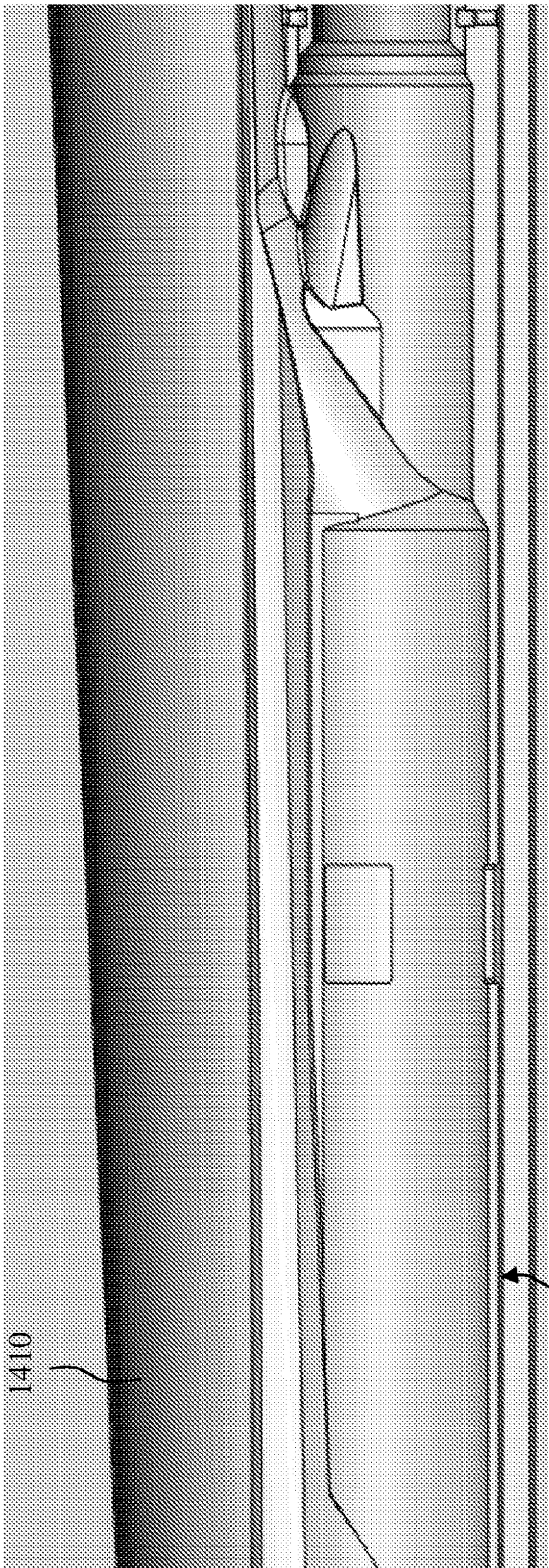

FIG. 17B

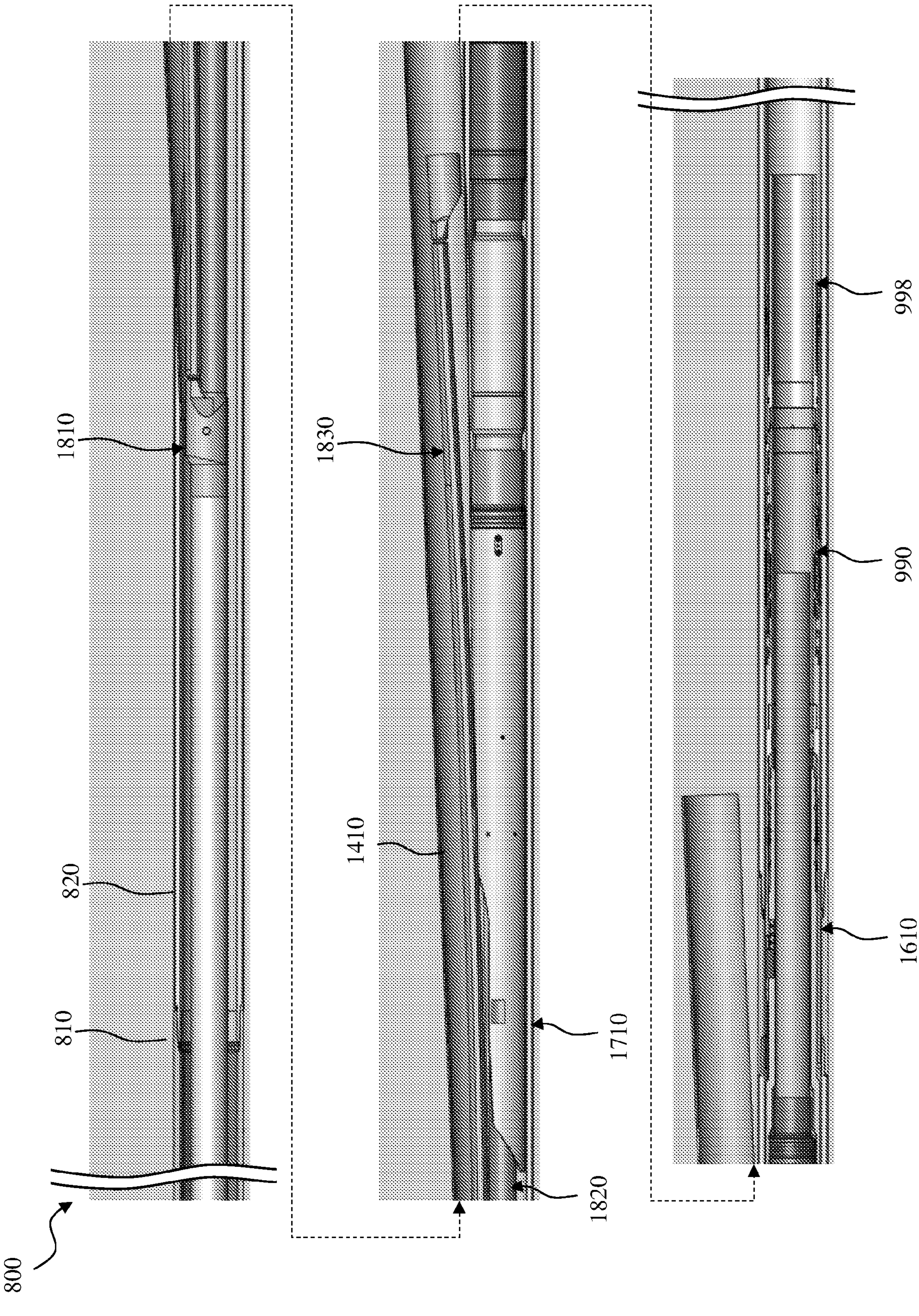

FIG. 18

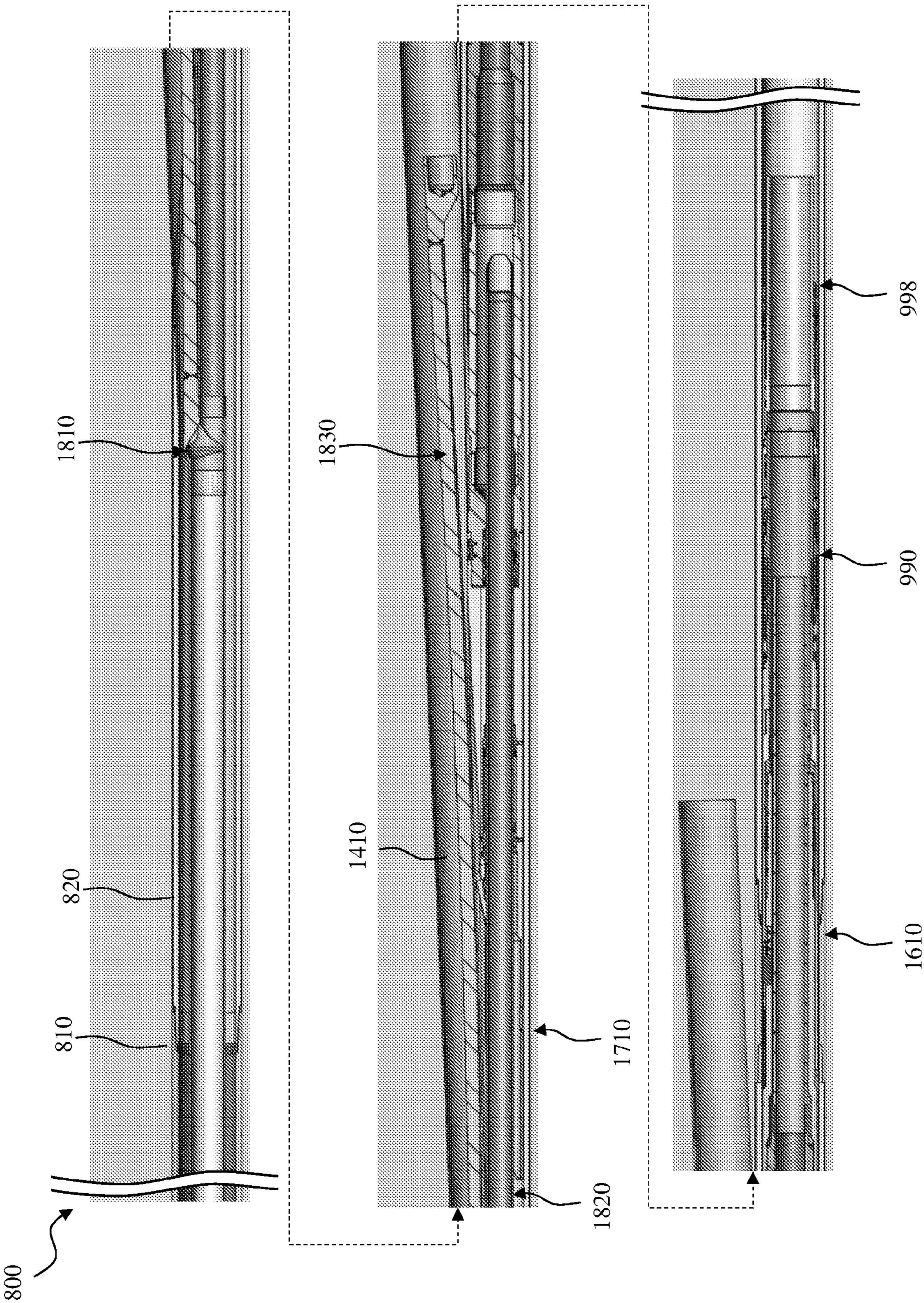

FIG. 19

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2022/081994

A. CLASSIFICATION OF SUBJECT MATTER

E21B 7/06(2006.01)i; **E21B 43/10**(2006.01)i; **E21B 23/01**(2006.01)i

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B 7/06(2006.01); E21B 10/64(2006.01); E21B 29/06(2006.01); E21B 33/13(2006.01); E21B 7/04(2006.01); E21B 7/08(2006.01)

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKOMPASS(KIPO internal) & Keywords: lateral well, whipstock, anchor, mill, drill, slide, combine, single trip

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 6050334 A (MCGARIAN et al.) 18 April 2000 (2000-04-18) column 4, line 3 - column 6, line 65 and figure 1	1-32
A	US 2020-0011134 A1 (WILDCAT OIL TOOLS, INC.) 09 January 2020 (2020-01-09) paragraphs [0046]-[0048] and figures 1-5	1-32
A	US 5474126 A (LYNDE et al.) 12 December 1995 (1995-12-12) column 4, line 58 - column 6, line 51 and figures 3, 4a, 6, 7	1-32
A	US 2013-0319693 A1 (SPONCHIA et al.) 05 December 2013 (2013-12-05) paragraphs [0021]-[0027] and figure 4	1-32
A	US 2012-0222902 A1 (ALSUP et al.) 06 September 2012 (2012-09-06) paragraphs [0021]-[0027] and figure 1	1-32

☐ Further documents are listed in the continuation of Box C. ☑ See patent family annex.

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

Date of the actual completion of the international search	Date of mailing of the international search report
25 April 2023	**25 April 2023**

Name and mailing address of the ISA/KR	Authorized officer
Korean Intellectual Property Office **189 Cheongsa-ro, Seo-gu, Daejeon** **35208, Republic of Korea**	**PARK, Tae Wook**
Facsimile No. **+82-42-481-8578**	Telephone No. **+82-42-481-3405**

INTERNATIONAL SEARCH REPORT
Information on patent family members

International application No.
PCT/US2022/081994

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				US	2020-0087987	A1	19 March 2020
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				WO	2019-032149	A1	14 February 2019
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				WO	2012-118992	A2	07 September 2012
				WO	2012-118992	A3	15 November 2012