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An agency of Industry Canada

CA 2738805 A1 2010/04/22

(21) 2 738 805

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2009/10/09
(87) Date publication PCT/PCT Publication Date: 2010/04/22
(85) Entrée phase nationale/National Entry: 2011/03/28
(86) N° demande PCT/PCT Application No.: US 2009/060092
(87) N° publication PCT/PCT Publication No.: 2010/045098
(30) Priorités/Priorities: 2008/10/13 (US61/104,974); 2009/04/10 (US61/168,498)

(51) Cl.Int./Int.Cl. *E21B 43/24* (2006.01)

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(54) Titre : SYSTEMES DE FLUIDE DE TRANSFERT CHAUFFE EN CIRCULATION UTILISE POUR TRAITER UNE FORMATION SOUTERRAINE

(54) Title: CIRCULATED HEATED TRANSFER FLUID SYSTEMS USED TO TREAT A SUBSURFACE FORMATION

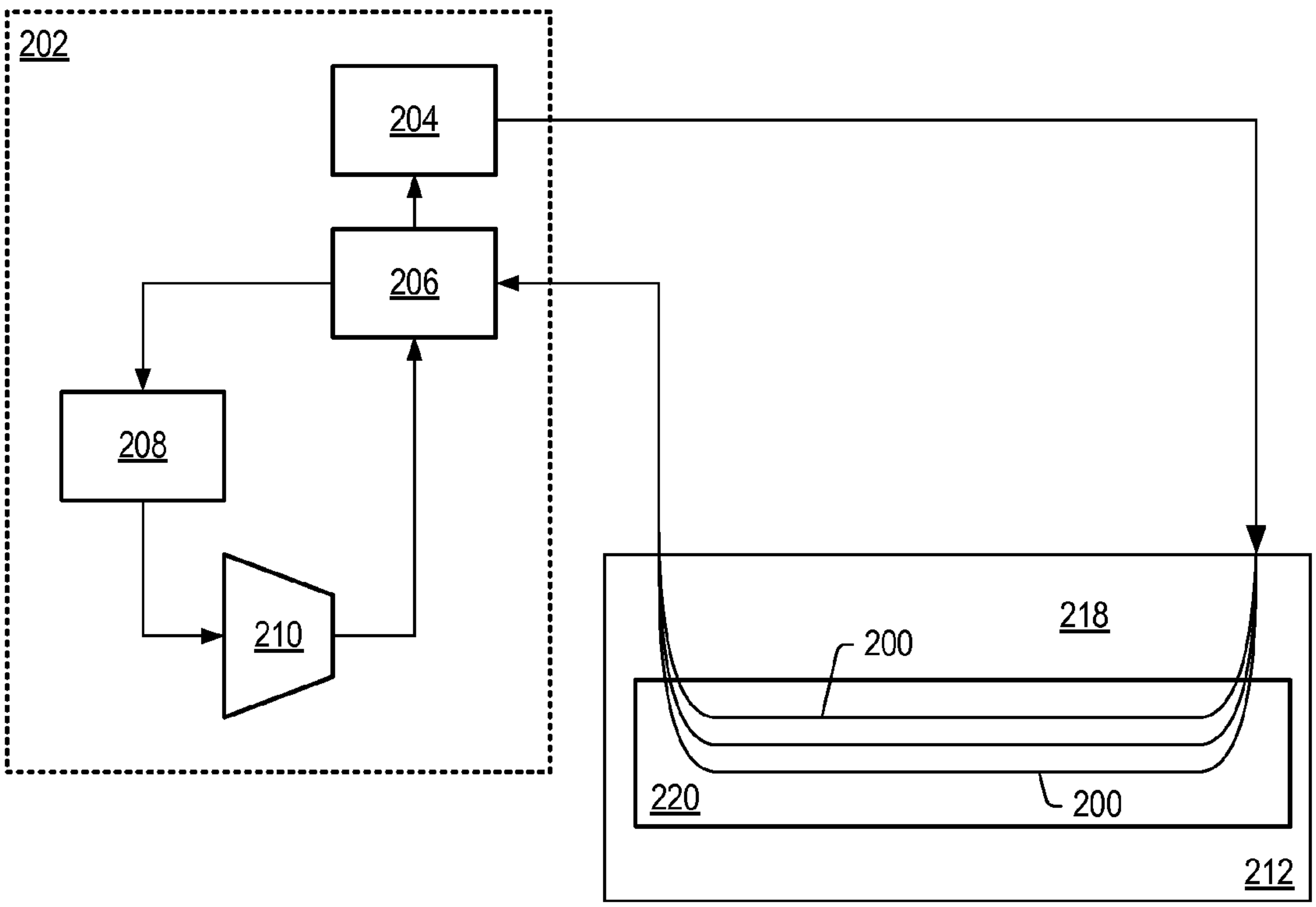

FIG. 2

(57) Abrégé/Abstract:
Systems and methods for treating a subsurface formation are described herein. A method of heating a subsurface formation may include applying heat from a plurality of heaters to the formation, and allowing a portion of one or more of the heaters to move out of wellheads equipped with sliding seals to accommodate thermal expansion of the heaters.

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

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
22 April 2010 (22.04.2010)

PCT

(10) International Publication Number
WO 2010/045098 A1

(51) International Patent Classification:
E21B 43/24 (2006.01)

(21) International Application Number:
PCT/US2009/060092

(22) International Filing Date:
9 October 2009 (09.10.2009)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
61/104,974 13 October 2008 (13.10.2008) US
61/168,498 10 April 2009 (10.04.2009) US

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(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PE, PG, PH, PL, PT, RO, RS, RU, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

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

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(54) **Title**: CIRCULATED HEATED TRANSFER FLUID SYSTEMS USED TO TREAT A SUBSURFACE FORMATION

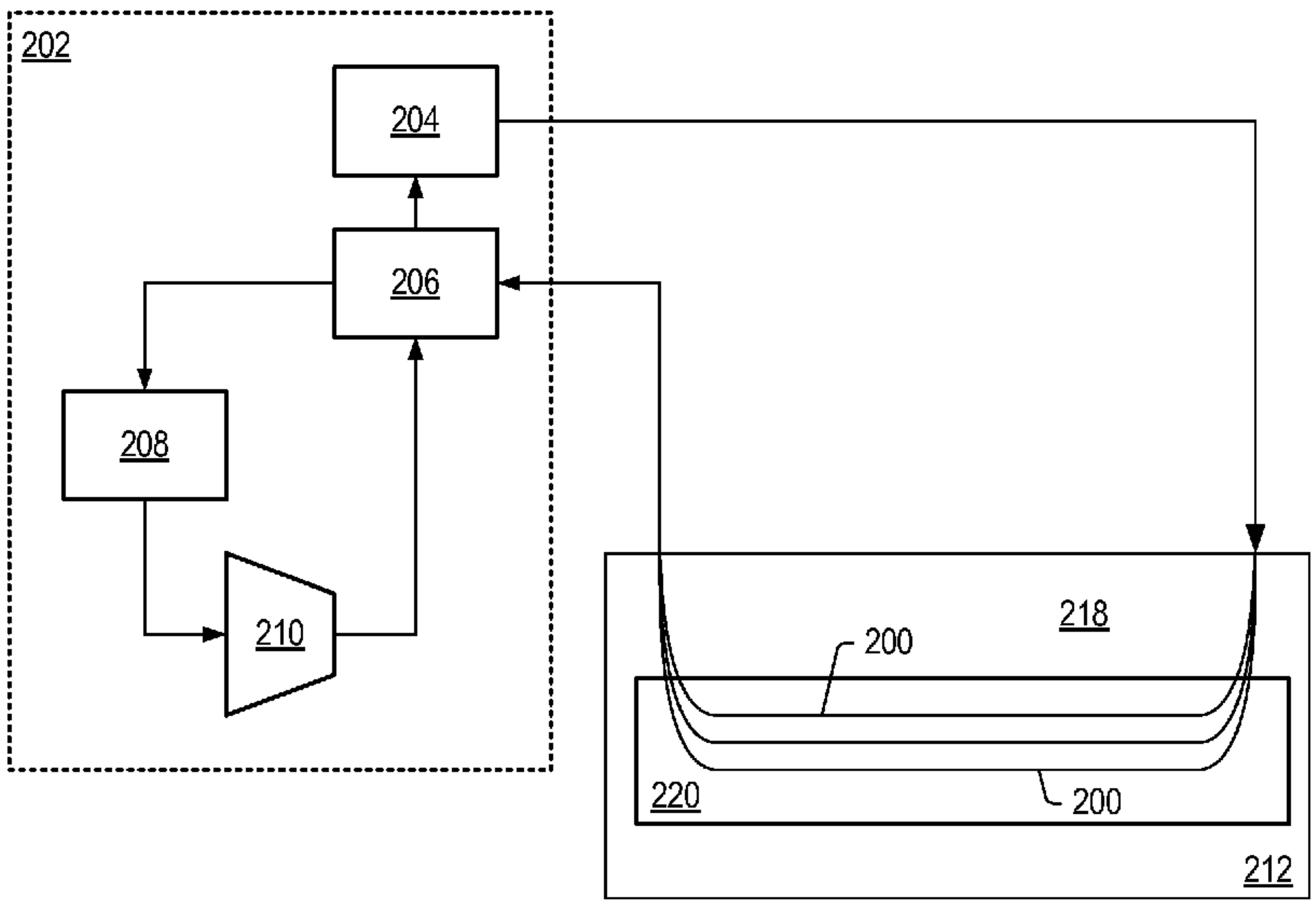

FIG. 2

(57) **Abstract**: Systems and methods for treating a subsurface formation are described herein. A method of heating a subsurface formation may include applying heat from a plurality of heaters to the formation, and allowing a portion of one or more of the heaters to move out of wellheads equipped with sliding seals to accommodate thermal expansion of the heaters.

WO 2010/045098 A1

WO 2010/045098 A1

Published:

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

CIRCULATED HEATED TRANSFER FLUID SYSTEMS USED TO TREAT A SUBSURFACE FORMATION

BACKGROUND

1. Field of the Invention

[0001] The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from various subsurface formations such as hydrocarbon containing formations. In particular, certain embodiments relate to using a closed loop circulation system for heating a portion of the formation during an in situ conversion process.

2. Description of Related Art

[0002] Hydrocarbons obtained from subterranean formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and concerns over declining overall quality of produced hydrocarbons have led to development of processes for more efficient recovery, processing and/or use of available hydrocarbon resources. In situ processes may be used to remove hydrocarbon materials from subterranean formations. Chemical and/or physical properties of hydrocarbon material in a subterranean formation may need to be changed to allow hydrocarbon material to be more easily removed from the subterranean formation. The chemical and physical changes may include in situ reactions that produce removable fluids, composition changes, solubility changes, density changes, phase changes, and/or viscosity changes of the hydrocarbon material in the formation. A fluid may be, but is not limited to, a gas, a liquid, an emulsion, a slurry, and/or a stream of solid particles that has flow characteristics similar to liquid flow.

[0003] Many different types of wells or wellbores may be used to treat the hydrocarbon containing formation using an in situ heat treatment process. In some embodiments, vertical and/or substantially vertical wells are used to treat the formation. In some embodiments, horizontal or substantially horizontal wells (such as J-shaped wells and/or L-shaped wells), and/or u-shaped wells are used to treat the formation. In some embodiments, combinations of horizontal wells, vertical wells, and/or other combinations are used to treat the formation. In certain embodiments, wells extend through the overburden of the formation to a hydrocarbon containing layer of the formation. In some situations, heat in the wells is lost to the overburden. In some situations, surface and overburden infrastructures used to support heaters and/or production equipment in horizontal wellbores or u-shaped wellbores are large in size and/or numerous.

[0004] U.S. Patent No. 7,575,052 to Sandberg et al. describes an in situ heat treatment process that utilizes a circulation system to heat one or more treatment areas. The circulation system may use a heated liquid heat transfer fluid that passes through piping in the formation to transfer heat to the formation.

[0005] U.S. Patent Application Publication No. 2008-0135254 to Vinegar et al. describes systems and methods for an in situ heat treatment process that utilizes a circulation system to heat one or more treatment areas. The circulation system uses a heated liquid heat transfer fluid that passes through piping in the formation to transfer heat to the formation. In some embodiments, the piping is positioned in at least two wellbores.

[0006] U.S. Patent Application Publication No. 2009-0095476 to Nguyen et al. describes a heating system for a subsurface formation includes a conduit located in an opening in the subsurface formation. An insulated conductor is located in the conduit. A material is in the conduit between a portion of the insulated conductor and a portion of the conduit. The material may be a salt. The material is a fluid at operating temperature of the heating system. Heat transfers from the insulated conductor to the fluid, from the fluid to the conduit, and from the conduit to the subsurface formation.

[0007] There has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations. At present, however, there are still many hydrocarbon containing formations from which hydrocarbons, hydrogen, and/or other products cannot be economically produced. There is also a need for improved methods and systems that reduce energy costs for treating the formation, reduce emissions from the treatment process, facilitate heating system installation, and/or reduce heat loss to the overburden as compared to hydrocarbon recovery processes that utilize surface based equipment.

SUMMARY

[0008] Embodiments described herein generally relate to systems and methods for treating a subsurface formation.

[0009] The invention, in some embodiments provides, a method for heating a subsurface formation, comprising: applying heat from a plurality of heaters to the formation; and allowing a portion of one or more of the heaters to move out of wellheads equipped with sliding seals to accommodate thermal expansion of the heaters.

[0010] The invention, in some embodiments provides, a method for heating a subsurface formation, comprising: applying heat from a plurality of heaters to the formation; and allowing a portion of one or more of the heaters to move out of wellheads using one or more slip joints.

[0011] The invention, in some embodiments provides, a method for accommodating thermal expansion of a heater in a formation, comprising: heating a heater in the formation; and lifting a portion of the heater out of the formation to accommodate thermal expansion of the heater.

[0012] The invention, in some embodiments provides, a system for heating a subsurface formation, comprising: a plurality of heaters positioned in the formation, the heaters configured to provide heat to the formation; and at least one lifter coupled to a portion of a heater, the lifter configured to lift portions of the heater out of the formation to accommodate thermal expansion of the heater.

[0013] In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments. In further embodiments, treating a subsurface formation is performed using any of the methods and systems described herein. In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings in which:

[0015] FIG. 1 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

[0016] FIG. 2 depicts a schematic representation of an embodiment of a heat transfer fluid circulation system for heating a portion of a formation.

[0017] FIG. 3 depicts a schematic representation of an embodiment of an L-shaped heater for use with a heat transfer fluid circulation system for heating a portion of a formation.

[0018] FIG. 4 depicts a schematic representation of an embodiment of a vertical heater for use with a heat transfer fluid circulation system for heating a portion of a formation where thermal expansion of the heater is accommodated below the surface.

[0019] FIG. 5 depicts a schematic representation of another embodiment of a vertical heater for use with a heat transfer fluid circulation system for heating a portion of a formation where thermal expansion of the heater is accommodated above and below the surface.

[0020] FIG. 6 depicts a cross-sectional view of an embodiment of overburden insulation that utilizes insulating cement.

[0021] FIG. 7 depicts a cross-sectional view of an embodiment of overburden insulation that utilizes an insulating sleeve.

[0022] FIG. 8 depicts a cross-sectional view of an embodiment of overburden insulation that utilizes an insulating sleeve and a vacuum.

[0023] FIG. 9 depicts a representation an embodiment of bellows used to accommodate thermal expansion.

[0024] FIG. 10A depicts a representation of an embodiment of piping with an expansion loop for accommodating thermal expansion.

[0025] FIG. 10B depicts a representation of an embodiment of piping with coiled or spooled piping for accommodating thermal expansion.

[0026] FIG. 10C depicts a representation of an embodiment of piping with coiled or spooled piping for accommodating thermal expansion enclosed in an insulated volume.

[0027] FIG. 11 depicts a representation of an embodiment of insulated piping in a large diameter casing in the overburden.

[0028] FIG. 12 depicts a representation of an embodiment of insulated piping in a large diameter casing in the overburden to accommodate thermal expansion.

[0029] FIG. 13 depicts a representation of an embodiment of a wellhead with a sliding seal, stuffing box, or other pressure control equipment that allows a portion of a heater to move relative to the wellhead.

[0030] FIG. 14 depicts a representation of an embodiment of a wellhead with a slip joint that interacts with a fixed conduit above the wellhead.

[0031] FIG. 15 depicts a representation of an embodiment of a wellhead with a slip joint that interacts with a fixed conduit coupled to the wellhead.

[0032] FIG. 16 depicts a schematic representation of an embodiment a heat transfer fluid circulating system with seals.

[0033] FIG. 17 depicts a schematic representation of another embodiment a heat transfer fluid circulating system with seals.

[0034] FIG. 18 depicts a schematic representation an embodiment a heat transfer fluid circulating system with locking mechanisms and seals.

[0035] FIG. 19 depicts a representation of a u-shaped wellbore with a hot heat transfer fluid circulation system heater positioned in the wellbore.

[0036] FIG. 20 depicts an end view representation of an embodiment of a conduit-in-conduit heater for a heat transfer circulation heating system adjacent to the treatment area.

[0037] FIG. 21 depicts a representation of an embodiment for heating various portions of a heater to restart flow of heat transfer fluid in the heater.

[0038] FIG. 22 depicts a schematic of an embodiment of conduit-in-conduit heaters of a fluid circulation heating system positioned in the formation.

[0039] FIG. 23 depicts a cross-sectional view of an embodiment of a conduit-in-conduit heater adjacent to the overburden.

[0040] FIG. 24 depicts a schematic representation of an embodiment of a circulation system for a liquid heat transfer fluid.

[0041] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but on the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the present invention as defined by the appended claims.

DETAILED DESCRIPTION

[0042] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products, hydrogen, and other products.

[0043] "API gravity" refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.

[0044] "Fluid pressure" is a pressure generated by a fluid in a formation. "Lithostatic pressure" (sometimes referred to as "lithostatic stress") is a pressure in a formation equal to a weight per unit area of an overlying rock mass. "Hydrostatic pressure" is a pressure in a formation exerted by a column of water.

[0045] A "formation" includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. "Hydrocarbon layers" refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The “overburden” and/or the “underburden” include one or more different types of impermeable materials. For example, the overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate. In some embodiments of in situ heat treatment processes, the overburden and/or the underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ heat treatment processing that result in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or the underburden. For example, the underburden may contain shale or mudstone, but the underburden is not allowed to heat to pyrolysis temperatures during the in situ heat treatment process. In some cases, the overburden and/or the underburden may be somewhat permeable.

[0046] “Formation fluids” refer to fluids present in a formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbons, and water (steam). Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. The term “mobilized fluid” refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. “Produced fluids” refer to fluids removed from the formation.

[0047] A “heat source” is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may electrically conducting materials and/or include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed in a conduit. A heat source may also include systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. Thus, for example, for a given formation some heat sources may supply heat from electrically conducting materials, electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (for example, chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (for example, an oxidation reaction). A heat source may also include a electrically conducting material and/or a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0048] A "heater" is any system or heat source for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors that react with material in or produced from a formation, and/or combinations thereof.

[0049] "Heavy hydrocarbons" are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.

[0050] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. "Relatively permeable" is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). "Relatively low permeability" is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.

[0051] Certain types of formations that include heavy hydrocarbons may also include, but are not limited to, natural mineral waxes, or natural asphaltites. "Natural mineral waxes" typically occur in substantially tubular veins that may be several meters wide, several kilometers long, and hundreds of meters deep. "Natural asphaltites" include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of hydrocarbons from the formations.

[0052] “Hydrocarbons” are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. “Hydrocarbon fluids” are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

[0053] An “in situ conversion process” refers to a process of heating a hydrocarbon containing formation from heat sources to raise the temperature of at least a portion of the formation above a pyrolysis temperature so that pyrolyzation fluid is produced in the formation.

[0054] An “in situ heat treatment process” refers to a process of heating a hydrocarbon containing formation with heat sources to raise the temperature of at least a portion of the formation above a temperature that results in mobilized fluid, visbreaking, and/or pyrolysis of hydrocarbon containing material so that mobilized fluids, visbroken fluids, and/or pyrolyzation fluids are produced in the formation.

[0055] “Insulated conductor” refers to any elongated material that is able to conduct electricity and that is covered, in whole or in part, by an electrically insulating material.

[0056] “Pyrolysis” is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause pyrolysis.

[0057] “Pyrolyzation fluids” or “pyrolysis products” refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, “pyrolysis zone” refers to a volume of a formation (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

[0058] “Superposition of heat” refers to providing heat from two or more heat sources to a selected section of a formation such that the temperature of the formation at least at one location between the heat sources is influenced by the heat sources.

[0059] A “tar sands formation” is a formation in which hydrocarbons are predominantly present in the form of heavy hydrocarbons and/or tar entrained in a mineral grain framework or other host lithology (for example, sand or carbonate). Examples of tar sands formations include formations such as the Athabasca formation, the Grosmont formation, and the Peace River formation, all three in Alberta, Canada; and the Faja formation in the Orinoco belt in Venezuela.

[0060] “Temperature limited heater” generally refers to a heater that regulates heat output (for example, reduces heat output) above a specified temperature without the use of external controls such as temperature controllers, power regulators, rectifiers, or other devices. Temperature limited heaters may be AC (alternating current) or modulated (for example, “chopped”) DC (direct current) powered electrical resistance heaters.

[0061] “Thickness” of a layer refers to the thickness of a cross section of the layer, wherein the cross section is normal to a face of the layer.

[0062] A "u-shaped wellbore" refers to a wellbore that extends from a first opening in the formation, through at least a portion of the formation, and out through a second opening in the formation. In this context, the wellbore may be only roughly in the shape of a "v" or "u", with the understanding that the "legs" of the "u" do not need to be parallel to each other, or perpendicular to the "bottom" of the "u" for the wellbore to be considered "u-shaped".

[0063] “Upgrade” refers to increasing the quality of hydrocarbons. For example, upgrading heavy hydrocarbons may result in an increase in the API gravity of the heavy hydrocarbons.

[0064] “Visbreaking” refers to the untangling of molecules in fluid during heat treatment and/or to the breaking of large molecules into smaller molecules during heat treatment, which results in a reduction of the viscosity of the fluid.

[0065] “Viscosity” refers to kinematic viscosity at 40 °C unless otherwise specified. Viscosity is as determined by ASTM Method D445.

[0066] The term “wellbore” refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or another cross-sectional shape. As used herein, the terms “well” and “opening,” when referring to an opening in the formation may be used interchangeably with the term "wellbore."

[0067] A formation may be treated in various ways to produce many different products. Different stages or processes may be used to treat the formation during an in situ heat treatment process. In some embodiments, one or more sections of the formation are solution mined to remove soluble minerals from the sections. Solution mining minerals may be performed before, during, and/or after the in situ heat treatment process. In some embodiments, the average temperature of one or more sections being solution mined may be maintained below about 120 °C.

[0068] In some embodiments, one or more sections of the formation are heated to remove water from the sections and/or to remove methane and other volatile hydrocarbons from the sections. In some embodiments, the average temperature may be raised from ambient temperature to temperatures below about 220 °C during removal of water and volatile hydrocarbons.

[0069] In some embodiments, one or more sections of the formation are heated to temperatures that allow for movement and/or visbreaking of hydrocarbons in the formation. In some embodiments, the average temperature of one or more sections of the formation are raised to mobilization temperatures of hydrocarbons in the sections (for example, to temperatures ranging from 100 °C to 250 °C, from 120 °C to 240 °C, or from 150 °C to 230 °C).

[0070] In some embodiments, one or more sections are heated to temperatures that allow for pyrolysis reactions in the formation. In some embodiments, the average temperature of one or more sections of the formation may be raised to pyrolysis temperatures of hydrocarbons in the sections (for example, temperatures ranging from 230 °C to 900 °C, from 240 °C to 400 °C or from 250 °C to 350 °C).

[0071] Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that raise the temperature of hydrocarbons in the formation to desired temperatures at desired heating rates. The rate of temperature increase through mobilization temperature range and/or pyrolysis temperature range for desired products may affect the quality and quantity of the formation fluids produced from the hydrocarbon containing formation. Slowly raising the temperature of the formation through the mobilization temperature range and/or pyrolysis temperature range may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the temperature of the formation through the mobilization temperature range and/or pyrolysis temperature range may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.

[0072] In some in situ heat treatment embodiments, a portion of the formation is heated to a desired temperature instead of slowly heating the temperature through a temperature range. In some embodiments, the desired temperature is 300 °C, 325 °C, or 350 °C. Other temperatures may be selected as the desired temperature.

[0073] Superposition of heat from heat sources allows the desired temperature to be relatively quickly and efficiently established in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at a desired temperature.

[0074] Mobilization and/or pyrolysis products may be produced from the formation through production wells. In some embodiments, the average temperature of one or more sections is raised to mobilization temperatures and hydrocarbons are produced from the production wells. The average temperature of one or more of the sections may be raised to pyrolysis temperatures after production due to mobilization decreases below a selected value. In some embodiments, the average temperature of one or more sections may be raised to pyrolysis temperatures without significant production before reaching pyrolysis temperatures. Formation fluids including pyrolysis products may be produced through the production wells.

[0075] In some embodiments, the average temperature of one or more sections may be raised to temperatures sufficient to allow synthesis gas production after mobilization and/or pyrolysis. In some embodiments, hydrocarbons may be raised to temperatures sufficient to allow synthesis gas production without significant production before reaching the temperatures sufficient to allow synthesis gas production. For example, synthesis gas may be produced in a temperature range from about 400 °C to about 1200 °C, about 500 °C to about 1100 °C, or about 550 °C to about 1000 °C. A synthesis gas generating fluid (for example, steam and/or water) may be introduced into the sections to generate synthesis gas. Synthesis gas may be produced from production wells.

[0076] Solution mining, removal of volatile hydrocarbons and water, mobilizing hydrocarbons, pyrolyzing hydrocarbons, generating synthesis gas, and/or other processes may be performed during the in situ heat treatment process. In some embodiments, some processes may be performed after the in situ heat treatment process. Such processes may include, but are not limited to, recovering heat from treated sections, storing fluids (for example, water and/or hydrocarbons) in previously treated sections, and/or sequestering carbon dioxide in previously treated sections.

[0077] FIG. 1 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 100. Barrier wells are used to form a barrier around a treatment area. The barrier inhibits fluid flow into and/or out of the treatment area. Barrier wells include, but are not limited to, dewatering wells, vacuum wells, capture wells, injection wells, grout wells, freeze wells, or combinations thereof. In some embodiments, barrier wells 100 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. In the embodiment depicted in FIG. 1, the barrier wells 100 are shown extending only along one side of heat sources 102, but the barrier wells typically encircle all heat sources 102 used, or to be used, to heat a treatment area of the formation.

[0078] Heat sources 102 are placed in at least a portion of the formation. Heat sources 102 may include electrically conducting materials. In some embodiments, heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 102 may also include other types of heaters. Heat sources 102 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 102 through supply lines 104. Supply lines 104 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 104 for heat sources may transmit electricity for electrically conducting materials or electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated in the formation. In some embodiments, electricity for an in situ heat treatment process may be provided by a nuclear power plant or nuclear power plants. The use of nuclear power may allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0079] Heating the formation may cause an increase in permeability and/or porosity of the formation. Increases in permeability and/or porosity may result from a reduction of mass in the formation due to vaporization and removal of water, removal of hydrocarbons, and/or creation of fractures. Fluid may flow more easily in the heated portion of the formation because of the increased permeability and/or porosity of the formation. Fluid in the heated portion of the formation may move a considerable distance through the formation because of the increased permeability and/or porosity. The considerable distance may be over 1000 m depending on various factors, such as permeability of the formation, properties of the fluid, temperature of the formation, and pressure gradient allowing movement of the fluid. The ability of fluid to travel considerable distance in the formation allows production wells 106 to be spaced relatively far apart in the formation.

[0080] Production wells 106 are used to remove formation fluid from the formation. In some embodiments, production well 106 includes a heat source. The heat source in the production well may heat one or more portions of the formation at or near the production well. In some in situ heat treatment process embodiments, the amount of heat supplied to the formation from the production well per meter of the production well is less than the amount of heat applied to the formation from a heat source that heats the formation per meter of the heat source. Heat applied to the formation from the production well may increase formation permeability adjacent to the production well by vaporizing and removing liquid phase fluid adjacent to the production well and/or by increasing the permeability of the formation adjacent to the production well by formation of macro and/or micro fractures.

[0081] In some embodiments, the heat source in production well 106 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C_6 hydrocarbons and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0082] Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of thermal expansion of in situ fluids, increased fluid generation and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation. Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.

[0083] In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been mobilized and/or pyrolyzed. Formation fluid may be produced from the formation when the formation fluid is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are mobilized and/or pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

[0084] In some embodiments, pressure generated by expansion of mobilized fluids, pyrolysis fluids or other fluids generated in the formation may be allowed to increase although an open path to production wells 106 or any other pressure sink may not yet exist in the formation. The fluid pressure may be allowed to increase towards a lithostatic pressure. Fractures in the hydrocarbon containing formation may form when the fluid approaches the lithostatic pressure. For example, fractures may form from heat sources 102 to production wells 106 in the heated portion of the formation. The generation of fractures in the heated portion may relieve some of the pressure in the portion. Pressure in the formation may have to be maintained below a selected pressure to inhibit unwanted production, fracturing of the overburden or underburden, and/or coking of hydrocarbons in the formation.

[0085] After mobilization and/or pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

[0086] In some in situ heat treatment process embodiments, pressure in the formation may be maintained high enough to promote production of formation fluid with an API gravity of greater than 20°. Maintaining increased pressure in the formation may inhibit formation subsidence during in situ heat treatment. Maintaining increased pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

[0087] Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a minimal amount of compounds above a selected carbon number. The selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. Maintaining increased pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. High carbon number compounds and/or multi-ring hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

[0088] Formation fluid produced from production wells 106 may be transported through collection piping 108 to treatment facilities 110. Formation fluids may also be produced from heat sources 102. For example, fluid may be produced from heat sources 102 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 102 may be transported through tubing or piping to collection piping 108 or the produced fluid may be transported through tubing or piping directly to treatment facilities 110. Treatment facilities 110 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and/or other systems and units for processing produced formation fluids. The treatment facilities may form transportation fuel from at least a portion of the hydrocarbons produced from the formation. In some embodiments, the transportation fuel may be jet fuel, such as JP-8.

[0089] In certain embodiments, heat sources, heat source power sources, production equipment, supply lines, and/or other heat source or production support equipment are positioned in tunnels to enable smaller sized heat sources and/or smaller sized equipment to be used to treat the formation. Positioning such equipment and/or structures in tunnels may also reduce energy costs for treating the formation, reduce emissions from the treatment process, facilitate heating system installation, and/or reduce heat loss to the overburden as compared to hydrocarbon recovery processes that utilize surface based equipment. The tunnels may be, for example, substantially horizontal tunnels and/or inclined tunnels.

[0090] In some in situ heat treatment process embodiments, a circulation system is used to heat the formation. Using the circulation system for in situ heat treatment of a hydrocarbon containing formation may reduce energy costs for treating the formation, reduce emissions from the treatment process, and/or facilitate heating system installation. In certain embodiments, the circulation system is a closed loop circulation system. FIG. 2 depicts a schematic representation of a system for heating a formation using a circulation system. The system may be used to heat hydrocarbons that are relatively deep in the ground and that are in formations that are relatively large in extent. In some embodiments, the hydrocarbons may be 100 m, 200 m, 300 m or more below the surface. The circulation system may also be used to heat hydrocarbons that are not as deep in the ground. The hydrocarbons may be in formations that extend lengthwise up to 1000 m, 3000 m, 5000 m, or more. The heaters of the circulation system may be positioned relative to adjacent heaters such that superposition of heat between heaters of the circulation system allows the temperature of the formation to be raised at least above the boiling point of aqueous formation fluid in the formation.

[0091] In some embodiments, heaters 200 may be formed in the formation by drilling a first wellbore and then drilling a second wellbore that connects with the first wellbore. Piping may be positioned in the u-shaped wellbore to form u-shaped heater 200. Heaters 200 are connected to heat transfer fluid circulation system 202 by piping. In some embodiments, the heaters are positioned in triangular patterns. In some embodiments, other regular or irregular patterns are used. Production wells and/or injection wells may also be located in the formation. The production wells and/or the injection wells may have long substantially horizontal sections similar to the heating portions of heaters 200, or the production wells and/or injection wells may be otherwise oriented (for example, the wells may be vertically oriented wells, or wells that include one or more slanted portions).

[0092] As depicted in FIG. 2, heat transfer fluid circulation system 202 may include heat supply 204, first heat exchanger 206, second heat exchanger 208, and fluid movers 210. Heat supply 204 heats the heat transfer fluid to a high temperature. Heat supply 204 may be a furnace, solar collector, chemical reactor, nuclear reactor, fuel cell, and/or other high temperature source able to supply heat to the heat transfer fluid. If the heat transfer fluid is a gas, fluid movers 210 may be compressors. If the heat transfer fluid is a liquid, fluid movers 210 may be pumps.

[0093] After exiting formation 212, the heat transfer fluid passes through first heat exchanger 206 and second heat exchanger 208 to fluid movers 210. First heat exchanger 206 transfers heat between heat transfer fluid exiting formation 212 and heat transfer fluid exiting fluid movers 210 to raise the temperature of the heat transfer fluid that enters heat supply 204 and reduce the temperature of the fluid exiting formation 212. Second heat exchanger 208 further reduces the temperature of the heat transfer fluid. In some embodiments, second heat exchanger 208 includes or is a storage tank for the heat transfer fluid.

[0094] Heat transfer fluid passes from second heat exchanger 208 to fluid movers 210. Fluid movers 210 may be located before heat supply 204 so that the fluid movers do not have to operate at a high temperature.

[0095] In an embodiment, the heat transfer fluid is carbon dioxide. Heat supply 204 is a furnace that heats the heat transfer fluid to a temperature in a range from about 700 °C to about 920 °C, from about 770 °C to about 870 °C, or from about 800 °C to about 850 °C. In an embodiment, heat supply 204 heats the heat transfer fluid to a temperature of about 820 °C. The heat transfer fluid flows from heat supply 204 to heaters 200. Heat transfers from heaters 200 to formation 212 adjacent to the heaters. The temperature of the heat transfer fluid exiting formation 212 may be in a range from about 350 °C to about 580 °C, from about 400 °C to about 530 °C, or from about 450 °C to about 500 °C. In an embodiment, the temperature of the heat transfer fluid exiting formation 212 is about 480 °C. The metallurgy of the piping used to form heat transfer fluid circulation system 202 may be varied to significantly reduce costs of the piping. High temperature steel may be used from heat supply 204 to a point where the temperature is sufficiently low so that less expensive steel can be used from that point to first heat exchanger 206. Several different steel grades may be used to form the piping of heat transfer fluid circulation system 202.

[0096] In some embodiments, solar salt (for example, a salt containing 60 wt% $NaNO_3$ and 40 wt% KNO_3) is used as the heat transfer fluid in the circulated fluid system. Solar salt may have a melting point of about 230 °C and an upper working temperature limit of about 565 °C. In some embodiments, $LiNO_3$ (for example, between about 10% by weight and about 30% by weight $LiNO_3$) may be added to the solar salt to produce tertiary salt mixtures with wider operating temperature ranges and lower melting temperatures with only a slight decrease in the maximum working temperature as compared to solar salt. The lower melting temperature of the tertiary salt mixtures may decrease the preheating requirements and allow the use of pressurized water and/or pressurized brine as a heat transfer fluid for preheating the piping of the circulation system. The corrosion rates of the metal of the heaters due to the tertiary salt compositions at 550 °C is comparable to the corrosion rate of the metal of the heaters due to solar salt at 565 °C. TABLE 1 shows melting points and upper limits for solar salt and tertiary salt mixtures. Aqueous solutions of tertiary salt mixtures may transition into a molten salt upon removal of water without solidification, thus allowing the molten salts to be provided and/or stored as aqueous solutions.

TABLE 1

NO_3 Salt	Composition of NO_3 Salt (weight %)	Melting Point (°C) of NO_3 salt	Upper working temperature limit (°C) of NO_3 salt
Na:K	60:40	230	600
Li:Na:K	12:18:70	200	550
Li:Na:K	20:28:52	150	550
Li:Na:K	27:33:40	160	550
Li:Na:K	30:18:52	120	550

[0097] Heat supply 204 may be a furnace that heats the heat transfer fluid to a temperature of about 560 °C. The return temperature of the heat transfer fluid may be from about 350 °C to about 450 °C. Piping from heat transfer fluid circulation system 202 may be insulated and/or heat traced to facilitate startup and to ensure fluid flow.

[0098] In some embodiments vertical, slanted, or L-shaped wells heater wellbores may be used instead of u-shaped wellbores (for example, wellbores that have an entrance at a first location and an exit at another location). FIG. 3 depicts L-shaped heater 200. Heater 200 may be coupled to heat transfer fluid circulation system 202 and may include inlet conduit 214, and outlet conduit 216. Heat transfer fluid circulation system 202 may supply heat transfer fluid to multiple heaters. Heat transfer fluid from heat transfer fluid circulation system 202 may flow down inlet conduit 214 and back up outlet conduit 216. Inlet conduit 214 and outlet conduit 216 may be insulated through overburden 218. In some embodiments, inlet conduit 214 is insulated through overburden 218 and hydrocarbon containing layer 220 to inhibit undesired heat transfer between ingoing and outgoing heat transfer fluid.

[0099] In some embodiments, portions of wellbore 222 adjacent to overburden 218 are larger than portions of the wellbore adjacent to hydrocarbon containing layer 220. Having a larger opening adjacent to the overburden may allow for accommodation of insulation used to insulate inlet conduit 214 and/or outlet conduit 216. Some heat loss to the overburden from the return flow may not affect the efficiency significantly, especially when the heat transfer fluid is molten salt or another fluid that needs to be heated to remain a liquid. The heated overburden adjacent to heater 200 may maintain the heat transfer fluid as a liquid for a significant time should circulation of heat transfer fluid stop. Having some allowance for some heat transfer to overburden 218 may eliminate the need for expensive insulation systems between outlet conduit 216 and the overburden. In some embodiments, insulative cement is used between overburden 218 and outlet conduit 216.

[0100] For vertical, slanted, or L-shaped heaters, the wellbores may be drilled longer than needed to accommodate non-energized heaters (for example, installed but inactive heaters). Thermal expansion of the heaters after energization may cause portions of the heaters to move into the extra length of the wellbores designed to accommodate the thermal expansion of the heaters. For L-shaped heaters, remaining drilling fluid and/or formation fluid in the wellbore may facilitate movement of the heater deeper into the wellbore as the heater expands during preheating and/or heating with heat transfer fluid.

[0101] For vertical or slanted wellbores, the wellbores may be drilled deeper than needed to accommodate the non-energized heaters. When the heater is preheated and/or heated with the heat transfer fluid, the heater may expand into the extra depth of the wellbore. In some embodiments, an expansion sleeve may be attached at the end of the heater to ensure available space for thermal expansion in case of unstable boreholes.

[0102] FIG. 4 depicts a schematic representation of an embodiment of a portion of vertical heater 200. Heat transfer fluid circulation system 202 may provide heat transfer fluid to inlet conduit 214 of heater 200. Heat transfer fluid circulation system 202 may receive heat transfer fluid from outlet conduit heat 216. Inlet conduit 214 may be secured to outlet conduit 216 by welds 228. Inlet conduit 214 may include insulating sleeve 224. Insulating sleeve 224 may be formed of a number of sections. Each section of insulating sleeve 224 for inlet conduit 214 is able to accommodate the thermal expansion caused by the temperature difference between the temperature of the inlet conduit and the temperature outside the insulating sleeve. Change in length of inlet conduit 214 and insulation sleeve 224 due to thermal expansion is accommodated in outlet conduit 216.

[0103] Outlet conduit 216 may include insulating sleeve 224'. Insulating sleeve 224' may end near the boundary between overburden 218 and hydrocarbon layer 220. In some embodiments, insulating sleeve 224' is installed using a coiled tubing rig. An upper first portion of insulating sleeve 224' may be secured to outlet conduit 216 above or near wellhead 226 by weld 228. Heater 200 may be supported in wellhead 226 by a coupling between the outer support member of insulating sleeve 224' and the wellhead. The outer support member of insulating sleeve 224' may have sufficient strength to support heater 200.

[0104] In some embodiments, insulating sleeve 224' includes a second portion (insulating sleeve portion 224'') that is separate and lower than the first portion of insulating sleeve 224'. Insulating sleeve portion 224'' may be secured to outlet conduit 216 by welds 228 or other types of seals that can withstand high temperatures below packer 230. Welds 228 between insulating sleeve portion 224'' and outlet conduit 216 may inhibit formation fluid from passing between the insulating sleeve and the outlet conduit. During heating, differential thermal expansion between the cooler outer surface and the hotter inner surface of insulating sleeve 224' may cause separation between the first portion of the insulating sleeve and the second portion of the insulating sleeve (insulating sleeve portion 224''). This separation may occur adjacent to the overburden portion of heater 200 above packer 230. Insulating cement between casing 238 and the formation may further inhibit heat loss to the formation and improve the overall energy efficiency of the system.

[0105] Packer 230 may be a polished bore receptacle. Packer 230 may be fixed to casing 238 of the wellbore 222. In some embodiments, packer 230 is 1000 m or more below the surface. Packer 230 may be located at a depth above 1000 m if desired. Packer 230 may inhibit formation fluid from flowing from the heated portion of the formation up the wellbore to wellhead 226. Packer 230 may allow movement of insulating sleeve portion 224'' downwards to accommodate thermal expansion of heater 200.

[0106] In some embodiments, wellhead 226 includes fixed seal 232. Fixed seal 232 may be a second seal that inhibits formation fluid from reaching the surface through wellbore 222 of heater 200.

[0107] FIG. 5 depicts a schematic representation of another embodiment of a portion of vertical heater 200 in wellbore 222. The embodiment depicted in FIG. 5 is similar to the embodiment depicted in FIG. 4, but fixed seal 232 is located adjacent to overburden 218, and sliding seal 234 is located in wellhead 226. The portion of insulating sleeve 224' from fixed seal 232 to wellhead 226 is able to expand upward out of the wellhead to accommodate thermal expansion. The portion of heater located below fixed seal 232 is able to expand into the excess length of wellbore 222 to accommodate thermal expansion.

[0108] In some embodiments, the heater includes a flow switcher. The flow switcher may allow the heat transfer fluid from the circulation system to flow down through the overburden in the inlet conduit of the heater. The return flow from the heater may flow upwards through the annular region between the inlet conduit and the outlet conduit. The flow switcher may change the downward flow from the inlet conduit to the annular region between the outlet conduit and the inlet conduit. The flow switcher may also change the upward flow from the inlet conduit to the annular region. The use of the flow switcher may allow the heater to operate at a higher temperature adjacent to the treatment area without increasing the initial temperature of the heat transfer fluid provided to the heaters.

[0109] For vertical, slanted, or L-shaped heaters where the flow of heat transfer fluid is directed down the inlet conduit and returns through the annular region between the inlet conduit and the outlet conduit, a temperature gradient may form in the heater with the hottest portion being located at a distal end of the heater. For L-shaped heaters, horizontal portions of a set of first heaters may be alternated with the horizontal portions of a second set of heaters. The hottest portions used to heat the formation of the first set of heaters may be adjacent to the coldest portions used to heat the formation of the second set of heaters, while the hottest portions used to heat the formation of the second set of heaters are adjacent to the coldest portions used to heat the formation of the first set of heaters. For vertical or slanted heaters, flow switchers in selected heaters may allow the heaters to be arranged with the hottest portions used to heat the formation of first heaters adjacent to coldest portions used to heat the formation of second heaters. Having hottest portions used to heat the formation of the first set of heaters adjacent to coldest portions used to heat the formation of the second set of heaters may allow for more uniform heating of the formation.

[0110] In some embodiments, the diameter of the conduit through which the heat transfer fluid flows in overburden 218 may be smaller than the diameter of the conduit through the treatment area. For example, the diameter of the pipe in the overburden may be about 3 inches (about 7.6 cm), and the diameter of the pipe adjacent to the treatment area may be about 5 inches (about 12.7 cm). The smaller diameter pipe through overburden 218 may reduce heat loss from the heat transfer fluid to the overburden. Reducing heat loss to overburden 218 reduces cooling of the heat transfer fluid supplied to the conduit adjacent to hydrocarbon layer 220. In certain embodiments, any increased heat loss in the smaller diameter pipe due to increased velocity of the heat transfer fluid through the smaller diameter pipe is offset by the smaller surface area of the smaller diameter pipe and the decrease in residence time of the heat transfer fluid in the smaller diameter pipe.

[0111] Heat transfer fluid from heat supply 204 of heat transfer fluid circulation system 202 passes through overburden 218 of formation 212 to hydrocarbon layer 220. In certain embodiments, portions of heaters 200 extending through overburden 218 are insulated. In some embodiments, the insulation or part of the insulation is a polyimide insulating material. In some embodiments, inlet portions of heaters 200 in hydrocarbon layer 220 have tapering insulation to reduce overheating of the hydrocarbon layer near the inlet of the heater into the hydrocarbon layer.

[0112] The overburden section of heaters 200 may be insulated to prevent or inhibit heat loss into non-hydrocarbon bearing zones of the formation. In some embodiments, thermal insulation is provided by a conduit-in-conduit design. The heat transfer fluid flows through the inner conduit. Insulation fills the space between the inner conduit and the outer conduit. An effective insulation may be a combination of metal foil to inhibit radiative heat loss and microporous silica powder to inhibit conductive heat loss. Reducing the pressure in the space between the inner conduit and the outer conduit by pulling a vacuum during assembly and/or with getters may further reduce heat losses when using the conduit-in-conduit design. To account for the differential thermal expansion of the inner conduit and the outer conduit, the inner conduit may be pre-stressed or made of a material with low thermal expansion (for example, Invar alloys). The insulated conduit-in-conduit may be installed continuously in conjunction with coiled tubing installation. Insulated conduit-in-conduit systems may be available from Industrial Thermo Polymers Limited (Ontario, Canada) and Oil Tech Services, Inc. (Houston, Texas, U.S.A.). Other effective insulation materials include, but are not limited to, ceramic blankets, foam cements, cements with low thermal conductivity aggregates (such as vermiculite), Izoflex™ insulation, and aerogel/glass-fiber composites such as those provided by Aspen Aerogels, Inc. (Northborough, Massachusetts, U.S.A.).

[0113] FIG. 6 depicts a cross-sectional view of an embodiment of overburden insulation. Insulating cement 236 may be placed between casing 238 and formation 212. Insulating cement 236 may also be placed between heat transfer fluid conduit 240 and casing 238.

[0114] FIG. 7 depicts a cross-sectional view of an alternate embodiment of overburden insulation that includes insulating sleeve 224 around heat transfer fluid conduit 240. Insulating sleeve 224 may include, for example, an aerogel. Gap 242 may be located between insulating sleeve 224 and casing 238. The emissivities of insulating sleeve 224 and casing 238 may be low to inhibit radiative heat transfer in gas 242. A non-reactive gas may be placed in gap 242 between insulating sleeve 224 and casing 238. Gas in gap 242 may inhibit conductive heat transfer between insulating sleeve 224 and casing 238. In some embodiments, a vacuum may be drawn and maintained in gap 242. Insulating cement 236 may be placed between casing 238 and formation 212. In some embodiments, insulating sleeve 224 has a significantly smaller thermal conductivity value than the thermal conductivity value of insulating cement. In certain embodiments, the insulation provided by the insulation depicted in FIG. 7 may be better than the insulation provided by the insulation depicted in FIG. 6.

[0115] FIG. 8 depicts a cross-sectional view of an alternative embodiment of overburden insulation with insulating sleeve 224 around heat transfer fluid conduit 240, vacuum gap 244 between the insulating sleeve and conduit 246, and gap 242 between the conduit and casing 238. Insulating cement 236 may be placed between casing 238 and formation 212. A non-reactive gas may be placed in gap 242 between conduit 246 and casing 238. In some embodiments, a vacuum may be drawn and maintained in gap 242. A vacuum may be drawn and maintained in vacuum gap 244 between insulating sleeve 224 and conduit 246. Insulating sleeve 224 may include layers of insulating material separated by foil 248. The insulation material may be, for example, aerogel. The layers of insulating material separated by foil 248 may provide substantial insulation around heat transfer fluid conduit 240. Vacuum gap 244 may inhibit radiative, convective, and/or conductive heat transfer between insulating sleeve 224 and conduit 246. A non-reactive gas may be placed in gap 242. The emissivities of conduit 246 and casing 238 may be low to inhibit radiative heat transfer between the conduit and the casing. In certain embodiments, the insulation provided by the insulation depicted in FIG. 8 may be better than the insulation provided by the insulation depicted in FIG. 7.

[0116] When heat transfer fluid is circulated through piping in the formation to heat the formation, the heat of the heat transfer fluid may cause changes in the piping. The heat in the piping may reduce the strength of the piping since Young's modulus and other strength characteristics vary with temperature. The high temperatures in the piping may raise creep concerns, may cause buckling conditions, and may move the piping from the elastic deformation region to the plastic deformation region.

[0117] Heating the piping may cause thermal expansion of the piping. For long heaters placed in the wellbore, the piping may expand 20 m or more. In some embodiments, the horizontal portion of the piping is cemented in the formation with thermally conductive cement. Care may need to be taken to ensure that there are no significant gaps in the cement to inhibit expansion of the piping into the gaps and possible failure. Thermal expansion of the piping may cause ripples in the pipe and/or an increase in the wall thickness of the pipe.

[0118] For long heaters with gradual bend radii (for example, about 10° of bend per 30 m), thermal expansion of the piping may be accommodated in the overburden or at the surface of the formation. After thermal expansion is completed, the position of the heaters relative to the wellheads may be secured. When heating is finished and the formation is cooled, the position of the heaters may be unsecured so that thermal contraction of the heaters does not destroy the heaters.

[0119] FIGS. 9-19 depict schematic representations of various methods for accommodating thermal expansion. In some embodiments, change in length of the heater due to thermal expansion may be accommodated above the wellhead. After substantial changes in the length of the heater due to thermal expansion cease, the heater position relative to the wellhead may be fixed. The heater position relative to the wellhead may remain fixed until the end of heating of the formation. After heating is ended, the position of the heater relative to the wellhead may be freed (unfixed) to accommodate thermal contraction of the heater as the heater cools.

[0120] FIG. 9 depicts a representation of bellows 250. Length L of bellows 250 may change to accommodate thermal expansion and/or contraction of piping 252. Bellows 250 may be located subsurface or above the surface. In some embodiments, bellows 250 includes a fluid that transfers heat out of the wellhead.

[0121] FIG. 10A depicts a representation of piping 252 with expansion loop 254 above wellhead 226 for accommodating thermal expansion. Sliding seals in wellhead 226, stuffing boxes, or other pressure control equipment of the wellhead allow piping 252 to move relative to casing 238. Expansion of piping 252 is accommodated in expansion loop 254. In some embodiments, two or more expansion loops 254 are used to accommodate expansion of piping 252.

[0122] FIG. 10B depicts a representation of piping 252 with coiled or spooled piping 256 above wellhead 226 for accommodating thermal expansion. Sliding seals in wellhead 226, stuffing boxes, or other pressure control equipment of the wellhead allow piping 252 to move relative to casing 238. Expansion of piping 252 is accommodated in coiled piping 256. In some embodiments, expansion is accommodated by coiling the portion of the heater exiting the formation on a spool using a coiled tubing rig.

[0123] In some embodiments, coiled piping 256 may be enclosed in insulated volume 258, as shown in FIG. 10C. Enclosing coiled piping 256 in insulated volume 258 may reduce heat loss from the coiled piping and fluids inside the coiled piping. In some embodiments, coiled piping 256 has a diameter between 2' (about 0.6 m) and 4' (about 1.2 m) to accommodate up to about 30' (about 9.1 m) of expansion in piping 252.

[0124] FIG. 11 depicts a portion of piping 252 in overburden 218 after thermal expansion of the piping has occurred. Casing 238 has a large diameter to accommodate buckling of piping 252. Insulating cement 236 may be between overburden 218 and casing 238. Thermal expansion of piping 252 causes helical or sinusoidal buckling of the piping. The helical or sinusoidal buckling of piping 252 accommodates the thermal expansion of the piping, including the horizontal piping adjacent to the treatment area being heated. As depicted in FIG. 12, piping 252 may be more than one conduit positioned in large diameter casing 238. Having piping 252 as multiple conduits allows for accommodation of thermal expansion of all of the piping in the formation without increasing the pressure drop of the fluid flowing through piping in overburden 218.

[0125] In some embodiments, thermal expansion of subsurface piping is translated up to the wellhead. Expansion may be accommodated by one or more sliding seals at the wellhead. The seals may include Grafoil® gaskets, Stellite® gaskets, and/or Nitronic® gaskets. In some embodiments, the seals include seals available from BST Lift Systems, Inc. (Ventura, California, U.S.A.).

[0126] FIG. 13 depicts a representation of wellhead 226 with sliding seal 234. Wellhead 226 may include a stuffing box and/or other pressure control equipment. Circulated fluid may pass through conduit 240. Conduit 240 may be at least partially surrounded by insulated conduit 224. The use of insulated conduit 224 may obviate the need for a high temperature sliding seal and the need to seal against the heat transfer fluid. Expansion of conduit 240 may be handled at the surface with expansion loops, bellows, coiled or spooled pipe, and/or sliding joints. In some embodiments, packers 260 between insulated conduit 224 and casing 238 seal the wellbore against formation pressure and hold gas for additional insulation. Packers 260 may be inflatable packers and/or polished bore receptacles. In certain embodiments, packers 260 are operable up to temperatures of about 600 °C. In some embodiments, packers 260 include seals available from BST Lift Systems, Inc. (Ventura, California, U.S.A.).

[0127] In some embodiments, thermal expansion of subsurface piping is handled at the surface with a slip joint that allows the heat transfer fluid conduit to expand out of the formation to accommodate the thermal expansion. Hot heat transfer fluid may pass from a fixed conduit into the heat transfer fluid conduit in the formation. Return heat transfer fluid from the formation may pass from the heat transfer fluid conduit into the fixed conduit. A sliding seal between the fixed conduit and the piping in the formation, and a sliding seal between the wellhead and the piping in the formation, may accommodate expansion of the heat transfer fluid conduit as the slip joint.

[0128] FIG. 14 depicts a representation of a system where heat transfer fluid in conduit 240 is transferred to or from fixed conduit 262. Insulating sleeve 224 may surround conduit 240. Sliding seal 234 may be between insulated sleeve 224 and wellhead 226. Packers between insulating sleeve 224 and casing 238 may seal the wellbore against formation pressure. Heat transfer fluid seals 264 may be positioned between a portion of fixed conduit 262 and conduit 240. Heat transfer fluid seals 264 may be secured to fixed conduit 262. The resulting slip joint allows insulating sleeve 224 and conduit 240 to move relative to wellhead 226 to accommodate thermal expansion of the piping positioned in the formation. Conduit 240 is also able to move relative to fixed conduit 262 in order to accommodate thermal expansion. Heat transfer fluid seals 264 may be uninsulated and spatially separated from the flowing heat transfer fluid to maintain the heat transfer fluid seals at relatively low temperatures.

[0129] In some embodiments, thermal expansion is handled at the surface with a slip joint where the heat transfer fluid conduit is free to move and the fixed conduit is part of the wellhead. FIG. 15 depicts a representation of a system where fixed conduit 262 is secured to wellhead 226. Fixed conduit 262 may include insulating sleeve 224. Heat transfer fluid seals 264 may be coupled to an upper portion of conduit 240. Heat transfer fluid seals 264 may be uninsulated and spatially separated from the flowing heat transfer fluid to maintain the heat transfer fluid seals at relatively low temperatures. Conduit 240 is able to move relative to fixed conduit 262 without the need for a sliding seal in wellhead 226.

[0130] FIG. 16 depicts an embodiment of seals 264. Seals 264 may include seal stack 266 attached to packer body 268. Packer body 268 may be coupled to conduit 240 using packer setting slips 270 and packer insulation seal 272. Seal stack 266 may engage polished portion 274 of conduit 262. In some embodiments, cam rollers 276 are used to provide support to seal stack 266. For example, if side loads are too large for the seal stack. In some embodiments, wipers 278 are coupled to packer body 268. Wipers 278 may be used to clean polished portion 274 as conduit 262 is inserted through seal 264. Wipers 278 may be placed on the upper side of seals 264, if needed. In some embodiments, seal stack 266 is loaded for better contact using a bow spring or other preloaded means to enhance compression of the seals.

[0131] In some embodiments, seals 264 and conduit 262 are run together into conduit 240. Locking mechanisms such as mandrels may be used to secure the seals and the conduits in place. FIG. 17 depicts an embodiment of seals 264, conduit 240, and conduit 262 secured in place with locking mechanisms 280. Locking mechanisms 280 include insulation seals 282 and locking slips 284. Locking mechanisms 280 may be activated as seals 264 and conduit 262 enter into conduit 240.

[0132] As locking mechanisms 280 engage a selected portion of conduit 240, springs in the locking mechanisms are activated and open and expose insulations seals 282 against the surface of conduit 240 just above locking slips 284. Locking mechanisms 280 allow insulations seals 282 to be retracted as the assembly is moved into conduit 240. The insulation seals are opened and exposed when the profile of conduit 240 activates the locking mechanisms.

[0133] Pins 286 secure locking mechanisms 280, seals 264, conduit 240, and conduit 262 in place. In certain embodiments, pins 286 unlock the assembly after a selected temperature to allow movement (travel) of the conduits. For example, pins 286 may be made of materials that thermally degrade (for example, melt) above a desired temperature.

[0134] In some embodiments, locking mechanisms 280 are set in place using soft metal seals (for example, soft metal friction seals commonly used to set rod pumps in thermal wells). FIG. 18 depicts an embodiment with locking mechanisms 280 set in place using soft metal seals 288. Soft metal seals 288 work by collapsing against a reduction in the inner diameter of conduit 240. Using metal seals may increase the lifetime of the assembly versus using elastomeric seals.

[0135] In certain embodiments, lift systems are coupled to the piping of a heater that extends out of the formation. The lift systems may lift portions of the heater out of the formation to accommodate thermal expansion. FIG. 19 depicts a representation of u-shaped wellbore 222 with heater 200 positioned in the wellbore. Wellbore 222 may include casings 238 and lower seals 290. Heater 200 may include insulated portions 292 with heater portion 294 adjacent to treatment area 300. Moving seals 264 may be coupled to an upper portion of heater 200. Lifting systems 296 may be coupled to insulated portions 292 above wellheads 226. A non-reactive gas (for example, nitrogen and/or carbon dioxide) may be introduced in subsurface annular region 298 between casings 238 and insulated portions 292 to inhibit gaseous formation fluid from rising to wellhead 226 and to provide an insulating gas blanket. Insulated portions 292 may be conduit-in-conduits with the heat transfer fluid of the circulation system flowing through the inner conduit. The outer conduit of each insulated portion 292 may be at a substantially lower temperature than the inner conduit. The lower temperature of the outer conduit allows the outer conduits to be used as load bearing members for lifting heater 200. Differential expansion between the outer conduit and the inner conduit may be mitigated by internal bellows and/or by sliding seals.

[0136] Lifting systems 296 may include hydraulic lifters, powered coiled tubing rigs, and/or counterweight systems capable of supporting heater 200 and moving insulated portions 292 into or out of the formation. When lifting systems 296 include hydraulic lifters, the outer conduits of insulated portions 292 may be kept cool at the hydraulic lifters by dedicated slick transition joints. The hydraulic lifters may include two sets of slips. A first set of slips may be coupled to the heater. The hydraulic lifters may maintain a constant pressure against the heater for the full stroke of the hydraulic cylinder. A second set of slips may periodically be set against the outer conduit while the stroke of the hydraulic cylinder is reset. Lifting systems 296 may also include strain gauges and control systems. The strain gauges may be attached to the outer conduit of insulated portions 292, or the strain gauges may be attached to the inner conduits of the insulated portions below the insulation. Attaching the strain gauges to the outer conduit may be easier and the attachment coupling may be more reliable.

[0137] Before heating begins, set points for the control systems may be established by using lifting systems 296 to lift heater 200 such that portions of the heater contact casing 238 in the bend portions of wellbore 222. The strain when heater 200 is lifted may be used as the set point for the control system. In other embodiments, the set point is chosen in a different manner. When heating begins, heater portion 294 will begin expanding and some of the heater section will advance horizontally. If the expansion forces portions of heater 200 against casing 238, the weight of the heater will be supported at the contact points of insulated portions 292 and the casing. The strain measured by lifting system 296 will go towards zero. Additional thermal expansion may cause heater 200 to buckle and fail. Instead of allowing heater 200 to press against casing 238, hydraulic lifters of lifting systems 296 may move sections of insulated portions 292 upwards and out of the formation to keep the heater against the top of the casing. The control systems of lifting systems 296 may lift heater 200 to maintain the strain measured by the strain gauges near the set point value. Lifting system 296 may also be used to reintroduce insulated portions 292 into the formation when the formation cools to avoid damage to heater 200 during thermal contraction.

[0138] In certain embodiments, thermal expansion of the heater is completed in a relatively short time frame. In some embodiments, the position of the heater is fixed relative to the wellbore after thermal expansion is completed. The lifting systems may be removed from the heaters and used on other heaters that have not yet been heated. Lifting systems may be reattached to the heaters when the formation is cooled to accommodate thermal contraction of the heaters.

[0139] In some embodiments, the lifting systems are controlled based on the hydraulic pressure of the lifters. Changes in the tension of the pipe may result in a change in the hydraulic pressure. The control system may maintain the hydraulic pressure substantially at a set hydraulic pressure to provide accommodation of thermal expansion of the heater in the formation.

[0140] In certain embodiments, the circulation system uses a liquid to heat the formation. The use of liquid heat transfer fluid may allow for high overall energy efficiency for the system as compared to electrical heating or gas heaters due to the high energy efficiency of heat supplies used to heat the liquid heat transfer fluid. If furnaces are used to heat the liquid heat transfer fluid, the carbon dioxide footprint of the process may be reduced as compared to electrically heating or using gas burners positioned in wellbores due to the efficiencies of the furnaces. If nuclear power is used to heat the liquid heat transfer fluid, the carbon dioxide footprint of the process may be significantly reduced or even eliminated. The surface facilities for the heating system may be formed from commonly available industrial equipment in simple layouts. Commonly available equipment in simple layouts may increase the overall reliability of the system.

[0141] In certain embodiments, the liquid heat transfer fluid is a molten salt or other liquid that has the potential to solidify if the temperature is below a selected temperature. A secondary heating system may be needed to ensure that heat transfer fluid remains in liquid form and that the heat transfer fluid is at a temperature that allows the heat transfer fluid to flow through the heaters from the circulation system. In certain embodiments, the secondary heating system heats the heater and/or the heat transfer fluid to a temperature that is sufficient to melt and ensure flowability of the heat transfer fluid instead of heating to a higher temperature. The secondary heating system may only be needed for a short period of time during startup and/or re-startup of the fluid circulation system. In some embodiments, the secondary heating system is removable from the heater. In some embodiments, the secondary heating system does not have an expected lifetime on the order of the life of the heater.

[0142] In certain embodiments, molten salt is used as the heat transfer fluid. Insulated return storage tanks receive return molten salt from the formation. Temperatures in the return storage tanks may be, for example, in the vicinity of about 350 °C. Pumps may move the molten salt from the return storage tanks to furnaces. Each of the pumps may need to move between 4 kg/s and 30 kg/s of the molten salt. Each furnace may provide heat to the molten salt. Exit temperatures of the molten salt from the furnaces may be about 550 °C. The molten salt may pass from the furnaces to insulated feed storage tanks through piping. Each feed storage stank may supply molten salt to, for example, 50 or more piping systems that enter into the formation. The molten salt flows through the formation and to the return storage tanks. In certain embodiments, the furnaces have efficiencies that are 90% or greater. In certain embodiments, heat loss to the overburden is 8% or less.

[0143] In some embodiments, the heaters for the circulation systems include insulation along the lengths of the heaters, including portions of the heaters that are used to heat the treatment area. The insulation may facilitate insertion of the heaters into the formation. The insulation adjacent to portions used to heat the treatment area may be sufficient to provide insulation during preheating, but may decompose at temperatures produced by steady state circulation of the heat transfer fluid. In some embodiments, the insulation layer changes the emissivity of the heater to inhibit radiative heat transfer from the heater. After decomposition of the insulation, the emissivity of the heater may promote radiative heat transfer to the treatment area. The insulation may reduce the time needed to raise the temperature of the heaters and/or the heat transfer fluid in the heaters to temperatures sufficient to ensure melt and flowability of the heat transfer fluid. In some embodiments, the insulation adjacent to portions of the heaters that will heat the treatment area may include polymer coatings. In certain embodiments, insulation of portions of the heaters adjacent to the overburden is different than the insulation of the heaters adjacent to the portions of the heaters used to heat the treatment area. The insulation of the heaters adjacent to the overburden may have an expected lifetime equal to or greater than the lifetime of the heaters.

[0144] In some embodiments, degradable insulation material (for example, a polymer foam) may be introduced into the wellbore after or during placement of the heater. The degradable insulation may provide insulation adjacent to the portions of the heaters used to heat the treatment area during preheating. The liquid heat transfer fluid used to heat the treatment area may raise the temperature of the heater sufficiently enough to degrade and eliminate the insulation layer.

[0145] In some embodiments of circulation systems that use molten salt or another liquid as the heat transfer fluid, the heater may be a single conduit in the formation. The conduit may be preheated to a temperature sufficient to ensure flowability of the heat transfer fluid. In some embodiments, a secondary heat transfer fluid is circulated through the conduit to preheat the conduit and/or the formation adjacent to the conduit. After the temperature of the conduit and/or the formation adjacent to the conduit is sufficiently hot, the secondary fluid may be flushed from the conduit and the heat transfer fluid may be circulated through the pipe.

[0146] In some embodiments, aqueous solutions of the salt composition (for example, $Li:Na:K:NO_3$) that is to be used as the heat transfer fluid are used to preheat the conduit. A temperature of the secondary heat transfer fluid may be below or equal to a temperature of a subsurface outlet of the wellhead.

[0147] In some embodiments, the secondary heat transfer fluid (for example, water) is heated to a temperature ranging from 0 °C to about 95°C or up to the boiling point of the secondary heat transfer fluid. The salt composition may be added to the secondary heat transfer fluid while in a storage tank of the circulation systems. The composition of the salt and/or the pressure of the system may be adjusted to inhibit boiling of the aqueous solution as the temperature is increased. When the conduit is preheated to a temperature sufficient to ensure flowability of the molten salt, the remaining water may be removed from the aqueous solution to leave only the molten salt. The water may be removed by evaporation while the salt solution is in a storage tank of the circulation system. In some embodiments, the temperature of the molten salt solution is raised to above 100 °C. When the conduit is preheated to a temperature sufficient to ensure flowability of the molten salt, substantially or all of the remaining secondary heat transfer fluid (for example, water) may be removed from the salt solution to leave only the molten salt. In some embodiments, the temperature of the molten salt solution during the evaporation process ranges from 100 °C to 250°C.

[0148] Upon completion of the in situ heat treatment process, the molten salt may be cooled and water added to the salt to form another aqueous solution. The aqueous solution may be transferred to another treatment area and the process continued. Use of tertiary molten salts as aqueous solutions facilitates transportation of the solution and allows more than one section of a formation to be treated with the same salt.

[0149] In some embodiments of circulation systems that use molten salt or other liquid as the heat transfer fluid, the heater may have a conduit-in-conduit configuration. The liquid heat transfer fluid used to heat the formation may flow through a first passageway through the heater. A secondary heat transfer fluid may flow through a second passageway through the conduit-in-conduit heater for preheating and/or for flow assurance of the liquid heat transfer fluid. After the heater is raised to a temperature sufficient to ensure continued flow of heat transfer fluid through the heater, a vacuum may be drawn on the passageway for the secondary heat transfer fluid to inhibit heat transfer from the first passageway to the second passageway. In some embodiments, the passageway for the secondary heat transfer fluid is filled with insulating material and/or is otherwise blocked. The passageways in the conduit of the conduit-in-conduit heater may include the inner conduit and the annular region between the inner conduit and the outer conduit. In some embodiments, one or more flow switchers are used to change the flow in the conduit-in-conduit heater from the inner conduit to the annular region and/or vice versa.

[0150] FIG. 20 depicts a cross-sectional view of an embodiment of conduit-in-conduit heater 200 for a heat transfer circulation heating system adjacent to treatment area 300. Heater 200 may be positioned in wellbore 222. Heater 200 may include outer conduit 304 and inner conduit 306. During normal operation of heater 200, liquid heat transfer fluid may flow through annular region 308 between outer conduit 304 and inner conduit 306. During normal operation, fluid flow through inner conduit 306 may not be needed.

[0151] During preheating and/or for flow assurance, a secondary heat transfer fluid may flow through inner conduit 306. The secondary fluid may be, but is not limited to, air, carbon dioxide, exhaust gas, and/or a natural or synthetic oil (for example, DowTherm A, Syltherm, or Therminol 59), room temperature molten salts (for example, $NaCl_2$-$SrCl_2$, VCl_4, $SnCl_4$, or $TiCl_4$), high pressure liquid water, steam, or room temperature molten metal alloys (for example, a K-Na eutectic or a Ga-In-Sn eutectic). In some embodiments, outer conduit 304 is heated by the secondary heat transfer fluid flowing through annular region 308 (for example, carbon dioxide or exhaust gas) before the heat transfer fluid that is used to heat the formation is introduced into the annular region. If exhaust gas or other high temperature fluid is used, another heat transfer fluid (for example, water or steam) may be passed through the heater to reduce the temperature below the upper working temperature limit of the liquid heat transfer fluid. The secondary heat transfer fluid may be displaced from the annular region when the liquid heat transfer fluid is introduced into the heater. The secondary heat transfer fluid in inner conduit 306 may be the same fluid or a different fluid than the secondary fluid used to preheat outer conduit 304 during preheating. Using two different secondary heat transfer fluids may help in the identification of integrity problems in heater 200. Any integrity problems may be identified and fixed before the use of the molten salt is initiated.

[0152] In some embodiments, the secondary heat transfer fluid that flows through annular region 308 during preheating is an aqueous mixture of the salt to be used during normal operation. The salt concentration may be increased periodically to increase temperature while remaining below the boiling temperature of the aqueous mixture. The aqueous mixture may be used to raise the temperature of outer conduit 304 to a temperature sufficient to allow the molten salt to flow in annular region 308. When the temperature is reached, the remaining water in the aqueous mixture may evaporate out of the mixture to leave the molten salt. The molten salt may be used to heat treatment area 300.

[0153] In some embodiments, inner conduit 306 may be made of a relatively inexpensive material such as carbon steel. In some embodiments, inner conduit 306 is made of material that survives through an initial early stage of the heat treatment process. Outer conduit 304 may be made of material resistant to corrosion by the molten salt and formation fluid (for example, P91 steel).

[0154] For a given mass flow rate of liquid heat transfer fluid, heating the treatment area using liquid heat transfer fluid flowing in annular region 308 between outer conduit 304 and inner conduit 306 may have certain advantages over flowing the liquid heat transfer fluid through a single conduit. Flowing secondary heat transfer fluid through inner conduit 306 may pre-heat heater 200 and ensure flow when liquid heat transfer fluid is first used and/or when flow needs to be restarted after a stop of circulation. The large outer surface area of outer conduit 304 provides a large surface area for heat transfer to the formation while the amount of liquid heat transfer fluid needed for the circulation system is reduced because of the presence of inner conduit 306. The circulated liquid heat transfer fluid may provide a better power injection rate distribution to the treatment area due to increased velocity of the liquid heat transfer fluid for the same mass flow rate. Reliability of the heater may also be improved.

[0155] In some embodiments, the heat transfer fluid (molten salt) may thicken and flow of the heat transfer fluid through outer conduit 304 and/or inner conduit 306 is slowed and/or impaired. Selectively heating various portions of inner conduit 306 may provide sufficient heat to various parts of the heater 200 to increase flow of the heat transfer fluid through the heater. Portions of heater 200 may include ferromagnetic material, for example insulated conductors, to allow current to be passed along selected portions of the heater. Resistively heating inner conduit 306 transfers sufficient heat to thickened heat transfer fluid in outer conduit 304 and/or inner conduit 306 to lower the viscosity of the heat transfer fluid such that increased flow, as compared to flow prior to heating of the molten salt, through the conduits is obtained. Using time-varying current allows current to be passed along the inner conduit without passing current through the heat transfer fluid.

[0156] FIG. 21 depicts a schematic for heating various portions of heater 200 to restart flow of thickened or immobilized heat transfer fluid (for example, a molten salt) in the heater. In certain embodiments, portions of inner conduit 306 and/or outer conduit 304 include ferromagnetic materials surrounded by thermal insulation. Thus, these portions of inner conduit 306 and/or outer conduit 304 may be insulated conductors 302. Insulated conductors 302 may operate as temperature limited heaters or skin-effect heaters. Because of the skin-effect of insulated conductors 302, electrical current provided to the insulated conductors remains confined to inner conduit 306 and/or outer conduit 304 and does not flow through the heat transfer fluid located in the conduits.

[0157] In certain embodiments, insulated conductors 302 are positioned along a selected length of inner conduit 306 (for example, the entire length of the inner conduit or only the overburden portion of the inner conduit). Applying electricity to inner conduit 306 generates heat in insulated conductors 302. The generated heat may heat thickened or immobilized heat transfer fluid along the selected length of the inner conduit. The generated heat may heat the heat transfer fluid both inside the inner conduit and in the annulus between the inner conduit and outer conduit 304. In certain embodiments, inner conduit 306 only includes insulated conductors 302 positioned in the overburden portion of the inner conduit. These insulated conductors selectively generate heat in the overburden portions of inner conduit 306. Selectively heating the overburden portion of inner conduit 306 may transfer heat to thickened heat transfer fluid and restart flow in the overburden portion of the inner conduit. Such selective heating may increase heater life and minimize electrical heating costs by concentrating heat in the region most likely to encounter thickening or immobilization of the heat transfer fluid.

[0158] In certain embodiments, insulated conductors 302 are positioned along a selected length of outer conduit 304 (for example, the overburden portion of the outer conduit). Applying electricity to outer conduit 304 generates heat in insulated conductors 302. The generated heat may selectively heat the overburden portions of the annulus between inner conduit 306 and outer conduit 304. Sufficient heat may be transferred from outer conduit 304 to lower the viscosity of the thickened heat transfer fluid to allow unimpaired flow of the molten salt in the annulus.

[0159] In certain embodiments, having a conduit-in-conduit heater configuration allows flow switchers to be used that change the flow of heat transfer fluid in the heater from flow through the annular region between the outer conduit and the inner conduit, when flow is adjacent to the treatment area, to flow through the inner conduit, when flow is adjacent to the overburden. FIG. 22 depicts a schematic representation of conduit-in-conduit heaters 200 that are used with fluid circulation systems 202, 202’ to heat treatment area 300. In certain embodiments, heaters 200 include outer conduit 304, inner conduit 306, and flow switchers 310. Fluid circulation systems 202, 202’ provide heated liquid heat transfer fluid to wellheads 226. The direction of flow of liquid heat transfer fluid is indicated by arrows 312.

[0160] Heat transfer fluid from fluid circulation system 202 passes through wellhead 226 to inner conduit 306. The heat transfer fluid passes through flow switcher 310, which changes the flow from inner conduit 306 to the annular region between outer conduit 304 and the inner conduit. The heat transfer fluid then flows through heater 200 in treatment area 300. Heat transfer from the heat transfer fluid provides heat to treatment area 300. The heat transfer fluid then passes through second flow switcher 310', which changes the flow from the annular region back to inner conduit 306. The heat transfer fluid is removed from the formation through second wellhead 226' and is provided to fluid circulation system 202'. Heated heat transfer fluid from fluid circulation system 202' passes through heater 200' back to fluid circulation system 202.

[0161] Using flow switchers 310 to pass the fluid through the annular region while the fluid is adjacent to treatment area 300 promotes increased heat transfer to the treatment area due in part to the large heat transfer area of outer conduit 304. Using flow switchers 310 to pass the fluid through the inner conduit when adjacent to overburden 218 may reduce heat losses to the overburden. Additionally, heaters 200 may be insulated adjacent to overburden 218 to reduce heat losses to the formation.

[0162] FIG. 23 depicts a cross-sectional view of an embodiment of a conduit-in-conduit heater 200 adjacent to overburden 218. Insulation 314 may be positioned between outer conduit 304 and inner conduit 306. Liquid heat transfer fluid may flow through the center of inner conduit 306. Insulation 314 may be a highly porous insulation layer that inhibits radiation at high temperatures (for example, temperatures above 500 °C) and allows flow of a secondary heat transfer fluid during preheating and/or flow assurance stages of heating. During normal operation, flow of fluid through the annular region between outer conduit 304 and inner conduit 306 adjacent to overburden 218 may be stopped or inhibited.

[0163] Insulating sleeve 224 may be positioned around outer conduit 304. Insulating sleeves 224 on each side of a u-shaped heater may be securely coupled to outer conduit 304 over a long length when the system is not heated so that the insulating sleeves on each side of the u-shaped wellbore are able to support the weight of the heater. Insulating sleeve 224 may include an outer member that is a structural member that allows heater 200 to be lifted to accommodate thermal expansion of the heater. Casing 238 may surround insulating sleeve 224. Insulating cement 236 may couple casing 238 to overburden 218. Insulating cement 236 may be a low thermal conductivity cement that reduces conductive heat losses. For example, insulating cement 236 may be a vermiculite/cement aggregate. A non-reactive gas may be introduced into gap 242 between insulating sleeve 224 and casing 238 to inhibit formation fluid from rising in the wellbore and/or to provide an insulating gas blanket.

[0164] FIG. 24 depicts a schematic of an embodiment of circulation system 202 that supplies liquid heat transfer fluid to conduit-in-conduit heaters positioned in the formation (for example, the heaters depicted in FIG. 22). Circulation system 202 may include heat supply 204, compressor 316, heat exchanger 318, exhaust system 320, liquid storage tank 322, fluid movers 210 (for example, pumps), supply manifold 324, return manifold 326, and secondary heat transfer fluid circulation system 328. In certain embodiments, heat supply 204 is a furnace. Fuel for heat supply 204 may be supplied through fuel line 330. Control valve 332 may regulate the amount of fuel supplied to heat supply 204 based on the temperature of hot heat transfer fluid as measured by temperature monitor 334.

[0165] Oxidant for heat supply 204 may be supplied through oxidant line 336. Exhaust from heat supply 204 may pass through heat exchanger 318 to exhaust system 320. Oxidant from compressor 316 may pass through heat exchanger 318 to be heated by the exhaust from heat supply 204.

[0166] In some embodiments, valve 338 may be opened during preheating and/or during start-up of fluid circulation to the heaters to supply secondary heat transfer fluid circulation system 328 with a heating fluid. In some embodiments, exhaust gas is circulated through the heaters by secondary heat transfer fluid circulation system 328. In some embodiments, the exhaust gas passes through one or more heat exchangers of secondary heat transfer fluid circulation system 328 to heat fluid that is circulated through the heaters.

[0167] During preheating, secondary heat transfer fluid circulation system 328 may supply secondary heat transfer fluid to the inner conduit of the heaters and/or to the annular region between the inner conduit and the outer conduit. Line 340 may provide secondary heat transfer fluid to the part of supply manifold 324 that supplies fluid to the inner conduits of the heaters. Line 342 may provide secondary heat transfer fluid to the part of supply manifold 324 that supplies fluid to the annular regions between the inner conduits and the outer conduits of the heaters. Line 344 may return secondary heat transfer fluid from the part of the return manifold 326 that returns fluid from the inner conduits of the heaters. Line 346 may return secondary heat transfer fluid from the part of the return manifold 326 that returns fluid from the annular regions of the heaters. Valves 348 of secondary heat transfer fluid circulation system 328 may allow or stop secondary heat transfer flow to or from supply manifold 324 and/or return manifold 326. During preheating, all valves 348 may be open. During the flow assurance stage of heating, valves 348 for line 340 and for line 344 may be closed, and valves 348 for line 342 and line 346 may be open. Liquid heat transfer fluid from heat supply 204 may be provided to the part of supply manifold 324 that supplies fluid to the inner conduits of the heaters during the flow assurance stage of heating. Liquid heat transfer fluid may return to liquid storage tank 322 from the portion of return manifold 326 that returns fluid from the inner conduits of the heaters. During normal operation, all valves 348 may be closed.

[0168] In some embodiments, secondary heat transfer fluid circulation system 328 is a mobile system. Once normal flow of heat transfer fluid through the heaters is established, mobile secondary heat transfer fluid circulation system 328 may be moved and attached to another circulation system that has not been initiated.

[0169] During normal operation, liquid storage tank 322 may receive heat transfer fluid from return manifold 326. Liquid storage tank 322 may be insulated and heat traced. Heat tracing may include steam circulation system 350 that circulates steam through coils in liquid storage tank 322. Steam passed through the coils maintains heat transfer fluid in liquid storage tank 322 at a desired temperature or in a desired temperature range.

[0170] Fluid movers 210 may move liquid heat transfer fluid from liquid storage tank 322 to heat supply 204. In some embodiments, fluid movers 210 are submersible pumps that are positioned in liquid storage tank 322. Having fluid movers 210 in storage tanks may keep the pumps at temperatures well within the operating temperature limits of the pumps. Also, the heat transfer fluid may function as a lubricant for the pumps. One or more redundant pump systems may be placed in liquid storage tank 322. A redundant pump system may be used if the primary pump system shuts down or needs to be serviced.

[0171] During start-up of heat supply 204, valves 352 may direct liquid heat transfer fluid to liquid storage tank. After preheating of a heater in the formation is completed, valves 352 may be reconfigured to direct liquid heat transfer fluid to the part of supply manifold 324 that supplies the liquid heat transfer fluid to the inner conduit of the preheated heater. Return liquid heat transfer fluid from the inner conduit of a preheated return conduit may pass through the part of return manifold 326 that receives heat transfer fluid that has passed through the formation and directs the heat transfer fluid to liquid storage tank 322.

[0172] To begin using fluid circulation system 202, liquid storage tank 322 may be heated using steam circulation system 350. The heat transfer fluid may be added to liquid storage tank 322. The heat transfer fluid may be added as solid particles that melt in liquid storage tank 322 or liquid heat transfer fluid may be added to the liquid storage tank. Heat supply 204 may be started, and fluid movers 210 may be used to circulate heat transfer fluid from liquid storage tank 322 to the heat supply and back. Secondary heat transfer fluid circulation system 328 may be used to heat heaters in the formation that are coupled to supply manifolds 324 and return manifolds 326. Supply of secondary heat transfer fluid to the portion of supply manifold 324 that feeds the inner conduits of the heaters may be stopped. The return of secondary heat transfer fluid from the portion of return manifold that receives heat transfer fluid from the inner conduits of the heaters may also be stopped. Heat transfer fluid from heat supply 204 may then be directed to the inner conduit of the heaters.

[0173] The heat transfer fluid may flow through the inner conduits of the heaters to flow switchers that change the flow of fluid from the inner conduits to the annular regions between the inner conduits and the outer conduits. The heat transfer fluid may then pass through flow switchers that change the flow back to the inner conduits. Valves coupled to the heaters may allow heat transfer fluid flow to the individual heaters to be started sequentially instead of having the fluid circulation system supply heat transfer fluid to all of the heaters at once.

[0174] Return manifold 326 receives heat transfer fluid that has passed through heaters in the formation that are supplied from a second fluid circulation system. Heat transfer fluid in return manifold 326 may be directed back into liquid storage tank 322.

[0175] During initial heating, secondary heat transfer fluid circulation system 328 may continue to circulate secondary heat transfer fluid through the portion of the heater not receiving the heat transfer fluid supplied from heat supply 204. In some embodiments, secondary heat transfer fluid circulation system 328 directs the secondary heat transfer fluid in the same direction as the flow of heat transfer fluid supplied from heat supply 204. In some embodiments, secondary heat transfer fluid circulation system 328 directs the secondary heat transfer fluid in the opposite direction to the flow of heat transfer fluid supplied from heat supply 204. The secondary heat transfer fluid may ensure continued flow of the heat transfer fluid supplied from heat supply 204. Flow of the secondary heat transfer fluid may be stopped when the secondary heat transfer fluid leaving the formation is hotter than the secondary heat transfer fluid supplied to the formation due to heat transfer with the heat transfer fluid supplied from heat supply 204. In some embodiments, flow of secondary heat transfer fluid may be stopped when other conditions are met, after a selected period of time.

[0176] Further modifications and alternative embodiments of various aspects of the invention may be apparent to those skilled in the art in view of this description. Accordingly, this description is to be construed as illustrative only and is for the purpose of teaching those skilled in the art the general manner of carrying out the invention. It is to be understood that the forms of the invention shown and described herein are to be taken as the presently preferred embodiments. Elements and materials may be substituted for those illustrated and described herein, parts and processes may be reversed, and certain features of the invention may be utilized independently, all as would be apparent to one skilled in the art after having the benefit of this description of the invention. Changes may be made in the elements described herein without departing from the spirit and scope of the invention as described in the following claims. In addition, it is to be understood that features described herein independently may, in certain embodiments, be combined.

CLAIMS

1. A method for heating a subsurface formation, comprising:

applying heat from a plurality of heaters to the formation; and

allowing a portion of one or more of the heaters to move out of wellheads equipped with sliding seals to accommodate thermal expansion of the heaters.

2. The method of claim 1, wherein applying heat from the plurality of heaters comprises flowing heat transfer fluid through one or more heaters.

3. The method of claim 1, wherein the portion of a heater that moves out of a wellhead is insulated.

4. The method of claim 1, further comprising fixing a position of a heater relative to a wellhead through which the heater passes after significant change in length of the heater due to thermal expansion ceases.

5. A method for heating a subsurface formation, comprising:

applying heat from a plurality of heaters to the formation; and

allowing a portion of one or more of the heaters to move out of wellheads using one or more slip joints.

6. The method of claim 5, wherein at least a portion of at least one slip joint comprises at least one sliding seal, wherein the sliding seal is spatially separated from heat.

7. The method of claim 5, wherein applying heat from the plurality of heaters comprises flowing heat transfer fluid through one or more heaters.

8. The method of claim 5, wherein the portion of a heater that moves out of a wellhead is insulated.

9. The method of claim 5, further comprising fixing a position of a heater relative to a wellhead through which the heater passes after significant change in length of the heater due to thermal expansion ceases.

10. A method for accommodating thermal expansion of a heater in a formation, comprising:

heating a heater in the formation; and

lifting a portion of the heater out of the formation to accommodate thermal expansion of the heater.

11. The method of claim 10, wherein at least a portion of at least one slip joint comprises at least one sliding seal, wherein the sliding seal is spatially separated from heat.

12. The method of claim 10, wherein applying heat from the plurality of heaters comprises flowing heat transfer fluid through one or more heaters.

13. The method of claim 10, wherein the portion of a heater that moves out of a wellhead is insulated.

14. The method of claim 10, further comprising fixing a position of a heater relative to a wellhead through which the heater passes after significant change in length of the heater due to thermal expansion ceases.

15. A system for heating a subsurface formation, comprising:

a plurality of heaters positioned in the formation, the heaters configured to provide heat to the formation; and

at least one lifter coupled to a portion of a heater, the lifter configured to lift portions of the heater out of the formation to accommodate thermal expansion of the heater.

16. The system of claim 15, wherein applying heat from the plurality of heaters comprises flowing heat transfer fluid through one or more heaters.

17. The system of claim 15, wherein at least one lifter comprises a hydraulic lifter.

18. The system of claim 15, further comprising measuring the strain of the heater near at least one lifter, and controlling the amount of lift applied to the heater from the lifter based on the measured strain.

19. The system of claim 15, further comprising measuring a first hydraulic pressure of a lifter coupled to a heater before heating the heater, and controlling the hydraulic pressure of the lifter after heating is initiated to maintain the hydraulic pressure of the lifter at least close to the first hydraulic pressure.

20. The system of claim 15, further comprising fixing a position of a heater relative to a wellhead through which the heater passes after significant change in length of the heater due to thermal expansion ceases.

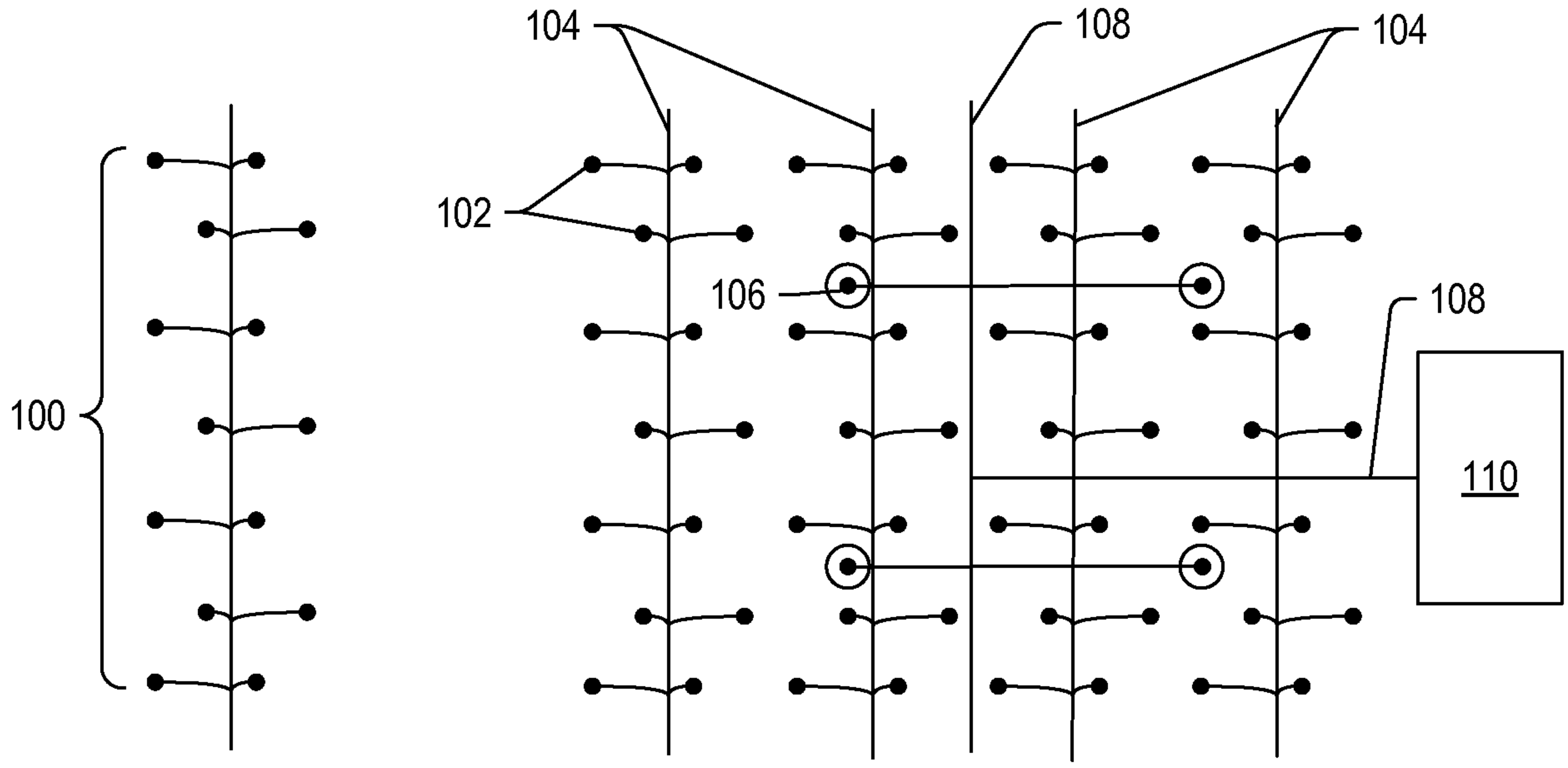

FIG. 1

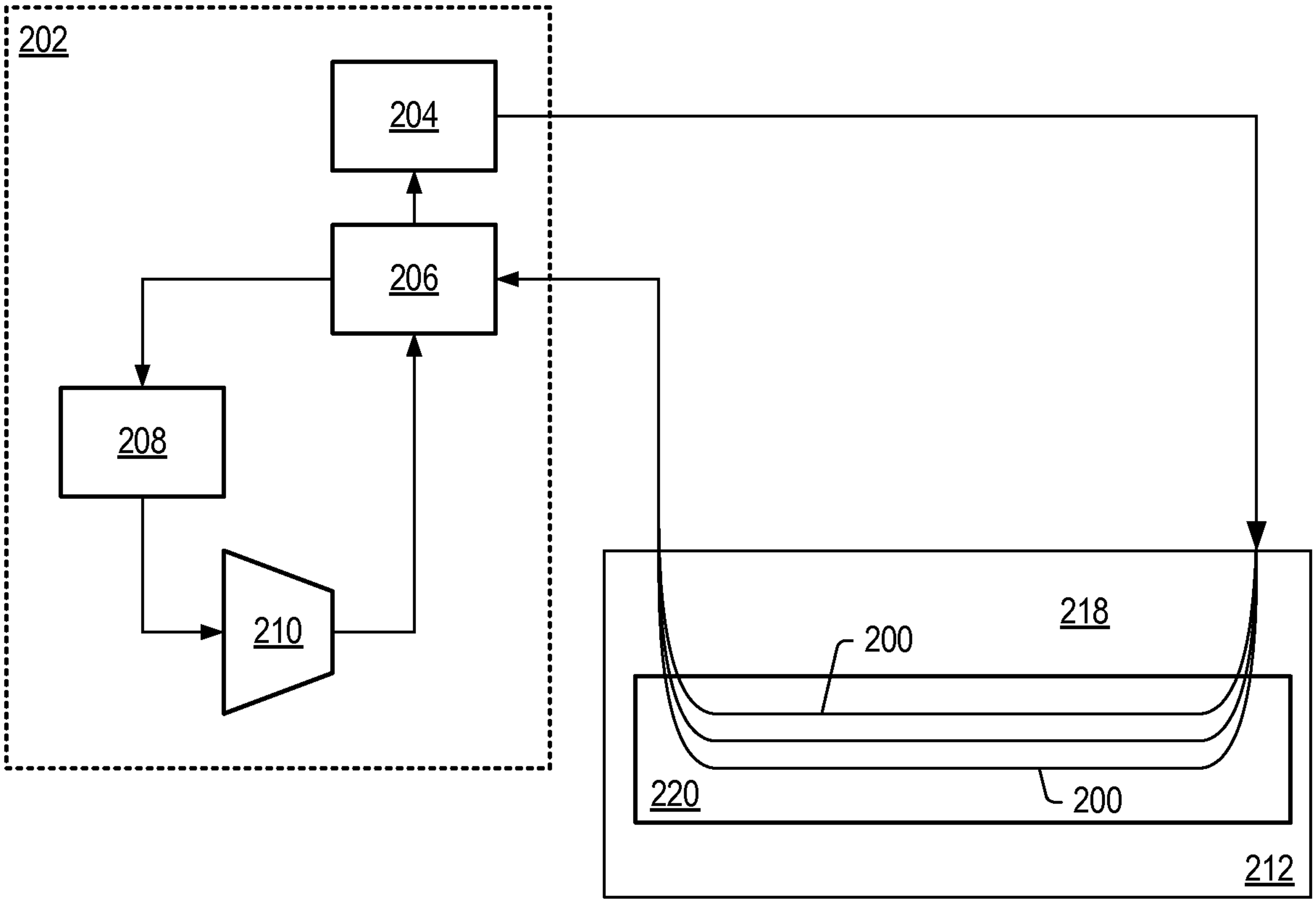
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FIG. 2

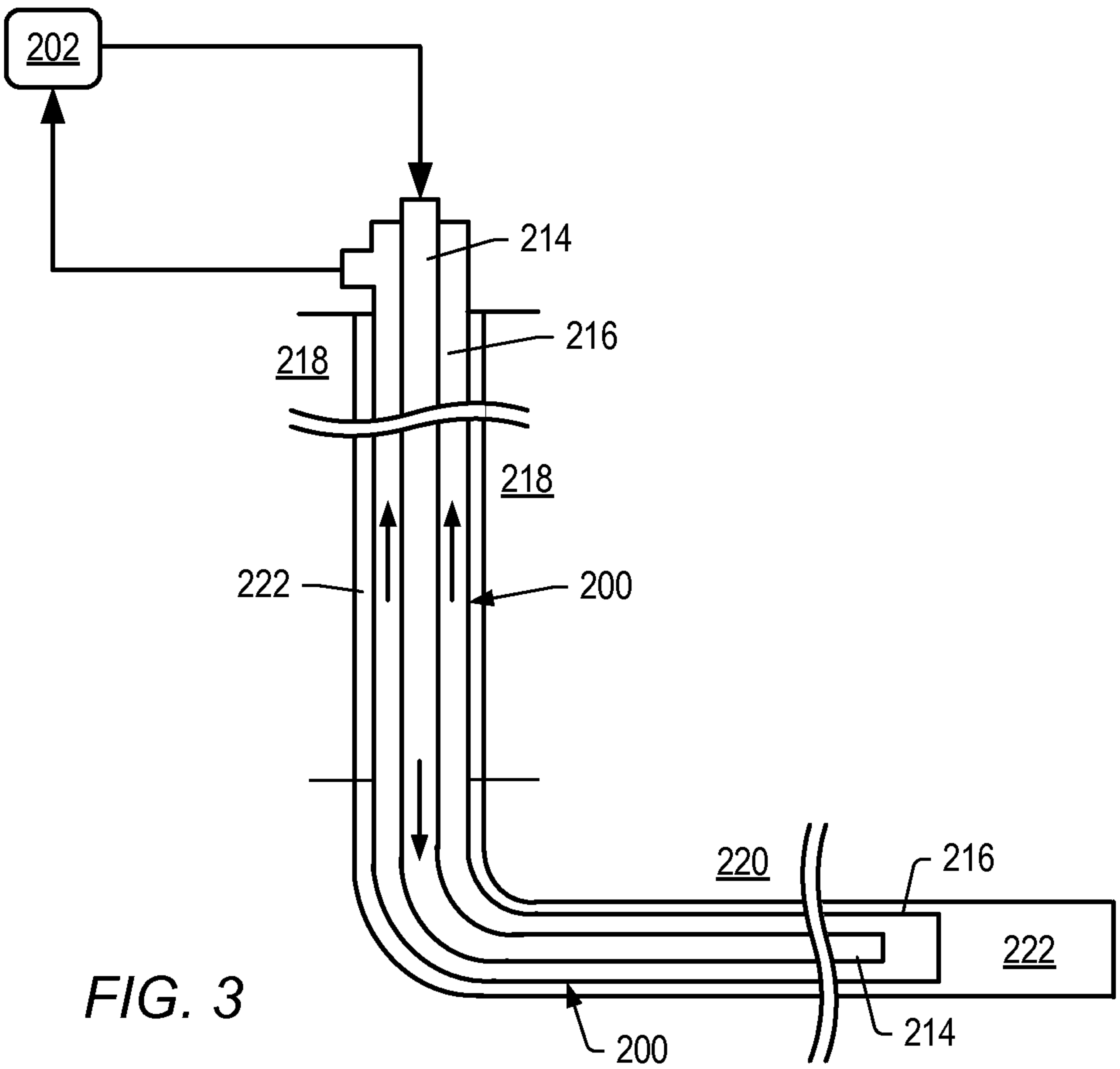
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FIG. 3

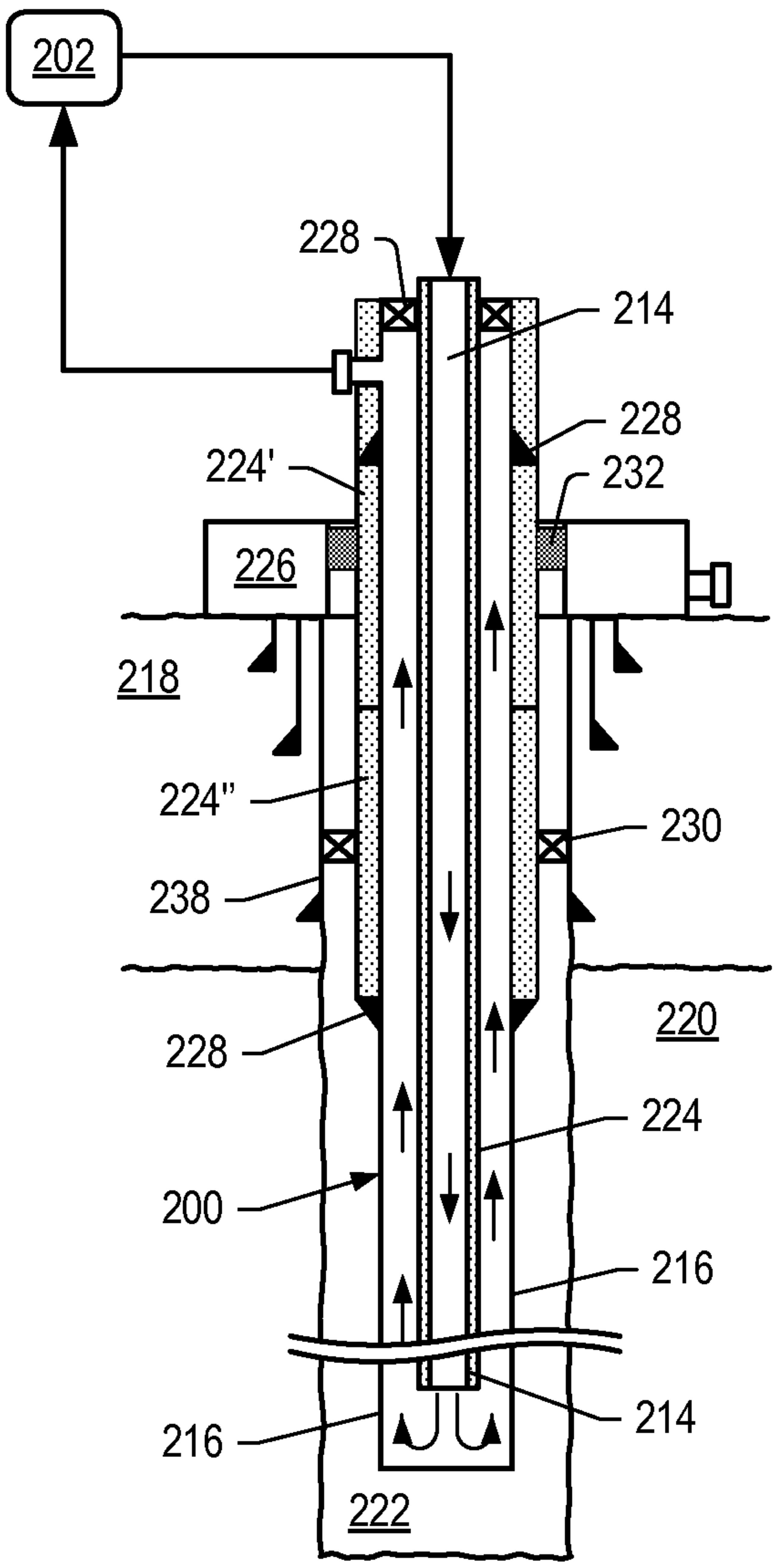
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FIG. 4

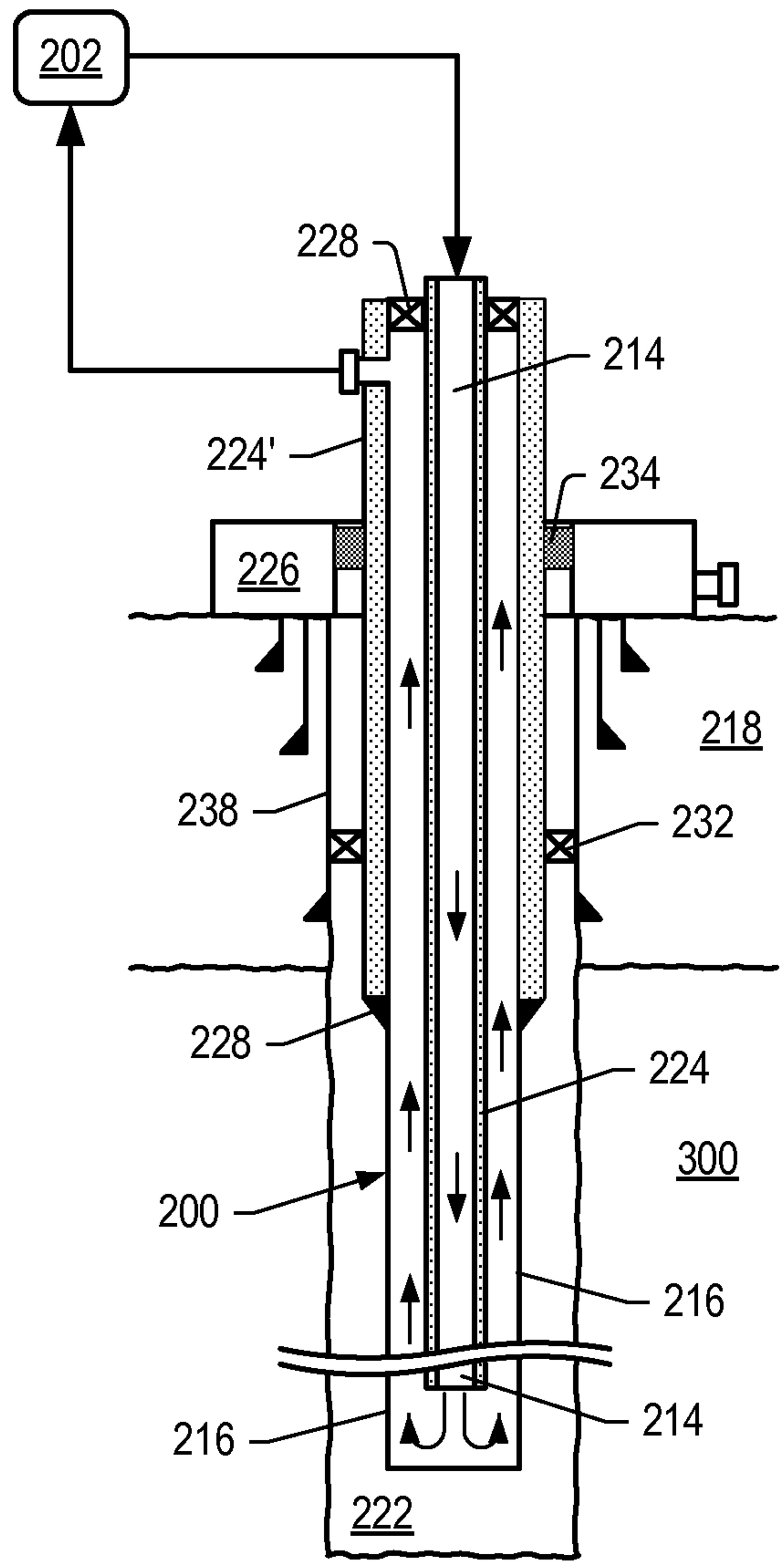
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FIG. 5

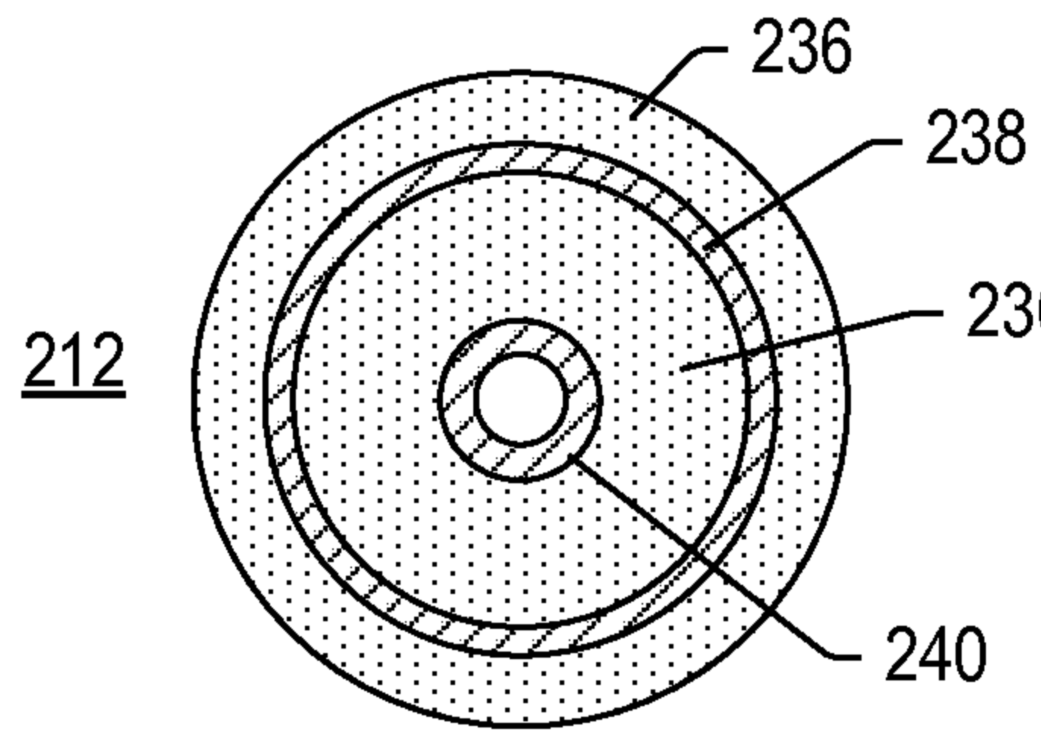

FIG. 6

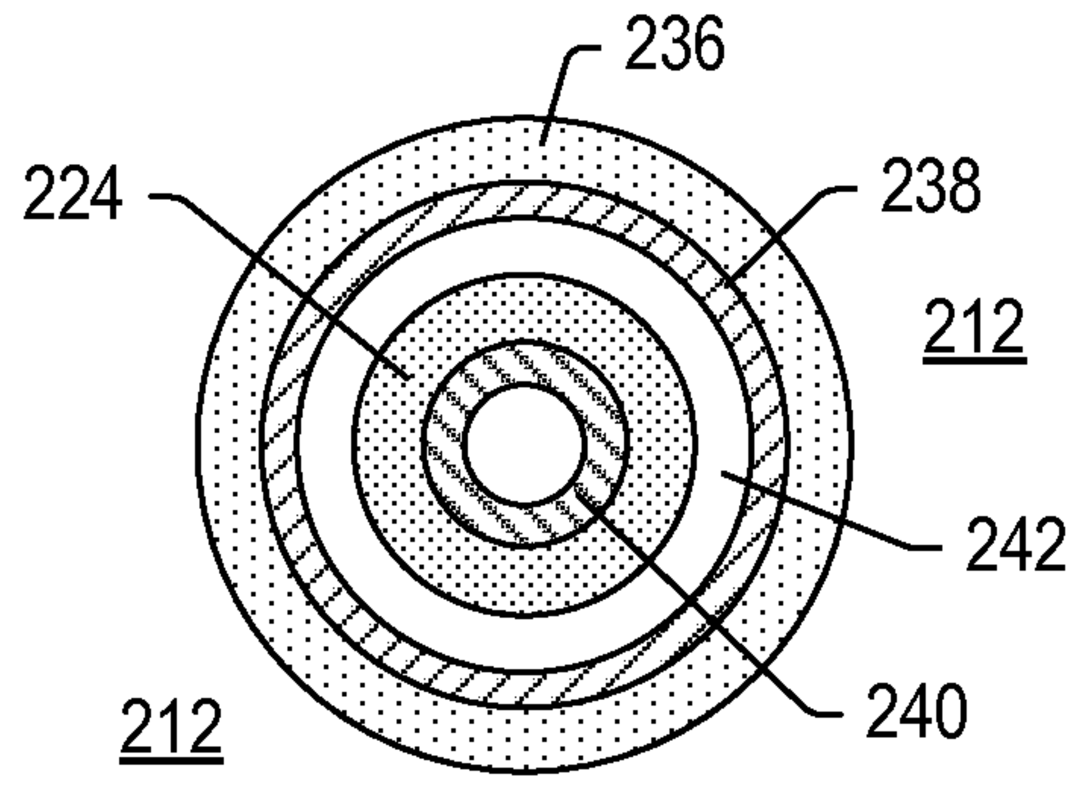

FIG. 7

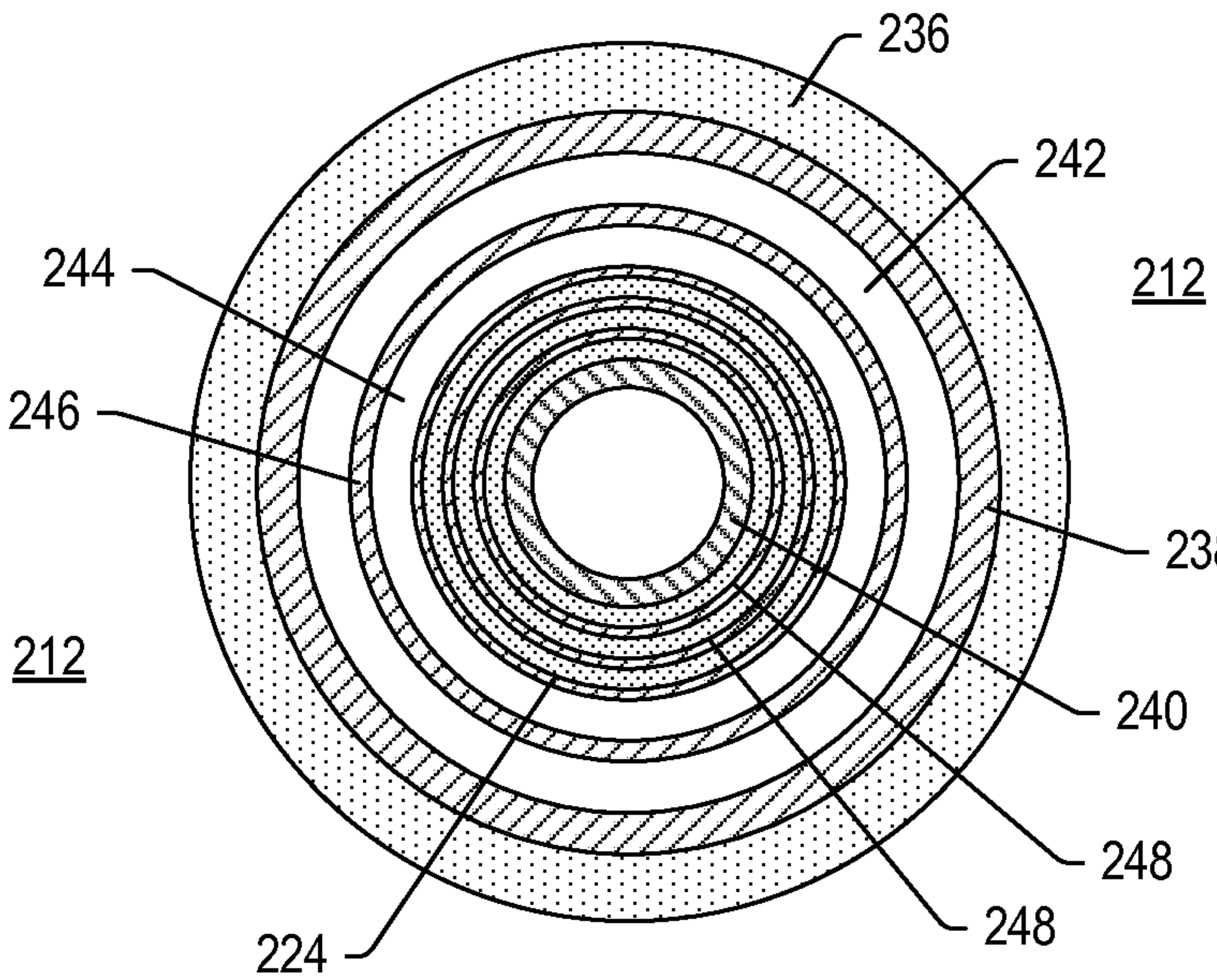

FIG. 8

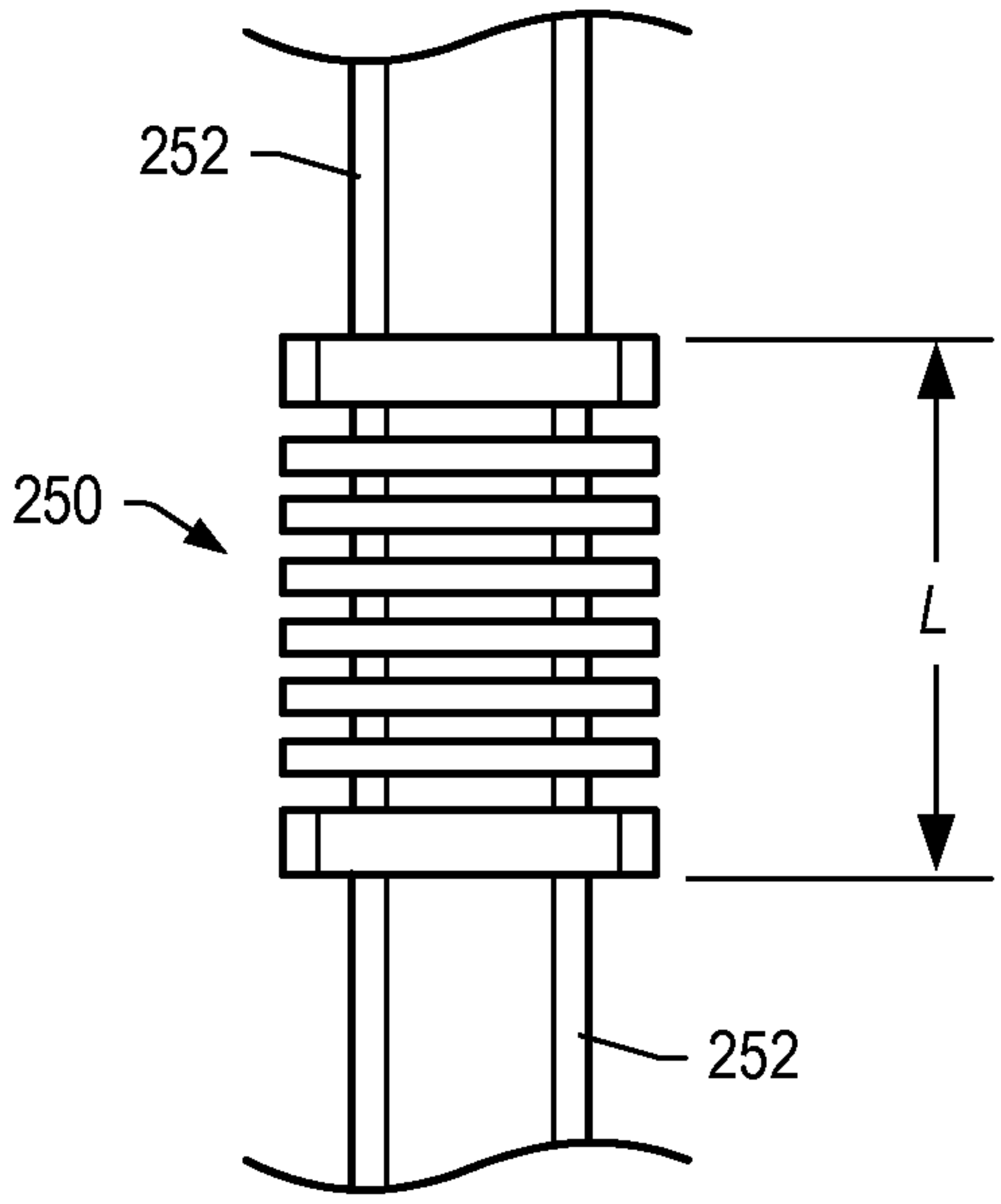

FIG. 9

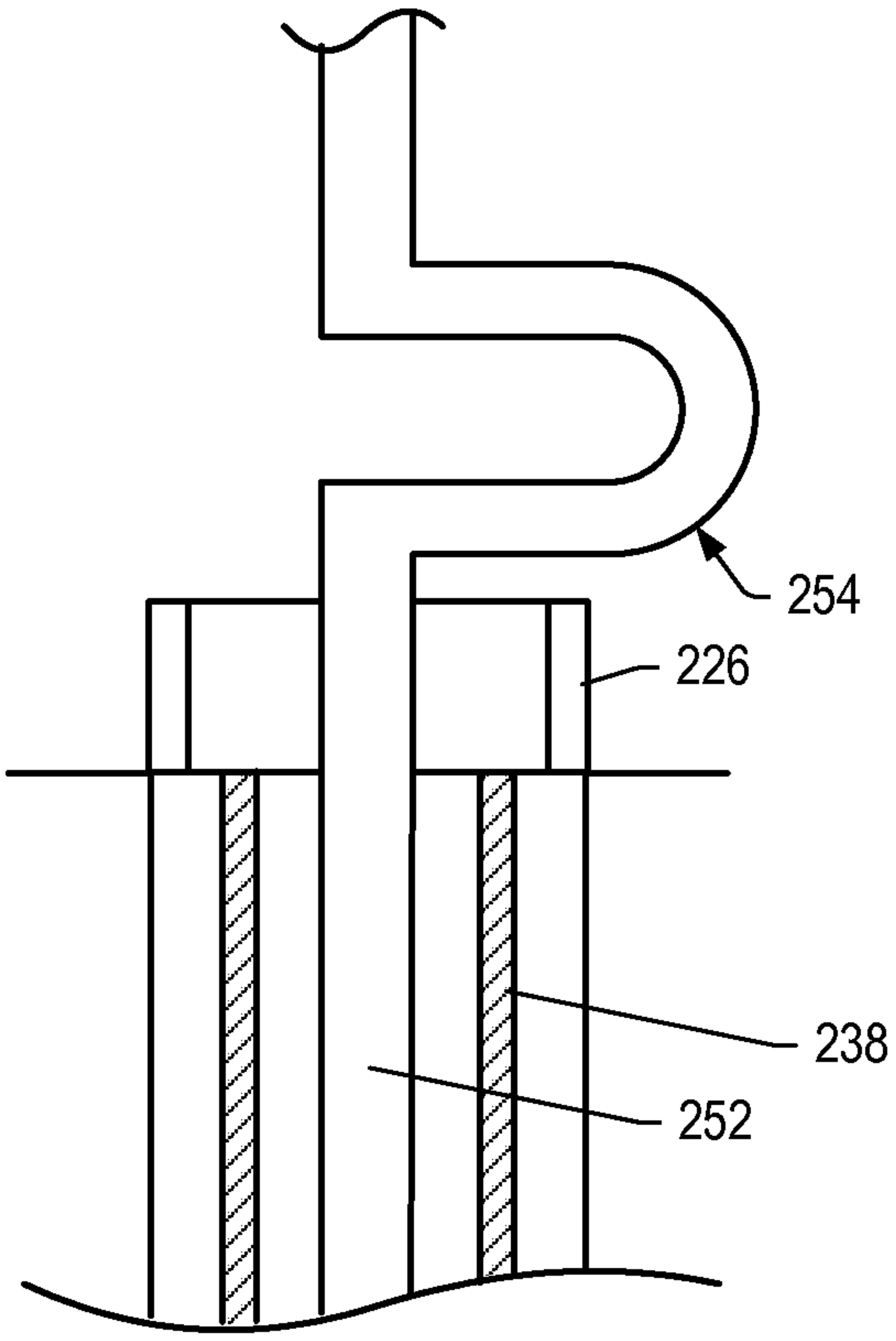

FIG. 10A

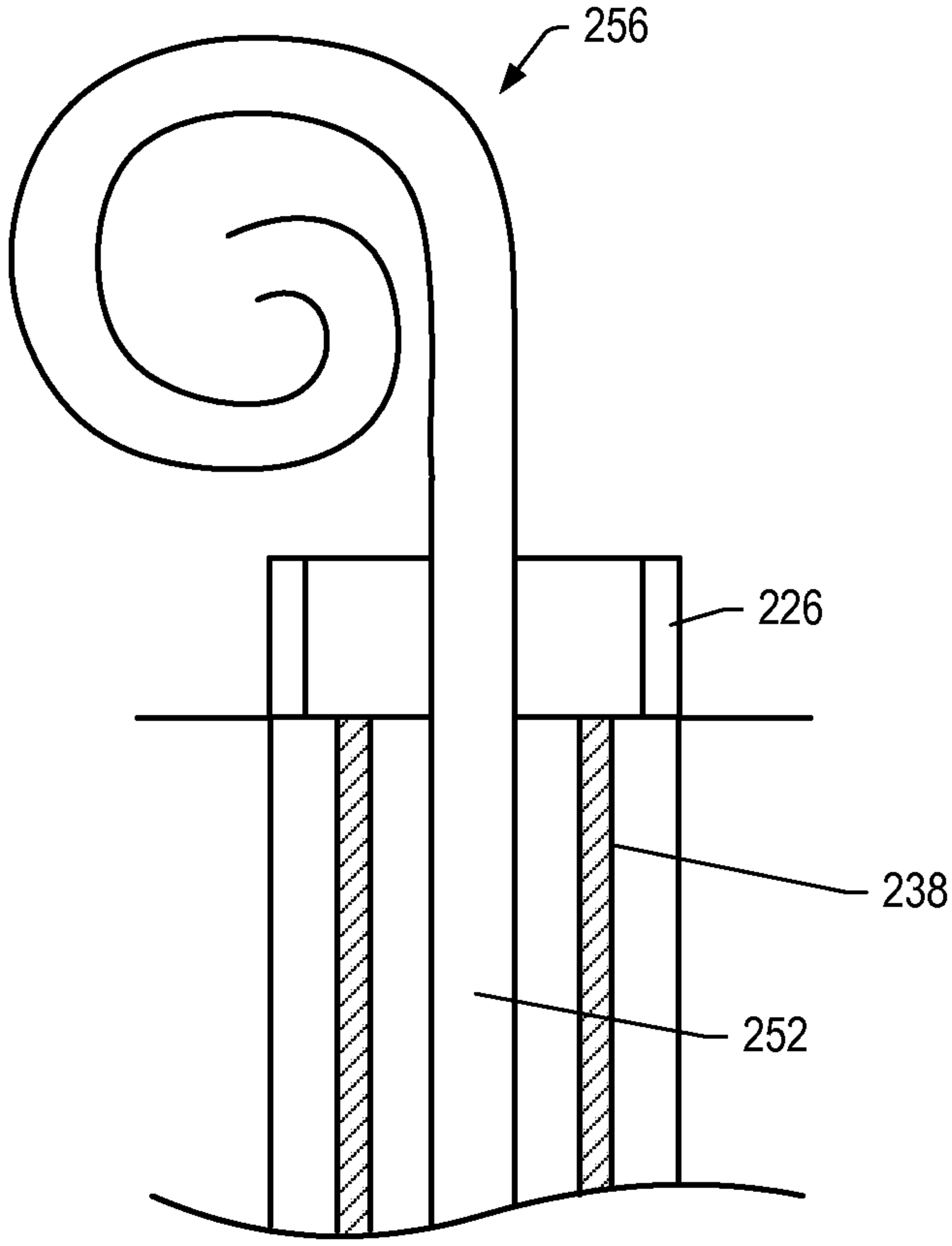

FIG. 10B

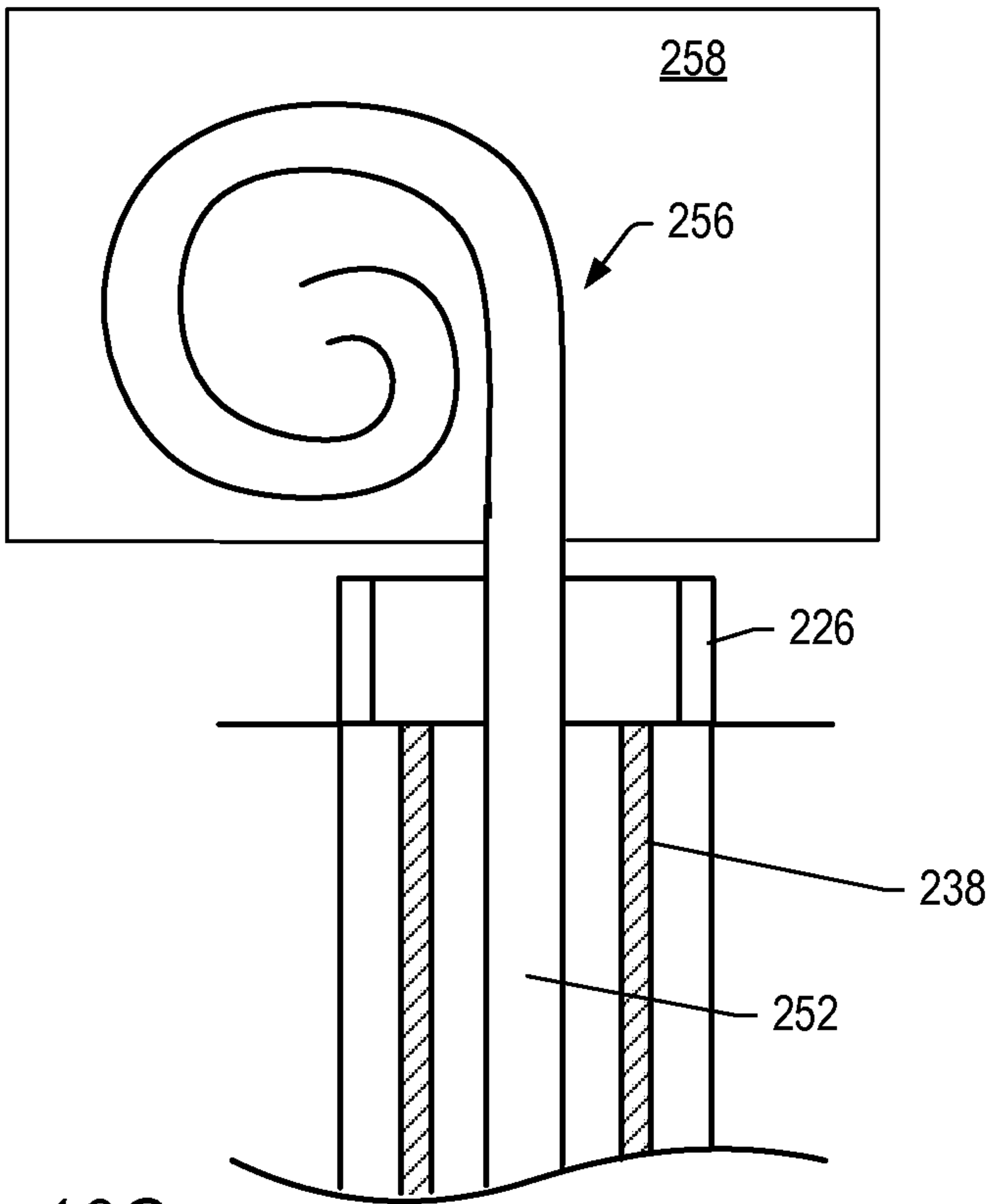

FIG. 10C

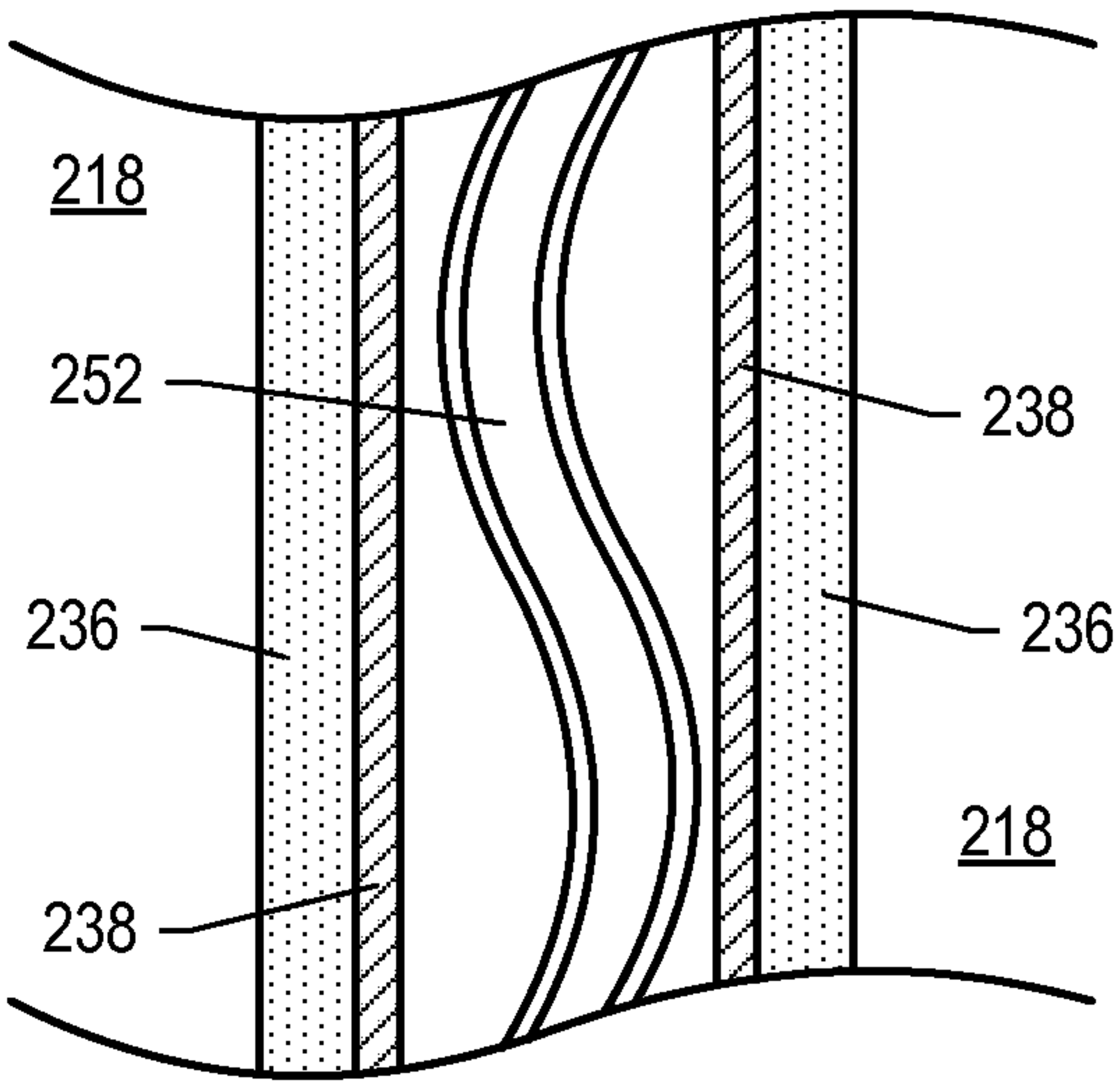

FIG. 11

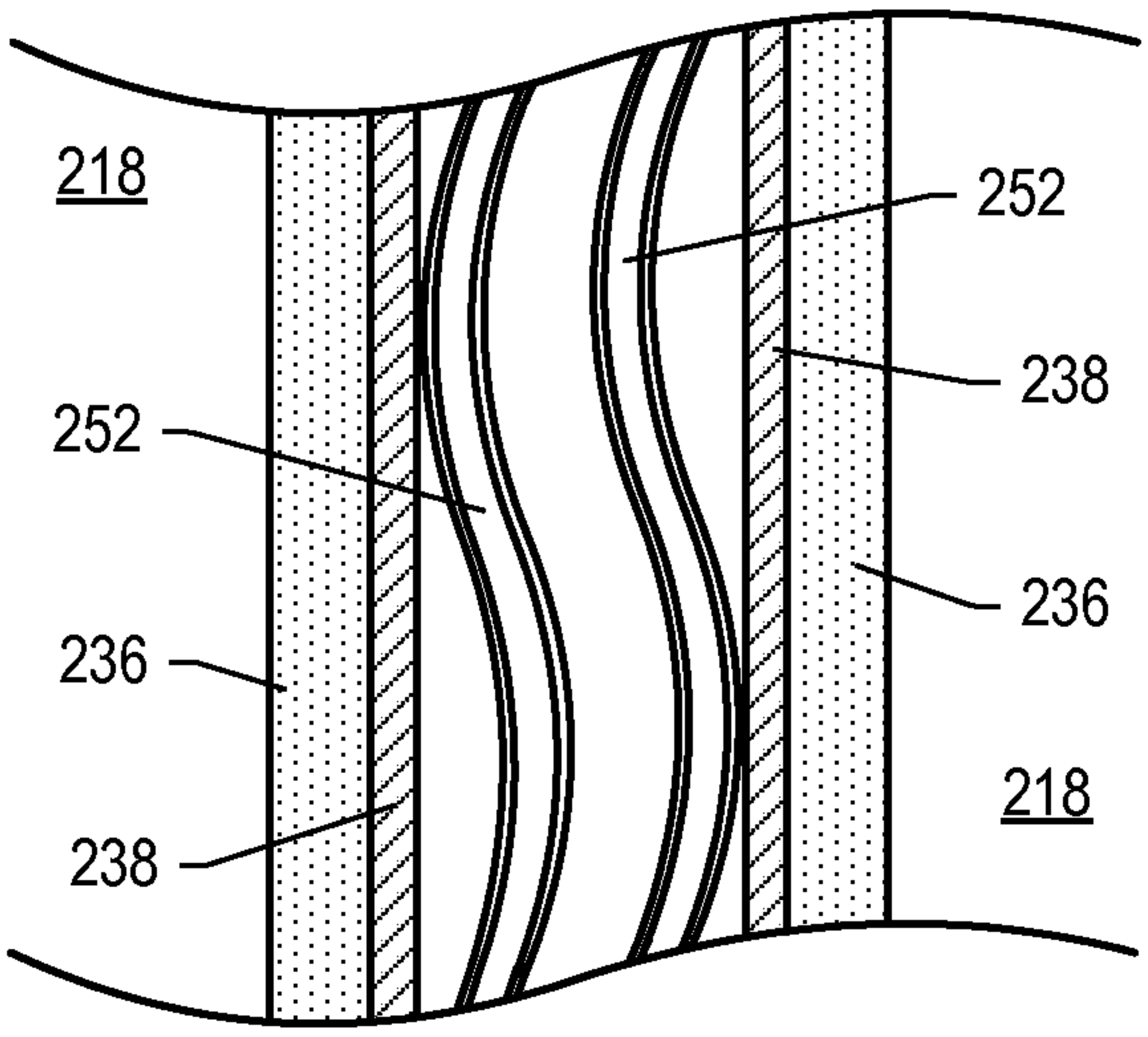

FIG. 12

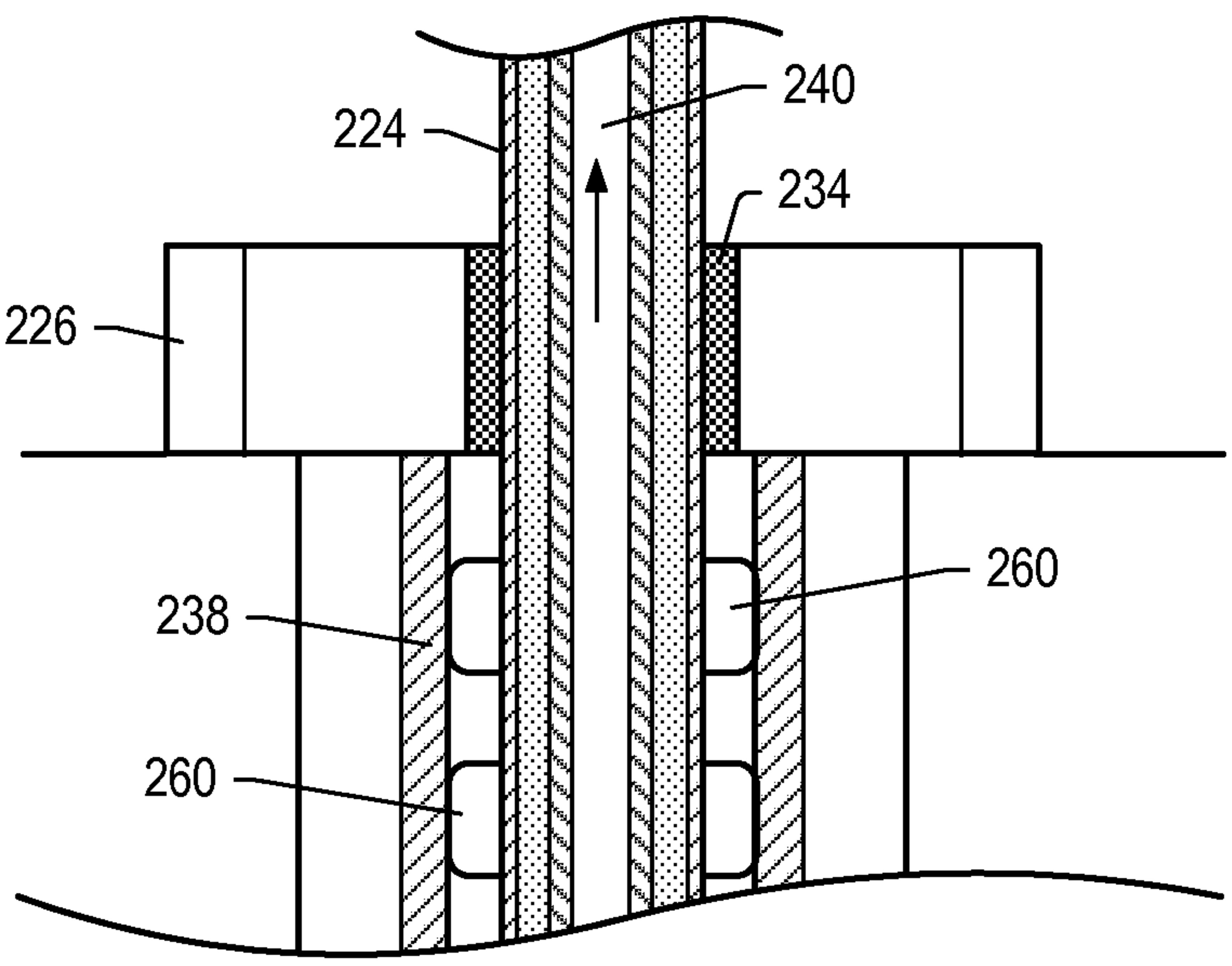

FIG. 13

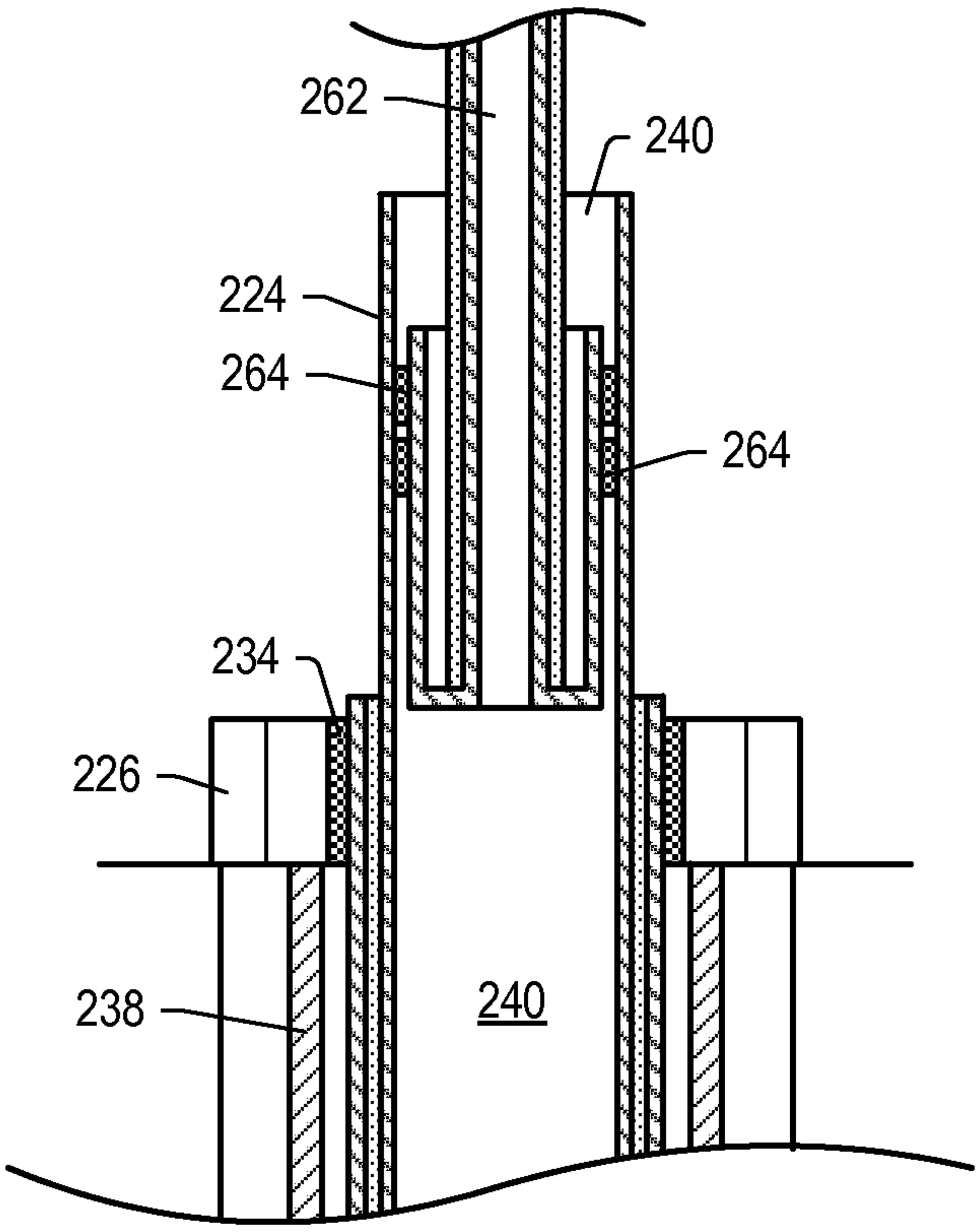
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FIG. 14

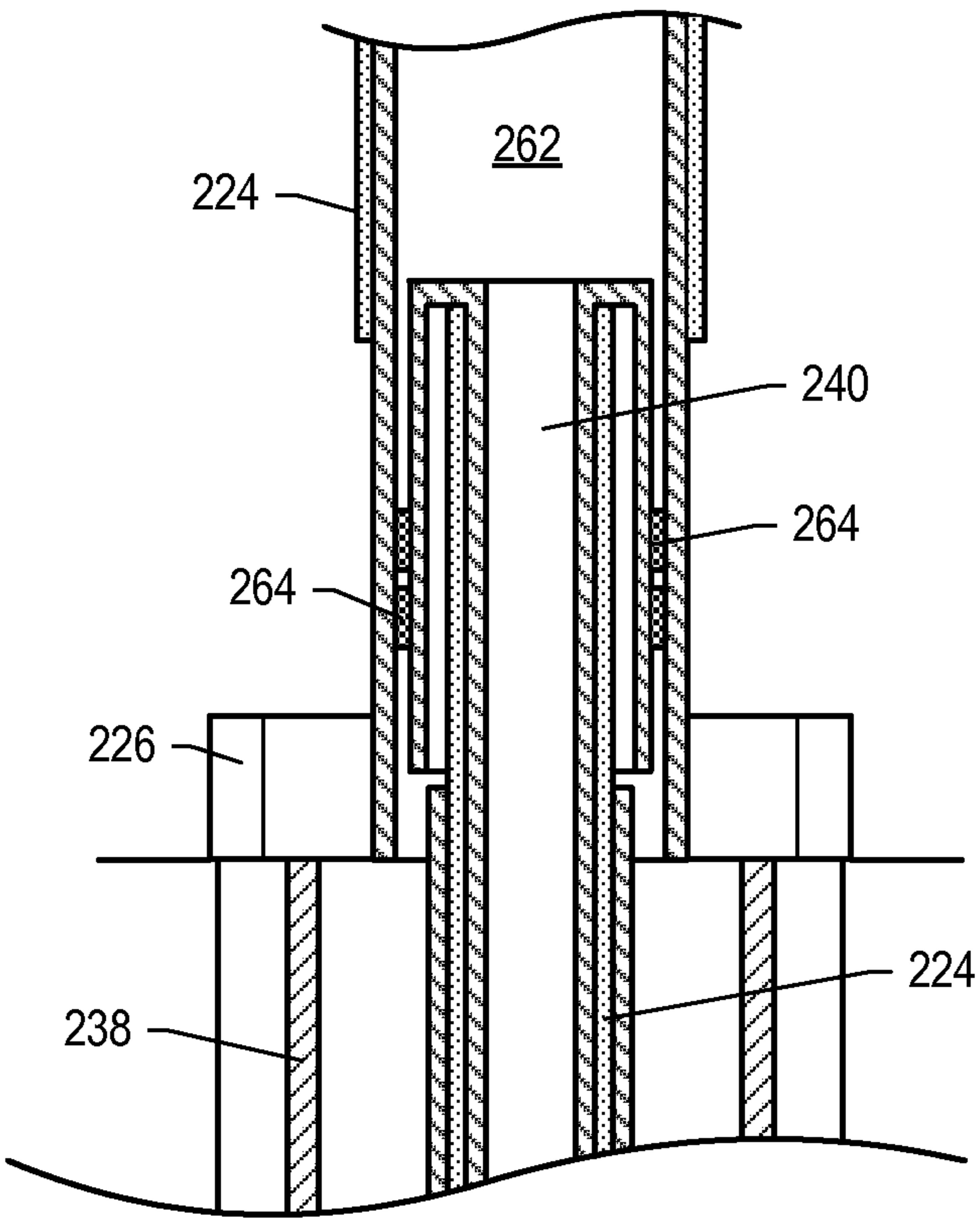
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FIG. 15

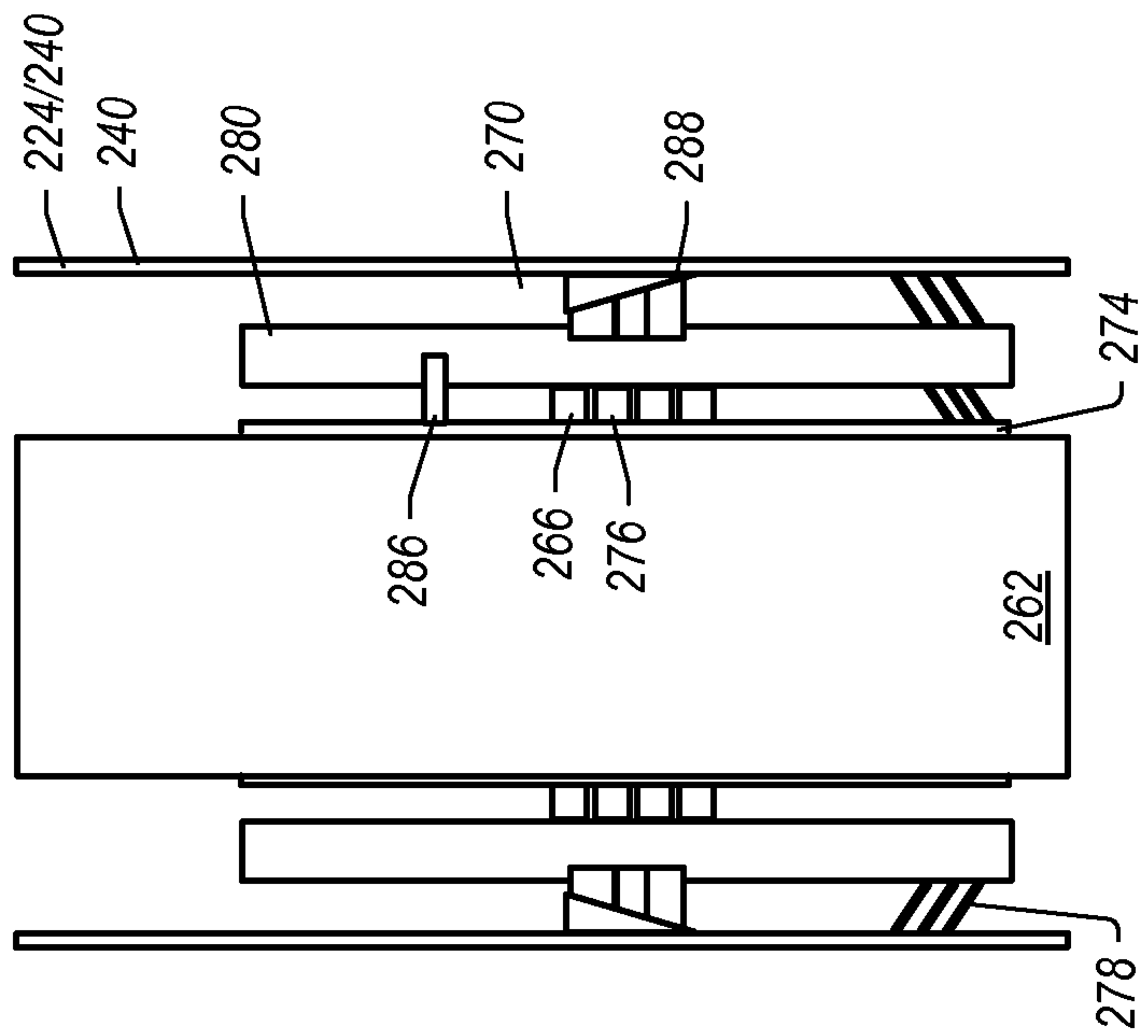

FIG. 18

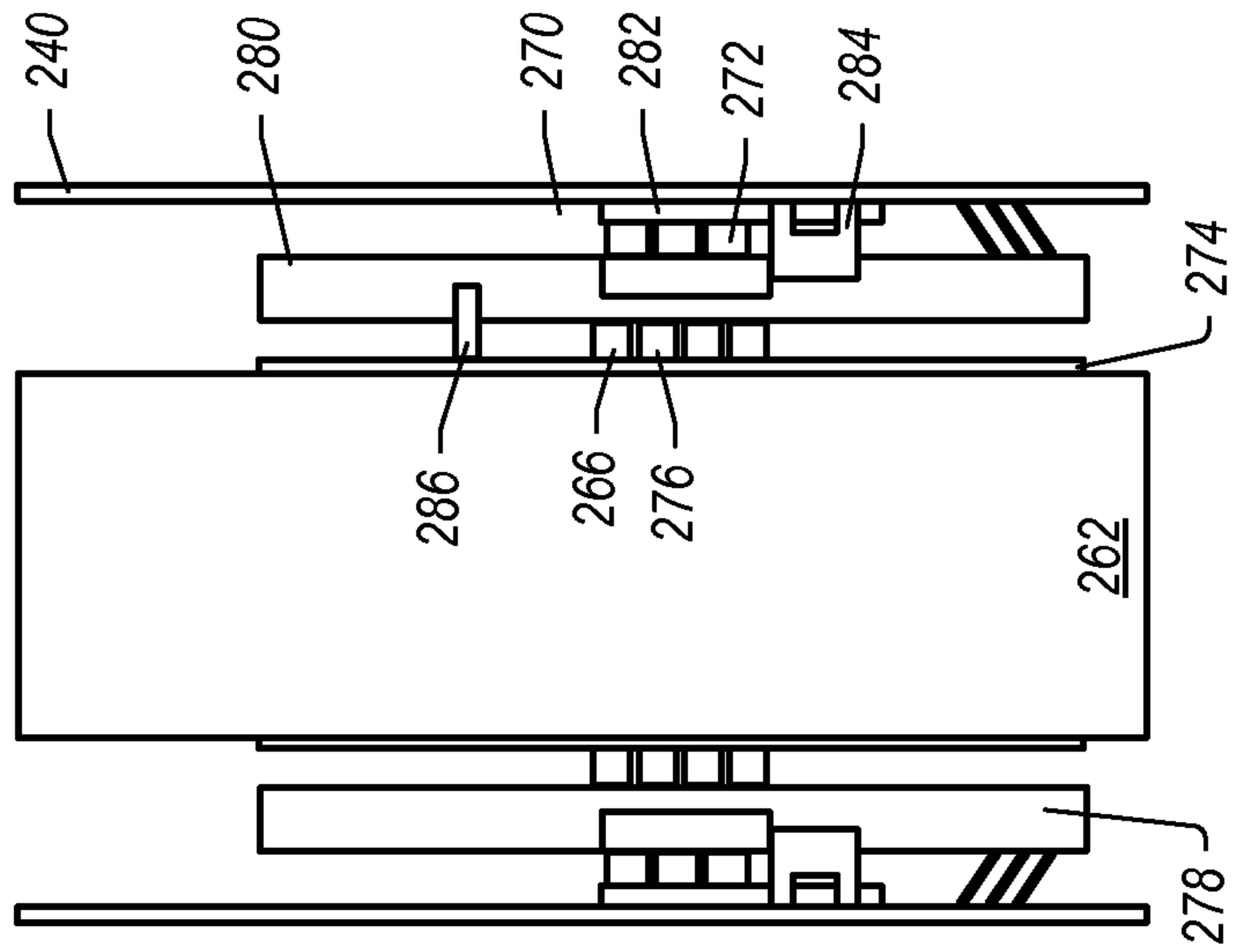

FIG. 17

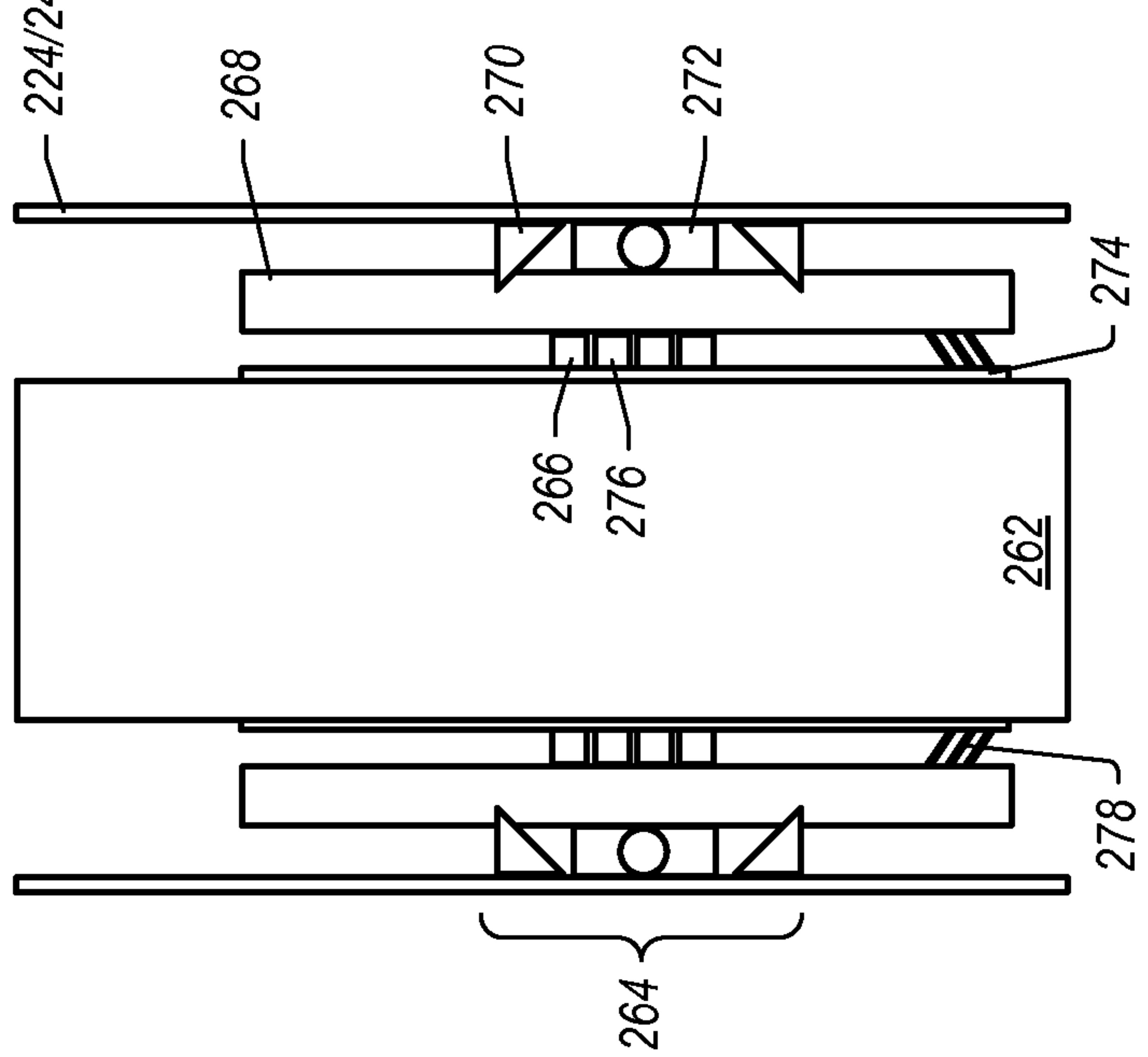

FIG. 16

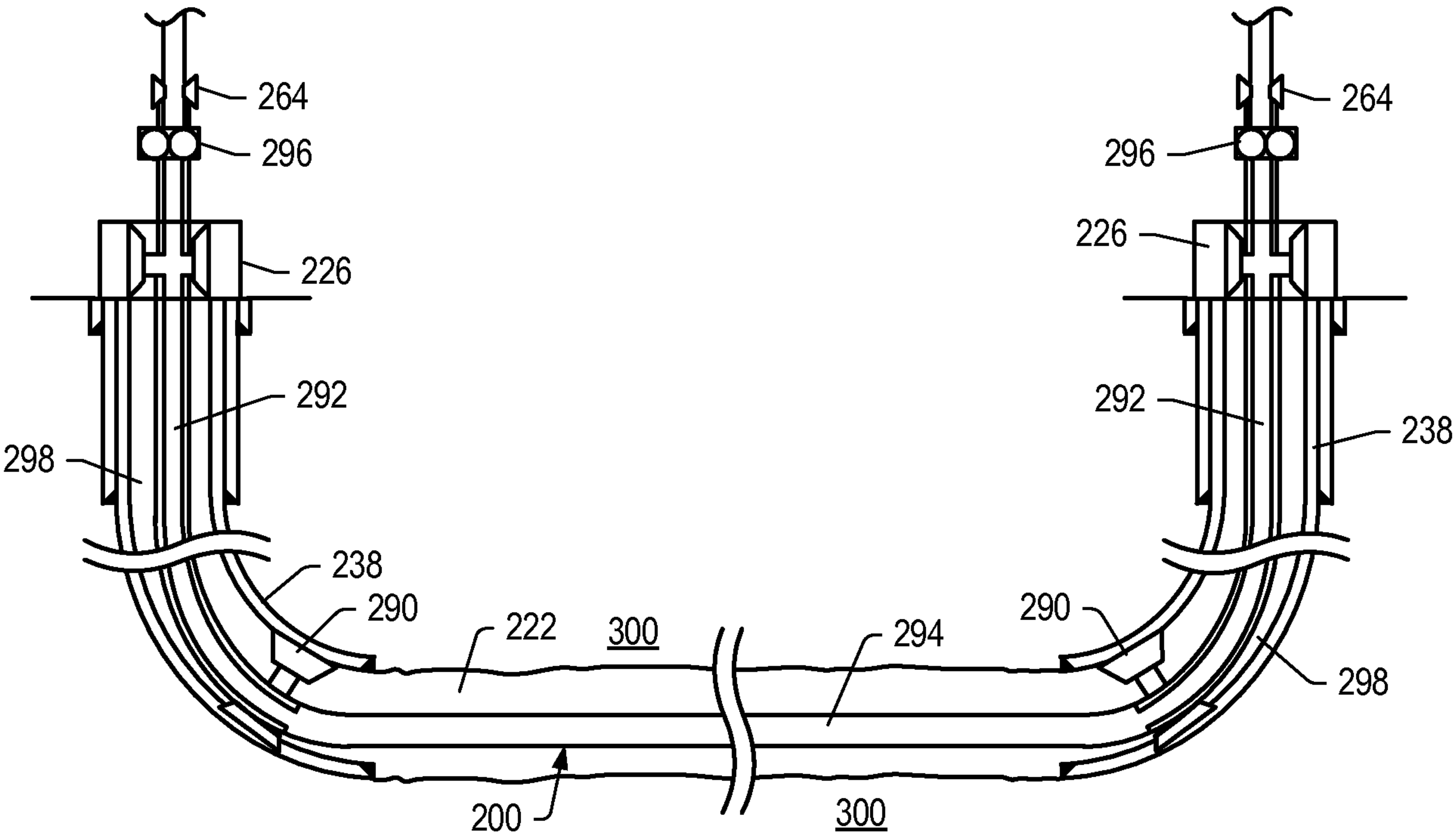
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FIG. 19

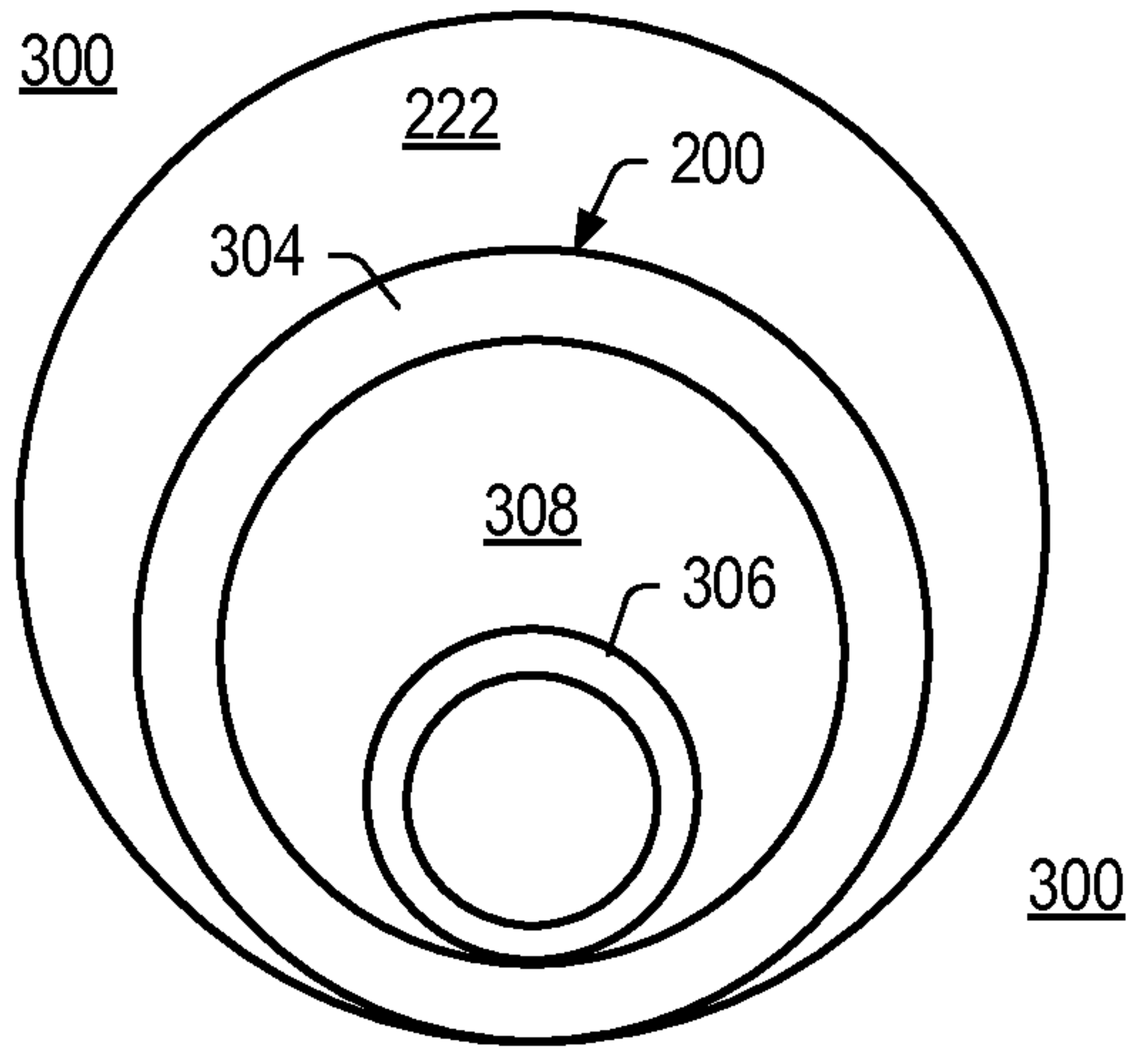
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FIG. 20

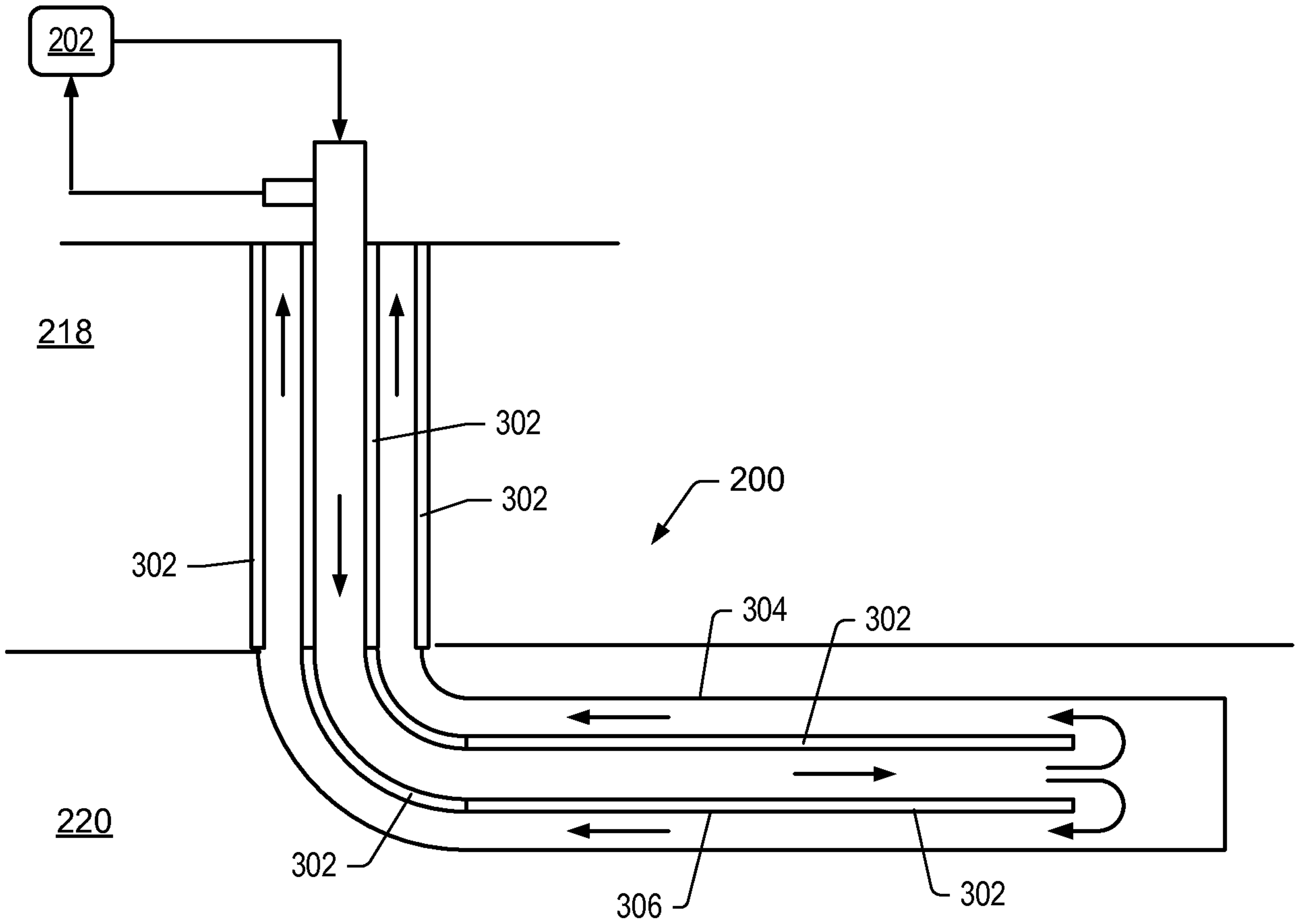
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FIG. 21

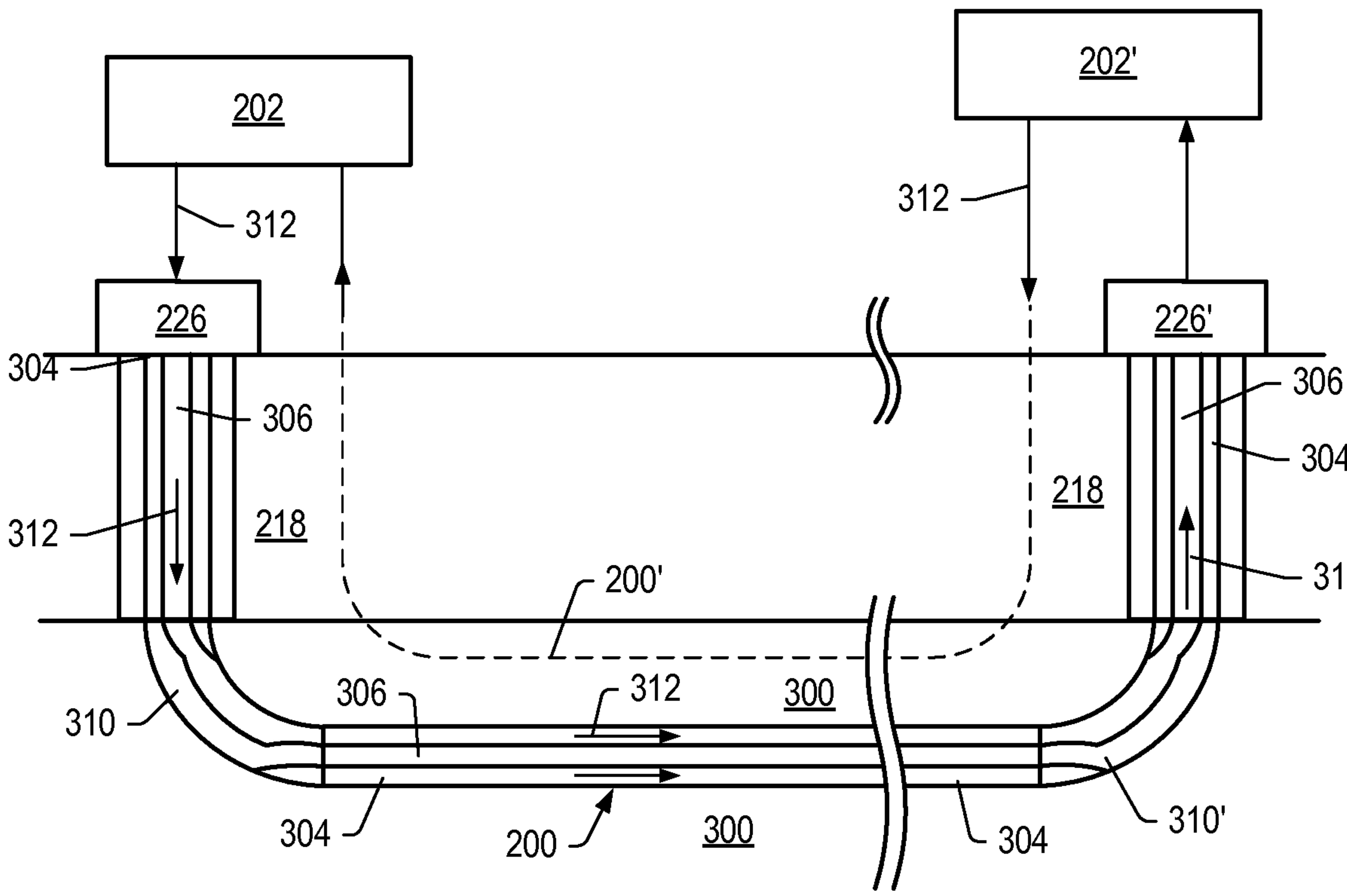
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FIG. 22

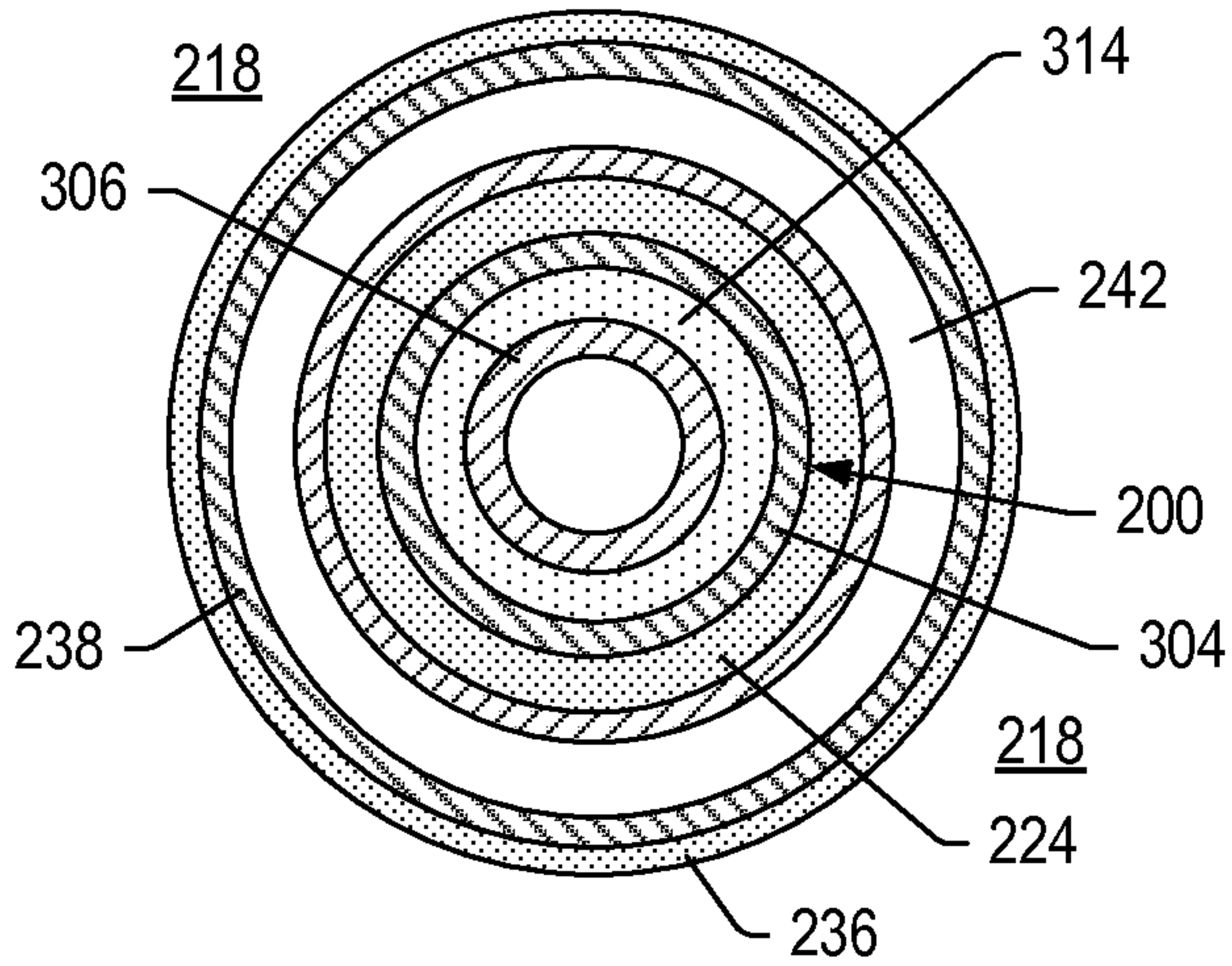
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FIG. 23

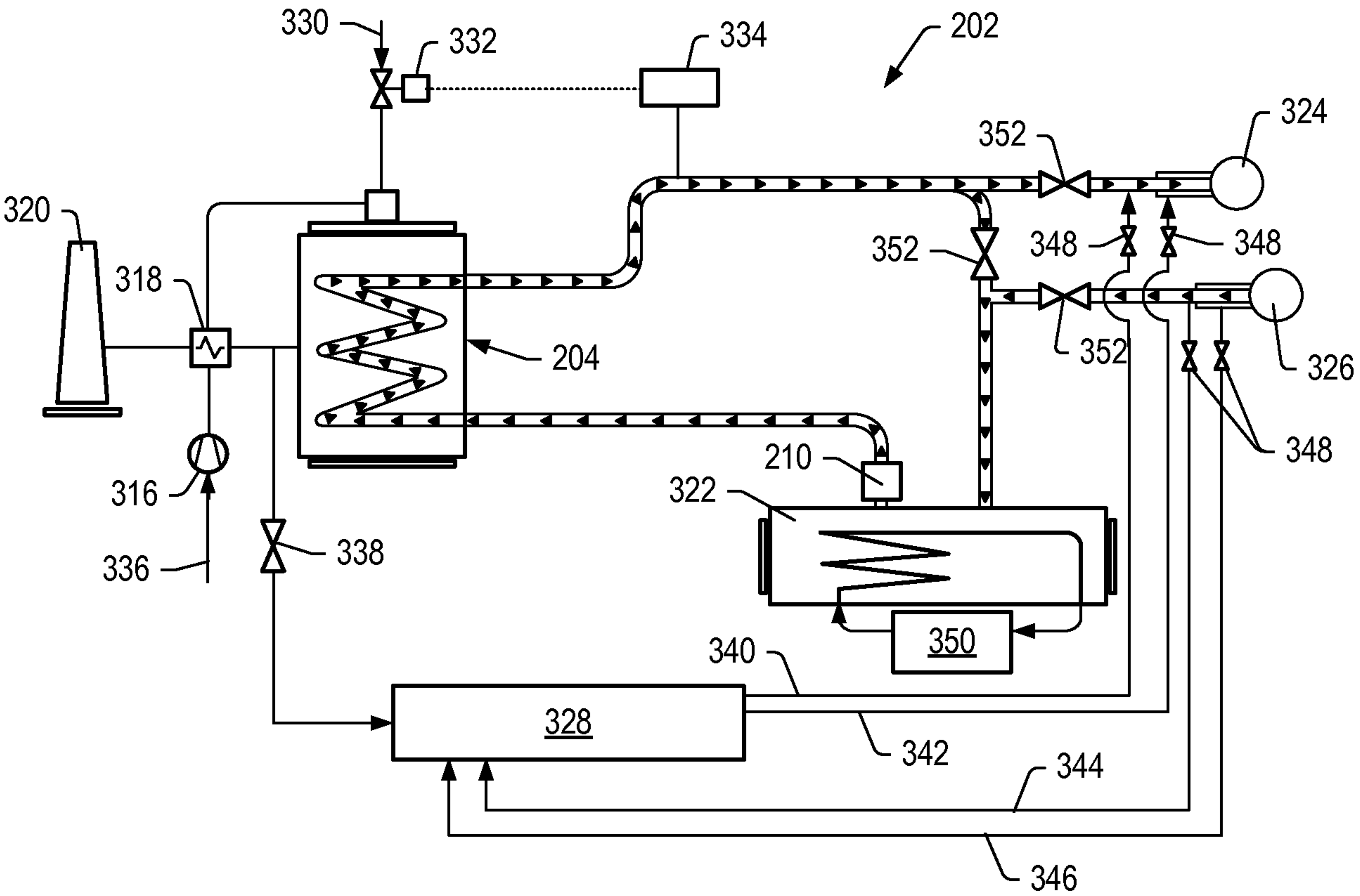
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FIG. 24

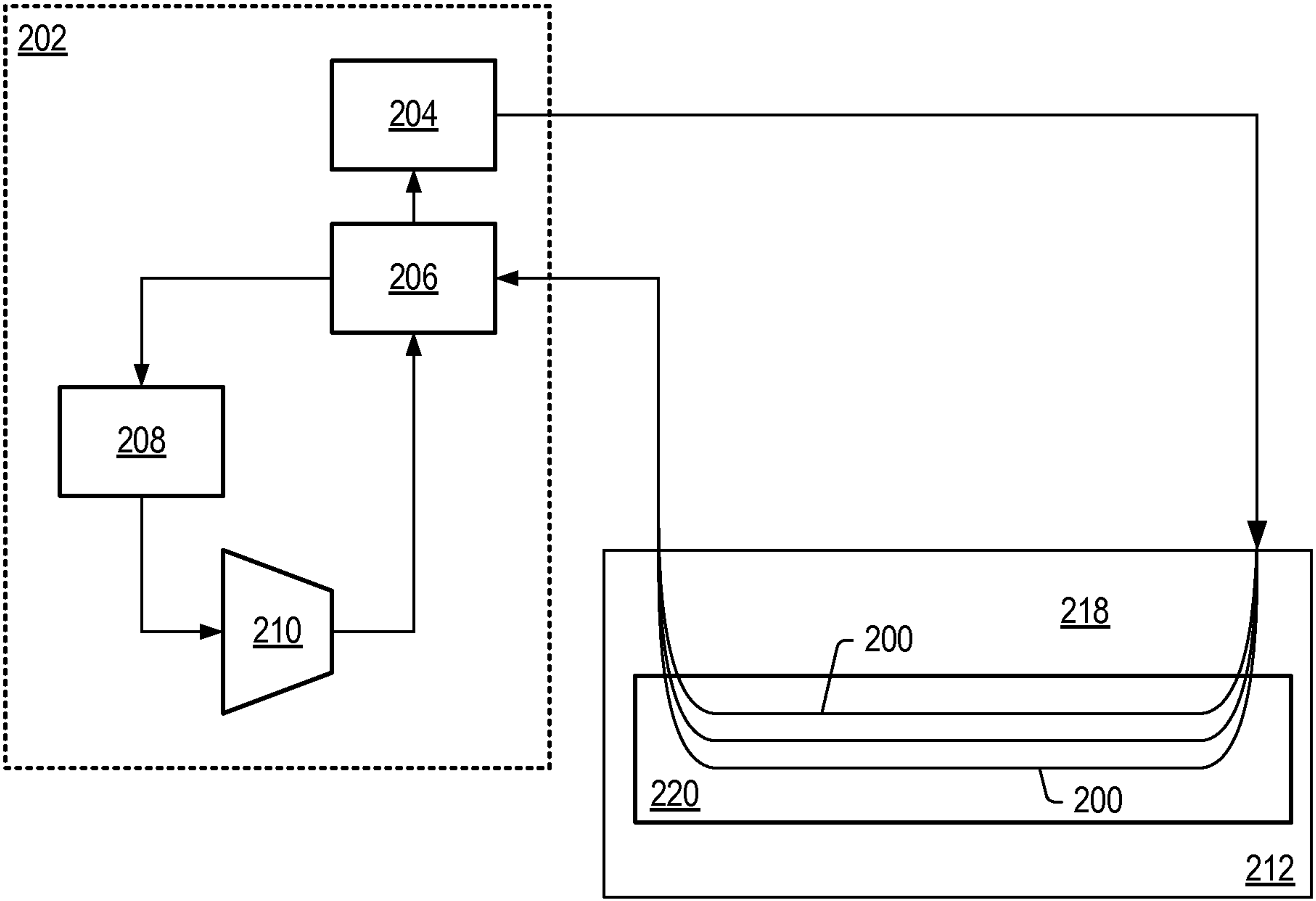

FIG. 2