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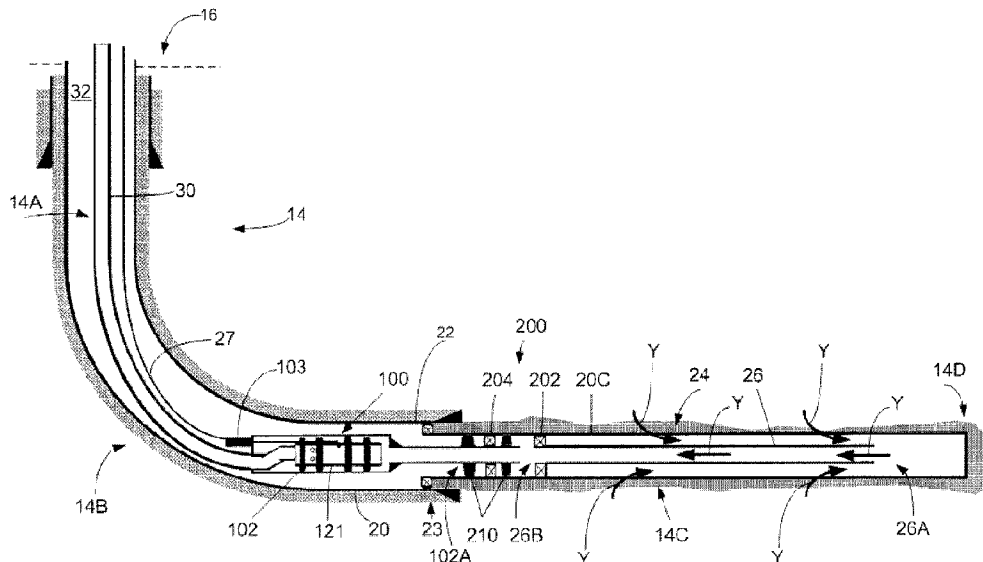
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(54) Titre : UN APPAREIL A CARTOUCHE DESTINE A UNE POMPE SUBMERSIBLE ELECTRIQUE MULTIPHASEE

(54) Title: A CANISTER APPARATUS FOR A MULTIPHASE ELECTRIC SUBMERSIBLE PUMP



(57) **Abrégé/Abstract:**

Implementations of the present disclosure relate to an apparatus for producing a multiphase production-stream (MPS) from within in situ oil-and-gas production wellbore. The wellbore has a toe section, a heel section, and a horizontal section therebetween. The apparatus includes a canister positioned proximate to the heel section and in fluid communication with the substantially horizontal section for receiving substantially all of the MPS from the horizontal section. The canister houses an electric submersible pump (ESP) that pumps the received MPS to the surface through a production tubing-string. The canister includes a secondary canister with a sealing member and a section of cables for the ESP housed therein. The sealing member prevents wellbore fluids from interfering with the pump.

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ABSTRACT

Implementations of the present disclosure relate to an apparatus for producing a multiphase production-stream (MPS) from within *in situ* oil-and-gas production wellbore. The wellbore has a toe section, a heel section, and a horizontal section therebetween. The apparatus includes a canister positioned proximate to the heel section and in fluid communication with the substantially horizontal section for receiving substantially all of the MPS from the horizontal section. The canister houses an electric submersible pump (ESP) that pumps the received MPS to the surface through a production tubing-string. The canister includes a secondary canister with a sealing member and a section of cables for the ESP housed therein. The sealing member prevents wellbore fluids from interfering with the pump.

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A CANISTER APPARATUS FOR A MULTIPHASE ELECTRIC SUBMERSIBLE PUMP

TECHNICAL FIELD

[0001] The present disclosure generally relates to producing hydrocarbons. In particular, the disclosure relates to producing a multiphase stream from a subterranean reservoir using an electric submersible pump within a canister apparatus.

BACKGROUND

[0002] Oil sands are found in surface reservoirs and in deeper subterranean reservoirs. The oil sands in the surface reservoirs can be collected by surface mining. The deeper oil sands can be collected by *in situ* operations that include drilling one or more well bores from the surface into or near to the subterranean reservoir. The deeper oil sands are typically produced by mobilizing the bitumen within the oil sands and pumping the mobilized bitumen up to the surface.

[0003] During *in situ* operations, bitumen within oil sands can be mobilized by decreasing its viscosity through thermal-based, solvent-based processes, and combinations thereof. One commercially used *in situ* thermal-based process is referred to as steam-assisted gravity drainage (SAGD). SAGD typically involves drilling a pair of wellbores. One wellbore is referred to as the injection wellbore and the other wellbore is referred to as the production wellbore. Typically, the paired wellbores have a substantially vertical section that extends downward from the surface to about the depth of the targeted reservoir. There, the paired wellbores change direction and transition from the substantially vertical section to a substantially horizontal section. The horizontal section can extend for many hundreds of meters through or near to a targeted reservoir. Within the horizontal section, the injection wellbore is typically positioned a few meters above the production wellbore. Generally, the point where the paired wellbores change direction is referred to as a heel section and the end of the horizontal section is referred to as the toe section.

[0004] High-temperature and high-pressure steam is introduced into the injection wellbore at the surface. The steam travels down the injection wellbore and exits the horizontal section to enter into the targeted reservoir. The steam heats up the targeted reservoir which decreases the viscosity of the bitumen therein. The mobilized bitumen

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then flows downward under gravity into the production wellbore along the horizontal section. The production wellbore also collects water that forms as the steam cools and condenses, or water that can otherwise be present within or near the targeted reservoir. The production well also collects various gases that are produced from the targeted reservoir by the steam. Together, the mobilized bitumen, the water, and the produced gases that are collected in the production well are referred to as a multiphase production-stream (MPS).

[0005] An artificial-lift system is located within the production wellbore proximate to the heel section. The artificial-lift system draws the MPS from the toe towards the heel. The artificial-lift system is often submersed in a liquid made up of the mobilized bitumen, liquid water, and a small proportion of the produced gas within the multiphase production stream. Typically, the artificial lift system is an electrical submersible pump (ESP). The ESP collects and pumps the liquid up to surface through a production string that is positioned within the wellbore.

[0006] As the MPS approaches the heel, the majority of the produced gases within the multiphase production stream break out from the liquids as free produced-gas. The free produced-gas collects within an annulus between the production string and a layer of casing on the inner surface of the production wellbore.

[0007] The annular produced-gas can be collected at the surface with gas-handling equipment. However, the collected annular produced-gas can contain corrosive chemicals that, over time, can corrode metals within the production wellbore, including the casing. Corrosion of the casing can result in casing failure which requires an extensive work-over to repair. Additionally, the pressure of the collected annular produced-gas can fluctuate, which in turn can fluctuate the level of the liquid in which the ESP is submersed. When the level of the liquid drops below the level of the ESP, the ESP can fail due to gas locking or overheating.

SUMMARY

[0008] Implementations of the present disclosure relate to an apparatus for producing a multiphase production-stream (MPS) within an *in situ* oil-and-gas production operation. The *in situ* operation can be any of a thermal-based operation, a solvent-based operation, combinations of thermal-based operations and solvent-based operations or other

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operations for producing oil-and-gas from an *in situ* production wellbore. Non-limiting examples of thermal-based operations include *in situ* combustion and steam-assisted gravity drainage (SAGD), with SAGD being used herein as but one example.

[0009] The production wellbore has a toe section, a heel section, and a substantially horizontal-section therebetween with at least the heel section encased with a plurality of tubulars. The apparatus is for producing a multiphase production-stream (MPS) within the production wellbore. The apparatus includes a string of production tubulars that is insertable within the production wellbore for providing fluid communication between an electrical submersible pump (ESP) and the surface above. The string of production tubulars and the plurality of tubulars define an annulus therebetween. The apparatus also includes a canister that is insertable within the production wellbore for housing the ESP. The canister has a first end that is in fluid communication with the substantially horizontal section and a second end that is in fluid communication with the string of production tubulars. The second end of the canister also provides a fluid-tight seal with one or more channels therethrough for conducting one or more ESP cables therethrough. The canister is for receiving at least part or substantially all of the MPS from the substantially horizontal section and for directing the received MPS to the ESP. The apparatus also includes one or more sealing members for providing a fluid-tight seal between the plurality of tubulars of the heel section while avoiding an accumulation of a broken-out gas component from the MPS within the annulus.

[0010] Further implementations of the present disclosure relate to a canister apparatus for housing an ESP in a production wellbore. The canister apparatus includes a first canister and a second canister. The first canister has a substantially first open end and a substantially closed second end. The first canister houses the ESP. The second canister is sealingly connected to the substantially closed second end of the first canister. The second canister houses a sealing member that defines one or more channels for conducting a portion of one or more ESP cables (which can include instrumentation cables) through the substantially closed second end. The sealing member is also configured to provide a fluid-tight seal against the one or more ESP cables for reducing or preventing an incursion of fluids into the canister apparatus.

[0011] Further implementations of the present disclosure relate to a method of producing a MPS from a production wellbore. The method includes the steps of collecting

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at least a portion of the MPS within a production wellbore that is proximate to a source of the MPS; directing the collected MPS to an artificial lift-system within the production wellbore for delivering the MPS up the production wellbore to a surface above; and avoiding an accumulation of a broken-out gas component from the MPS within an annular portion the production wellbore. The annular portion extends from the surface above to proximate the artificial lift-system.

[0012] Implementations of the present disclosure include a canister apparatus within which the ESP of a SAGD production wellbore is housed. The canister collects a portion of MPS, directs the collected MPS to the ESP which then pumps the collected MPS to the surface through the production string. Because the MPS contains all or substantially all of the produced gas, the canister apparatus reduces the amount of produced gas within the production-wellbore annulus to low levels or to substantially none. The reduced amount of produced gas in the annulus can avoid some or all of the costs associated with gas-handling surface equipment at each production well or each well pad. The reduced amount of produced gas in the annulus can also reduce or prevent corrosion induced casing failure and the problems associated with operating the ESP in the face of fluctuating levels of the liquid within which the ESP is submersed.

BRIEF DESCRIPTION OF THE DRAWINGS

[0013] Features of the present disclosure will become more apparent in the following detailed description in which reference is made to the appended drawings, which illustrate by way of example only:

[0014] FIG. 1 is an elevation-view schematic illustration of a typical SAGD paired wellbore arrangement;

[0015] FIG. 2 is an elevation-view schematic illustration of one implementation of the present disclosure for use in an *in situ* oil-and-gas production wellbore;

[0016] FIG. 3 shows illustrations of some implementations of the present disclosure wherein FIG. 3A shows a mid-line, cross-sectional view of one implementation of a canister apparatus; FIG. 3B shows a mid-line, cross-sectional view of another implementation of a canister apparatus also taken along line 3-3 of FIG. 3C; and FIG. 3C shows a cross-sectional view taken along line 3-3 in FIG. 3A;

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[0017] FIG. 4 shows illustrations of some implementations of the present disclosure wherein FIG. 4A shows a mid-line cross-sectional view through an example of a secondary canister; FIG. 4B shows a front view of one example of a swellable-matrix arrangement; and FIG. 4C shows another example of a swellable-matrix arrangement;

[0018] FIG. 5 shows one implementation of the present disclosure with an elevation view of an example of an ESP and a centralizer arrangement within a partially cut-away canister apparatus; and

[0019] FIG. 6 is an elevation-view schematic illustration of another implementation of the present disclosure for use in an *in situ* oil-and-gas production wellbore.

DETAILED DESCRIPTION

[0020] Implementations of the present disclosure relate to an apparatus for producing a multiphase production-stream (MPS) within an *in situ* oil-and-gas production operation. Steam-assisted gravity drainage (SAGD) wellbore is discussed herein as but one example of an *in situ* oil-and-gas production operation. It is understood that implementations of the present disclosure can be used in various different types of *in situ* oil-and-gas production operations such as thermal-based operations, solvent-based operations, combinations of thermal-based operations and solvent-based operations and other *in situ* production operations. The production wellbore has at least a toe section, a heel section, and a substantially horizontal-section therebetween. The apparatus can include an electric submersible pump (ESP) that is positionable within the heel section for collecting the MPS from the substantially horizontal section and lifting the MPS to a surface above the SAGD wellbore. The apparatus also includes a string of production tubulars that are positioned within the production wellbore to provide fluid communication between the ESP and the surface. The string of production tubulars and the production wellbore define an annulus therebetween. One or more sealing members provide a fluid-tight seal between the substantially horizontal section and the annulus. The apparatus additionally includes a canister that is insertable within the heel section and is in fluid communication with the substantially horizontal section, the canister apparatus for housing the ESP, for receiving the MPS from the substantially horizontal section and directing the received MPS to the ESP.

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[0021] Definitions

[0022] Unless defined otherwise, all technical and scientific terms used herein have the same meaning as commonly understood by one of ordinary skill in the art to which this disclosure belongs.

[0023] As used herein, the term “about” refers to an approximately $\pm 10\%$ variation from a given value. It is to be understood that such a variation is always included in any given value provided herein, whether or not it is specifically referred to.

[0024] As used herein, the term “downhole” generally describes a direction within a wellbore that is away from the surface and towards the toe. The term “downhole” can also be more generally used herein to refer to a position within a wellbore that is below the surface.

[0025] As used herein, the term “multiphase production-stream” or the acronym “MPS” refer to a stream of fluid that is produced from an underground reservoir during a steam-assisted gravity drainage operation. The stream of fluid includes mobilized bitumen, water and produced gases.

[0026] As used herein, “uphole” generally describes a direction within a wellbore that is towards the surface and away from the toe. Uphole is opposite to downhole and it can be used in this context in a reference to a direction within a wellbore or a position within a wellbore that is relative to another feature.

[0027] Implementations of the present disclosure will now be described in reference to FIG. 1 to FIG. 6.

[0028] FIG. 1 shows a typical pair of SAGD wellbores 10 with an injection wellbore 12 and a production wellbore 14, as is known in the prior art. Although not shown in FIG. 1, it is understood that more than one pair of SAGD wellbores 10 can be localized together into well pads. At each well pad, multiple pairs of SAGD wellbores 10 can effectively share infrastructure such as equipment, man power, power-utility connections, pipelines, and other resources.

[0029] Each wellbore 12, 14 of the paired wellbore 10 has a substantially vertical section 12A, 14A respectively that extends from a surface 16 to a depth that is about the

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same depth as a targeted subterranean oil-sands reservoir 18. The substantially vertical sections 12A, 14A can deviate from a true vertical orientation. At this depth, each wellbore 12, 14 changes direction or turns in a section referred to herein as a heel section 12B, 14B and transitions to a substantially horizontal section 12C, 14C that terminates in a toe section 12D, 14D. The substantially horizontal sections 12C, 14C can deviate from a true horizontal orientation.

[0030] One or both of the pair of SAGD wellbores 10 can be encased with a plurality of metal tubulars 20, such as a casing, an intermediate casing, or a liner. For simplicity, FIG. 1 only shows the metal tubulars 20 as a cross-section through each of the pair of SAGD wellbores 10, it is understood that the metal tubulars 20 extends around the entire inner surface of each of the pair of SAGD wellbores 10. From the surface 16 to the heel section 12B, 14B, each of the pair of the SAGD wellbores 10 is encased with a string of casing 20A that is made up of many interconnected casing-joints. The wellbores can be encased through the heel section 12B, 14B with a string of intermediate casing 20B that is made up of interconnected intermediate casing joints. One or both of the string of casing 20A or the string of intermediate casing 20B can be fixed to and sealed against the open wellbore by cement (not shown). Within the production wellbore 14 and at a point downhole from the heel section 14B, there is a last intermediate casing joint 22. Downhole from the last intermediate casing joint 22, the substantially horizontal section 14C can be encased with a string of liner 20C that is made up of interconnected liner-joints. The string of liner 20C extends towards the toe section 14D. It is understood that the string of casing 20A has a larger outer diameter than the string of intermediate casing 20B which has a larger outer diameter than the string of liner 20C. Furthermore, a liner hanger and packing element 23 is positioned at the junction between the last intermediate casing joint 22 and the string of liner 20C. The specific completion shown in FIG.1 is one non-limiting example of a SAGD wellbore completion, and it is understood that various wellbore completions can be used.

[0031] To mobilize the bitumen within the targeted reservoir 18, steam is injected at the surface 16 into the injection wellbore 12. In some implementations, the steam can include other additives of varying percentages by volume, such as solvents or surfactants. As shown by the arrows identified with X, the steam travels downhole and exits the injection wellbore 12 along the substantially horizontal section 12C and enters the

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reservoir 18. Generally, the steam forms a chamber (not shown) about the substantially horizontal section 12C within the reservoir 18 by warming and mobilizing a bitumen component within the reservoir 18. Forming the chamber also produces vapor that includes water and liberated gas, which can also be referred to herein as produced gas. Over time the mobilized bitumen, water and produced gases flow into the production wellbore 14 in the form of a multiphase production-stream (MPS), as shown by the arrows identified with Y in FIG. 1.

[0032] Because sand and other particulate matter can be entrained in the MPS, the substantially horizontal section 14C typically includes a sand control means 24 for reducing or preventing an inflow of sand and other particulate matter into the production wellbore 14. Sand control means 24 can include for example, layers of gravel pack or sand consolidation means and the like that are positioned adjacent the string of liner (not shown). In some instances, the string of liner 20C includes one or more slotted liner joints that can reduce or prevent the inflow of sand into the production wellbore 14. Optionally, the slotted liner joints can be covered with another filtering means, for example, such as steel wool or a wire wrap or other such coverings.

[0033] The horizontal section 14C can include an internal tubular 26, which can also be referred to as a tailpipe or production pipe. The tailpipe 26 has a first end 26A that is oriented towards the toe section 14D of the production wellbore 14 and a second end 26B that is opposite the first end 26A. The tailpipe 26 can have any length that fits between the heel section 14B and the toe section 14D. The tailpipe 26 collects the MPS as it flows into the wellbore and directs the MPS in a direction from the toe section 14D towards the heel section 14B.

[0034] An ESP 21 is housed within the heel section 14B to create a differential pressure within the production wellbore 14 with a lower pressure at the heel section 14B relative to the toe section 14D. This differential pressure helps the MPS to flow towards the heel section 14B. Proximate to the heel section 14B, some of the produced gas within the MPS can break out while the mobilized bitumen, water and any remaining and entrained produced-gas can remain in a primarily liquid-phase that pools around and submerses the ESP 21. In FIG. 1, the broken-out produced gas is represented by the arrows indicated with G and the primarily liquid phase is shown as the arrow Z. The primary liquid phase can pool at the heel section 14B and can define a surface Zs that extends

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upward into the substantially horizontal section 14A. In an effort to reduce drawing any broken-out produced gas into the ESP 21, an intake is typically positioned below the ESP 21, away from the broken-out gas to draw the primarily liquid-phase into the ESP 21 for lifting the primary liquid-phase up to the surface 16 via a production tubing-string 30. The production tubing-string 30 can include interconnected tubing joints or it can include coiled tubing or any other suitable type of conduit that can withstand the temperatures and pressures that occur within the production wellbore 14 during SAGD operations.

[0035] Together, the metal tubulars 20 and the production string 30 define an annulus 32 therebetween. The broken-out produced gas G travels through the pooled primary liquid phase and exits the surface Zs to travel up the annulus 32 for collection and processing by gas-handling equipment 34 at the surface 16. The gas-handling equipment 34 can include various coolers, separators, pumps, compressors, and conductive pipe that interconnects the coolers, separators, pumps, compressors, and a gas pipeline system. Providing and maintaining the gas-handling surface equipment 34 can cost millions of dollars per well pad through the operational life of the well pad.

[0036] Implementations of the present disclosure include a canister apparatus within which the ESP of an *in situ* oil-and-gas production wellbore is housed. Due to a combination of sealing members about and within the canister apparatus, the canister apparatus collects a portion or substantially all of the MPS and directs the collected MPS to the ESP. The ESP pumps the collected MPS to the surface through a production string. Because the MPS contains all or substantially all of the produced gas, the canister apparatus reduces the amount of MPS and the produced gas therein that accesses the production-wellbore annulus to low levels or to substantially none. In other words and as shown in the non-limiting example of FIG. 2, when using the canister apparatus of the present disclosure, there is no Zs because there is little or substantially no MPS and little or substantially no broken-out production gas within the annulus 32. The reduced amount of produced gas in the annulus can avoid some or all of the costs associated with gas-handling surface equipment at each production well or each well pad. The reduced amount of broken-out produced gas in the annulus can also reduce or prevent corrosion induced casing failure and the problems associated with operating the ESP in the face of fluctuating levels of the liquid within which the ESP is submersed.

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[0037] The canister apparatus employs a combination of sealing members that are positioned between the canister apparatus and the tubulars of the production well. These sealing members direct some, most or substantially all of the MPS into the canister apparatus (rather than into the annulus 32). The sealing member's direction of the MPS into the canister apparatus can reduce the amount of MPS and broken-out production gas within the annulus. The combination of sealing members also includes an elastomer matrix that is within the canister apparatus. The elastomer matrix is temperature stable during thermally-based *in situ* operations, such as SAGD. In particular, the elastomer matrix provides a fluid-tight seal within the canister apparatus, which reduces or substantially prevents the leak of MPS fluids from within the canister apparatus into the annulus 32 and vice versa. While providing this fluid-tight seal, the elastomer matrix provides a channel for ESP cords to pass into the canister apparatus to access the ESP therein.

[0038] FIG. 2 shows one implementation of the present disclosure that relates to a canister apparatus 100 for housing an ESP 121. Any features that are the same or that are similar between the figures are indicated with the same reference numbers throughout the figures. The specific wellbore completion shown in FIG. 2 is of a SAGD wellbore completion, which is provided as but one example of an *in situ* oil-and-gas wellbore completion that includes implementations of the present disclosure. It is understood that the implementations of the present disclosure can be used with various wellbore completions and various other *in situ* oil-and-gas production operations.

[0039] FIG. 3 shows that the canister apparatus 100 includes a primary canister 102 and a secondary canister 103. The canister apparatus 100 is positionable within the heel section 14B of a production wellbore 14. The primary canister 102 is configured to house an ESP 121, a portion of ESP cables 27, and a portion of the production tubing-string 30. The primary canister 102 receives at least part of the MPS from the horizontal section 14C of the production wellbore 14 (see lines Y in FIG. 2). The primary canister 102 communicates the received MPS to the ESP 121 for delivery to the surface 16 via the production tubing-string 30.

[0040] In some implementations of the present disclosure, the primary canister 102 is generally tubular with a first end 102A, a second end 102B, and a plenum 107 that is defined therebetween. FIG. 3A shows a portion of the primary canister 102 and the

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secondary canister 103 within a section of the metal tubulars 20. When the primary canister 102 is positioned within the heel section 14B, the first end 102A is downhole of the second end 102B. The first end 102A is in fluid communication with the substantially horizontal section 14C of the production wellbore 14. In some implementations of the present disclosure, the first end 102A is sealingly engaged with an inner surface of the metal tubular 20 that is radially adjacent the first end 102A.

[0041] The second end 102B is substantially sealed with at least a portion of the secondary canister 103 and at least a portion of the production tubing-string 30 extending therethrough. Both of the secondary canister 103 and the production tubing-string 30 are sealingly connected to the second end 102B of the primary canister 102.

[0042] The primary canister 102 can be a substantially unitary body or it can be made up of at least two modular components. The implementation of the primary canister 102 that is shown in FIG. 3A includes multiple modular components. For example, the primary canister 102 can include a first tubular body 112 that defines the plenum 107. The ends of the first tubular body 112 are configured to sealingly connect to a first connector 114 and a second connector 116. In some implementations of the present disclosure, these components of the primary canister 102 can be threadably connected, friction fit, snap fit or other types of connections that provide a fluid-tight seal that can withstand the temperatures and pressures that occur within the production wellbore 14 during SAGD operations. In some implementations of the present disclosure, the first tubular body 112 is a quick-connector body wherein the first connector 114 is a casing connector and the second connector 116 is a quick-connector nut.

[0043] Because both of the secondary canister 103 and the production tubing-string 30 extend through the second end 102B, neither of the production tubing-string 30 or the secondary canister 103 are centralized at the second end 102B (see FIG. 3B). The production tubing-string 30 can have a bent shape and be fixed at either or both ends of the first tubular body to facilitate the connection with the ESP 121 when the ESP 21 is also centralized, as discussed further below.

[0044] The second end 106 can include an uphole wall 122 that defines a secondary canister aperture 124 and a production tubing-string aperture 126 (see the cross-sectional view of FIG. 3C). The secondary canister aperture 124 receives the secondary

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canister 103 therethrough and the production tubing-string aperture 126 receives the production tubing string 30 therethrough. In some implementations of the present disclosure, the uphole wall 122 can be sealingly retained at or near the second end 106 by one or more seals (not shown) that prevent fluid communication across the uphole wall 122, except through the production tubing-string 30 that extends through and is sealed against the production tubing-string aperture 126. Additionally, an instrumentation line (not shown) can extend through one or more instrumentation ports 300 that are defined by the uphole wall 122. More seals can include but are not limited to friction fit, snap fit, set screws, threading or combinations thereof, and can withstand the temperatures and pressures that occur downhole during SAGD operations.

[0045] The secondary canister 103 is received through the secondary canister aperture 124 that is defined by the uphole wall 122. The secondary canister 103 has a first end 103A and a second end 103B (see FIG. 4A). The first end 103A is sealingly connected to the uphole wall 122 at or proximate to the secondary canister aperture 124. The secondary canister 103 is configured to house a portion of the ESP cables 27. As shown in FIG. 3C, the ESP cables can be an armoured ESP electrical cable 27A and optionally, any sensor lines 27B that can provide information to the surface 16 such as pressure and temperature information about the ESP 121 and/or the fluids that are entering the ESP 121. The ESP electrical cable 27A can include one or more individual electrical-conductor cables. In some implementations of the present disclosure, the ESP electrical cable 27A includes three individual electrical-conductor cables.

[0046] Referring now to FIG. 4, FIG 4A shows a mid-line, cross-sectional view through an example of a secondary canister, for example the implementations of the secondary canister 103 shown in FIG. 3A, FIG. 3B and FIG. 3C. FIG. 4B shows a front view of one example of a sealing member with a swellable-matrix arrangement, for example a front view of the sealing member 150 shown in FIG. 4A. and FIG. 4C shows another implementation of the sealing member 150.

[0047] As shown in FIG. 4A, the secondary canister 103 has can have an internally extending shoulder at the first end 103A for abuttingly receiving a sealing member 150 that is temperature stable during SAGD operations. For example, in a SAGD production wellbore 12, the temperatures can rise to between about 200 °C to about 300 °C and the sealing member 150 does not substantially degrade or deteriorate when exposed to these

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temperature ranges. In some implementations of the present disclosure, the sealing member 150 provides a fluid-tight seal to reduce or prevent the incursion of fluids into the secondary canister 103. In some implementations of the present disclosure, the sealing member 150 is a swellable elastomer matrix which is also referred to herein as the elastomer member 150. The elastomer member 150 can deform by absorbing fluids and swelling. In other implementations of the present disclosure, the elastomer member 150 can be deformed when compressed by a compression nut (not shown). The elastomer member 150 can be a single element or alternatively, multiple elements that are inserted into the secondary canister 103. FIG. 4 shows some implementations of the present disclosure wherein the elastomer member 150 is provided as a two-piece clamshell arrangement. As shown in FIG. 4A, the elastomer member 150 defines one or more channels 152 that extend longitudinally through the secondary canister 103 along or near the midline of the elastomer member 150. As shown in FIG. 4B, the one or more channels 152 can include a first channel 152A that allows the ESP electrical cable 27A to pass through the elastomer member 150 within the secondary canister 103. Optionally, the sensor line 27B passes through a second channel 152B. At or near the first end 103A of the secondary canister 103, the elastomer member 150 abuts against the shoulder and a top cap can be secured to the second end 103B of the secondary canister 103 to retain the elastomer member 150 within the secondary canister 103.

[0048] In the implementations of the present disclosure where the elastomer member 150 is a swellable matrix, when the elastomer member 150 contacts fluids it increases in volume within the secondary canister 103 and provides a fluid-tight seal around the ESP cables 27 along their respective channels 152A. In other implementations of the present disclosure, the elastomer member 150 can be compressed by a compression nut (not shown) to form the fluid-tight seal around the ESP cables 27. The fluid-tight seal prevents the incursion of any fluids from uphole of the secondary canister 103 into the secondary canister 103 while providing the channels 152 for the ESP cables 27 to pass through and physically connect with the ESP 121 that is further downhole within the canister apparatus 100. If wellbore fluids such as any conductive liquid or gas were to pass through the secondary canister 103, the ESP 121 could be subject to an increased susceptibility of gas locking.

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[0049] In some implementations of the present disclosure, the ESP electrical cable 27A is an armoured electrical cable. The inventors have observed that by drilling a pilot hole through the armour, a sealing fluid can be introduced into the armour to provide further sealing against the movement of any fluids that are within the armour towards the ESP 121. In some implementations of the present disclosure, the sealing fluid can be a polymerizable fluid such as an epoxy that can be injected into the pilot hole and then set, or polymerized, within the armour. In other implementations of the present disclosure, the sealing fluid can be an expandable fluid that can be injected into the pilot hole and then expand to provide a fluid tight seal within the armour. FIG. 4B shows one example of an arrangement of the channels 152 that is suitable for an armoured ESP electrical cable 27A and a sensor cable 27B.

[0050] In other implementations of the present disclosure, a portion of the armour is stripped off the ESP electrical cable 27A to reveal the individual electrical-conductor cables therein for the section of the ESP electrical cable 27A that will be housed within the canister apparatus 100. In these implementations, the first channel 152A has a cross-sectional shape that accommodates the number and shape of individual electrical-conductor cables. FIG. 4C shows an example of the first channel 152A shaped to accommodate three individual electrical-conductor cables, as is typical for ESP electrical cables 27A.

[0051] FIG. 5 shows a schematic example of the ESP 121 that is positioned within the primary canister 102. The ESP 121 has a first end 121A and a second end 121B that is opposite the first end 121A. The first end 121A is proximate to the first end 102A of the primary canister 102. FIG. 5 shows an optional feature of a centralizer 160. The centralizer 160 can include collars 162A, and 162B for securing the centralizer 160 about the outer surface of the ESP 121 for example by hinges and connectors. Optionally, multiple centralizers 160 can be used, such as the four centralizers shown in FIG. 5. The centralizer 160 can also include at least one rib 164 that extends radially outwardly from the centralizer 160. The at least one rib 164 can also be referred to as a bowspring. The at least one rib 164 engages an inner surface 170 of the primary canister 102 for supporting the ESP 121 off of the inner surface 170. In some implementations of the present disclosure, the centralizer 160 includes enough ribs 164 to support the ESP 121 in a substantially centralized position within the primary canister 102.

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[0052] As shown in FIG. 5, the ESP 121 includes the following components: a motor section 123, a sealing section 125, an intake section 127, and a pumping section 129. The motor section 123 includes a receptacle for receiving the ESP cables 27A and 27B. The ESP electrical cable 27A provides electrical power to the motor section 123. While not shown, a rotatable shaft is operably coupled to the motor section 123 and the pumping section 129. The sealing section 125 is adjacent the motor section 123. The sealing section 125 seals about the rotatable shaft and prevents the communication of fluids from the intake section 127 into the motor section 123. The intake section 127 receives the MPS within the primary canister 102 (as shown by arrows Z in FIG. 5). Due to the pumping action of the pumping section 129, the intake section 127 can receive MPS about the entire outer circumference of the ESP 121 or alternatively, just sections of the outer circumference of the ESP 121. The intake section 127 directs the received MPS towards the pumping section 129 which pumps the received MPS towards the production tubing 30 (as shown by arrow Zp in FIG. 5).

[0053] The pumping section 129 can include any type of pumping stage that can deliver the received MPS to the surface through the production tubing-string 30 and handle any produced gas that is entrained in the received MPS while reducing the incidence of gas locking of the ESP 121. In some implementations of the present disclosure, the pumping section 129 includes a centrifugal gas-handling pumping stage. The centrifugal gas-handling stage has vanes that are designed to reduce the development of low pressure areas and blades that can break the produced gas within the received MPS into smaller bubbles. Both of these features can increase the homogeneity of the received MPS, which can reduce the incidence of gas locking of the ESP 121. In other implementations of the present disclosure, the pumping section 129 includes a helicoaxial gas-handling pumping stage. The helicoaxial gas-handling pumping stage includes both an axial compressor and a centrifugal pump with a boosting pressure that is sufficiently high to compress the produced gas within the received MPS, which also can reduce the incidence of gas locking of the ESP 121. In further implementations of the present disclosure, the pumping section 129 can be part of a progressive cavity pump.

[0054] Referring again to FIG. 2, in order to facilitate movement of the MPS from the tail pipe 26 into the primary canister 102, the production wellbore 14 can include a sealing assembly 200 that prevents the communication of MPS or any component thereof

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across any individual sealing member of the sealing assembly 200. The individual sealing members can be an inflatable packer, a swellable packer, a mechanically actuated packer, a diverter, and the like.

[0055] As shown in FIG. 2, the sealing member assembly 200 can include a first sealing member 202 that provides a fluid seal formed an outer surface of the tailpipe 26 and an inner surface of the string of liner 20C. The first sealing member 202 can be positioned proximate the second end 26B of the tailpipe 26 for preventing the flow of MPS therepast. The first sealing member 202 can help direct the MPS within the production wellbore towards the toe section 14D and into the first end 26A of the tailpipe 26. A second sealing member 204 can provide a fluid-tight seal against an outer surface of the primary canister 102 and an inner surface of the string of liner 20C. The second sealing member 204 can be positioned proximate to the first end 102A of the primary canister 102. The second sealing member 204 can help direct the MPS from the tailpipe 26 into the first end 102A of the primary canister 102.

[0056] In some implementations of the present disclosure, at least one of the first end 102A of the primary canister 102 and the tailpipe 26 can be centralized within the production wellbore 14 by one or more centralizers 210.

[0057] As shown in FIG. 2, in some implementations of the present disclosure, the first end 102A of the primary canister 102 can have an extension that narrows to a smaller outer diameter as it extends towards the toe section 14D. Optionally, the smaller outer diameter of the extension is substantially the same size as the outer diameter of the tailpipe 26. In a further optional implementation of the present disclosure, the extension 106A is directly connected to the tailpipe 26, as shown in FIG. 6.

[0058] FIG. 3B shows another implementation of the present disclosure wherein the production tubing-string 30 sealingly terminates at the upper wall 122 by a connection 136 at or about the production tubing-string aperture 126. The connection 136 can be a friction fit, set screws, threading, or combinations thereof and can withstand the temperatures and pressures that occur downhole during SAGD operations. Within the primary canister 102, there is a production conduit 130 that is in fluid communication with the production tubing-string 30 through the connection 136. The production conduit 130

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extends from the connection 136 to the ESP 121. The production conduit 130 provides a conduit for communicating the MPS from the ESP 121 to the production tubing-string 30.

[0059] In some implementations of the present disclosure, the tailpipe 26 is not present. In these implementations, the MPS flows into the horizontal section 14C and then the MPS flows towards the primary canister 102. The second sealing member 204 directs the MPS flow into the primary canister 102.

[0060] In operation, the first end 102A of the primary canister 102 receives some or substantially all of the MPS from the horizontal section 14C of the production wellbore 14. Some produced gas within the MPS can break-out in a region of the production wellbore 14 that is between the first and second sealing members 202, 204. Because this region is bookended by the sealing members 202, 204, any produced gas that does break out can form a bubble in the upper portion of this region. Once this bubble has occupied as much volume within the region that is available, at the downhole pressures and temperatures that occur during SAGD operations, the bubble will equilibrate and possibly prevent the break-out of any further produced gas.

[0061] The received MPS within the primary canister 102 can flow into the intake section 127 of the ESP 121. The flow of received MPS into the intake section 127 can be enhanced by operation of the pumping section 129. The MPS then flows through the pumping section 129 into the production tubing-string 30 for delivery to the surface 16. Because the produced gas within the MPS is mostly contained within the received MPS within the primary canister 102, there is substantially no produced gas within the annulus 32. The absence of produced gas within the annulus 32 reduces the corrosion of the metal tubulars 20 within the annulus 32, such as the casing and intermediate casing 20A, 20B. Furthermore, the reduced amount or lack of produced gas within the annulus 32 reduces or removes the requirement of surface equipment 34 for handling the produced gas within the annulus 32.

[0062] If the elastomer member 150 is a swellable matrix, then the elastomer member 150 can be deformed by contacting it with a liquid prior to when the elastomer member 150 is secured within the secondary canister 103. Alternatively, the elastomer member 150 can deform when the apparatus is installed downhole and the elastomer member 150 comes into contact with a liquid. If the elastomer member 150 is deformed

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by compression, then the compression nut can be tightened to compress the elastomer member 150 when the elastomer member 150 is secured within the secondary canister 103 prior to downhole installation.

[0063] In some implementations of the present disclosure, an annular gas other than a produced gas, can be introduced into the annulus 32 from the surface 16. For example nitrogen, or another suitable inert gas, can be introduced into the annulus 32 as a blanket gas.

[0064] In the implementation of the present disclosure shown in FIG. 6, a blanket gas BG and/or steam S and/or corrosion inhibited fluid can be introduced into the annulus 32 from the surface 16. In these implementations, because the tailpipe 26 is directly connected to the first end 102A of the primary canister 102, the annulus 32 can extend past the heel section 14B and into the horizontal section 14C. The steam S can be of sufficient quality and pressure that it can pass through the MPS liquid surface Zs and exit the production wellbore 14 along the horizontal section 14C. The steam S or blanket gas BG can be useful for maintaining a desired downhole temperature and for optimizing the mobility of the bitumen within the MPS.

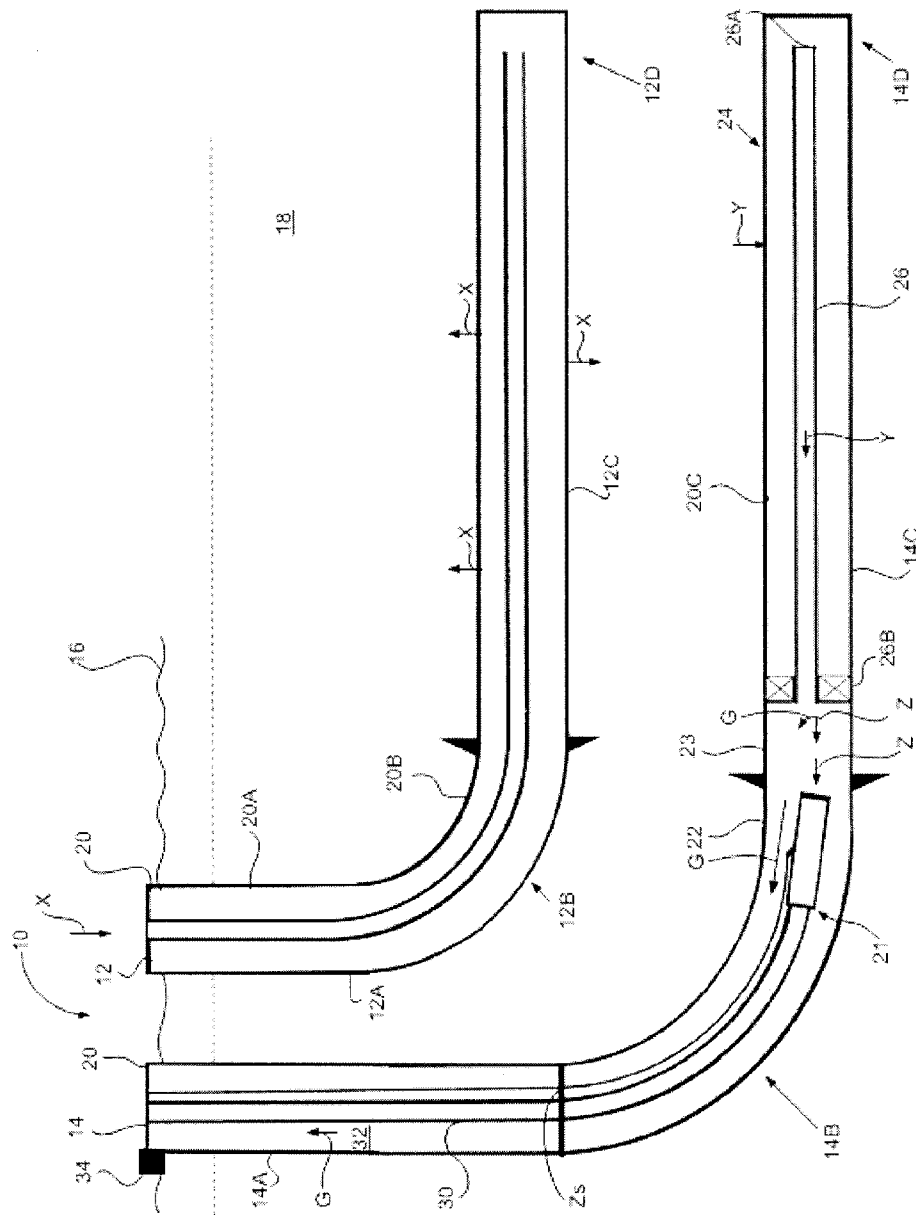
Claims:

1. A method of producing a multiphase production-stream (MPS) from an *in situ* oil-and-gas production wellbore, the method comprising steps of:
 - a. collecting at least a portion of the MPS within a production wellbore that is proximate to a source of MPS;
 - b. housing an artificial-lift system of the production wellbore within a canister that is substantially open at a first end and in fluid communication with a production string at a second end, the second end being otherwise substantially closed;
 - c. directing the collected MPS through the first end of the canister to the artificial-lift system, the artificial lift system delivering the MPS up the production string to a surface above; and
 - d. avoiding an accumulation of a broken-out gas component from the MPS within an annular portion of the production wellbore, wherein the annular portion extends from the surface to at least proximate to the artificial lift-system.
2. The method of claim 1, wherein the step of avoiding accumulation of the broken-out gas further includes a step of providing at least one sealing member at the second end of the canister, the sealing member is configured to conduct one or more ESP cables through the second end and to provide a fluid-tight seal against the one or more ESP cables for reducing or preventing an incursion of fluids into the second end.
3. The method of any one of claims 1 to 2, wherein the step of collecting at least a portion of the MPS further includes providing a tail pipe within the production wellbore for directing therethrough the collected MPS towards the artificial-lift system.
4. The method of claim 3, further comprising a step of directly connecting the tail pipe to the first end of the canister.

REPLACEMENT SHEET

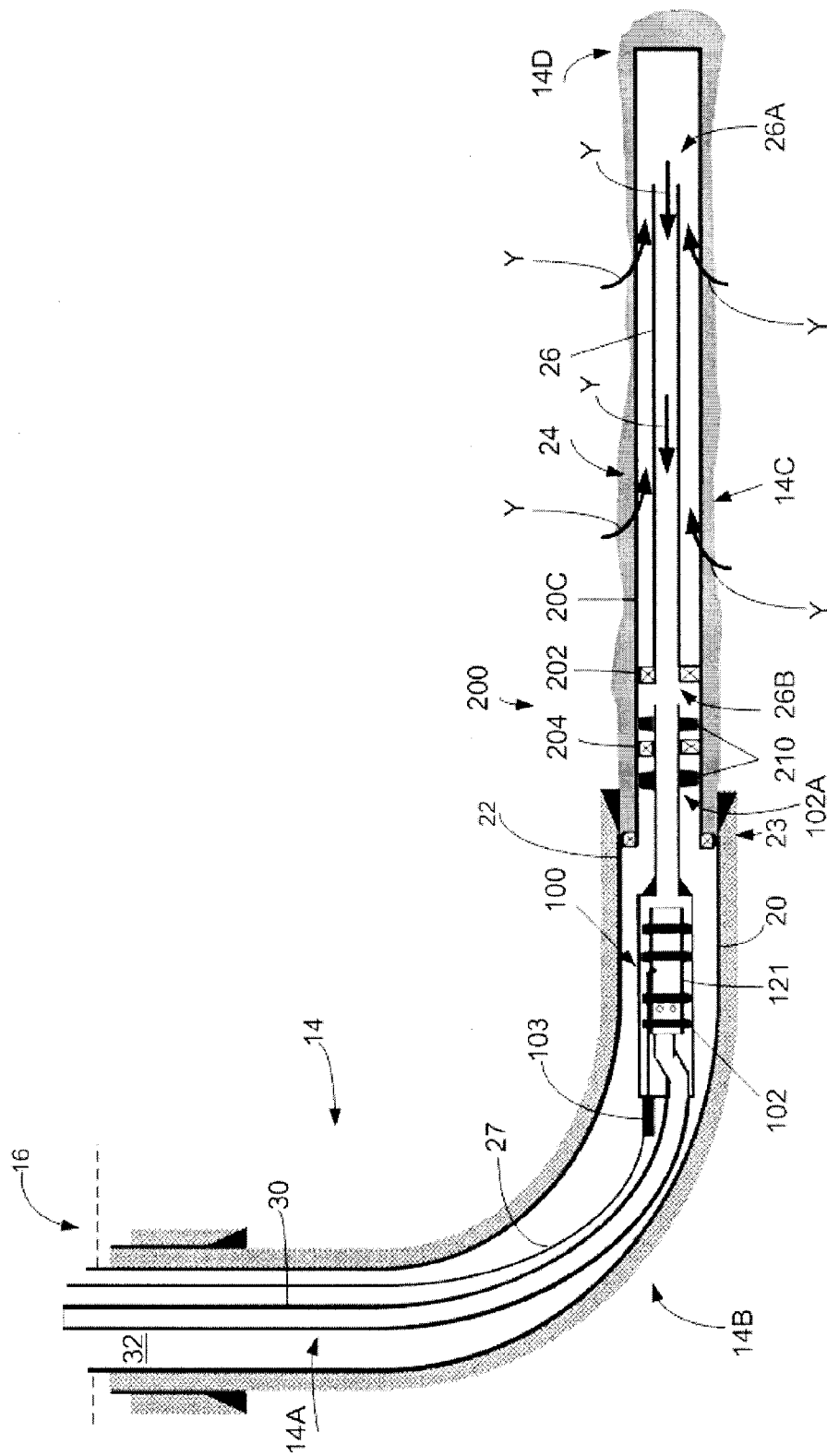
5. The method of claim 4, further comprising a step of injecting one or more of a blanket gas, a steam supply, and a corrosion-inhibited fluid into the annular portion.
6. The method of any one of claims 1 to 5, wherein the step of collecting at least a portion of the MPS further comprises a step of maintaining a temperature of about 200 °C to about 300 °C within the production wellbore.
7. The method of any one of claims 1 to 5, wherein the *in situ* oil-and-gas production wellbore is a steam-assisted gravity drainage wellbore.

REPLACEMENT SHEET



(PRIOR ART)

FIG. 1



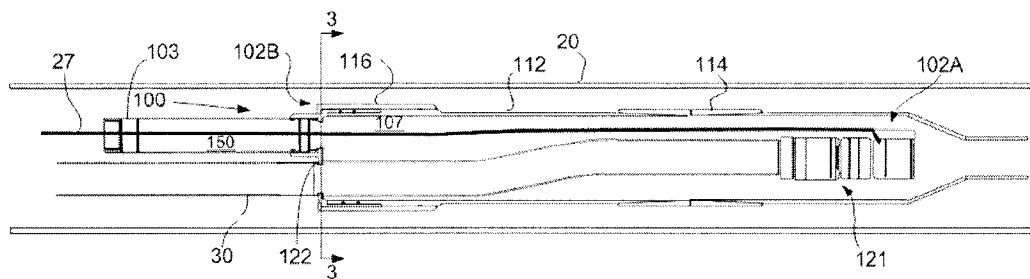


FIG. 3A

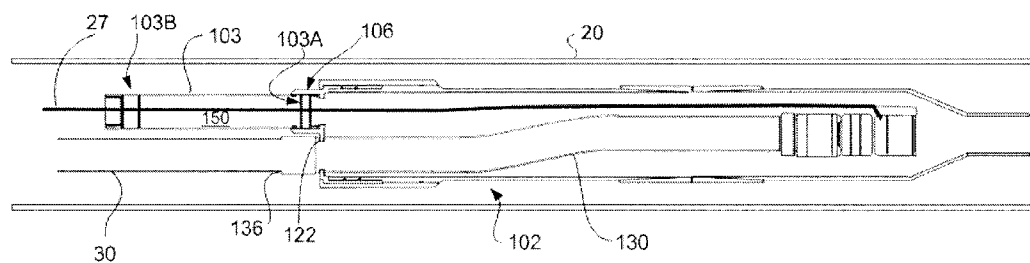


FIG. 3B

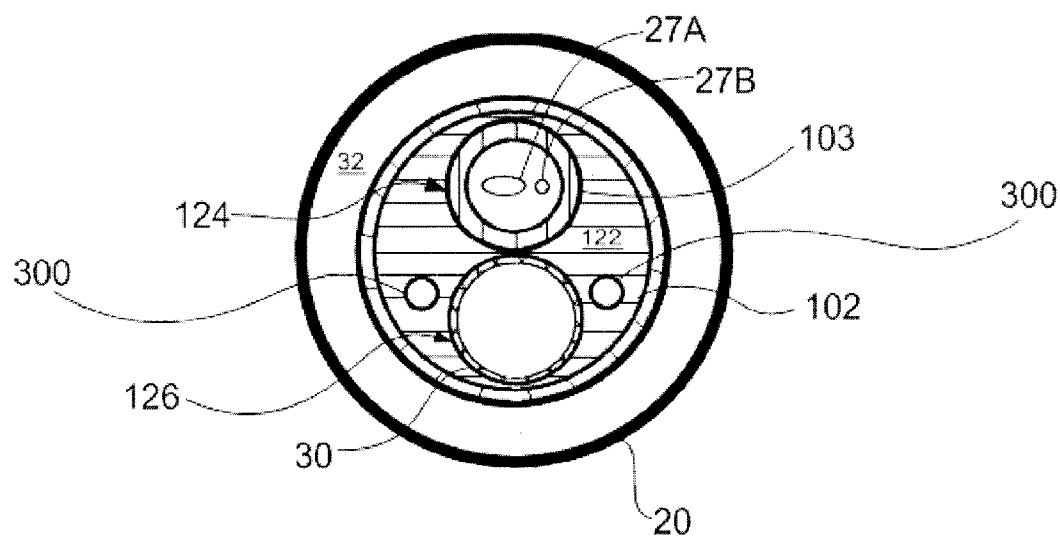


FIG. 3C

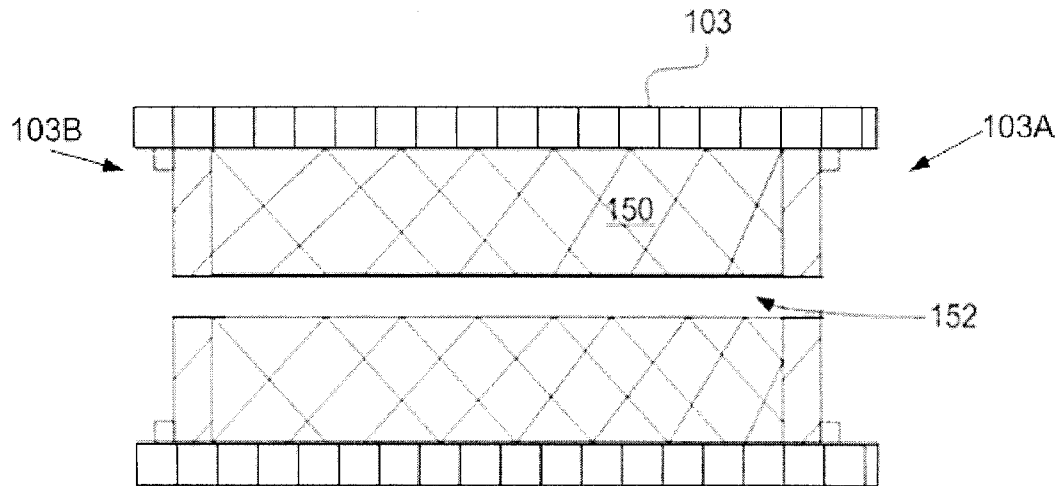


FIG. 4A

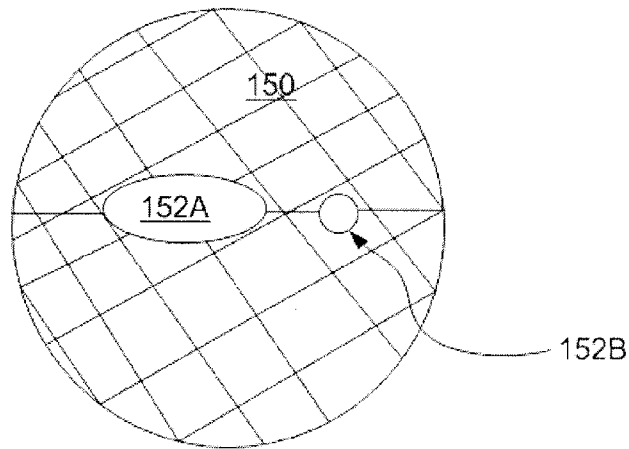


FIG. 4B

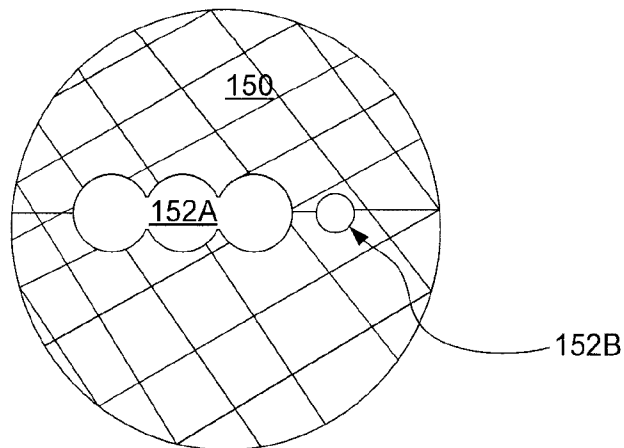


FIG. 4C

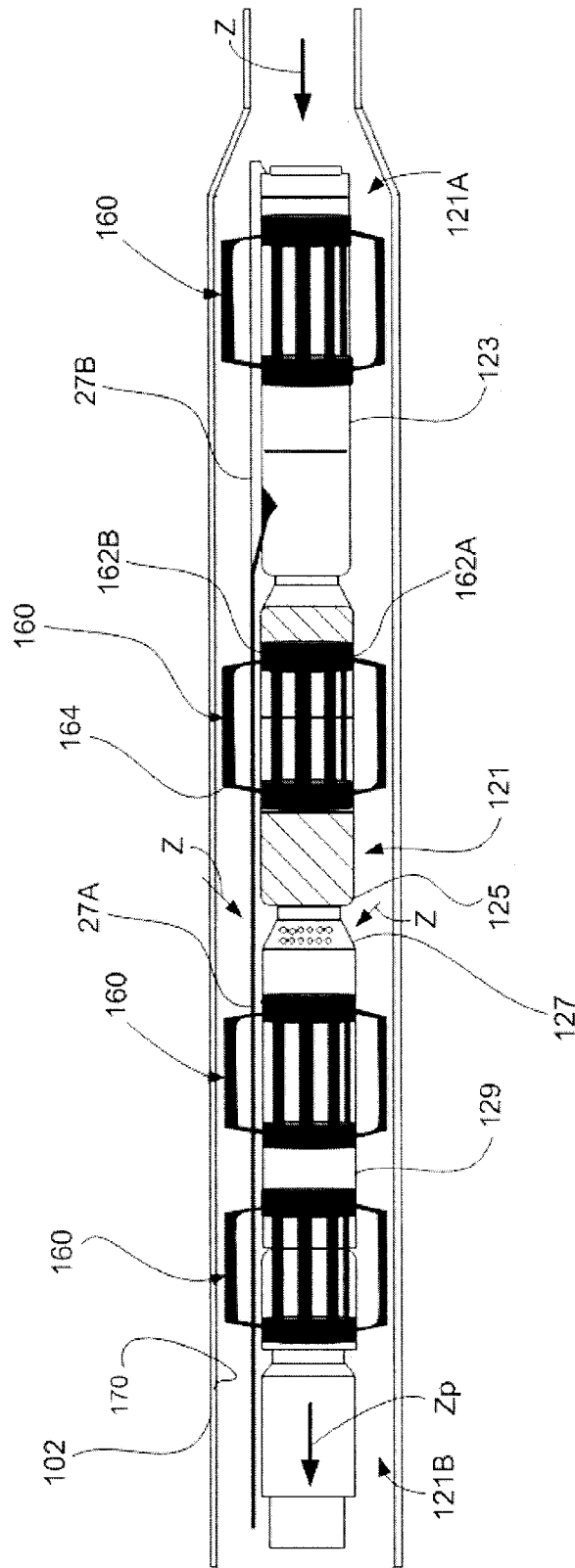


FIG. 5

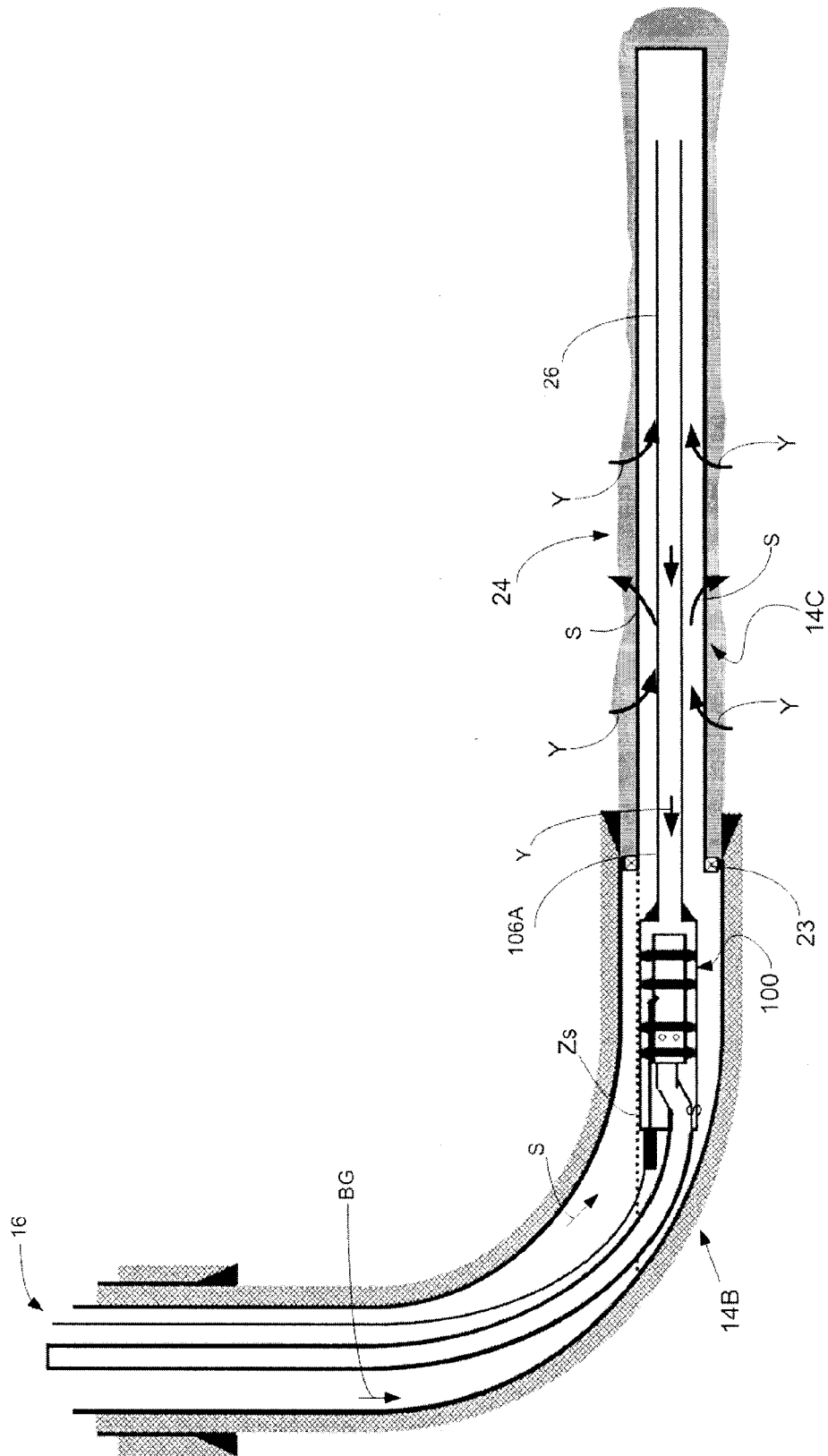


FIG. 6

