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Lee et al.

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(54) **SYSTEMS AND METHODS FOR SEALING A WELLBORE**

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Sep. 24, 2021, now Pat. No. 11,814,925, which is a
(Continued)

(51) **Int. Cl.**
E21B 33/129 (2006.01)
E21B 23/06 (2006.01)
(Continued)

(52) **U.S. Cl.**
CPC **E21B 33/1293** (2013.01); **E21B 23/06**
(2013.01); **E21B 33/128** (2013.01); **E21B**
43/26 (2013.01)

(58) **Field of Classification Search**
CPC E21B 23/06; E21B 33/128; E21B
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See application file for complete search history.

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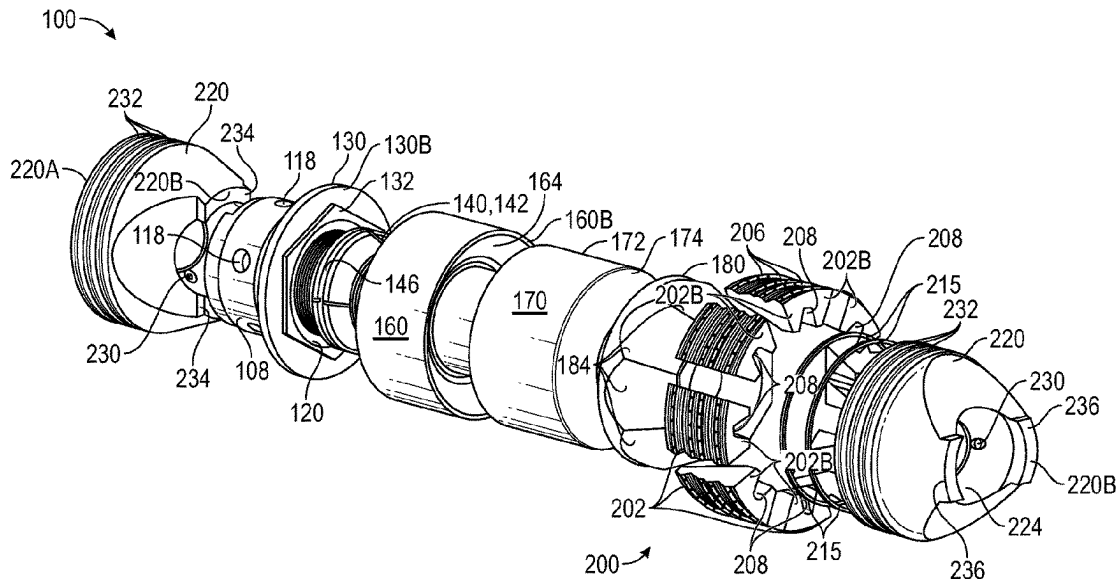
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(57) **ABSTRACT**

A plug for sealing a wellbore includes a mandrel extending between an uphole end defining an uphole end of the plug, and a downhole end opposite the uphole end of the mandrel, a slip assembly extending around the mandrel and including a plurality of arcuate slip segments, a nose coupled to the downhole end of the mandrel and defining a downhole end of the plug, wherein the nose includes an uphole end coupled to the downhole end of the mandrel and a downhole end opposite the uphole end of the nose and defining a downhole end of the plug, and a packer extending around the mandrel and including a first configuration configured to permit fluid flow across the plug when the plug is received in the wellbore, and a second configuration configured to seal the wellbore when the plug is positioned in the wellbore.

17 Claims, 14 Drawing Sheets



Related U.S. Application Data

continuation of application No. 16/152,184, filed on Oct. 4, 2018, now Pat. No. 11,131,163.

- (60) Provisional application No. 62/734,803, filed on Sep. 21, 2018, provisional application No. 62/569,447, filed on Oct. 6, 2017.

- (51) **Int. Cl.**
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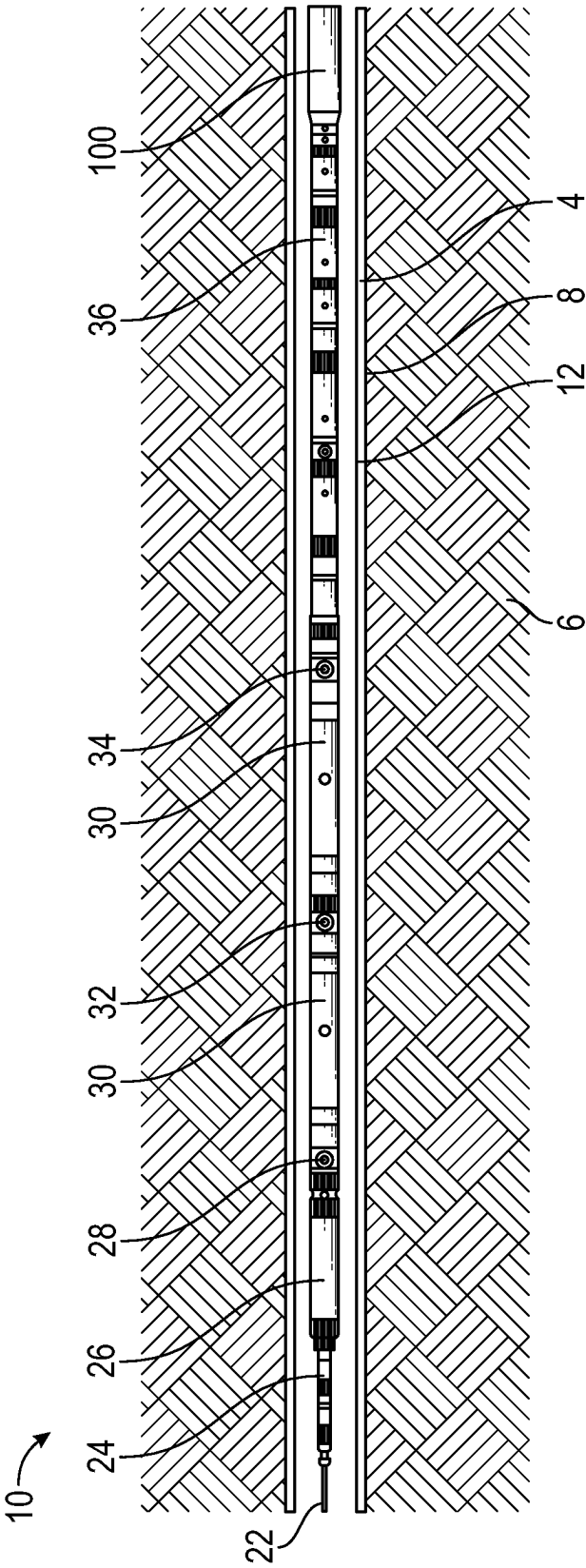


FIG. 1

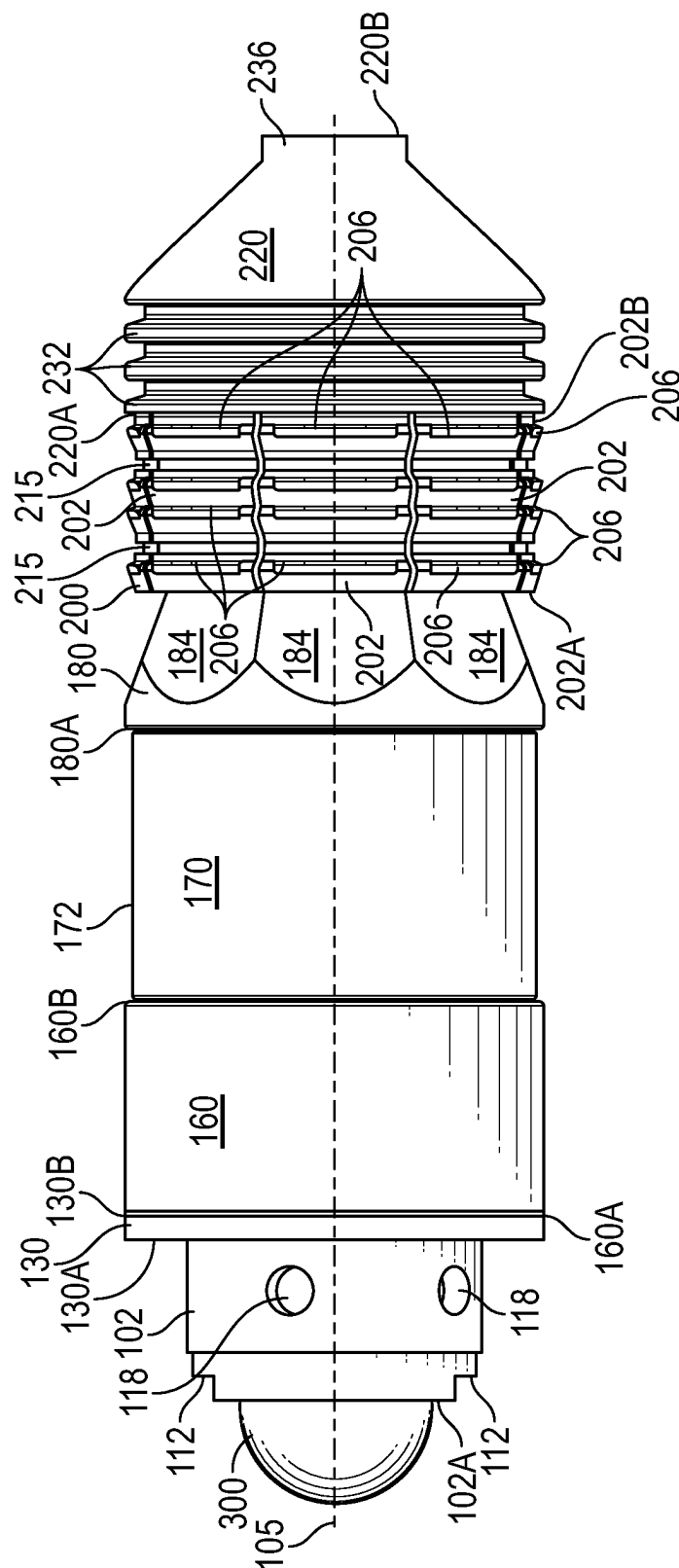


FIG. 2

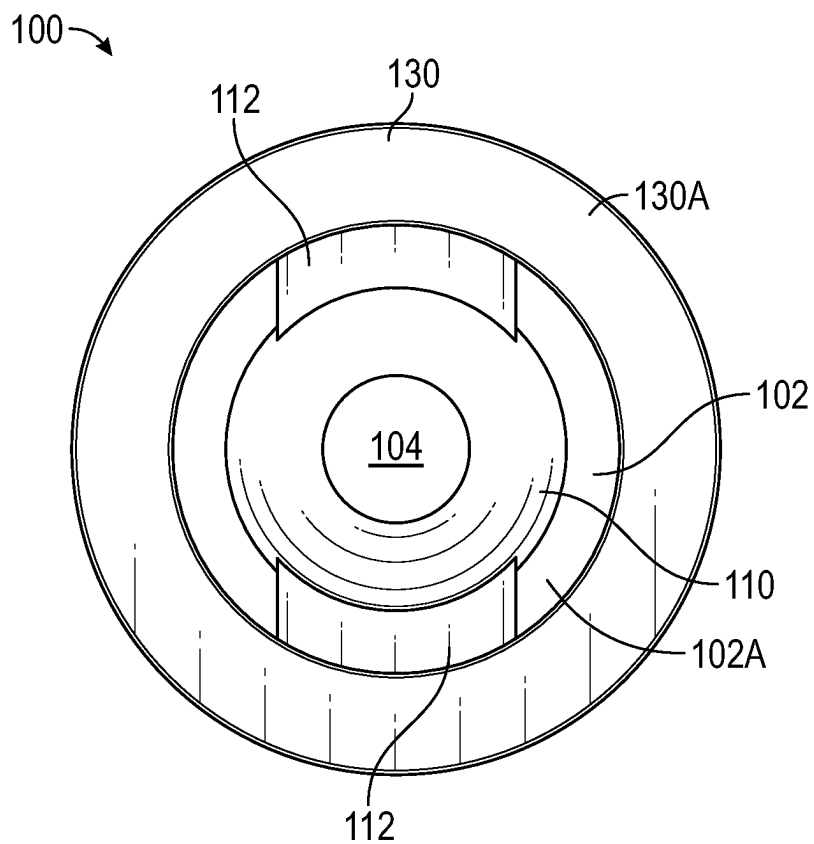


FIG. 3

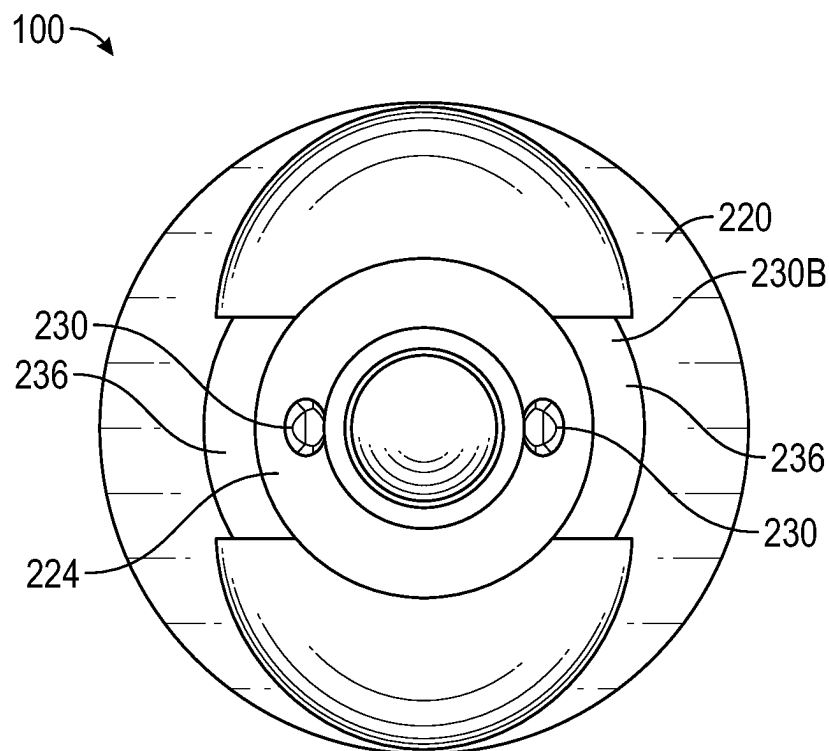


FIG. 4

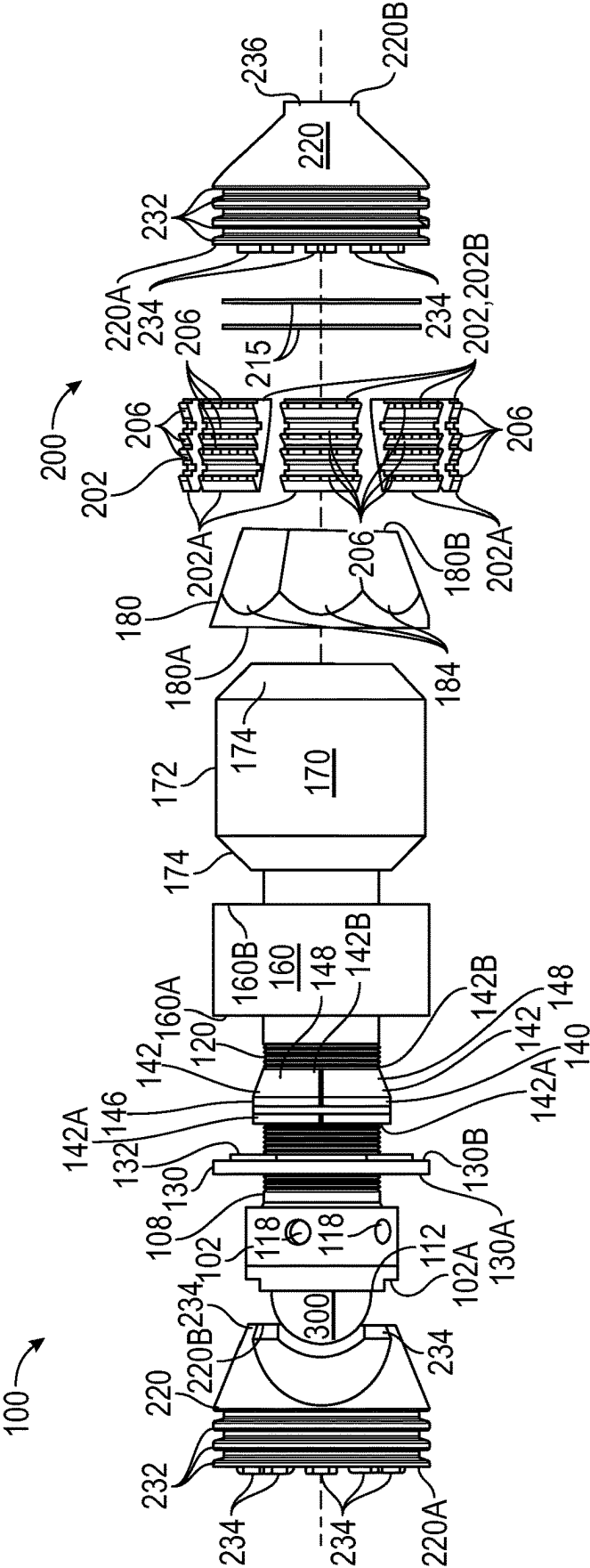


FIG. 5

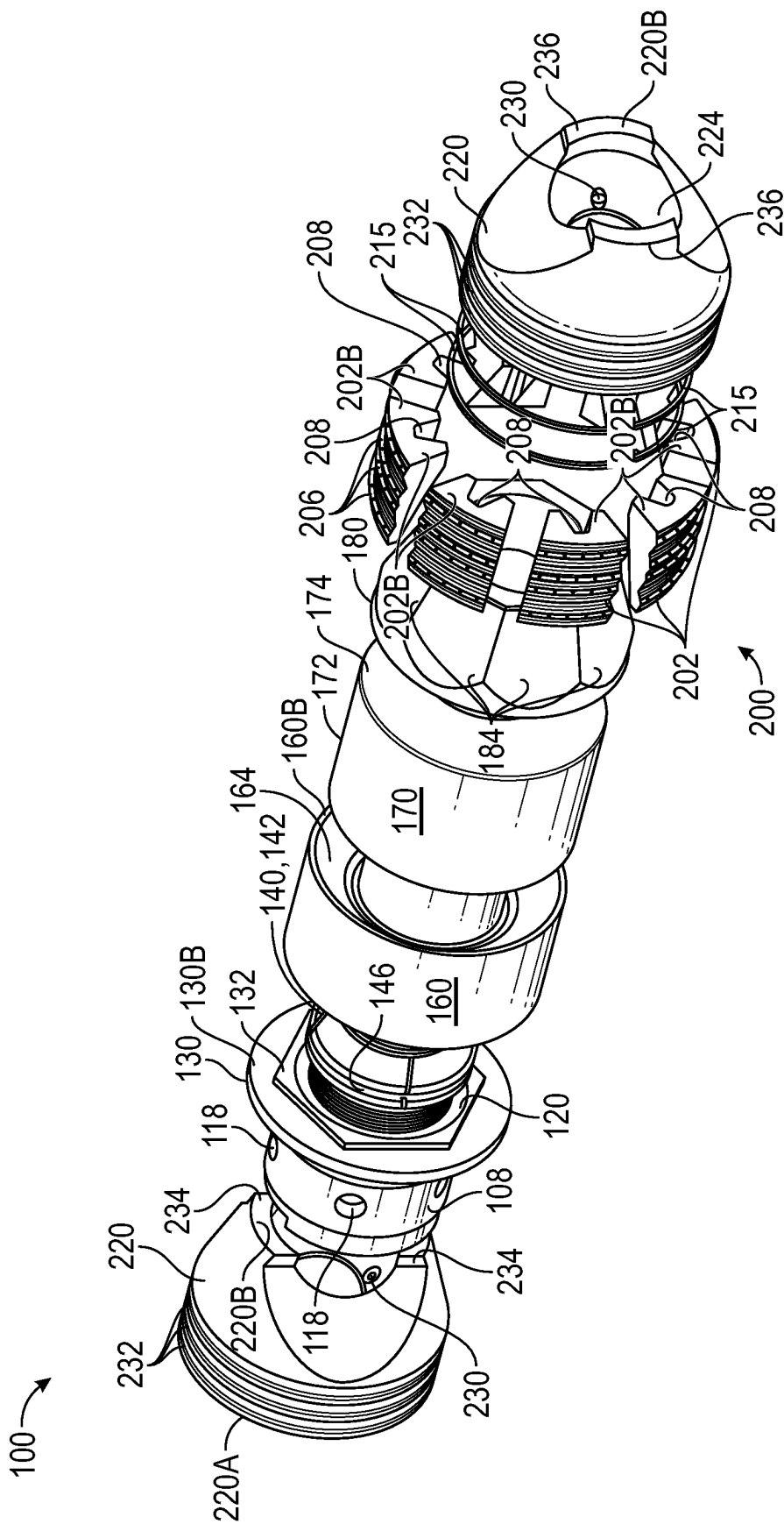


FIG. 6

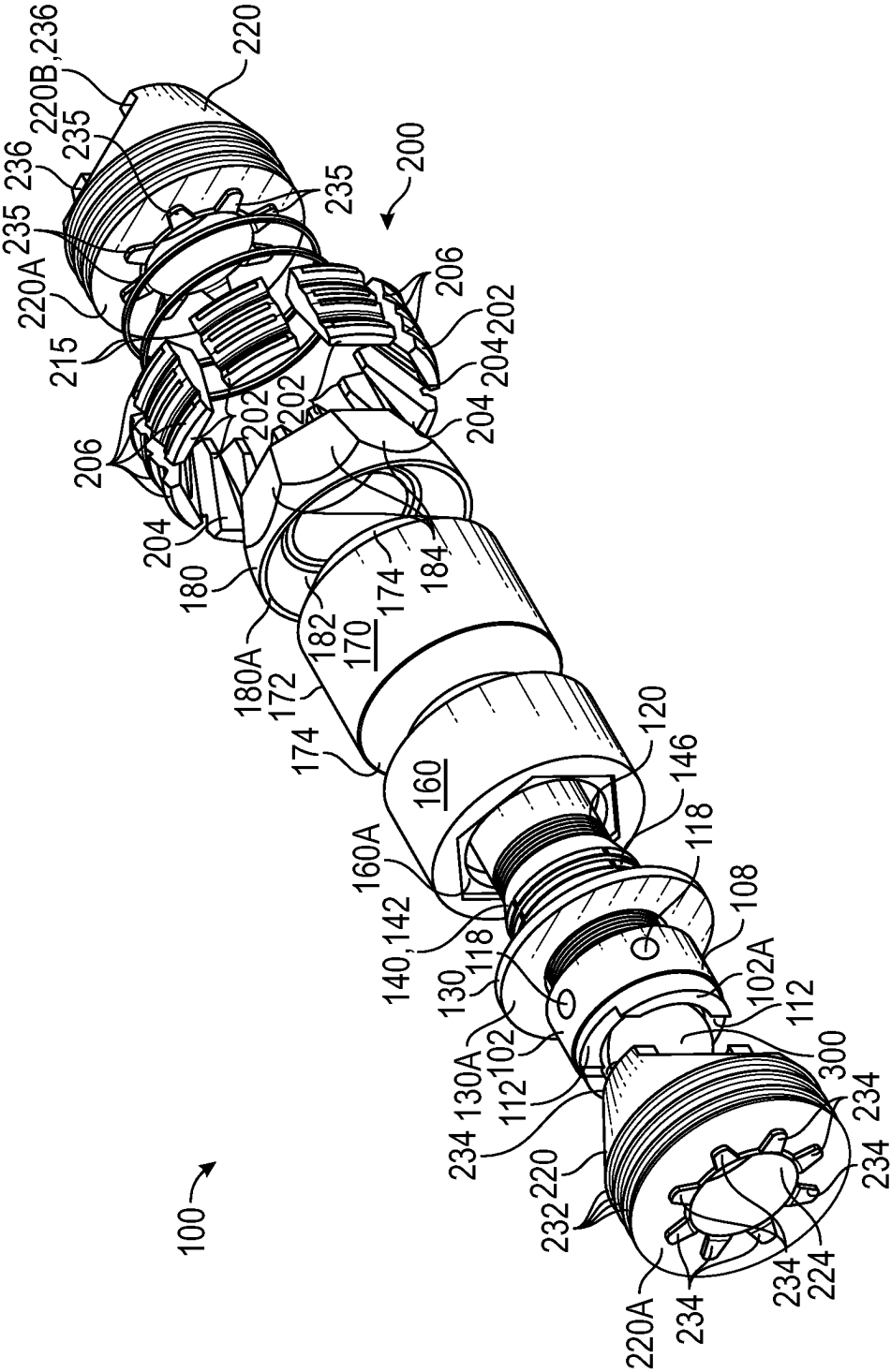


FIG. 7

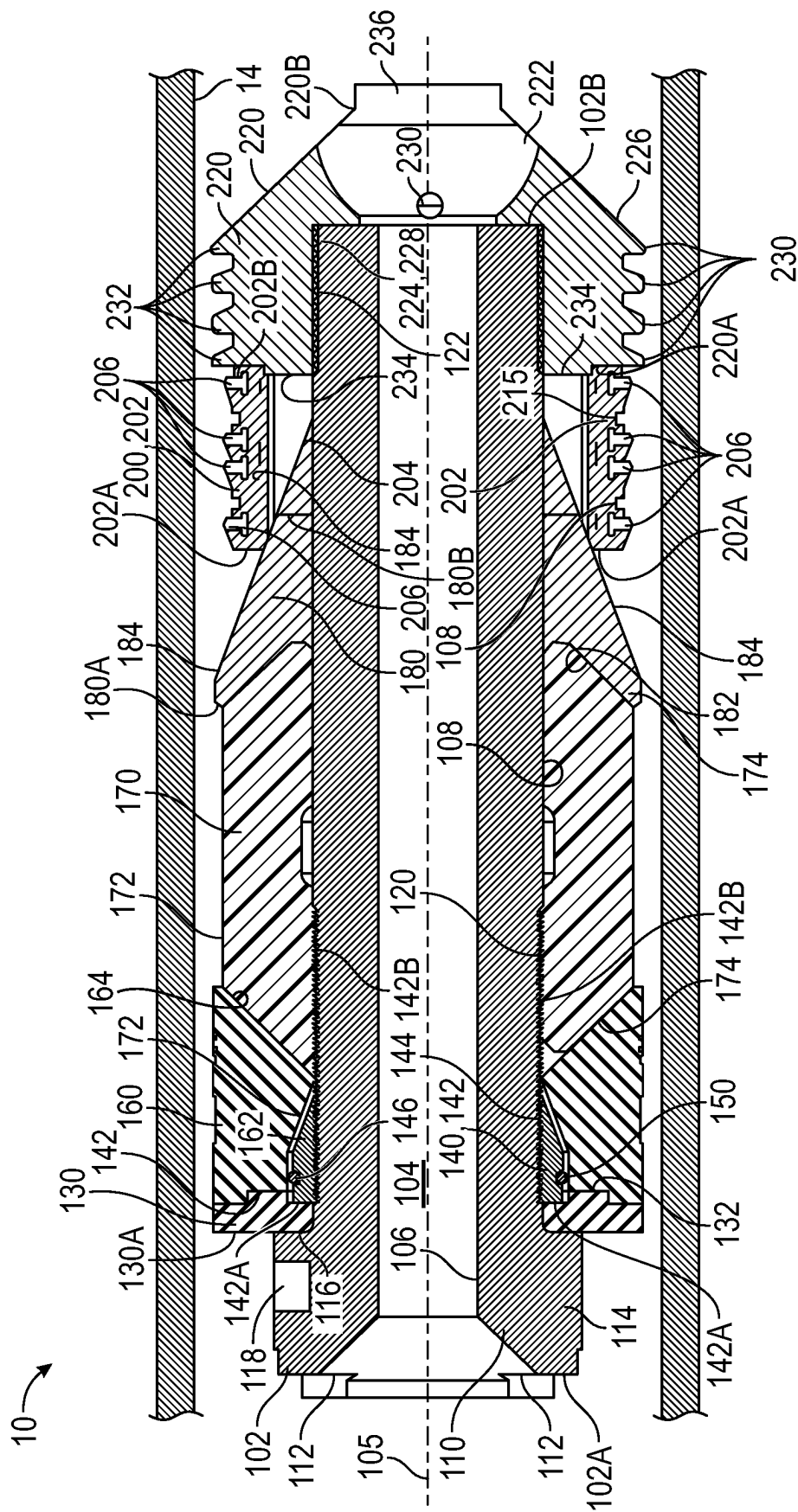


FIG. 8

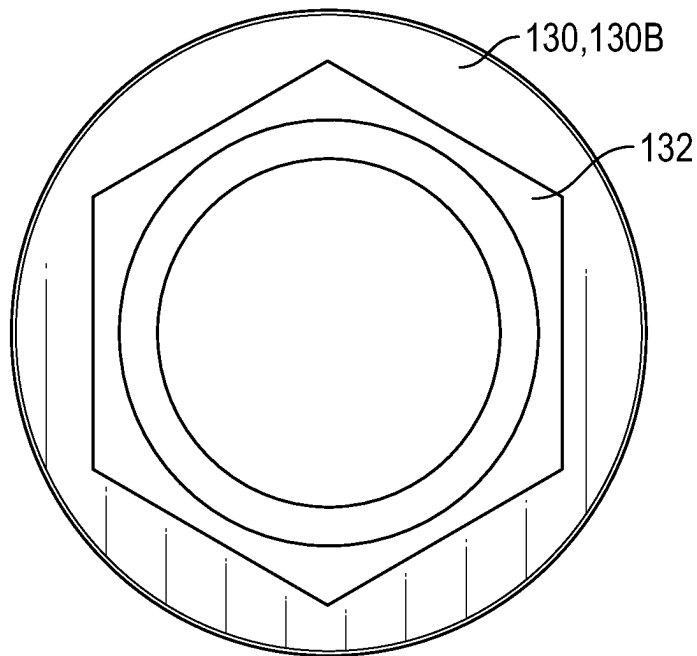


FIG. 9

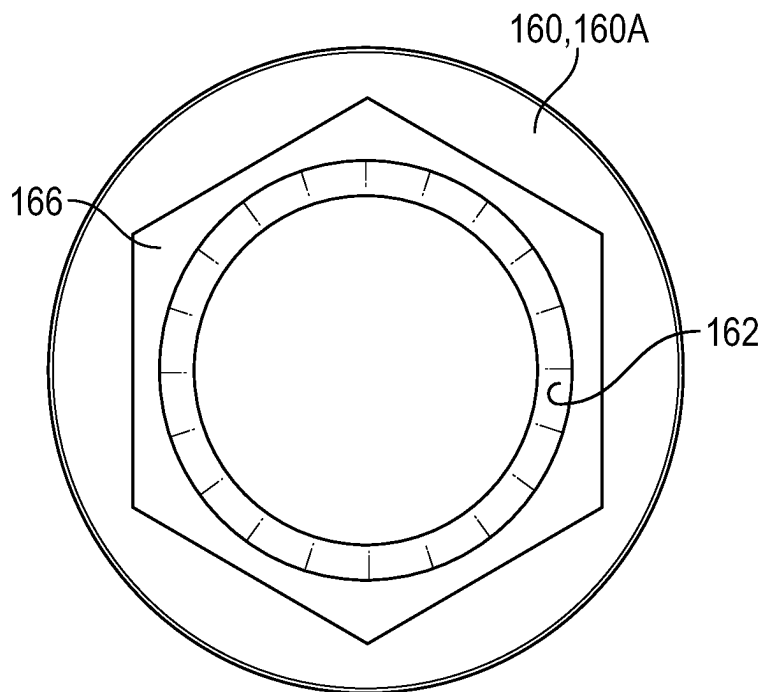


FIG. 10

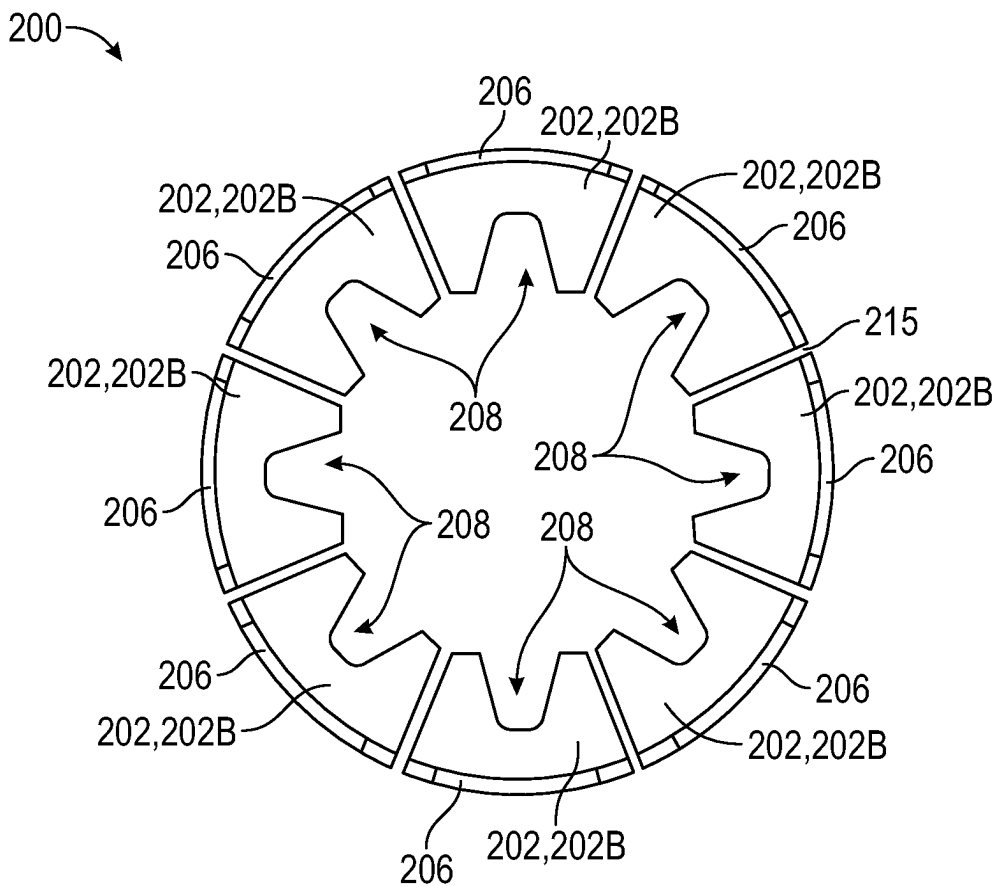


FIG. 11

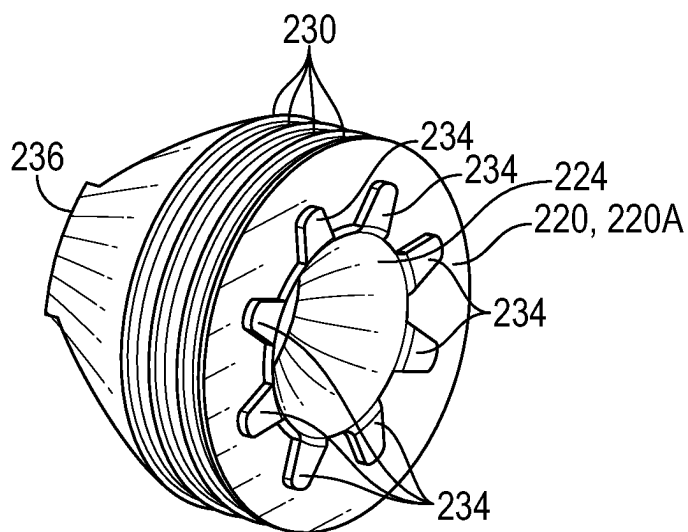


FIG. 12

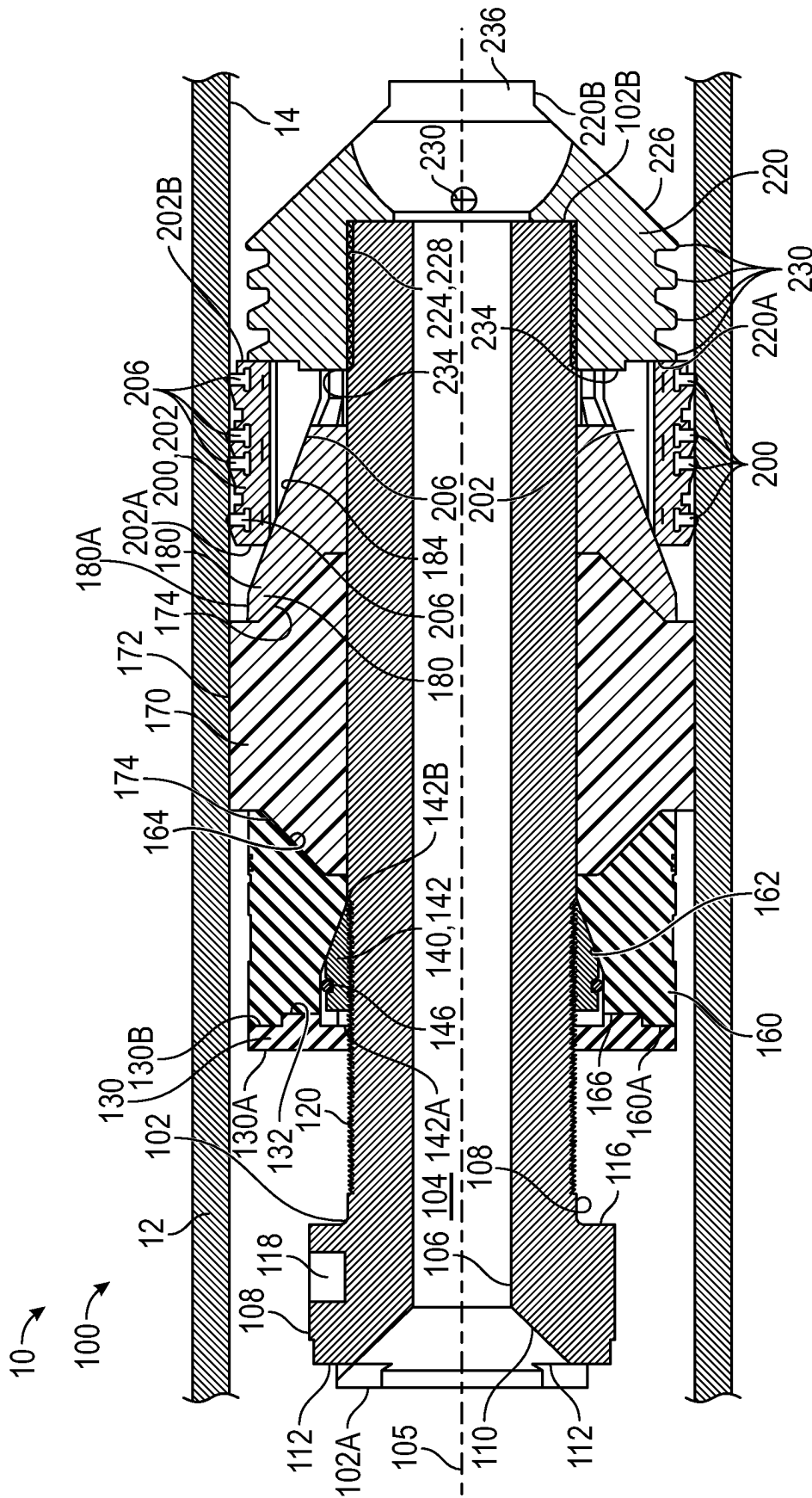


FIG. 13

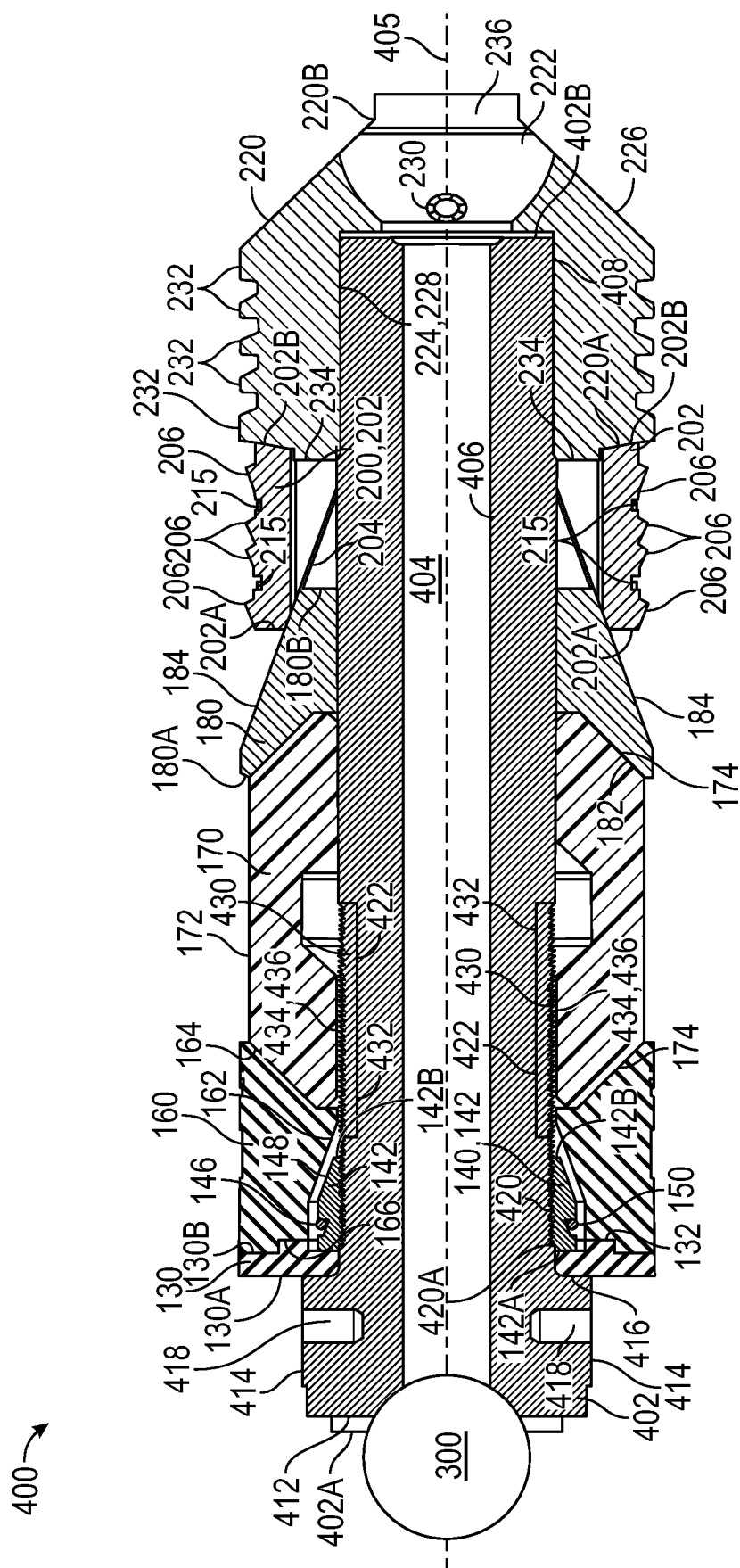


FIG. 14

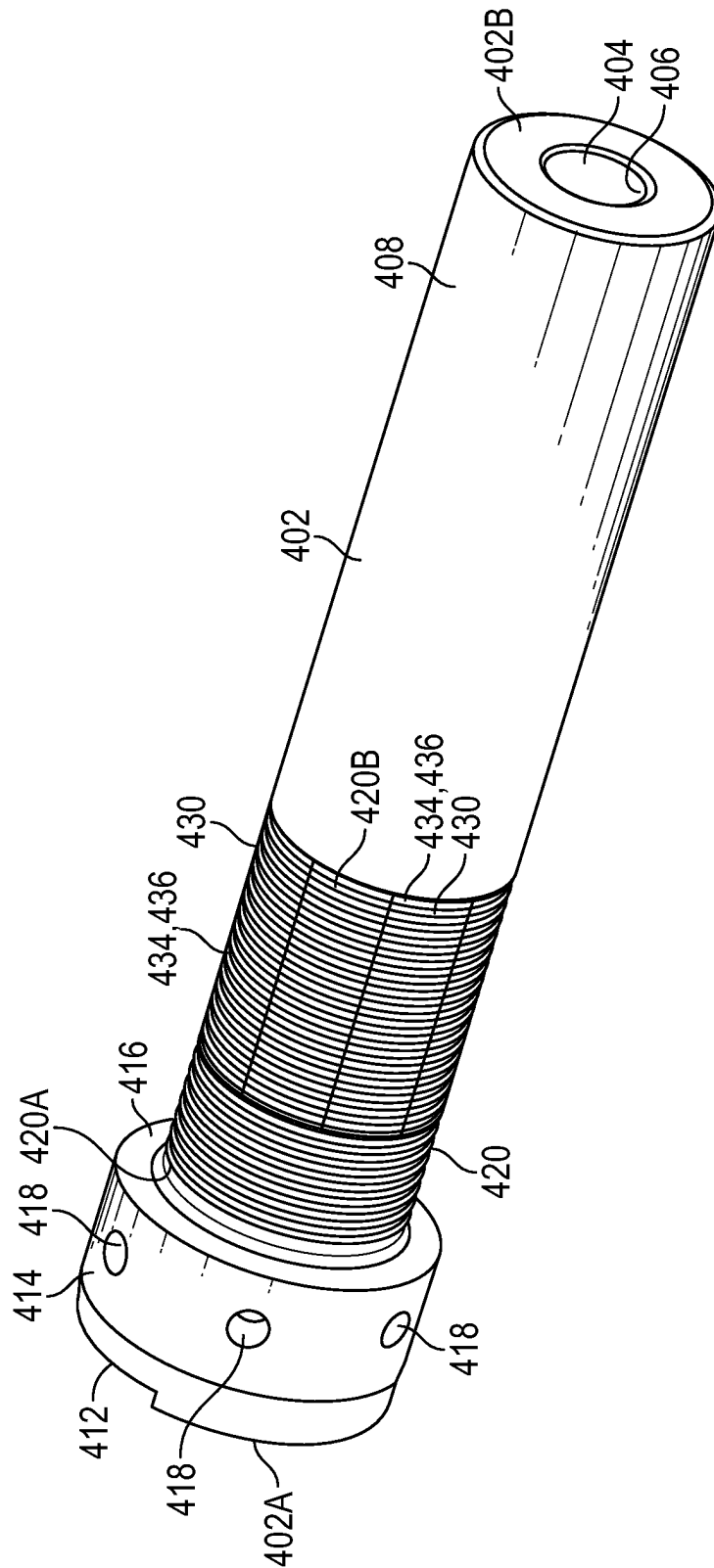


FIG. 15

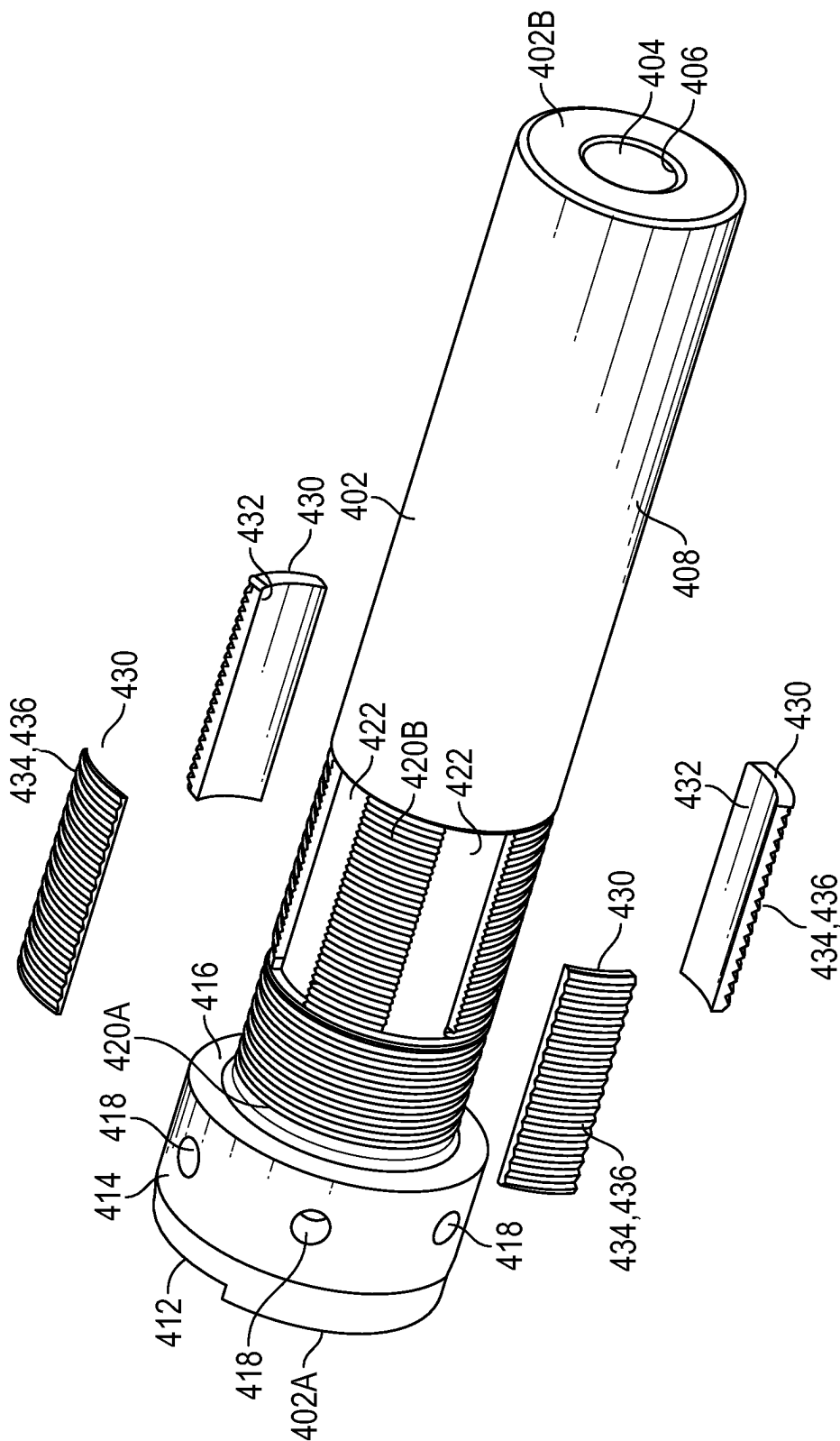


FIG. 16

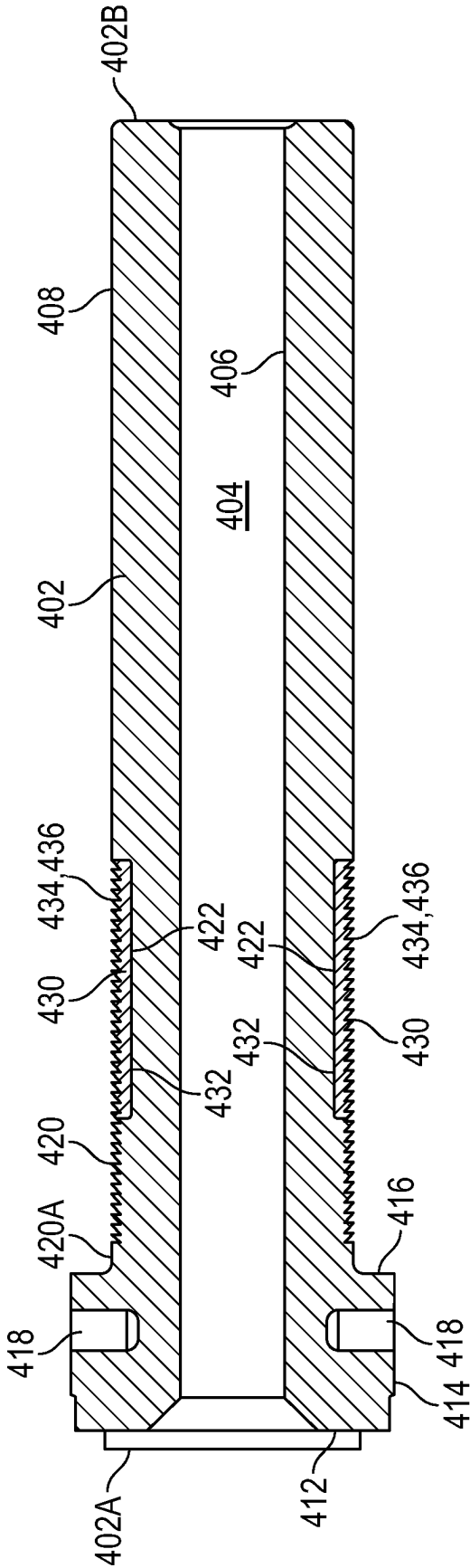


FIG. 17

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SYSTEMS AND METHODS FOR SEALING A WELLBORE**CROSS-REFERENCE TO RELATED APPLICATIONS**

The present application is a continuation of U.S. non-provisional patent application Ser. No. 17/484,260 filed Sep. 24, 2021, entitled "Systems and Methods for Sealing a Wellbore", which is a continuation of U.S. non-provisional patent application Ser. No. 16/152,184 filed Oct. 4, 2018, entitled "Systems and Methods for Sealing a Wellbore", now U.S. Pat. No. 11,131,163 issued Sep. 28, 2021, which claims benefit of U.S. provisional patent application No. 62/569,447 filed Oct. 6, 2017, entitled "Downhole Plug," and U.S. provisional patent application No. 62/734,803 filed Sep. 21, 2018, entitled "Downhole Plug," all of which are hereby incorporated herein by reference in their entirety.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

Not applicable.

BACKGROUND

After a wellbore has been drilled through a subterranean formation, the wellbore may be cased by inserting lengths of pipe ("casing sections") connected end-to-end into the wellbore. Threaded exterior connectors known as casing collars may be used to connect adjacent ends of the casing sections at casing joints, providing a casing string including casing sections and connecting casing collars that extends from the surface towards the bottom of the wellbore. The casing string may then be cemented into place to secure the casing string within the wellbore.

In some applications, following the casing of the wellbore, a wireline tool string may be run into the wellbore as part of a "plug-n-perf" hydraulic fracturing operation. The wireline tool string may include a perforating gun for perforating the casing string at a desired location in the wellbore, a downhole plug that may be set to couple with the casing string at a desired location in the wellbore, and a setting tool for setting the downhole plug. In certain applications, once the casing string has been perforated by the perforating gun and the downhole plug has been set, a ball or dart may be pumped into the wellbore for landing against the set downhole plug, thereby isolating the portion of the wellbore extending uphole from the set downhole plug. With this uphole portion of the wellbore isolated, the formation extending about the perforated section of the casing string may be hydraulically fractured by fracturing fluid pumped into the wellbore.

SUMMARY OF THE DISCLOSURE

An embodiment of a plug for sealing a wellbore comprises a mandrel extending between an uphole end defining an uphole end of the plug, and a downhole end opposite the uphole end of the mandrel, a slip assembly extending around the mandrel and comprising a plurality of arcuate slip segments, a nose coupled to the downhole end of the mandrel and defining a downhole end of the plug, wherein the nose comprises an uphole end coupled to the downhole end of the mandrel and a downhole end opposite the uphole end of the nose and defining a downhole end of the plug, and a packer extending around the mandrel and comprising a

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first configuration configured to permit fluid flow across the plug when the plug is received in the wellbore, and a second configuration configured to seal the wellbore when the plug is positioned in the wellbore, wherein one of the downhole end of the nose and the uphole end of the mandrel comprises a plurality of axially extending protrusions circumferentially spaced about a central axis of the plug, wherein the other of the downhole end of the nose and the uphole end of the mandrel comprises which does not comprise the plurality of protrusions comprises a plurality of axially extending recesses circumferentially spaced about the central axis of the plug. In some embodiments, the plurality of protrusions are each arcuate in shape, and wherein the plurality of recesses are each arcuate in shape. In some embodiments, the plurality of protrusions and the plurality of recesses are positioned along a common diameter extending around the central axis of the plug. In certain embodiments, one of the uphole end of the nose and a downhole end of the slip assembly comprises a plurality of notches circumferentially spaced about the central axis of the plug while the other of the uphole end of the nose and the downhole end of the slip assembly comprises a plurality of pockets circumferentially spaced about the central axis of the plug and configured to interlockingly receive the plurality of notches to restrict relative rotation between the nose and the slip assembly. In certain embodiments, relative rotation about the central axis of the plug is restricted between the nose and the packer.

An embodiment of a system for completing a wellbore comprises a first plug, comprising a first mandrel extending between an uphole end defining an uphole end of the first plug, and a downhole end opposite the uphole end of the first mandrel, a first slip assembly extending around the first mandrel and comprising a plurality of arcuate first slip segments, a first nose coupled to the downhole end of the first mandrel and defining a downhole end of the first plug, wherein the first nose comprises an uphole end coupled to the downhole end of the first mandrel and a downhole end opposite the uphole end of the first nose and defining a downhole end of the first plug, and a first packer extending around the first mandrel and comprising a first configuration configured to permit fluid flow across the first plug when the first plug is received in the wellbore, and a second configuration configured to seal the wellbore when the first plug is positioned in the wellbore. In addition, the system comprises a second plug, comprising a second mandrel extending between an uphole end defining an uphole end of the second plug, and a downhole end opposite the uphole end of the second mandrel, a second slip assembly extending around the second mandrel and comprising a plurality of arcuate second slip segments, a second nose coupled to the downhole end of the second mandrel and defining a downhole end of the second plug, wherein the second nose comprises an uphole end coupled to the downhole end of the second mandrel and a downhole end opposite the uphole end of the second nose and defining a downhole end of the second plug, and a second packer extending around the second mandrel and comprising a first configuration configured to permit fluid flow across the second plug when the second plug is received in the wellbore, and a second configuration configured to seal the wellbore when the second plug is positioned in the wellbore, wherein one of the downhole end of the second nose and the uphole end of the first mandrel comprises a plurality of axially extending notches circumferentially spaced about a central axis of the plug, and wherein the other of the downhole end of the second nose and the uphole end of the first mandrel comprises which does not comprise the plurality of notches comprises a

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plurality of axially extending recesses circumferentially spaced about the central axis of the plug configured to interlockingly receive the plurality of notches to restrict relative rotation between the second nose and the first mandrel. In some embodiments, the plurality of notches are each arcuate in shape, and wherein the plurality of recesses are each arcuate in shape. In some embodiments, the plurality of notches and the plurality of recesses are positioned along a common diameter extending around the central axis of the plug. In certain embodiments, one of the uphole end of the first nose and a downhole end of the first slip assembly comprises a plurality of notches circumferentially spaced about the central axis of the first plug while the other of the uphole end of the first nose and the downhole end of the first slip assembly comprises a plurality of pockets circumferentially spaced about the central axis of the first plug and configured to interlockingly receive the plurality of notches to restrict relative rotation between the first nose and the first slip assembly. In certain embodiments, relative rotation about the central axis of the first plug is restricted between the first nose and the first packer.

An embodiment of a method for completing a wellbore comprises (a) positioning a first plug at a first location within the wellbore, (b) setting the first plug to lock the first plug at the first location to a casing string extending through wellbore and to seal the wellbore at the first location, (c) positioning a second plug at a second location within the wellbore that is uphole from the first location, (d) setting the second plug to lock the second plug at the second location to the casing string and to seal the wellbore at the second location, (e) releasing a nose of the second plug from the casing string permitting the nose of the second plug to travel through the wellbore, wherein a downhole end of the nose defines a downhole end of the second plug, and (f) interlocking the downhole end of nose of the second plug with an uphole end of a mandrel of the first plug to restrict relative rotation between the nose of the second plug and the mandrel of the first plug. In some embodiments, (e) comprises drilling into an uphole end of the second plug with a drill positioned in the wellbore to release the nose of the second plug from a slip assembly of the second plug. In some embodiments, (f) comprises interlockingly receiving a plurality of circumferentially spaced protrusions of one of the nose of the second plug and the mandrel of the first plug in a plurality of circumferentially spaced recesses of the other of the nose of the second plug and the mandrel of the first plug. In certain embodiments, the plurality of protrusions are each arcuate in shape, and wherein the plurality of recesses are each arcuate in shape. In certain embodiments, the plurality of protrusions and the plurality of recesses are positioned along a common diameter extending around a central axis of the plug. In some embodiments, the method further comprises (g) pumping the nose of the second plug through the wellbore following (e) whereby the downhole end of the nose lands against the uphole end of the mandrel of the first plug. In some embodiments, the method further comprises (g) pumping a fracturing fluid through the wellbore following (d) to form one or more fractures in an earthen subterranean formation through which the wellbore extends at one or more locations located along the wellbore uphole from the second location. In certain embodiments, the method further comprises (g) pumping a fracturing fluid through the wellbore following (b) to form one or more fractures in an earthen subterranean formation through which the wellbore extends at one or more locations located along the wellbore between the first location and the second location. In certain embodiments, the method further com-

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prises (g) drilling into an uphole end of the nose of the second plug following (f) with a drill positioned in the wellbore while the nose is interlocked with the mandrel of the first plug. In some embodiments, the method further comprises (h) releasing a nose of the first plug from the casing string following (g) to permit the nose of the first plug to travel through the wellbore.

BRIEF DESCRIPTION OF THE DRAWINGS

For a detailed description of exemplary embodiments of the disclosure, reference will now be made to the accompanying drawings in which:

FIG. 1 is a schematic, partial cross-sectional view of a system for completing a subterranean well including an embodiment of a downhole plug in accordance with the principles disclosed herein;

FIG. 2 is a side view of the downhole plug of FIG. 1;

FIG. 3 is a front view of the downhole plug of FIG. 1;

FIG. 4 is a rear view of the downhole plug of FIG. 1;

FIG. 5 is an exploded side view of the downhole plug of FIG. 1;

FIGS. 6 and 7 are exploded perspective views of the downhole plug of FIG. 1;

FIG. 8 is side cross-sectional view of the downhole plug of FIG. 1 in a run-in position in accordance with principles disclosed herein;

FIG. 9 is a rear view of an embodiment of an engagement disk of the downhole plug of FIG. 1 in accordance with principles disclosed herein;

FIG. 10 is a front view of an embodiment of a clamping member of the downhole plug of FIG. 1 in accordance with principles disclosed herein;

FIG. 11 is a rear view of an embodiment of a slip assembly of the downhole plug of FIG. 1 in accordance with principles disclosed herein;

FIG. 12 is a perspective view of an embodiment of a nose cone of the downhole plug of FIG. 1 in accordance with principles disclosed herein;

FIG. 13 is side cross-sectional view of the downhole plug of FIG. 1 in a set position in accordance with principles disclosed herein;

FIG. 14 is a perspective view of another embodiment of a downhole plug in accordance with the principles disclosed herein;

FIG. 15 is a perspective view of an embodiment of a mandrel of the downhole plug 14 in accordance with the principles disclosed herein;

FIG. 16 is an exploded perspective view of the mandrel of FIG. 15; and

FIG. 17 is a side cross-sectional view of the mandrel of FIG. 15.

DETAILED DESCRIPTION

The following discussion is directed to various exemplary embodiments. However, one skilled in the art will understand that the examples disclosed herein have broad application, and that the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment. Certain terms are used throughout the following description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names. This document does not intend to distinguish between components or fea-

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tures that differ in name but not function. The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

In the following discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to” Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be through a direct connection, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a central axis (e.g., central axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the central axis. For instance, an axial distance refers to a distance measured along or parallel to the central axis, and a radial distance means a distance measured perpendicular to the central axis. Any reference to up or down in the description and the claims is made for purposes of clarity, with “up”, “upper”, “upwardly”, “uphole”, or “upstream” meaning toward the surface of the borehole and with “down”, “lower”, “downwardly”, “downhole”, or “downstream” meaning toward the terminal end of the borehole, regardless of the borehole orientation. Further, the term “fluid,” as used herein, is intended to encompass both fluids and gasses.

Referring now to FIG. 1, a system 10 for completing a wellbore 4 extending into a subterranean formation 6 is shown. In the embodiment of FIG. 1, wellbore 4 is a cased wellbore including a casing string 12 secured to an inner surface 8 of the wellbore 4 using cement (not shown). In some embodiments, casing string 12 generally includes a plurality of tubular segments coupled together via a plurality of casing collars. In this embodiment, completion system 10 includes a tool string 20 disposed within wellbore 4 and suspended from a wireline 22 that extends to the surface of wellbore 4. Wireline 22 comprises an armored cable and includes at least one electrical conductor for transmitting power and electrical signals between tool string 20 and the surface. System 10 may further include suitable surface equipment for drilling, completing, and/or operating completion system 10 and may include, in some embodiments, derricks, structures, pumps, electrical/mechanical well control components, etc. Tool string 20 is generally configured to perforate casing string 12 to provide for fluid communication between formation 6 and wellbore 4 at predetermined locations to allow for the subsequent hydraulic fracturing of formation 6 at the predetermined locations.

In this embodiment, tool string 20 generally includes a cable head 24, a casing collar locator (CCL) 26, a direct connect sub 28, a plurality of perforating guns 30, a switch sub 32, a plug-shoot firing head 34, a setting tool 36, and a downhole or frac plug 100 (shown schematically in FIG. 1). Cable head 24 is the uppermost component of tool string 20 and includes an electrical connector for providing electrical signal and power communication between the wireline 22 and the other components (CCL 26, perforating guns 30, setting tool 36, etc.) of tool string 20. CCL 26 is coupled to a lower end of the cable head 24 and is generally configured to transmit an electrical signal to the surface via wireline 22 when CCL 26 passes through a casing collar, where the transmitted signal may be recorded at the surface as a collar kick to determine the position of tool string 20 within

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wellbore 4 by correlating the recorded collar kick with an open hole log. The direct connect sub 28 is coupled to a lower end of CCL 26 and is generally configured to provide a connection between the CCL 26 and the portion of tool string 20 including the perforating guns 30 and associated tools, such as the setting tool 36 and downhole plug 100.

Perforating guns 30 of tool string 20 are coupled to direct connect sub 28 and are generally configured to perforate casing string 12 and provide for fluid communication between formation 6 and wellbore 4. Particularly, perforating guns 30 include a plurality of shaped charges that may be detonated by a signal conveyed by the wireline 22 to produce an explosive jet directed against casing string 12. Perforating guns 30 may be any suitable perforation gun known in the art while still complying with the principles disclosed herein. For example, in some embodiments, perforating guns 30 may comprise a hollow steel carrier (HSC) type perforating gun, a scalloped perforating gun, or a retrievable tubing gun (RTG) type perforating gun. In addition, gun 30 may comprise a wide variety of sizes such as, for example, 2¼", 3⅛", or 3½", wherein the above listed size designations correspond to an outer diameter of perforating guns 30.

Switch sub 32 of tool string 20 is coupled between the pair of perforating guns 30 and includes an electrical conductor and switch generally configured to allow for the passage of an electrical signal to the lowermost perforating gun 30 of tool string 20. Tool string 20 further includes plug-shoot firing head 34 coupled to a lower end of the lowermost perforating gun 30. Plug-shoot firing head 34 couples the perforating guns of the tool string 20 to the setting tool 36 and downhole plug 100, and is generally configured to pass a signal from the wireline 22 to the setting tool 36 of tool string 20. Plug-shoot firing head 34 may also include mechanical and/or electrical components to fire the setting tool 36.

In this embodiment, tool string 20 further includes setting tool 36 and downhole plug 100, where setting tool 36 is coupled to a lower end of plug-shoot firing head 34 and is generally configured to set or install downhole plug 100 within casing string 12 to isolate desired segments of the wellbore 4. As will be discussed further herein, once downhole plug 100 has been set by setting tool 36, an outer surface of downhole plug 100 seals against an inner surface of casing string 12 to restrict fluid communication through wellbore 4 across downhole plug 100. Setting tool 36 of tool string 20 may be any suitable setting tool known in the art while still complying with the principles disclosed herein. For example, in some embodiments, tool 34 may comprise a #10 or #20 Baker style setting tool. In addition, setting tool 36 may comprise a wide variety of sizes such as, for example, 1.68 in., 2.125 in., 2.75 in., 3.5 in., 3.625 in., or 4 in., wherein the above listed sizes correspond to the overall outer diameter of the tool. Additionally, although downhole plug 100 is shown in FIG. 1 as incorporated in tool string 20, downhole plug 100 may be used in other tool strings comprising components differing from the components comprising tool string 20.

Referring to FIGS. 1-13, an embodiment of the downhole plug 100 of the tool string 20 of FIG. 1 is shown in FIGS. 2-13. In the embodiment of FIGS. 2-13, downhole plug 100 has a central or longitudinal axis 105 and generally includes a mandrel 102, an engagement disk 130, a body lock ring assembly 140, a first clamping member 160, an elastomeric member or packer 170, a second clamping member 180, a slip assembly 200, and a nose cone 220.

In this embodiment, mandrel **102** of downhole plug **100** has a first end **102A**, a second end **102B**, a central bore or passage **104** defined by a generally cylindrical inner surface **106** extending between ends **102A**, **102B**, and a generally cylindrical outer surface **108** extending between ends **102A**, **102B**. The inner surface **106** of mandrel **102** includes a frustoconical seat **110** proximal first end **102A**. As will be discussed further herein, following the setting of downhole plug **100**, a ball or dart **300** may be pumped into wellbore **4** for seating against seat **110** such that fluid flow through central bore **104** of mandrel **102** is restricted. In this embodiment, the first end **102A** of mandrel **102** includes a pair of circumferentially spaced arcuate slots or recesses **112**. Additionally, in this embodiment, the outer surface **108** of mandrel **102** includes an expanded diameter portion **114** at first end **102A** that forms an annular shoulder **116**. Expanded diameter portion **114** of outer surface **108** includes a plurality of circumferentially spaced apertures **118** configured to receive a plurality of connecting members for coupling mandrel **102** with setting tool **36**. Mandrel **102** includes a plurality of ratchet teeth **120** that extend along a portion of outer surface **108** proximal shoulder **116**. Further, in this embodiment, the outer surface **108** of mandrel **102** includes a connector **122** located proximal to second end **102B**.

Engagement disk **130** of downhole plug **100** is disposed about mandrel **102** and has a first end **130A** and a second end **130B**. In this embodiment, first end **130A** of engagement disk **130** comprises an annular engagement surface **130A** configured to engage a corresponding annular engagement surface of setting tool **36** for actuating downhole plug **100** from a first or run-in position shown in FIG. **8** to a second or set position shown in FIG. **13**, as will be discussed further herein. In the run-in position of downhole plug **100**, engagement surface **130A** of engagement disk **130** is disposed directly adjacent or contacts shoulder **116** of mandrel **102**. In this embodiment, the second end **130B** of engagement disk **130** includes an anti-rotation hexagonal shoulder or protrusion **132** extending axially therefrom.

In this embodiment, the body lock ring assembly **140** of downhole plug **100** comprises a plurality of circumferentially spaced arcuate lock ring segments **142** disposed about mandrel **102**, and an annular lock ring retainer **150** disposed about lock ring segments **142**. Each lock ring segment **142** includes a first end **142A**, a second end **142B**, and an arcuate inner surface extending between ends **142A**, **142B** that comprises a plurality of ratchet teeth **144**. Ratchet teeth **144** matingly engage the ratchet teeth **120** of mandrel **102** to restrict relative axial movement between lock ring segments **142** and mandrel **102**. Particularly, the mating engagement between ratchet teeth **144** of lock ring segments **142** and ratchet teeth **120** of mandrel **102** prevent lock ring segments **142** from travelling axially towards the first end **102A** of mandrel **102**, but permits lock ring segments **142** to travel axially towards the second end **102B** of mandrel **102**. Additionally, each lock ring segment **142** includes an outer surface extending between ends **142A**, **142B**, that comprises an arcuate groove **146** disposed proximate first end **142A** and a generally frustoconical surface **148** extending from second end **142B**. Lock ring retainer **150** retains lock ring segments **142** in position about mandrel **102** such that segments **142** do not move axially relative to each other.

First clamping member **160** of downhole plug **100** is generally annular and is disposed about mandrel **102** between engagement disk **130** and packer **170**. In this embodiment, first clamping member **160** has a first end **160A**, a second end **160B**, and a generally cylindrical inner surface extending between ends **160A**, **160B** that includes a

first frustoconical surface **162** located proximal first end **160A** and a second frustoconical surface **164** extending from second end **160B**. Additionally, in this embodiment, first clamping member **160** includes a hexagonal recess **166** that extends axially into the first end **160A** of first clamping member **160**. Hexagonal recess **166** of first clamping member **160** is configured to matingly receive the hexagonal shoulder **132** of engagement disk **130** to thereby restrict relative rotation between first clamping member **160** and engagement disk **130**. Although in this embodiment hexagonal shoulder **132** of engagement disk **130** and hexagonal recess **166** of first clamping member **160** are each six-sided in shape, in other embodiments, shoulder **132** and recess **166** may comprise varying number of sides. Additionally, as will be described further herein, the first frustoconical surface **162** of first clamping member **160** is configured to matingly engage the frustoconical surface **148** of each lock ring segment **142** when downhole plug **100** is set in wellbore **4**. Although in this embodiment engagement disk **130** comprises shoulder **132** and first clamping member **160** comprises recess **166**, in other embodiments, first clamping member **160** may comprise a hexagonal shoulder or protrusion while engagement disk **130** comprises a corresponding hexagonal recess configured to receive the shoulder of the first clamping member **160** to restrict relative rotation between engagement disk **130** and first clamping member **160**.

Packer **170** of downhole plug **100** is generally annular and disposed about mandrel **102** between first clamping member **160** and second clamping member **180**. Packer **170** comprises an elastomeric material and is configured to sealingly engage an inner surface **14** of casing string **12** when downhole plug **100** is set, as shown particularly in FIG. **13**. In this embodiment, packer **170** comprises a generally cylindrical outer surface **172** extending between first and second ends of packer **170**. Outer surface **172** of packer **170** includes a pair of frustoconical surfaces **174** extending from each end of packer **170**.

Second clamping member **180** of downhole plug **100** is generally annular and is disposed about mandrel **102** between packer **170** and slip assembly **200**. In this embodiment, second clamping member **180** has a first end **180A**, a second end **180B**, and a generally cylindrical inner surface extending between ends **180A**, **180B** that includes an inner frustoconical surface **182** extending from first end **180A**. Additionally, second clamping member **180** includes a generally cylindrical outer surface extending between ends **180A**, **180B** that includes a plurality of circumferentially spaced planar (e.g., flat) surfaces **184** extending from second end **180B**. Each planar surface **184** extends at an angle relative to the central axis **105** of downhole plug **100**. In some embodiments, friction resulting from contact between the elastomeric material comprising packer **170** and frustoconical surfaces **164** and **182** of clamping members **160**, **180**, respectively, assists in preventing relative rotation between packer **170** and clamping members **160**, **180**.

Slip assembly **200** is generally configured to engage or "bite into" the inner surface **14** of casing string **12** when downhole plug **100** is actuated into the set position to couple or affix downhole plug **100** to casing string **12**, thereby restricting relative axial movement between downhole plug **100** and casing string **12**. In this embodiment, slip assembly **200** comprises a plurality of circumferentially spaced arcuate slip segments **202** disposed about mandrel **102**, and a pair of axially spaced annular retainers **215** each disposed about the slip segments **202**. In this embodiment, each slip segment **202** includes a first end **202A**, a second end **202B**,

and an arcuate inner surface extending between ends 202A, 202B that includes a planar (e.g., flat) surface 204 extending from first end 202A. The planar surface 204 of each slip segment 202 extends at an angle relative to central axis 105 of downhole plug 100 and is configured to matingly engage one of the planar surfaces 184 of second clamping member 180.

The planar (e.g., flat) interface formed between each corresponding planar surface 184 of clamping member 180 and each planar surface 204 of slip segments 202 restricts relative rotation between second clamping member 180 and slip segments 202. Additionally, as will be described further herein, relative axial movement between second clamping member 180 and slip assembly 200 is configured to force slip segments 202 radially outwards, snapping retainers 215, via the angled or cammed sliding contact between planar surfaces 184 of second clamping member 180 and the planar surfaces 204 of slip segments 202. In this embodiment, retainers 215 each comprise a filament wound band; however, in other embodiments, retainers 215 may comprise various materials and may be formed in varying ways.

In this embodiment, each retainer ring 202 includes a generally arcuate outer surface extending between ends 202A, 202B that includes a plurality of engagement members 206. Engagement members 206 are configured to engage or bite into the inner surface 14 of casing string 12 when downhole plug 100 is actuated into the set position to thereby affix downhole plug 100 to casing string 12 at a desired or predetermined location. Thus, engagement members 206 comprise a suitable material for engaging with inner surface 14 of casing string 12 during operations. For example, engagement members 206 may comprise 8620 Chrome-Nickel-Molybdenum alloy, carbon steel, tungsten carbide, cast iron, and/or tool steel. In some embodiments, engagement members 206 may comprise a composite material. Additionally, in this embodiment, each slip segment 202 of slip assembly 200 includes a pocket or receptacle 208 located at the second end 202B which extends into the inner surface of the slip segment 202.

Nose cone 220 of downhole plug 100 is generally annular and is disposed about the second end 102B of mandrel 102. Nose cone 220 has a first end 220A, a second end 220B, a central bore or passage 222 defined by a generally cylindrical inner surface 224 extending between ends 220A, 220B, and a generally cylindrical outer surface 226 extending between ends 220A, 220B. In this embodiment, the inner surface 224 of nose cone 200 includes a connector 228 that releasably or threadably couples with the connector 122 of mandrel 102 to restrict relative axial movement between mandrel 102 and nose cone 220. Additionally, in this embodiment, nose cone 220 includes a plurality of circumferentially spaced protrusions or notches 230 extending from inner surface 224. As will be discussed further herein, protrusions 230 prevent ball 300 from seating and sealing against inner surface 224. Thus, in the event that ball 300 lands against inner surface 224 of nose cone 220, protrusions 230 will contact ball 300 to maintain fluid communication between passage 222 of nose cone 220 and passage 104 of mandrel 102.

In this embodiment, the outer surface 226 of nose cone 220 includes a plurality of axially spaced annular fins 232. Fins 232 increase the surface area of outer surface 226 to facilitate the creation of turbulent fluid flow around fins 232 when downhole plug 100 is pumped through wellbore 4 along with the other components of tool string 20. The turbulent fluid flow created by fins 232 increases the pressure differential in wellbore 4 between the uphole and

downhole ends of downhole plug 100, thereby reducing the amount of fluid in wellbore 4 that flows around downhole plug 100 as downhole plug 100 is pumped through wellbore 4. The reduction in fluid that flows around downhole plug 100 reduces the total volume of fluid required to pump tool string into the desired or predetermined position in wellbore 4, thereby reducing the cost of completing wellbore 4.

In this embodiment, nose cone 220 includes a plurality of circumferentially spaced protrusions or notches 234 extending axially from first end 220A of nose cone 220. Protrusions 234 of nose cone 220 are matingly received in pockets 208 of slip segments 202 to form an interlocking engagement between nose cone 220 and the slip segments 202 of slip assembly 200. The interlocking engagement formed between protrusions 234 of nose cone 220 and pockets 208 of slip segments 202 restrict relative rotation between slip segments 202 and nose cone 220. Additionally, the interlocking engagement between protrusions 234 and pockets 208 spaces slip segments equidistantly relative to each other about central axis 105 of downhole plug 100. Equidistant circumferential spacing of slip segments 202 ensures generally uniform contact and coupling between slip assembly 200 and the inner surface 14 of casing string 12 about the entire circumference of downhole plug 100. Further, in this embodiment, nose cone 220 includes a pair of circumferentially spaced arcuate clutching members or protrusions 236 that extend axially from second end 220B of nose cone 220. As will be discussed further herein, protrusions 236 of the nose cone 220 of downhole plug 100 are configured to be matingly received in the slots 112 of an adjacent downhole plug 100 disposed farther downhole in wellbore 4 to prevent relative rotation between the two downhole plugs 100 (FIGS. 5-7 illustrate an adjacently disposed nose cone 220 for clarity).

Downhole plug 100 includes multiple components comprising nonmetallic materials. Particularly, in this embodiment, engagement disk 130, first clamping member 170, and nose cone 220 are each molded from nonmetallic materials. In some embodiments, engagement disk 130, first clamping member 170, and nose cone 220 are injection or compression molded from various high performance resins. By forming engagement disk 130, first clamping member 170, and nose cone 220 using nonmetallic materials, components 130, 170, and 220 may include features including complex or irregular geometries that are easily and conveniently formed using a molding process. For instance, protrusions 230 and fins 232 of nose cone 220 are conveniently formed using a molding process whereas such features may be relatively difficult to form using a machining process.

As described above, downhole plug 100 is pumped downhole through wellbore 4 along with the other components of tool string 20. As tool string 20 is pumped through wellbore 4, the position of tool string 20 in wellbore 4 is monitored at the surface via signals generated from CCL 26 and transmitted to the surface using wireline 22. Once tool string 20 is disposed in a desired location in wellbore 4, one or more of perforating guns 30 may be fired to perforate casing 12 at the desired location and setting tool 36 may be fired or actuated to actuate downhole plug 100 from the run-in position shown in FIG. 8 to the set position shown in FIG. 13.

Particularly, setting tool 36 includes an inner member or mandrel (not shown) that moves axially relative to an outer member or housing of setting tool 36 upon the actuation of tool 36. The mandrel of setting tool 36 is coupled to mandrel 102 of downhole plug 100 such that the movement of the mandrel of setting tool 36 pulls mandrel 102 uphole (e.g.,

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towards setting tool 36). Additionally, the outer member of setting tool 36 contacts engagement surface 130A of engagement disk 130 to prevent disk 130, clamping members 160, 180, packer 170, and slip assembly 200 from travelling in concert with mandrel 102, thereby providing relative axial movement between mandrel 102 and disk 130, clamping members 160, 180, packer 170, and slip assembly 200.

As mandrel 102 travels uphole towards setting tool 36, the first end 220A of nose cone 220 and the second end 130B of engagement disk 130 apply an axially compressive force against clamping members 160, 180, packer 170, and slip assembly 200. In response to the application of the compressive force, slip segments 202 are forced radially outward towards casing string 12 as planar surfaces 184 of second clamping member 180 slide along the planar surfaces 204 of slip segments 202, snapping retainers 215. Slip segments 202 continue to travel radially outwards until engagement members 206 contact and couple to the inner surface 14 of casing string 12, locking downhole plug 100 to casing string 12 at the desired location in wellbore 4. Additionally, each end of packer 170 is compressed via contact between frustoconical surfaces 174 of packer 170 and frustoconical surfaces 164, 182 of clamping members 160, 180, respectively. The axially directed compressive force applied to packer 170 forces the outer surface 172 of packer 170 into sealing engagement with the inner surface 14 of casing string 12. With outer surface 172 of packer 170 sealing against the inner surface 14 of casing string 12, the only fluid flow permitted between the uphole and downhole ends of downhole plug 100 is permitted via passage 104 of mandrel 102.

Following the coupling of slip segments 202 with casing string 12 and the sealing of packer 170 against casing string 12 (shown in FIG. 13), setting tool 36 may be disconnected from downhole plug 100, allowing setting tool 36 and the other components of tool string 20 to be retrieved to the surface of wellbore 4, with downhole plug 100 remaining at the desired location in wellbore 4. Once setting tool 36 is released from downhole plug 100, contact between frustoconical surface 162 of first clamping member 160 and the frustoconical surfaces 148 of lock ring segments 142 applies an axial and radially inwards force against each lock ring segment 142. However, engagement between ratchet teeth 144 of lock ring segments 142 and ratchet teeth 120 of mandrel 102 prevent lock ring segments 142 from moving axially uphole relative to mandrel 102. With lock ring segments 142 prevented from travelling uphole in the direction of the upper end 102A of mandrel 102, downhole plug 100 is held in the set position shown in FIG. 13. Additionally, with lock ring assembly 140 comprising a plurality of arcuate lock ring segments 142, instead of a single lock ring (e.g., a C-ring), the radially inwards directed force applied by the frustoconical surface 162 of first clamping member 160 is evenly applied against each lock ring segment 142. The relatively even distribution of the radially inwards to each lock ring segment 142 assists in securing downhole plug 100 in the set position.

After tool string 20 has been retrieved from the wellbore 4, ball 300 may be pumped into and through wellbore 4 until ball 300 lands against seat 110 of mandrel 102. With ball 300 seated on seat 110 of mandrel 102, fluid flow through passage 104 of mandrel 102 is restricted which, in conjunction with the seal formed by packer 170 against the inner surface 14 of casing string 12, seals the portion of wellbore 4 extending downhole from downhole plug 100 from the surface. Thus, additional fluid pumped into wellbore 4 from the surface is then directed through the perforations previ-

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ously formed in casing string 12 by one or more of the perforating guns 30, thereby hydraulically fracturing the formation 6 at the desired location in wellbore 4.

In some embodiments, the hydraulic fracturing process described above is repeated a plurality of times at a plurality of desired locations in wellbore 4 moving towards the surface of wellbore 4. After the formation 6 has been hydraulically fractured at each desired location in wellbore 4, a tool may be deployed in wellbore 4 to drill out each downhole plug 100 disposed therein to allow fluids in formation 6 to flow to the surface via wellbore 4. With conventional downhole plugs, issues may arise during this drilling process if relative rotation is permitted either between components of each plug, or between separate plugs as the drill proceeds to drill out each conventional plug disposed in the borehole. However, in this embodiment, downhole plug 100 includes anti-rotation features configured to prevent, or at least inhibit, relative rotation between components thereof and between separate downhole plugs 100 disposed in wellbore 4. Particularly, as described above: hexagonal shoulder 132 and hexagonal recess 166 of engagement disk 130 and first clamping member 160, respectively, restrict relative rotation therebetween; frictional engagement between packer 170 and clamping members 160, 180 restrict or inhibit relative rotation therebetween; planar engagement between planar surfaces 184 of second clamping member 180 and planar surfaces 204 of slip segments 202 restrict relative rotation therebetween; pockets 208 of slip segments 202 and protrusions 234 of nose cone 220 restrict relative rotation therebetween; and engagement between notches 236 of the nose cone 220 of an uphole-positioned downhole plug 100 and slots 112 of the mandrel 102 of a downhole-positioned downhole plug 100 restrict relative rotation between the uphole and downhole positioned downhole plugs 100. Although in this embodiment nose cone 220 comprises notches 236 and mandrel 102 comprises slots 112, in other embodiments, mandrel 102 of a first downhole plug 100 may comprise notches or protrusions while a nose cone 220 of a second downhole plug 100 comprises corresponding slots or recesses configured to receive the notches of the mandrel 102 of the first downhole plug 100. Additionally, although in this embodiment nose cone 220 comprises notches 234 and slip segments 202 comprise pockets 208, in other embodiments, slip segments 202 may include notches or protrusions while nose cone 220 comprises corresponding pockets or recesses configured to receive the notches of slip segments 202.

Referring to FIGS. 14-17, another embodiment of a downhole plug 400 for use with the tool string 20 of FIG. 1 (in lieu of the downhole plug 100 shown in FIGS. 2-13) is shown in FIGS. 14-17. In the embodiment of FIGS. 14-17, downhole plug 400 has a central or longitudinal axis 405 and includes features in common with the downhole plug 100 shown in FIGS. 2-13, and shared features are labeled similarly. Particularly, downhole plug 400 is similar to downhole plug 100 except that downhole plug 400 includes a mandrel 402 that receives a plurality of circumferentially spaced arcuate inserts 430, as will be described further herein.

In this embodiment, mandrel 402 of downhole plug 400 has a first end 402A, a second end 402B, a central bore or passage 404 defined by a generally cylindrical inner surface 406 extending between ends 402A, 402B, and a generally cylindrical outer surface 408 extending between ends 402A, 402B. The inner surface 406 of mandrel 402 includes a frustoconical seat 410 proximal first end 402A. In this embodiment, the first end 402A of mandrel 402 includes a

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pair of circumferentially spaced arcuate slots or recesses 412. Additionally, in this embodiment, the outer surface 408 of mandrel 402 includes an expanded diameter portion 414 at first end 402A that forms an annular shoulder 416. Expanded diameter portion 414 of outer surface 408 includes a plurality of circumferentially spaced apertures 418 configured to receive a plurality of connecting members for coupling mandrel 102 with setting tool 36. Additionally, mandrel 402 includes a plurality of ratchet teeth 420 that extend along a portion of outer surface 408 proximal shoulder 416. In some embodiments, the outer surface 408 of mandrel 402 may include a connector located proximal to second end 402B for releasably or threadably coupling with the connector 228 of nose cone 200.

Unlike the mandrel 102 of the downhole plug 100 shown in FIGS. 2-13, the mandrel 402 of downhole plug 400 includes a plurality of circumferentially spaced, arcuate recesses 422 (shown in FIG. 16) formed in the outer surface 508 of mandrel 402 that axially overlap the ratchet teeth 420. As shown particularly in FIGS. 15 and 16, ratchet teeth 420 extend between a first end 420A and a second end 420B, where each arcuate recess 422 extends axially from the second end 420B of ratchet teeth 420 towards the first end 420A. Each arcuate recess 422 of mandrel 402 is configured to matingly receive one of the arcuate inserts 430, as shown particularly in FIG. 15. In this embodiment, mandrel 402 includes four circumferentially spaced arcuate recesses 422 that matingly receive four arcuate inserts 430; however, in other embodiments, the mandrel 402 of downhole plug 400 may include varying numbers of arcuate recesses 422 and corresponding arcuate inserts 430. In this embodiment, each arcuate insert 430 includes an arcuate inner surface 432 that matingly engages a corresponding arcuate recess 422 of mandrel 402, and an arcuate outer surface 434 that includes a plurality of arcuate ratchet teeth 436 formed thereon. When arcuate inserts 430 are matingly received in the arcuate recesses 422 of mandrel 402, the ratchet teeth 436 of each arcuate insert 430 axially aligns with the ratchet teeth 420 formed on the outer surface 408 of mandrel 402. In this embodiment, arcuate inserts 430 are each molded and comprise a nonmetallic material. In this embodiment, the inner surface 432 of each arcuate insert 430 is adhered or glued to one of the recesses 422 of mandrel 402; however, in other embodiments, other mechanisms may be employed for coupling arcuate inserts 430 with mandrel 402.

In this embodiment, arcuate inserts 430 are generally configured to provide additional shear strength so that ratchet teeth 420 are not inadvertently stripped or otherwise damaged during the operation of downhole plug 400. For instance, in some embodiments, mandrel 402 comprises fiber or filament wound tubing while arcuate inserts 430 each comprise a composite material; however, in other embodiments, the mandrel 402 and arcuate inserts 430 may comprise varying materials. The material from which mandrel 402 is formed may have a relatively high tensile strength to sustain the tensile loads applied to it by setting tool 36, but may be relatively weak in shear. Thus, arcuate inserts 430 may comprise a material that is relatively stronger in shear (e.g., a composite material) than the material of which mandrel 402 is comprised. In other words, in an embodiment, mandrel 402 comprises a first material having a first shear strength while each arcuate insert 430 comprises a second material having a second shear strength, where the second shear strength is greater than the first shear strength.

During the operation of downhole plug 400, shear loads may be transferred from ratchet teeth 142 of lock ring segments 140 to the relatively strong or shear resistant

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ratchet teeth 434 of arcuate inserts 430 which matingly engage ratchet teeth 142, thereby mitigating the risk of ratchet teeth 420 of mandrel 402 being sheared off or otherwise damaged by the shear loads transferred from ratchet teeth 142. In some embodiments, a majority of the shear loads transferred from ratchet teeth 142 of lock ring segments 140 may be applied against the ratchet teeth 436 of arcuate inserts 430.

While exemplary embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the disclosure presented herein. For example, the relative dimensions of various parts, the materials from which the various parts are made, and other parameters can be varied. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

What is claimed is:

1. A system for completing a wellbore, comprising:

a first plug, comprising:

a first mandrel extending between an uphole end defining an uphole end of the first plug, and a downhole end opposite the uphole end of the first mandrel;

a first slip assembly extending around the first mandrel and comprising a plurality of arcuate first slip segments for locking the first plug against a casing string positioned in the wellbore when the first plug is in a locked configuration;

a first nose coupled to the downhole end of the first mandrel and defining a downhole end of the first plug, wherein the first nose comprises an uphole end coupled to the downhole end of the first mandrel and a downhole end opposite the uphole end of the first nose and defining a downhole end of the first plug; and

a first packer extending around the first mandrel and comprising a first configuration configured to permit fluid flow across the first plug when the first plug is received in the wellbore, and a second configuration configured to seal the wellbore when the first plug is positioned in the wellbore;

a second plug, comprising:

a second mandrel extending between an uphole end defining an uphole end of the second plug, and a downhole end opposite the uphole end of the second mandrel;

a second slip assembly extending around the second mandrel and comprising a plurality of arcuate second slip segments for locking the second plug against the casing string when the second plug is in a locked configuration;

a second nose coupled to the downhole end of the second mandrel and defining a downhole end of the second plug, wherein the second nose comprises an uphole end coupled to the downhole end of the second mandrel and a downhole end opposite the

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- uphole end of the second nose and defining a downhole end of the second plug; and
- a second packer extending around the second mandrel and comprising a first configuration configured to permit fluid flow across the second plug when the second plug is received in the wellbore, and a second configuration configured to seal the wellbore when the second plug is positioned in the wellbore;
- wherein one of the downhole end of the second nose and the uphole end of the first mandrel comprises a plurality of axially extending notches circumferentially spaced about a central axis of the plug;
- wherein the other of the downhole end of the second nose and the uphole end of the first mandrel which does not comprise the plurality of notches comprises a plurality of axially extending recesses circumferentially spaced about the central axis of the plug configured to interlockingly receive the plurality of notches to restrict relative rotation between the second nose and the first mandrel; and
- wherein the second plug is drillable when in the locked configuration to release the second nose from the second slip assembly whereby the second nose is permitted to travel through the casing string and land against and interlock with the first mandrel of the first plug whereby relative rotation between the second nose and the first mandrel is restricted.
2. The system of claim 1, wherein the plurality of notches are each arcuate in shape, and wherein the plurality of recesses are each arcuate in shape.
3. The system of claim 1, wherein the plurality of notches and the plurality of recesses are positioned along a common diameter extending around the central axis of the plug.
4. The system of claim 1, wherein one of the uphole end of the first nose and a downhole end of the first slip assembly comprises a plurality of notches circumferentially spaced about the central axis of the first plug while the other of the uphole end of the first nose and the downhole end of the first slip assembly comprises a plurality of pockets circumferentially spaced about the central axis of the first plug and configured to interlockingly receive the plurality of notches to restrict relative rotation between the first nose and the first slip assembly.
5. The system of claim 1, wherein relative rotation about the central axis of the first plug is restricted between the first nose and the first packer.
6. The system of claim 1, wherein the plurality of notches defines a first set of castellations and the plurality of recesses define a second set of castellations interlockingly engageable with the first set of castellations.
7. A method for completing a wellbore, comprising:
- (a) positioning a first plug at a first location within the wellbore, wherein the first plug comprises a first slip assembly for locking the first plug against a casing string;
 - (b) setting the first plug to lock the first plug at the first location to the casing string extending through wellbore and to seal the wellbore at the first location;
 - (c) positioning a second plug at a second location within the wellbore that is uphole from the first location, wherein the second plug comprises a second slip assembly for locking the second plug against the casing string;
 - (d) setting the second plug to lock the second plug at the second location to the casing string and to seal the wellbore at the second location;

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- (e) releasing a nose of the second plug from the second slip assembly permitting the nose of the second plug to travel through the wellbore, wherein a downhole end of the nose defines a downhole end of the second plug; and
 - (f) interlocking the downhole end of nose of the second plug with an uphole end of a mandrel of the first plug to restrict relative rotation between the nose of the second plug and the mandrel of the first plug;
- wherein one of the downhole end of the nose of the second plug and the uphole end of the mandrel of the first plug comprises a plurality of axially extending and circumferentially spaced protrusions and the other of the downhole end of the nose of the second plug and the uphole end of the mandrel of the first plug which does not comprise the plurality of notches comprises a plurality of axially extending and circumferentially spaced recesses to interlockingly receive the plurality of notches to restrict relative rotation between the nose of the second plug and the mandrel of the first plug at (f).
8. The method of claim 7, wherein (e) comprises drilling into an uphole end of the second plug with a drill positioned in the wellbore to release the nose of the second plug from a slip assembly of the second plug.
9. The method of claim 7, wherein (f) comprises interlockingly receiving a plurality of circumferentially spaced protrusions of one of the nose of the second plug and the mandrel of the first plug in a plurality of circumferentially spaced recesses of the other of the nose of the second plug and the mandrel of the first plug, and wherein at least one of the plurality of circumferentially spaced protrusions and the plurality of the circumferentially spaced recesses comprise molded non-metallic materials.
10. The method of claim 9, wherein the plurality of protrusions are each arcuate in shape, and wherein the plurality of recesses are each arcuate in shape.
11. The method of claim 9, wherein the plurality of protrusions and the plurality of recesses are positioned along a common diameter extending around a central axis of the plug.
12. The method of claim 7, further comprising:
- (g) pumping the nose of the second plug through the wellbore following (e) whereby the downhole end of the nose lands against the uphole end of the mandrel of the first plug.
13. The method of claim 7, further comprising:
- (g) pumping a fracturing fluid through the wellbore following (d) to form one or more fractures in an earthen subterranean formation through which the wellbore extends at one or more locations located along the wellbore uphole from the second location.
14. The method of claim 7, further comprising:
- (g) pumping a fracturing fluid through the wellbore following (b) to form one or more fractures in an earthen subterranean formation through which the wellbore extends at one or more locations located along the wellbore between the first location and the second location.
15. The method of claim 7, further comprising:
- (g) drilling into an uphole end of the nose of the second plug following (f) with a drill positioned in the wellbore while the nose is interlocked with the mandrel of the first plug.

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16. The method of claim **15**, further comprising:

(h) releasing a nose of the first plug from the casing string following (g) to permit the nose of the first plug to travel through the wellbore.

17. The method of claim **7**, wherein the plurality of notches defines a first set of castellations and the plurality of recesses define a second set of castellations interlockingly engageable with the first set of castellations.

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