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(54) Downhole packer having swellable sleeve

(57) A packer (200) seals a wellbore annulus. The packer has a body defining a bore therethrough and has a swellable element (250) disposed on the body. An expander (240) movably disposed on the body adjacent the swellable element is actuated by fluid pressure communicated through a port in the body's bore. When actuated, the expander fits between the swellable element and the body to expand the swellable element radially outward an initial expansion amount. While downhole, the swellable element swells in the presence of an agent downhole and expands radially outward a subsequent expansion amount to produce a seal with a surrounding surface. With further fluid pressure, the expander can also compress the swellable element to further increase the expansion amount of the swellable element.

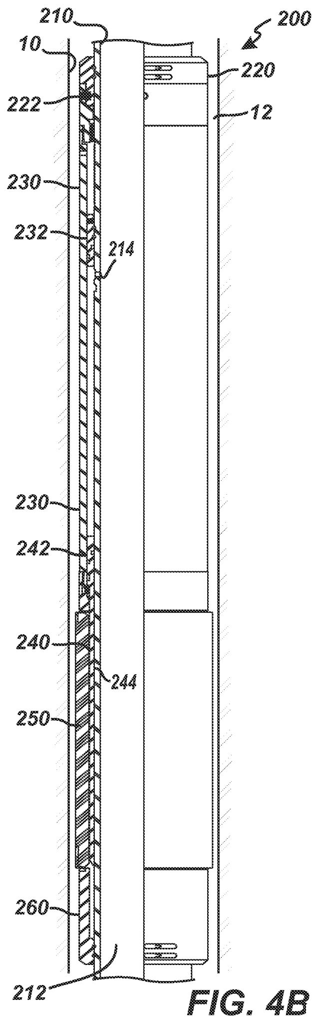

FIG. 4B

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Description

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is concurrently filed with U.S. Pat. Appl. Ser. No. 12/835,684 entitled "Downhole Packer having Tandem Packer Elements for Isolating Frac Zones" by the same inventors, which is incorporated herein by reference in its entirety.

BACKGROUND

[0002] Selective frac operations of multiple isolated zones can improve a well's production capabilities. To isolate multiple zones of a formation, operators deploy a tool string that has a number of port subs separated by packers into a borehole through the formation. The borehole may be an open hole or may be lined with a casing having perforations. When activated, the packers isolate the borehole annulus into separate zones. The individual port subs can then be opened and closed so that frac treatment can be applied to specific isolated zones of the formation.

[0003] Different types of conventional packers can been used to isolate zones in the borehole. One type of packer uses a compression-set element that expands radially outward to the borehole wall when subjected to compression. Being compression-set, the element's length is limited by practical limitations because a longer compression-set element would experience undesirable buckling and collapsing during use. However, the shorter compression-set element may not be able to adequately seal against irregularities of the surrounding borehole wall.

[0004] Another type of packer uses an inflatable element with a differential pressure limitation to produce a seal. Inflatable packers can be significantly more costly than compression-set packers and can be more difficult to implement and deploy. Yet another type of packer uses a swellable element. Once these packers are run into position, a fluid enlarges the element until it swells to produce a seal with the borehole wall. Unfortunately, high differential pressures or an absence of the fluid that initially caused the element to swell can compromise the swellable element's seal.

[0005] According to a first variant of the present invention there is provided a packer for sealing an annulus, comprising:

a body defining a bore therethrough;
a swellable element disposed on the body; and
an expander movably disposed on the body adjacent the swellable element, the expander actuatable to fit between the swellable element and the body,
the expander expanding the swellable element radially outward an initial expansion amount,
the swellable element being swellable in the presence of an agent downhole radially outward to produce a seal with a surrounding surface.

[0006] According to a second variant of the present invention there is provided a packer for sealing an annulus, comprising:

a body defining a bore therethrough;
means disposed on the body for swelling radially outward in the presence of an agent to produce a seal with a surrounding surface; and
means disposed on the body for expanding the swelling means radially outward an initial expansion amount.

[0007] In the packer according to the second variant the means for expanding can comprise means for fitting between the swelling means and the body to expand the swelling means the initial expansion amount. Alternatively the means for expanding comprises means for compressing the swelling means to expand the swelling means a subsequent expansion amount. The agent may be introduced downhole, or the agent may be naturally occurring downhole.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] FIG. 1A illustrates a downhole packer having tandem packer elements for isolating zones in a borehole.

[0009] FIG. 1B illustrates the downhole packer of FIG. 1A set in the borehole.

[0010] FIG. 2A illustrates a downhole packer having tandem packer elements in partial cross-section as initially deployed downhole.

[0011] FIG. 2B illustrates the downhole packer of FIG. 2A with both packer elements set in the borehole.

[0012] FIG. 2C illustrates the downhole packer of FIG. 2A in a stage of retrieval.

[0013] FIG. 3A illustrates a downhole packer having a compression-set packer portion and an inflatable packer portion.

[0014] FIGS. 3B-3C show alternative arrangements for packers having tandem packer portions.

[0015] FIG. 4A illustrates a downhole packer having a swellable element in partial cross-section deployed in a borehole.

[0016] FIG. 4B illustrates the downhole packer of FIG. 3A in an initial stage of deployment.

[0017] FIG. 4C illustrates the downhole packer of FIG. 3A in a subsequent stage of deployment.

[0018] FIG. 4D illustrates the downhole packer of FIG. 3A in a further stage of deployment.

DETAILED DESCRIPTION

[0019] A downhole packer 100 illustrated in FIG. 1A deploys in a borehole 10. The packer 100 can be used to isolate the annulus 12 into separate zones for treatment in a frac operation. In general, the borehole 10 may be an open hole or may be lined with a casing (not shown) having perforations. The packer 100 has a body 110 with first and second packer portions 120/170 disposed thereon. These packer portions 120/170 are capable of different forms of sealing. In particular, the first (upper) packer portion 120 provides a compressible form of sealing and includes an upper piston 130, a lower piston 140, a compression-set element 150, and a lower shoulder 160. The second (lower) packer portion 170 provides an engorgable (i.e., swellable) form of sealing and includes a swellable element 180 disposed on the body 110.

[0020] As shown in FIG. 1B and further detailed below, pumped fluid flowing in the body 110 hydraulically actuates the upper packer portion 120 by forcing the upper and lower pistons 130/140 towards the fixed lower shoulder 160. The pistons' movements compress the compression-set element 150 and set the element 150 against the inside of the borehole 10. By contrast, the swellable element 180 of the lower packer portion 170 swells and sets against the inside of the borehole 10 by interacting with an activating agent (e.g., well fluid, drilling fluid, or the like) and engorging the swellable element 180 in the agent's presence.

[0021] When set, the elements 150/180 create dual, tandem seals to isolate the annulus into a zone above the packer 100 and a zone below. Use of the two types of packer elements 150/180 allows the best features of each type to complement and improve the seal rating of the packer 100 between isolated zones. In particular, the compression-set element 150 provides high-pressure containment in the borehole 10, while the swellable element 180 having a longer element can accommodate irregularities in the borehole 10.

[0022] The downhole packer 100 is shown in further detail in FIG. 2A as initially deployed in the borehole 10. On the packer 100, the compression-set packer portion 120 can operate in a manner similar to a packer disclosed in U.S. Pat. No. 6,612,372, which is incorporated herein by reference in its entirety. As discussed herein, fluid pressure can activate the compression-set element 150 on the packer 100. However, other forms of activation could also be used, such as mechanical activation using a pulling tool or the like.

[0023] When the packer 100 as part of a tool string is positioned to a desired location in the borehole 10, operators pump fluid down the tool string. The pumped fluid reaches the packer 100 and passes from the bore 112, through a port 114, and into a lower annular chamber 146 between the body 110 and an outer piston housing 144. Fluid pressure building in this chamber 146 acts against a piston 140 slideably disposed on the body 110. Once the fluid pressure reaches a predetermined value, shear pins 143 that initially hold the piston 140 to the housing 110 break, freeing the piston 140 to move axially along the outside of the body 110 by the applied pressure.

[0024] As shown in FIG. 2B, the freed piston 140 moves along the body 110, and expansion portion of the piston 140 travels underneath the compression-set element 150 and expands the element 150 an initial expansion amount closer to the inner surface of the borehole 10. As the piston 140 then reaches a lower position relative to the outer piston housing 130, a lock ring and groove arrangement 148 becomes engaged between the piston 140 and the outer piston housing 144. Once engaged, the piston 140 and the outer piston housing 144 will move together along the body 110 as one unit.

[0025] Eventually, fluid pressure reaches a predetermined value to break shear pins (133; Fig. 2A) holding the upper piston 130. Once freed, the upper piston 130 can move together with the lower piston 140. Pumped fluid passes through a second port 113 into an upper annular chamber 136 and acts against a ratcheting assembly 132 of the upper piston 130. A slip ratchet with teeth on this ratchet assembly 132 prevents the upper piston 130 from travelling back towards its initial position against upper shoulder 138.

[0026] As the pistons 130 and 140 travel along the body 110, they compress the compression-set element 150 against the lower fixed shoulder 160 so that the compression-set element 150 expands radially outward a subsequent expansion amount. As shown set in FIG. 2B, the second chamber 136 has increased in volume, the outer piston housing 144 has axially pressed against the element 150, and the axially compressed element 150 has fully expanded in the radial direction to effectively seal the annulus 12 of the borehole 10.

[0027] In addition to the seal from the compression-set portion 120, the packer's swellable packer portion 170 also sets in the annulus 12 of the borehole 10 to provide a second (tandem) seal between zones. As shown in the initial stage of FIG. 2A, the swellable element 180 of this portion 170 disposes on the outside of the packer's body 110 and can be a sleeve or any other suitable shape. The swellable element 180 may be positioned between upper and lower rings 182 and 184 affixed to the body 110 with shear pins, although this may not be necessary in some implementations.

[0028] When initially deployed, the swellable element 180 does not engage the inside of the borehole 10. Once the packer 100 is located in its desired position in the borehole 10, the swellable element 180 can be set either concurrently with the activation of the compression-set packer portion 120 or sometime before or after depending on the implementation. For example, pumped fluid passed through the packer 100 to set the compression-set element 150 as discussed above can also cause the swellable element 180 to swell, filling the annulus 12 and engaging the inside of the borehole 10. Alternatively, the swellable element 180 may begin swelling by interacting with existing fluid downhole or with fluid introduced at a later stage of operation. Regardless of the activation method, the swellable element 180 becomes engorged by the activating agent and swells radially outward. As then shown in FIG. 2B, the swollen element 180 forms a secondary, tandem seal that isolates the annulus 12 in conjunction with the compression-set element 150.

[0029] In general, the compression-set element 150 can be composed of any expandable or otherwise malleable material such as metal, plastic, elastomer, or combination thereof that can stabilize the packer 100 and withstand tool movement and thermal fluctuations within the borehole 10. In addition, the compression-set element 150 can be uniform or can include grooves, ridges, indentations, or protrusions designed to allow the element 150 to conform to variations in the shape of the interior of the borehole 10. The swellable element 180 can be composed of an elastomeric material as detailed later that can swell in the presence of an activating agent, such as a fluid (e.g., liquid or gas) existing or introduced downhole.

[0030] As intimated previously, use of the compression-set packer portion 120 in combination with the swellable packer portion 170 enhances the pressure containment provided by the packer 100 during a frac operation. In general, these different types of packer elements 150 and 180 improve the isolation of the borehole's annulus beyond what can be achieved using just a single packer element as is common in the art. More particularly, the swellable element 180 with its increased axial length and ability to engage irregular surfaces can enhance the packer 100's seal by sealing against any irregularities in the borehole 10. On the other hand, the compression-set element 150 gives the packer 100 the ability to seal against higher differential pressures.

[0031] In FIG. 2C, the packer 100 is shown during a stage of retrieval. To release the activated packer 100, forces are applied to the packer 100 to break shear pins (162; Fig. 2B) that hold the lower shoulder 160 fixed to the body 110. Once released, the shoulder 160 travels axially along the body 110 until it reaches a profile (164; Fig. 2B) on the body 110. The release of the shoulder 160 thereby relaxes the compression-set element 150, allowing this packer portion 120 to be removed from the borehole 10. The ratcheting assembly 132 may also be released and free to move axially along the body 110.

[0032] During retrieval, the removal or absence of the activating agent downhole may allow the swellable element 180 to decrease in size, thereby disengaging it from the borehole 10 and making the swellable packer portion 170 removable from the borehole 10. In addition or in the alternative, the forces applied to the packer 100 may also free the swellable element 180 by breaking shear pins that retain one or both of the retaining rings 182 or 184. With the rings 182/184 freed, the swollen element 180 can relax axially so this portion 170 can be removed from the borehole 10.

[0033] The packer 100 shown in FIG. 2A has the engorgable portion 170 that uses the swellable element that swells in the presence of an activating agent. In FIG. 3A, the downhole packer 100 again has the compression-set packer portion 120 but includes an inflatable packer portion 175 rather than the swellable portion discussed previously. Here, operation of the compression-set packer portion 120 can be similar to that discussed previously. The inflatable packer portion 175 has an inflatable sleeve or bladder 190 disposed about the body 110 and fixed at the ends by retainers 192 and 194. The inflatable sleeve 190 can be composed of an elastomeric material reinforced with metal slats or other material. When activated, the inflatable sleeve 190 becomes engorged by an agent filing the sleeve 190 so that the sleeve 190 expands radially outward to the surrounding borehole 10.

[0034] In general, the agent filing the sleeve 190 can be the fluid pumped downhole. This pumped fluid enters a port 196 on the body 110 that allows the fluid from the bore 112 to fill inside the sleeve 190, causing it to expand and seal with the surrounding borehole wall. Any suitable valve arrangement 198 can be used on the port 196 to control the flow of fluid. For example, a control valve can be used. Alternatively, a valve that is activated using a ball drop, tubing movements, or manual manipulation by an ancillary tool can be used. In fact, control of the inflation of the inflatable packer element 190 can be linked to the operation of the compression-set packer portion 120. In this way, as fluid pressure activates the compression-set portion 120, the fluid pressure can also inflate the inflatable packer element 190.

[0035] The packer 100 as shown in FIG. 2A shows the compression-set packer portion 120 on the uphole end of the packer 100 and the swellable packer portion 170 on the downhole end. As shown in FIG. 3B, the packer 100 can have a reverse arrangement. In addition, FIG. 3C shows the packer 100 having the compression-set packer portion 120 interposed on the body 110 between an upper swellable packer portion 170A and a lower swellable packer portion 170B. With this arrangement, the high pressure differential seal created by the compression-set element 150 is complemented on both sides by the engorged seal of the swellable elements 180A and 180B. Any one or both of the swellable packer portions shown in FIGS. 3B-3C could also be an inflatable packer portion as disclosed herein.

[0036] To produce tandem seals to isolate zones for a frac operation, the packer 100 disclosed above uses tandem packer elements—*e.g.*, one compressible and one engorgable (i.e., swellable or inflatable). As an alternative, a downhole packer 200 illustrated in FIG. 4A has a single element 250 for isolating zones in a borehole 10. This element 250 is engorgable (i.e., swellable) in the presence of an agent and may also be compressible. The swellable element 250 disposes on the packer's body 210 between an outer piston housing 230 and a lower shoulder 260. As shown, this swellable element 250 can be a sleeve, but it can have any other suitable shape.

[0037] Also on the packer 200, an upper shoulder 220 supports the outer piston housing 230 on the body 210 with shear pins 222, and an inner piston 240 movably positions in an annular space between the body 210 and the outer piston housing 230. A seal 232 attached to the body 210 fits into the annular space between the body

210 and the outer piston housing 230 and separates the space into a lower chamber communicating with bore port 214 and an upper chamber communicating with an exterior port 234.

[0038] In an initial deployment stage shown in FIG. 4A, the packer 200 deploys in the borehole 10 to isolate the annulus 12 into separate zones that can be treated by a frac operation. When deployed, the swellable element 250 remains unswelled, and the piston 240 remains in an unextended condition retained by shear pins 243. Likewise, shear pins 222 hold the outer piston housing 230 in an unextended condition to the upper shoulder 220.

[0039] In a subsequent stage of deployment shown in FIG. 4B, operators pump fluid down the tubing string, and the fluid reaches the packer 200. The fluid pressure enters the bore port 214 from the housing's bore 212, fills an adjacent annular chamber below seal 232, and pushes against the sealed end 242 of the piston 240. With increase pressure, the shear pins (243; Fig. 4A) that initially held the piston 240 break, and the fluid pressure pushes the piston 240 downwardly. As the piston 240 moves, its expansion member 244 fits behind the swellable sleeve 250 and causes it to expand radially outward an initial expansion amount towards the surrounding borehole 10.

[0040] Eventually as shown in FIG. 4C, the partially expanded sleeve 250 interacts with an activating agent, such as drilling fluid, hydrocarbons, or the like, either introduced or existing downhole. As the activating agent interacts with the sleeve 250, the agent engorges the sleeve 250 and causes the sleeve 250 to swell outwardly a subsequent expansion amount to increase the sealing capability. Being fixed between the housing 230 and shoulder 260 and swelling outward from the body 210, the sleeve 250 expands radially outward to create a seal with the surrounding borehole wall.

[0041] As discussed above, the piston's expansion member 244 in expanding the sleeve 250 may only fit between the packer's body 210 and the sleeve 250 so that the sleeve 250 is pushed radially outward from the body 210. In some implementations, this expansion in combination with the swelling of the sleeve 250 may produce the desired seal with the surrounding borehole 10. In addition to this expansion and swelling, however, the packer 200 may also compress the sleeve 250 against the fixed shoulder 260 to expand the swellable element 250 an additional expansion amount. In this way, the seal produced can be generated by the initial expansion, swelling, and compression of the swellable element 250.

[0042] As shown in FIG. 4D, for example, an arrangement of the outer housing 230, piston 240, and sleeve 250 shows how the packer 200 can both expand and compresses the swollen sleeve 250 during operation. Here, fluid pressure has forced against the inner piston 240 until a lock ring and groove arrangement couples it to the outer piston housing 230 so that the piston 240 and housing 230 can move together. With continued fluid pressure, the shear pins (222; Fig. 4C) holding the top of the outer piston housing 230 break. With the housing 230 free to move, the fluid pressure against the piston 240 moves the outer piston housing 230 downward as well, and excess fluid in the chamber above the seal 232 is allowed to exit the external port 234 on the housing 230. As the housing 230 moves, teeth on its ratchet mechanism 236 engage grooves on the body 210 to prevent retraction, and the housing's lower end 238 compress the sleeve 250 against the fixed shoulder 260.

[0043] The packer 200 can perform the combination of enlarging, swelling, and compressing the swellable sleeve 250 in different orders. For example, the expansion member 244 of the piston 240 can initially enlarge the sleeve 250. The material of the initially expanded sleeve 250 can be swelled in the presence of the desired agent, and the packer 200 can then compress the swollen sleeve 250 to seal up the borehole 10. Alternatively, the expansion member 244 of the piston 240 can initially enlarge the sleeve 250, and then the packer 200 may further compress the sleeve 250 in an axial direction. Then, the material of the sleeve 250 can be swelled in the presence of the desired agent. Yet still, the sleeve 250 can first be swollen, then initially expanded, and finally compressed.

[0044] Regardless of the order, the enlarged, swollen, and compressed sleeve 250 may offer a differential pressure rating similar to that achievable with a compression-set element. Because the swellable sleeve 250 is initially expanded and swelled, the amount of compression applied to the sleeve 250 may be less than traditionally applied to a compression-set packer element. Consequently, the swellable sleeve 250 can be made longer than conventional compression-set packer elements because it may not suffer some of the undesirable effects of buckling and collapsing. With these benefits, the swellable sleeve 250 may advantageously be able to cover a significantly longer section of the borehole and can form a better seal against borehole irregularities than produced by existing packer elements.

[0045] The packer 200 can be retrieved by removing the activating agent that causes the swellable element 250 to swell. Once the agent is absent, the expansion of the swellable element 250 may reduce so that it dislodges from the borehole 10 and allows the packer 200 to be removed. In addition, as with the packer discussed previously, the lower shoulder 260 may have shear pins (not shown) that can be dislodged by jarring movements. Once freed, the shoulder 260 can move along the body 210 and enable the element 250 to relax so the packer 200 can be retrieved from the borehole 10.

[0046] The swellable elements 180/250 disclosed above are composed of a material that an activating agent engorges and causes to swell. For example, the material can be an elastomer, such as ethylene propylene diene M-class rubber (EPDM), ethylene propylene copolymer (EPM) rubber, styrene butadiene rubber, natural rubber, ethylene propylene monomer rubber, ethylene vinylacetate rubber, hydrogenated acrylonitrile butadiene rubber, acrylonitrile butadiene rubber, isoprene rubber, chloroprene rubber and polynorbornen, nitrile, VITON® fluoroelastomer, AFLAS® fluoropolymer, KALREZ® perfluoroelastomer, or other suitable material. (AFLAS is a registered trademark of the Asahi Glass Co., Ltd., and KALREZ and VITON are registered trademarks of DuPont Performance Elastomers). The swellable material of these elements 180/250 may or may not be encased in another expandable material that is porous or has holes.

[0047] What particular material is used for the elements 180/250 depends on the particular application, the intended activating agent, and the expected environmental conditions downhole. Likewise, what activating agent is used to swell the elements 180/250 depends on the properties of the element's material, the particular application, and what fluid (liquid and gas) may be naturally occurring or can be injected downhole. Typically, the activating agent can be mineral-based oil, water, hydraulic oil, production fluid, drilling fluid, or any other liquid or gas designed to react with the particular material of the swellable element 180/250.

[0048] The foregoing description of preferred and other embodiments is not intended to limit or restrict the scope or applicability of the inventive concepts conceived of by the Applicants. Although the packers disclosed herein have been described for use in a lined or open borehole, it will be appreciated that the packers can also be used through tubing. In exchange for disclosing the inventive concepts contained herein, the Applicants desire all patent rights afforded by the appended claims. Therefore, it is intended that the appended claims include all modifications and alterations to the full extent that they come within the scope of the following claims or the equivalents thereof.

Claims

1. A packer for sealing an annulus, comprising:

   a body defining a bore therethrough;
   a swellable element disposed on the body; and
   an expander movably disposed on the body adjacent the swellable element, the expander actuatable to fit between the swellable element and the body,
   the expander expanding the swellable element radially outward an initial expansion amount,
   the swellable element being swellable in the presence of an agent downhole radially outward to produce a seal with a surrounding surface.

2. The packer of claim 1, wherein the expander is hydraulically actuatable by fluid pumped through the bore of the body.

3. The packer of claim 1, wherein the swellable element comprises a sleeve disposed about an outer surface of the body.

4. The packer of claim 1, wherein the swellable element comprises an elastomeric material, and wherein_the elastomeric material swells in the presence of the agent selected from the group consisting of a fluid, a gas, an oil, water, production fluid, and drilling fluid.

5. The packer of claim 1, wherein the expander is actuatable to compress the swellable element against a shoulder disposed on the body.

6. The packer of claim 1, wherein the body defines a port from the bore, and wherein the expander comprises a piston axially movable along the body and having first and second ends, the first end acted upon by fluid pressure communicating from the port, the second end fitting between the swellable element and the body and expanding the swellable element the initial expansion amount.

7. The packer of claim 6, wherein a connection temporarily affixes the piston to the body until a predetermined fluid pressure is applied to the piston.

8. The packer of claim 6, wherein the expander comprises an outer housing engageable by the piston and movable along the body with the piston, the outer housing compressing the swellable element against a shoulder on the body and expanding the swellable element a subsequent expansion amount.

9. The packer of claim 8, wherein a connection temporarily affixes the outer housing to the body until a predetermined fluid pressure is applied.

10. A packer actuating method, comprising:

    running a packer into a wellbore;
    expanding a swellable element on the packer an initial expansion amount in an annulus of the wellbore; and
    creating a seal in the annulus of the wellbore with the swellable element by interacting the swellable element with an agent swelling the swellable element against a surrounding surface.

11. The method of claim 10, further comprising compressing the swellable element to expand a subsequent expansion amount.

12. The method of claim 10, wherein expanding the swellable element comprises actuating a piston disposed on the packer by pumping fluid pressure to the packer.

13. The method of claim 12, wherein expanding the swellable element comprises fitting a first portion of the piston between the swellable element and a body of the packer and expanding the swellable element the initial expansion amount.

14. The method of claim 13, wherein expanding the swellable element further comprises compressing the swellable element with a second portion of the piston against a shoulder on the packer and expanding the swellable element a subsequent expansion amount.

15. The method of claim 10, wherein interacting the swellable element on the packer with the agent comprises pumping the agent downhole; or subjecting the swellable element to the agent as naturally occurring downhole.

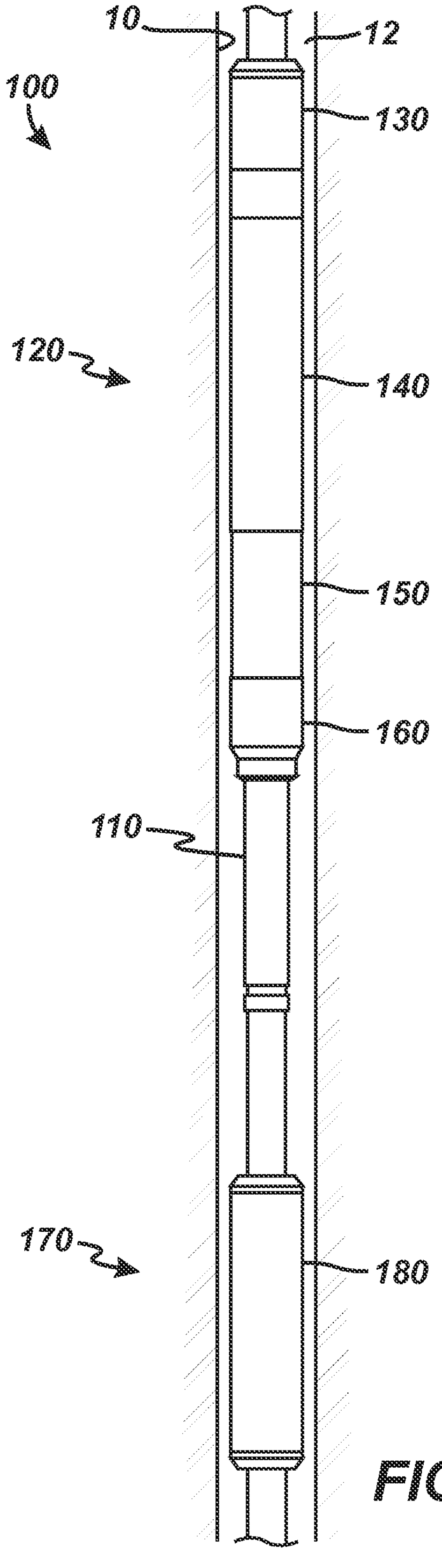
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FIG. 1A

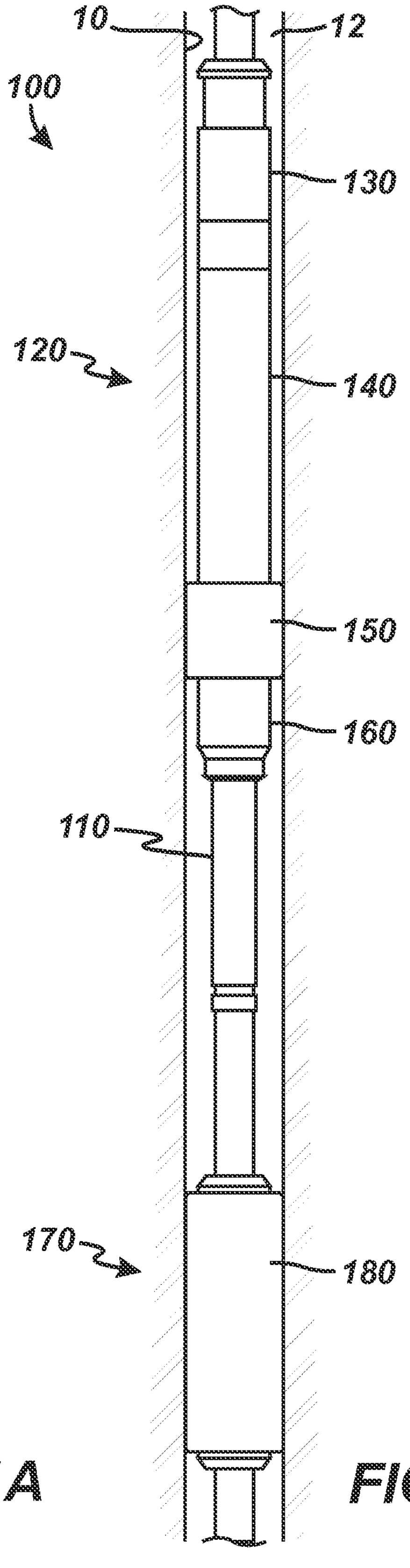
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FIG. 1B

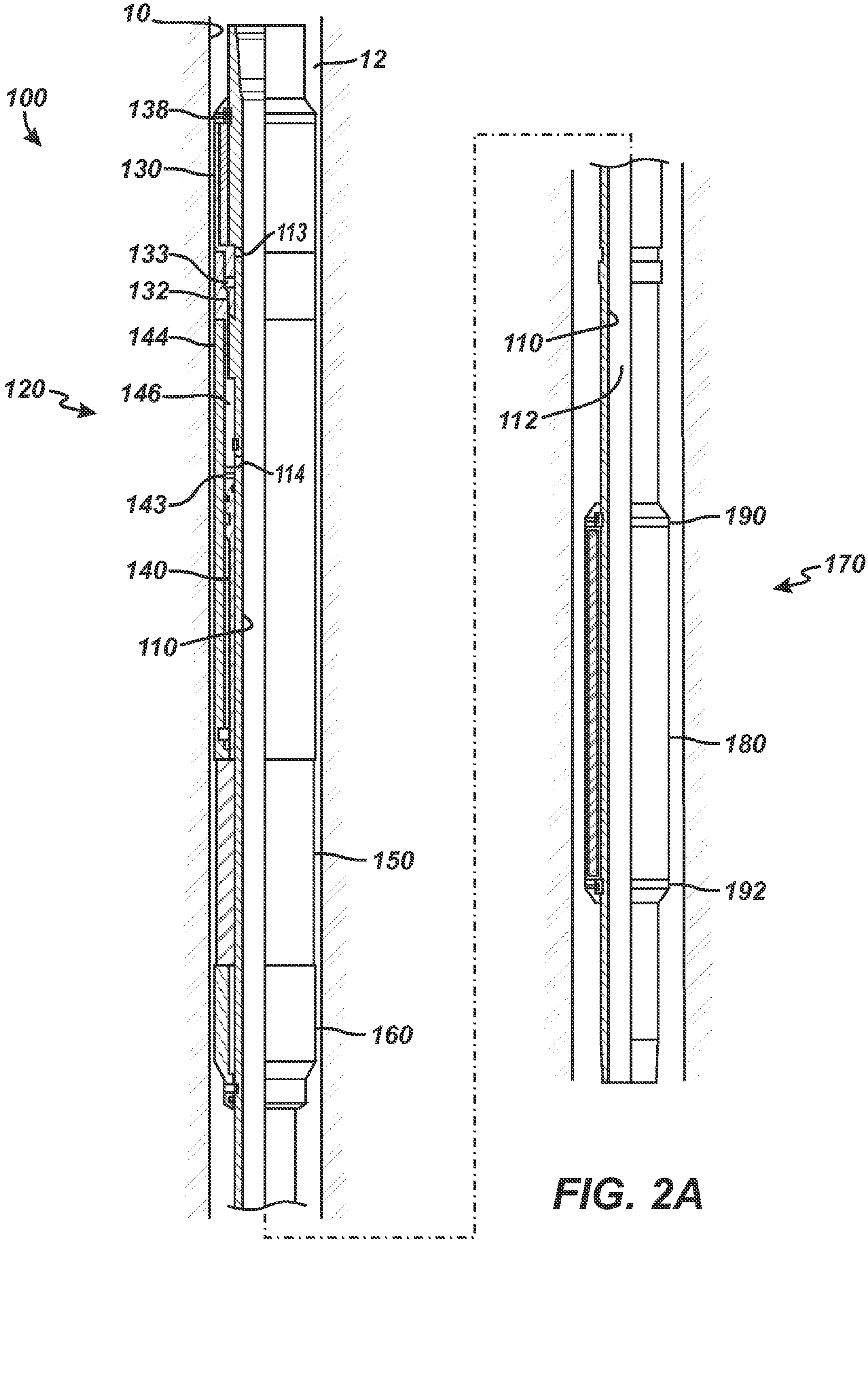
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FIG. 2A

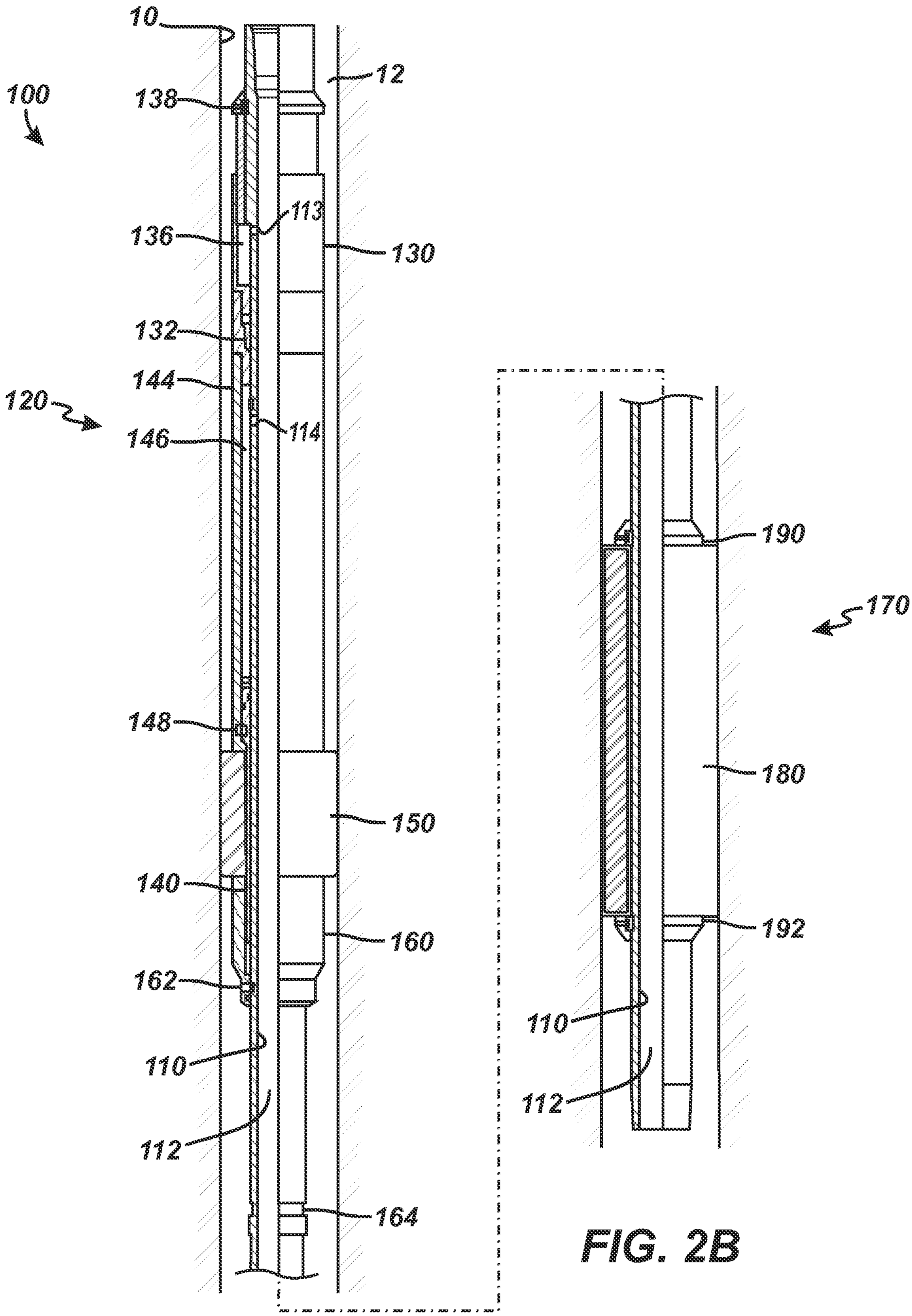
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FIG. 2B

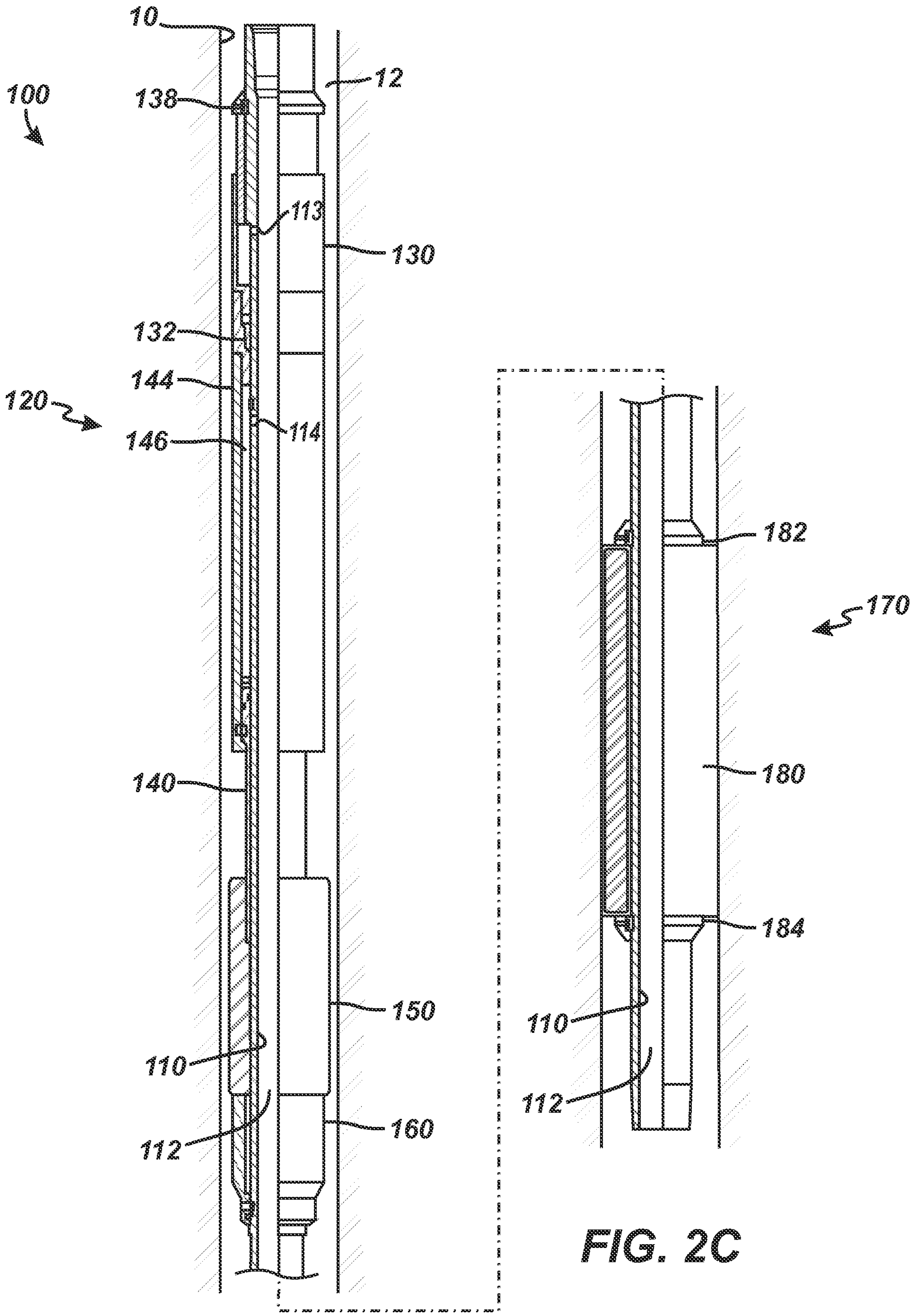
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FIG. 2C

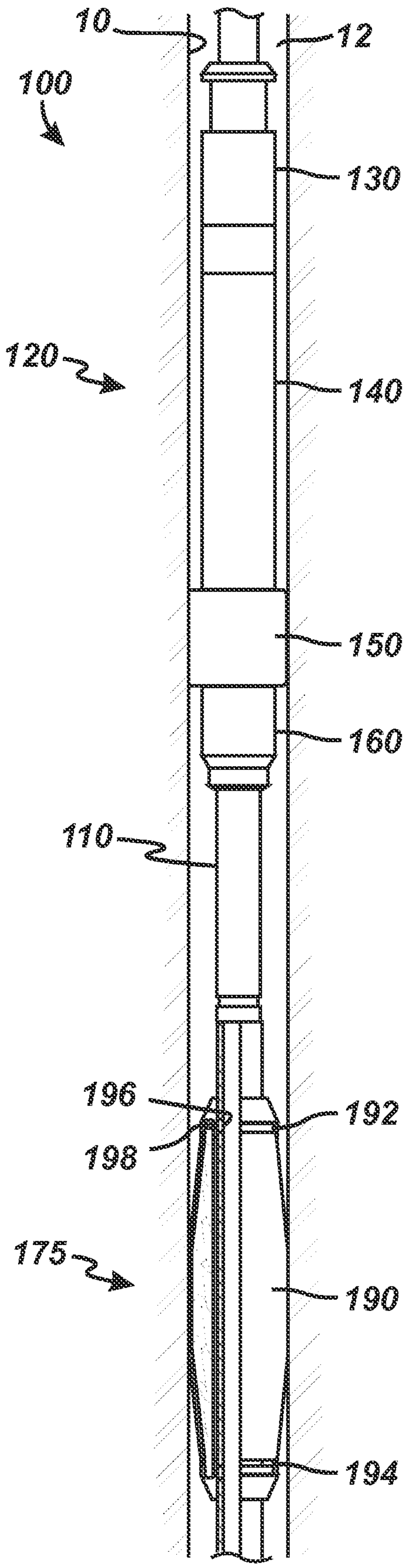

FIG. 3A

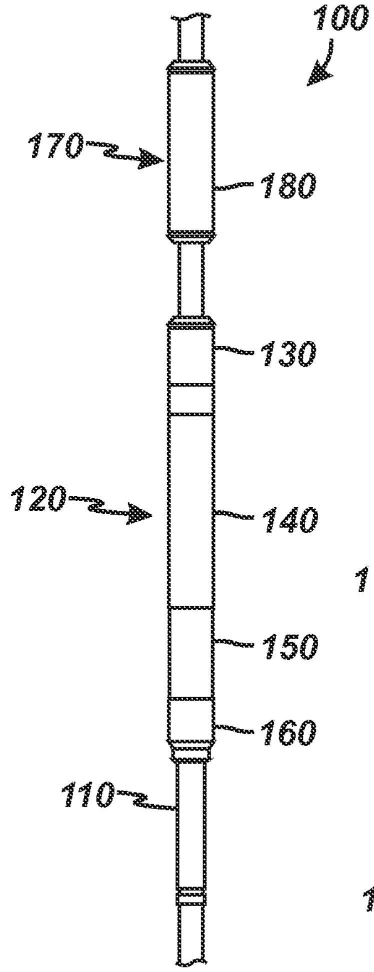

FIG. 3B

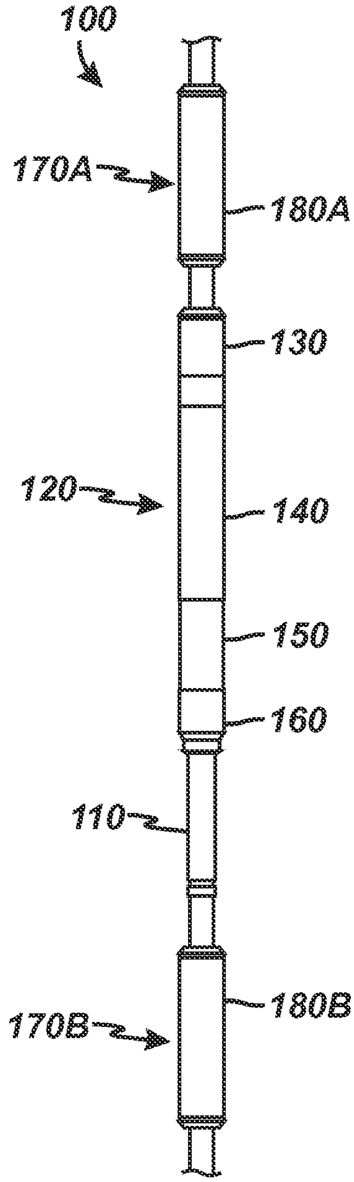

FIG. 3C

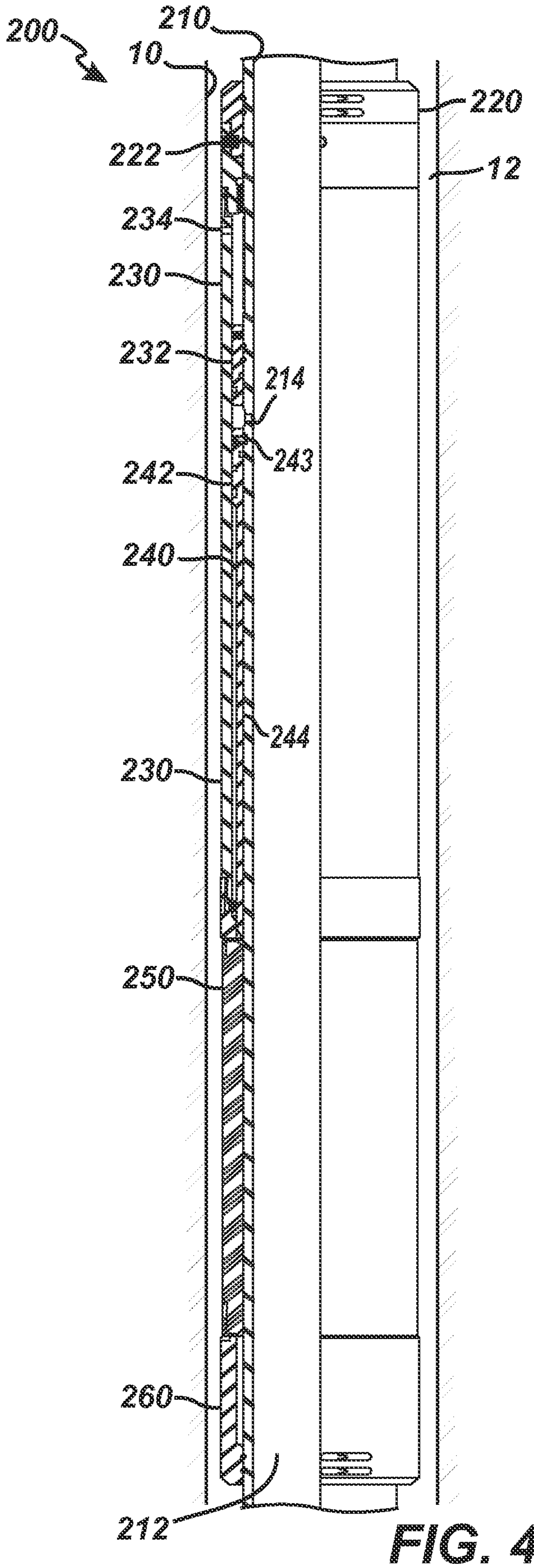
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FIG. 4A

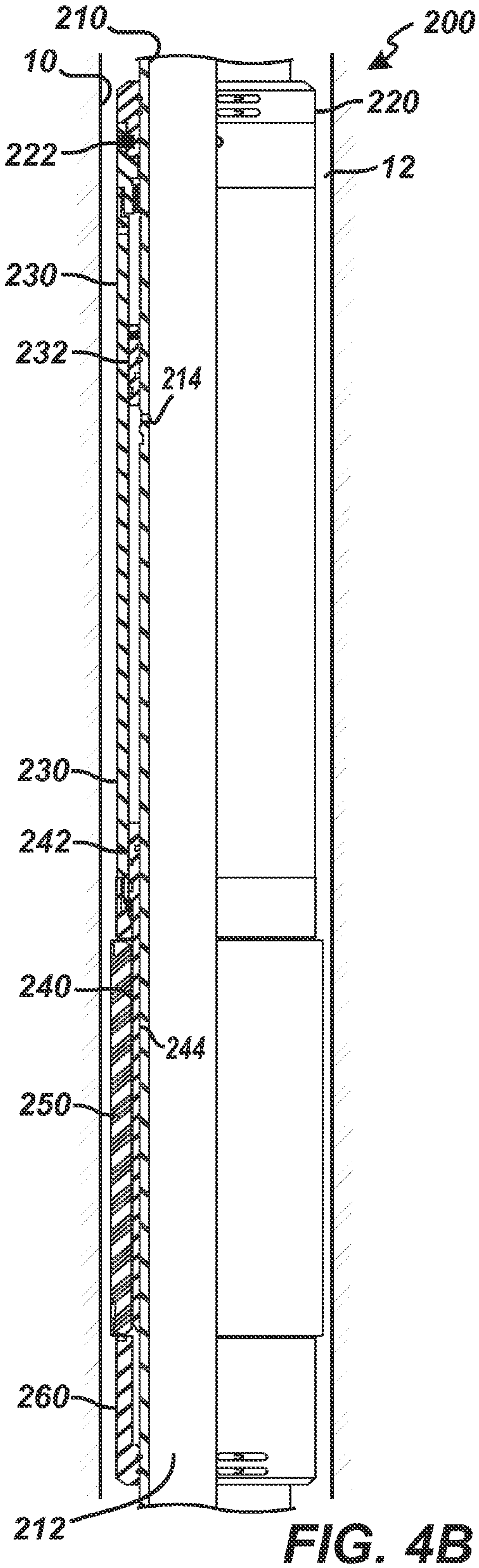
210
200
10
220
222
12
230
232
214
230
242
240
244
250
260
212

FIG. 4B

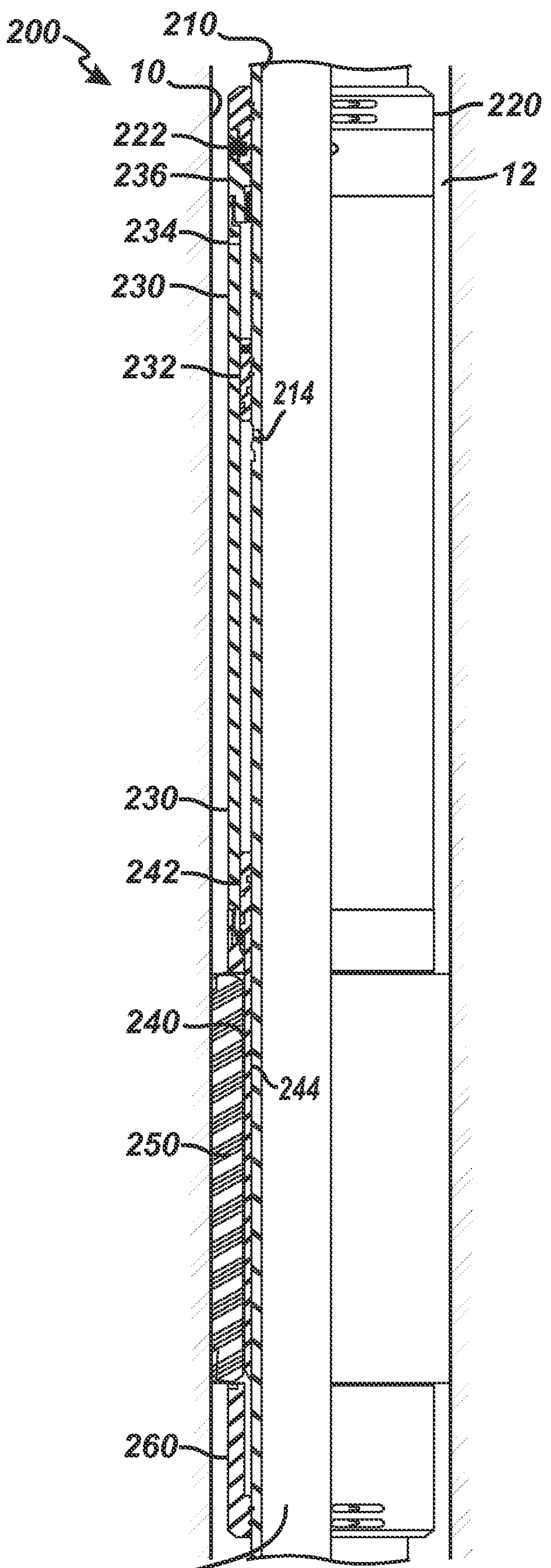
200
210
10
222
236
234
230
232
214
220
12
230
242
240
244
250
260
212

FIG. 4C

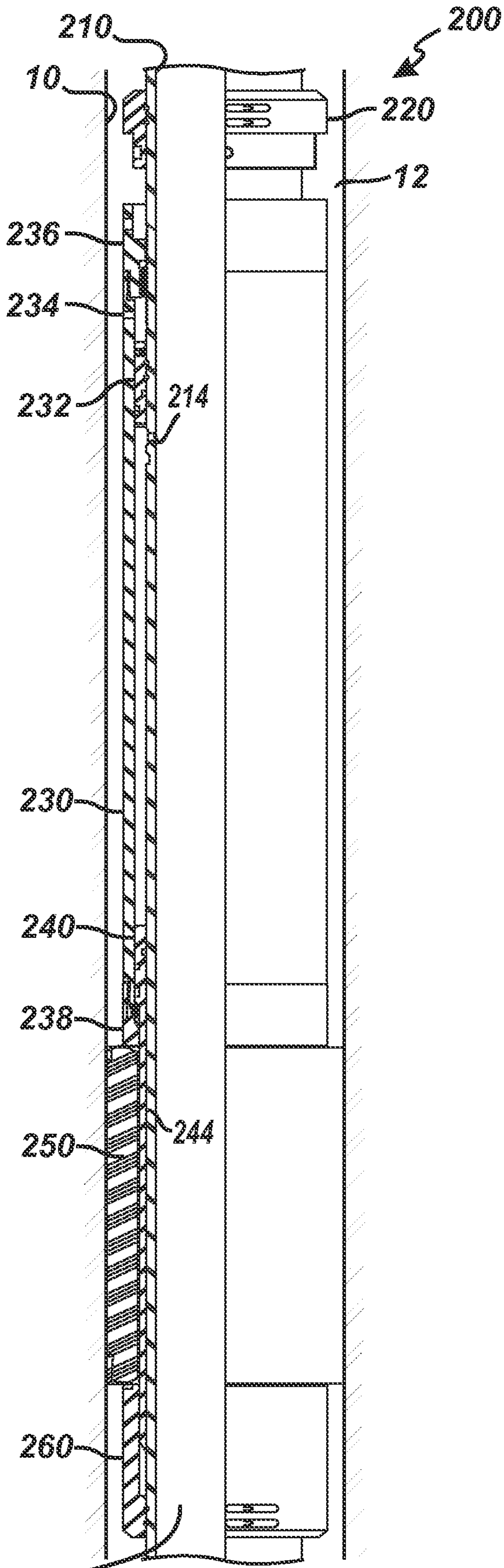
210
200
10
220
12
236
234
232
214
230
240
238
244
250
260
212

FIG. 4D

REFERENCES CITED IN THE DESCRIPTION

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Patent documents cited in the description

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