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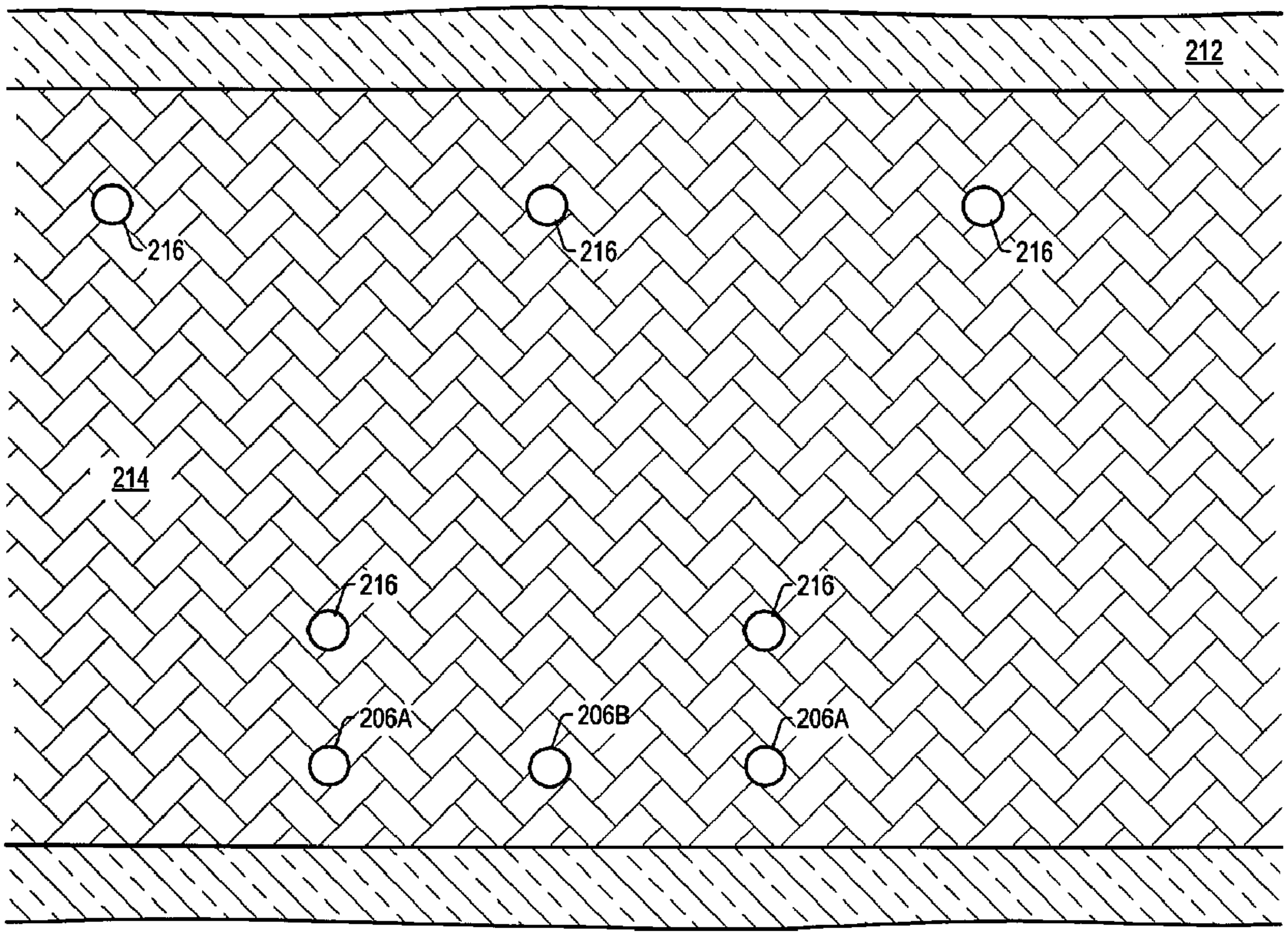

FIG. 3

(57) Abrégé/Abstract:

A method for treating a tar sands formation includes providing a drive fluid to a hydrocarbon containing layer of the tar sands formation to mobilize at least some hydrocarbons in the layer. At least some first hydrocarbons from the layer are produced. Heat is

(57) **Abrégé(suite)/Abstract(continued)**:
provided to the layer from one or more heaters located in the formation. At least some second hydrocarbons are produced from the layer of the formation. The second hydrocarbons include at least some hydrocarbons that are upgraded compared to the first hydrocarbons produced by using the drive fluid.

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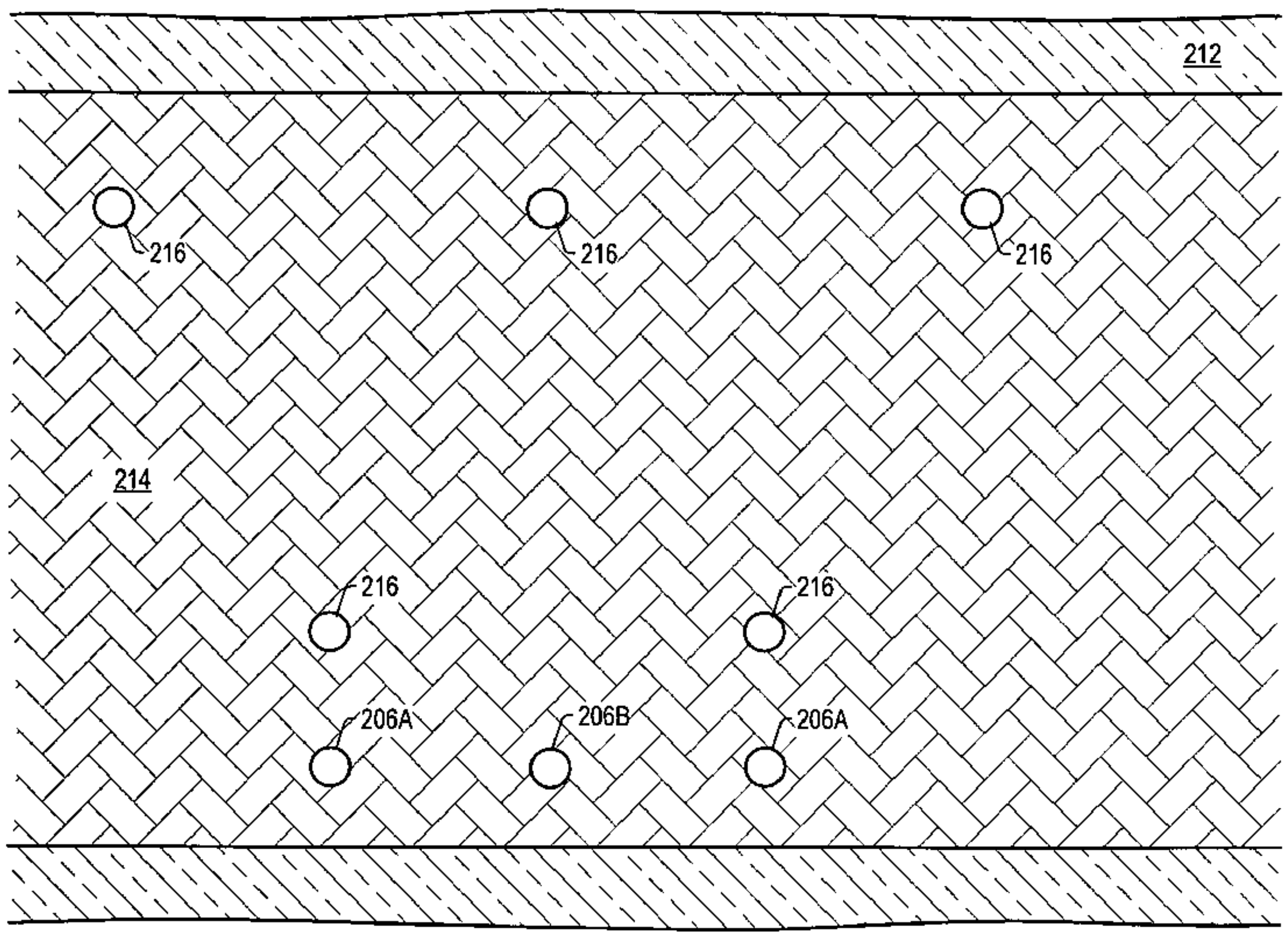

FIG. 3

(57) Abstract: A method for treating a tar sands formation includes providing a drive fluid to a hydrocarbon containing layer of the tar sands formation to mobilize at least some hydrocarbons in the layer. At least some first hydrocarbons from the layer are produced. Heat is provided to the layer from one or more heaters located in the formation. At least some second hydrocarbons are produced from the layer of the formation. The second hydrocarbons include at least some hydrocarbons that are upgraded compared to the first hydrocarbons produced by using the drive fluid.

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IN SITU HEAT TREATMENT OF A TAR SANDS FORMATION AFTER DRIVE PROCESS TREATMENT

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 (for example, tar sands formations).

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] Large deposits of heavy hydrocarbons (heavy oil and/or tar) contained in relatively permeable formations (for example in tar sands) are found in North America, South America, Africa, and Asia. Tar can be surface-mined and upgraded to lighter hydrocarbons such as crude oil, naphtha, kerosene, and/or gas oil. Surface milling processes may further separate the bitumen from sand. The separated bitumen may be converted to light hydrocarbons using conventional refinery methods. Mining and upgrading tar sand is usually substantially more expensive than producing lighter hydrocarbons from conventional oil reservoirs.

[0004] In situ production of hydrocarbons from tar sand may be accomplished by heating and/or injecting a gas into the formation. U.S. Patent Nos. 5,211,230 to Ostapovich et al. and 5,339,897 to Leaute describe a horizontal production well located in an oil-bearing reservoir. A vertical conduit may be used to inject an oxidant gas into the reservoir for in situ combustion.

[0005] U.S. Patent No. 2,780,450 to Ljungstrom describes heating bituminous geological formations in situ to convert or crack a liquid tar-like substance into oils and gases.

[0006] U.S. Patent No. 4,597,441 to Ware et al. describes contacting oil, heat, and hydrogen simultaneously in a reservoir. Hydrogenation may enhance recovery of oil from the reservoir.

[0007] U.S. Patent No. 5,046,559 to Glandt and 5,060,726 to Glandt et al. describe preheating a portion of a tar sand formation between an injector well and a producer well. Steam may be injected from the injector well into the formation to produce hydrocarbons at the producer well.

[0008] As outlined above, 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 such as tar sands formations. At present, drive processes such as SAGD or other steam drive process are used to recover hydrocarbons from tar sands formations. These drive processes, however, are inefficient at removing hydrocarbons from tar sands formations. Thus, there is still a need for improved methods and systems for producing hydrocarbons from tar sands formations with higher efficiency.

SUMMARY

[0009] Embodiments described herein generally relate to systems, methods, and heaters for treating a subsurface formation. Embodiments described herein also generally relate to heaters that have novel components therein. Such heaters can be obtained by using the systems and methods described herein.

[0010] In certain embodiments, the invention provides one or more systems, methods, and/or heaters. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

[0011] In certain embodiments, the invention provides a method for treating a tar sands formation, comprising: providing a drive fluid to a hydrocarbon containing layer of the tar sands formation to mobilize at least some hydrocarbons in the layer; producing at least some first hydrocarbons from the layer; providing heat to the layer from one or more heaters located in the formation; and producing at least some second hydrocarbons from the layer of the formation, the second hydrocarbons comprising at least some hydrocarbons that are upgraded compared to the first hydrocarbons produced by using the drive fluid.

[0012] In certain embodiments, the invention provides a method for treating a tar sands formation, comprising: providing heat to a hydrocarbon containing layer in the tar sands formation from one or more heaters located in the formation, wherein the hydrocarbon containing layer has been previously treated using a steam injection and production process; and producing at least some hydrocarbons from the layer of the formation, the produced hydrocarbons comprising at least some hydrocarbons that are upgraded compared to hydrocarbons produced by the steam injection and production process.

[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.

[0014] In further embodiments, treating a subsurface formation is performed using any of the methods, systems, or heaters described herein.

[0015] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0016] 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:

[0017] FIG. 1 depicts an illustration of stages of heating a hydrocarbon containing formation.

[0018] FIG. 2 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

[0019] FIG. 3 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a relatively thin hydrocarbon layer.

[0020] FIG. 4 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 3.

[0021] FIG. 5 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 4.

[0022] FIG. 6 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that has a shale break.

[0023] FIG. 7 depicts a side view representation of an embodiment of a tar sands formation subsequent to a steam injection process.

[0024] 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

[0025] 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.

[0026] "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.

[0027] "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.

[0028] 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.

[0029] “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.

[0030] 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 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 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 heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0031] 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.

[0032] “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.

[0033] 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.

[0034] 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.

[0035] “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.

[0036] 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.

[0037] 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.

[0038] “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.

[0039] “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.

[0040] “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.

[0041] “Tar” is a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15 °C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10°.

[0042] 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.

[0043] “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.

[0044] "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.

[0045] "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.

[0046] "Viscosity" refers to kinematic viscosity at 40 °C unless specified. Viscosity is as determined by ASTM Method D445.

[0047] 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."

[0048] Hydrocarbons in formations may be treated in various ways to produce many different products. In certain embodiments, hydrocarbons in formations are treated in stages. FIG. 1 depicts an illustration of stages of heating the hydrocarbon containing formation. FIG. 1 also depicts an example of yield ("Y") in barrels of oil equivalent per ton (y axis) of formation fluids from the formation versus temperature ("T") of the heated formation in degrees Celsius (x axis).

[0049] Desorption of methane and vaporization of water occurs during stage 1 heating. Heating of the formation through stage 1 may be performed as quickly as possible. For example, when the hydrocarbon containing formation is initially heated, hydrocarbons in the formation desorb adsorbed methane. The desorbed methane may be produced from the formation. If the hydrocarbon containing formation is heated further, water in the hydrocarbon containing formation is vaporized. Water may occupy, in some hydrocarbon containing formations, between 10% and 50% of the pore volume in the formation. In other formations, water occupies larger or smaller portions of the pore volume. Water typically is vaporized in a formation between 160 °C and 285 °C at pressures of 600 kPa absolute to 7000 kPa absolute. In some embodiments, the vaporized water produces wettability changes in the formation and/or increased formation pressure. The wettability changes and/or increased pressure may affect pyrolysis reactions or other reactions in the formation. In certain embodiments, the vaporized water is produced from the formation. In other embodiments, the vaporized water is used for steam extraction and/or distillation in the formation or outside the formation. Removing the water from and increasing the pore volume in the formation increases the storage space for hydrocarbons in the pore volume.

[0050] In certain embodiments, after stage 1 heating, the formation is heated further, such that a temperature in the formation reaches (at least) an initial pyrolyzation temperature (such as a temperature at the lower end of the temperature range shown as stage 2). Hydrocarbons in the formation may be pyrolyzed throughout stage 2. A pyrolysis temperature range varies depending on the types of hydrocarbons in the formation. The pyrolysis temperature range may include temperatures between 250 °C and 900 °C. The pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, the pyrolysis temperature range for producing desired products may include temperatures between 250 °C and 400 °C or temperatures between 270 °C and 350 °C. If a temperature of hydrocarbons in the formation is slowly raised through the temperature range from 250 °C to 400 °C, production of pyrolysis products may be substantially complete when the temperature approaches 400 °C. Average temperature of the hydrocarbons may be raised at a rate of less than 5 °C per day, less than 2 °C per day, less than 1 °C per day, or less than 0.5 °C per day through the pyrolysis temperature range for producing desired products. Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that slowly raise the temperature of hydrocarbons in the formation through the pyrolysis temperature range.

[0051] The rate of temperature increase through the 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 pyrolysis temperature range for desired products may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the temperature of the formation through the pyrolysis temperature range for desired products may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.

[0052] 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. 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 the desired temperature. The heated portion of the formation is maintained substantially at the desired temperature until pyrolysis declines such that production of desired formation fluids from the formation becomes uneconomical. Parts of the formation that are subjected to pyrolysis may include regions brought into a pyrolysis temperature range by heat transfer from only one heat source.

[0053] In certain embodiments, formation fluids including pyrolyzation fluids are produced from the formation. As the temperature of the formation increases, the amount of condensable hydrocarbons in the produced formation fluid may decrease. At high temperatures, the formation may produce mostly methane and/or hydrogen. If the hydrocarbon containing formation is heated throughout an entire pyrolysis range, the formation may produce only small amounts of hydrogen towards an upper limit of the pyrolysis range. After all of the available hydrogen is depleted, a minimal amount of fluid production from the formation will typically occur.

[0054] After pyrolysis of hydrocarbons, a large amount of carbon and some hydrogen may still be present in the formation. A significant portion of carbon remaining in the formation can be produced from the formation in the form of synthesis gas. Synthesis gas generation may take place during stage 3 heating depicted in FIG. 1. Stage 3 may include heating a hydrocarbon containing formation to a temperature sufficient to allow synthesis gas generation. 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. The temperature of the heated portion of the formation when the synthesis gas generating fluid is introduced to the formation determines the composition of synthesis gas produced in the formation. The generated synthesis gas may be removed from the formation through a production well or production wells.

[0055] Total energy content of fluids produced from the hydrocarbon containing formation may stay relatively constant throughout pyrolysis and synthesis gas generation. During pyrolysis at relatively low formation temperatures, a significant portion of the produced fluid may be condensable hydrocarbons that have a high energy content. At higher pyrolysis temperatures, however, less of the formation fluid may include condensable hydrocarbons. More non-condensable formation fluids may be produced from the formation. Energy content per unit volume of the produced fluid may decline slightly during generation of predominantly non-condensable formation fluids. During synthesis gas generation, energy content per unit volume of produced synthesis gas declines significantly compared to energy content of pyrolyzation fluid. The volume of the produced synthesis gas, however, will in many instances increase substantially, thereby compensating for the decreased energy content.

[0056] FIG. 2 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 200. 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 200 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. 2, the barrier wells 200 are shown extending only along one side of heat sources 202, but the barrier wells typically encircle all heat sources 202 used, or to be used, to heat a treatment area of the formation.

[0057] Heat sources 202 are placed in at least a portion of the formation. Heat sources 202 may include heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 202 may also include other types of heaters. Heat sources 202 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 202 through supply lines 204. Supply lines 204 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 204 for heat sources may transmit electricity for 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.

[0058] Production wells 206 are used to remove formation fluid from the formation. In some embodiments, production well 206 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.

[0059] In some embodiments, the heat source in production well 206 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 (C6 and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0060] 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 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.

[0061] In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been 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 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.

[0062] After 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.

[0063] 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 facilitate vapor phase production of fluids from the formation. Vapor phase production may allow for a reduction in size of collection conduits used to transport fluids produced from the formation. 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.

[0064] 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.

[0065] Formation fluid produced from production wells 206 may be transported through collection piping 208 to treatment facilities 210. Formation fluids may also be produced from heat sources 202. For example, fluid may be produced from heat sources 202 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 202 may be transported through tubing or piping to collection piping 208 or the produced fluid may be transported through tubing or piping directly to treatment facilities 210. Treatment facilities 210 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.

[0066] In certain embodiments, fluids in the relatively permeable formation containing heavy hydrocarbons are produced with little or no pyrolyzation of hydrocarbons in the formation. In certain embodiments, the relatively permeable formation containing heavy hydrocarbons is a tar sands formation. For example, the formation may be a tar sands formation such as the Athabasca tar sands formation in Alberta, Canada or a carbonate formation such as the Grosmont carbonate formation in Alberta, Canada. The fluids produced from the formation are mobilized fluids. Producing mobilized fluids may be more economical than producing pyrolyzed fluids from the tar sands formation. Producing mobilized fluids may also increase the total amount of hydrocarbons produced from the tar sands formation.

[0067] FIGS. 3-6 depict side view representations of embodiments for producing mobilized fluids from tar sands formations. In FIGS. 3-6, heaters 216 have substantially horizontal heating sections in hydrocarbon layer 214 (as shown, the heaters have heating sections that go into and out of the page). Hydrocarbon layer 214 may be below overburden 212. FIG. 3 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a relatively thin hydrocarbon layer. FIG. 4 depicts a side view representation of an embodiment for producing mobilized fluids from a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 3. FIG. 5 depicts a side view representation of an embodiment for producing mobilized fluids from a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 4. FIG. 6 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that has a shale break.

[0068] In FIG. 3, heaters 216 are placed in an alternating triangular pattern in hydrocarbon layer 214. In FIGS. 4, 5, and 6, heaters 216 are placed in an alternating triangular pattern in hydrocarbon layer 214 that repeats vertically to encompass a majority or all of the hydrocarbon layer. In FIG. 6, the alternating triangular pattern of heaters 216 in hydrocarbon layer 214 repeats uninterrupted across shale break 218. In FIGS. 3-6, heaters 216 may be equidistantly spaced from each other. In the embodiments depicted in FIGS. 3-6, the number of vertical rows of heaters 216 depends on factors such as, but not limited to, the desired spacing between the heaters, the thickness of hydrocarbon layer 214, and/or the number and location of shale breaks 218. In some embodiments, heaters 216 are arranged in other patterns. For example, heaters 216 may be arranged in patterns such as, but not limited to, hexagonal patterns, square patterns, or rectangular patterns.

[0069] In the embodiments depicted in FIGS. 3-6, heaters 216 provide heat that mobilizes hydrocarbons (reduces the viscosity of the hydrocarbons) in hydrocarbon layer 214. In certain embodiments, heaters 216 provide heat that reduces the viscosity of the hydrocarbons in hydrocarbon layer 214 below about 0.50 Pa•s (500 cp), below about 0.10 Pa•s (100 cp), or below about 0.05 Pa•s (50 cp). The spacing between heaters 216 and/or the heat output of the heaters may be designed and/or controlled to reduce the viscosity of the hydrocarbons in hydrocarbon layer 214 to desirable values. Heat provided by heaters 216 may be controlled so that little or no pyrolyzation occurs in hydrocarbon layer 214. Superposition of heat between the heaters may create one or more drainage paths (for example, paths for flow of fluids) between the heaters. In certain embodiments, production wells 206A and/or production wells 206B are located proximate heaters 216 so that heat from the heaters superimposes over the production wells. The superimposition of heat from heaters 216 over production wells 206A and/or production wells 206B creates one or more drainage paths from the heaters to the production wells. In certain embodiments, one or more of the drainage paths converge. For example, the drainage paths may converge at or near a bottommost heater and/or the drainage paths may converge at or near production wells 206A and/or production wells 206B. Fluids mobilized in hydrocarbon layer 214 tend to flow towards the bottommost heaters 216, production wells 206A and/or production wells 206B in the hydrocarbon layer because of gravity and the heat and pressure gradients established by the heaters and/or the production wells. The drainage paths and/or the converged drainage paths allow production wells 206A and/or production wells 206B to collect mobilized fluids in hydrocarbon layer 214.

[0070] In certain embodiments, hydrocarbon layer 214 has sufficient permeability to allow mobilized fluids to drain to production wells 206A and/or production wells 206B. For example, hydrocarbon layer 214 may have a permeability of at least about 0.1 darcy, at least about 1 darcy, at least about 10 darcy, or at least about 100 darcy. In some embodiments, hydrocarbon layer 214 has a relatively large vertical permeability to horizontal permeability ratio (K_v/K_h). For example, hydrocarbon layer 214 may have a K_v/K_h ratio between about 0.01 and about 2, between about 0.1 and about 1, or between about 0.3 and about 0.7.

[0071] In certain embodiments, fluids are produced through production wells 206A located near heaters 216 in the lower portion of hydrocarbon layer 214. In some embodiments, fluids are produced through production wells 206B located below and approximately midway between heaters 216 in the lower portion of hydrocarbon layer 214. At least a portion of production wells 206A and/or production wells 206B may be oriented substantially horizontal in hydrocarbon layer 214 (as shown in FIGS. 3-6, the production wells have horizontal portions that go into and out of the page). Production wells 206A and/or 206B may be located proximate lower portion heaters 216 or the bottommost heaters.

[0072] In some embodiments, production wells 206A are positioned substantially vertically below the bottommost heaters in hydrocarbon layer 214. Production wells 206A may be located below heaters 216 at the bottom vertex of a pattern of the heaters (for example, at the bottom vertex of the triangular pattern of heaters depicted in FIGS. 3-6). Locating production wells 206A substantially vertically below the bottommost heaters may allow for efficient collection of mobilized fluids from hydrocarbon layer 214.

[0073] In certain embodiments, the bottommost heaters are located between about 2 m and about 10 m from the bottom of hydrocarbon layer 214, between about 4 m and about 8 m from the bottom of the hydrocarbon layer, or between about 5 m and about 7 m from the bottom of the hydrocarbon layer. In certain embodiments, production wells 206A and/or production wells 206B are located at a distance from the bottommost heaters 216 that allows heat from the heaters to superimpose over the production wells but at a distance from the heaters that inhibits coking at the production wells. Production wells 206A and/or production wells 206B may be located a distance from the nearest heater (for example, the bottommost heater) of at most ¾ of the spacing between heaters in the pattern of heaters (for example, the triangular pattern of heaters depicted in FIGS. 3-6). In some embodiments, production wells 206A and/or production wells 206B are located a distance from the nearest heater of at most ⅔, at most ½, or at most ⅓ of the spacing between heaters in the pattern of heaters. In certain embodiments, production wells 206A and/or production wells 206B are located between about 2 m and about 10 m from the bottommost heaters, between about 4 m and about 8 m from the bottommost heaters, or between about 5 m and about 7 m from the bottommost heaters. Production wells 206A and/or production wells 206B may be located between about 0.5 m and about 8 m from the bottom of hydrocarbon layer 214, between about 1 m and about 5 m from the bottom of the hydrocarbon layer, or between about 2 m and about 4 m from the bottom of the hydrocarbon layer.

[0074] In some embodiments, at least some production wells 206A are located substantially vertically below heaters 216 near shale break 218, as depicted in FIG. 6. Production wells 206A may be located between heaters 216 and shale break 218 to produce fluids that flow and collect above the shale break. Shale break 218 may be an impermeable barrier in hydrocarbon layer 214. In some embodiments, shale break 218 has a thickness between about 1 m and about 6 m, between about 2 m and about 5 m, or between about 3 m and about 4 m. Production wells 206A between heaters 216 and shale break 218 may produce fluids from the upper portion of hydrocarbon layer 214 (above the shale break) and production wells 206A below the bottommost heaters in the hydrocarbon layer may produce fluids from the lower portion of the hydrocarbon layer (below the shale break), as depicted in FIG. 6. In some embodiments, two or more shale breaks may exist in a hydrocarbon layer. In such an embodiment, production wells are placed at or near each of the shale breaks to produce fluids flowing and collecting above the shale breaks.

[0075] In some embodiments, shale break 218 breaks down (is desiccated or decomposes) as the shale break is heated by heaters 216 on either side of the shale break. As shale break 218 breaks down, the permeability of the shale break increases and fluids flow through the shale break. Once fluids are able to flow through shale break 218, production wells above the shale break may not be needed for production as fluids can flow to production wells at or near the bottom of hydrocarbon layer 214 and be produced there.

[0076] In certain embodiments, the bottommost heaters above shale break 218 are located between about 2 m and about 10 m from the shale break, between about 4 m and about 8 m from the bottom of the shale break, or between about 5 m and about 7 m from the shale break. Production wells 206A may be located between about 2 m and about 10 m from the bottommost heaters above shale break 218, between about 4 m and about 8 m from the bottommost heaters above the shale break, or between about 5 m and about 7 m from the bottommost heaters above the shale break. Production wells 206A may be located between about 0.5 m and about 8 m from shale break 218, between about 1 m and about 5 m from the shale break, or between about 2 m and about 4 m from the shale break.

[0077] In some embodiments, heat is provided in production wells 206A and/or production wells 206B, depicted in FIGS. 3-6. Providing heat in production wells 206A and/or production wells 206B may maintain and/or enhance the mobility of the fluids in the production wells. Heat provided in production wells 206A and/or production wells 206B may superimpose with heat from heaters 216 to create the flow path from the heaters to the production wells. In some embodiments, production wells 206A and/or production wells 206B include a pump to move fluids to the surface of the formation. In some embodiments, the viscosity of fluids (oil) in production wells 206A and/or production wells 206B is lowered using heaters and/or diluent injection (for example, using a conduit in the production wells for injecting the diluent).

[0078] In certain embodiments, in situ heat treatment of the relatively permeable formation containing hydrocarbons (for example, the tar sands formation) includes heating the formation to visbreaking temperatures. For example, the formation may be heated to temperatures between about 100 °C and 260 °C, between about 150 °C and about 250 °C, between about 200 °C and about 240 °C, between about 205 °C and 230 °C, between about 210 °C and 225 °C. In one embodiment, the formation is heated to a temperature of about 220 °C. In one embodiment, the formation is heated to a temperature of about 230 °C. At visbreaking temperatures, fluids in the formation have a reduced viscosity (versus their initial viscosity at initial formation temperature) that allows fluids to flow in the formation. The reduced viscosity at visbreaking temperatures may be a permanent reduction in viscosity as the hydrocarbons go through a step change in viscosity at visbreaking temperatures (versus heating to mobilization temperatures, which may only temporarily reduce the viscosity). The visbroken fluids may have API gravities that are relatively low (for example, at most about 10°, about 12°, about 15°, or about 19° API gravity), but the API gravities are higher than the API gravity of non-visbroken fluid from the formation. The non-visbroken fluid from the formation may have an API gravity of 7° or less.

[0079] In some embodiments, heaters in the formation are operated at full power output to heat the formation to visbreaking temperatures or higher temperatures. Operating at full power may rapidly increase the pressure in the formation. In certain embodiments, fluids are produced from the formation to maintain a pressure in the formation below a selected pressure as the temperature of the formation increases. In some embodiments, the selected pressure is a fracture pressure of the formation. In certain embodiments, the selected pressure is between about 1000 kPa and about 15000 kPa, between about 2000 kPa and about 10000 kPa, or between about 2500 kPa and about 5000 kPa. In one embodiment, the selected pressure is about 10000 kPa. Maintaining the pressure as close to the fracture pressure as possible may minimize the number of production wells needed for producing fluids from the formation.

[0080] In certain embodiments, treating the formation includes maintaining the temperature at or near visbreaking temperatures (as described above) during the entire production phase while maintaining the pressure below the fracture pressure. The heat provided to the formation may be reduced or eliminated to maintain the temperature at or near visbreaking temperatures. Heating to visbreaking temperatures but maintaining the temperature below pyrolysis temperatures or near pyrolysis temperatures (for example, below about 230 °C) inhibits coke formation and/or higher level reactions. Heating to visbreaking temperatures at higher pressures (for example, pressures near but below the fracture pressure) keeps produced gases in the liquid oil (hydrocarbons) in the formation and increases hydrogen reduction in the formation with higher hydrogen partial pressures. Heating the formation to only visbreaking temperatures also uses less energy input than heating the formation to pyrolysis temperatures.

[0081] Fluids produced from the formation may include visbroken fluids, mobilized fluids, and/or pyrolyzed fluids. In some embodiments, a produced mixture that includes these fluids is produced from the formation. The produced mixture may have assessable properties (for example, measurable properties). The produced mixture properties are determined by operating conditions in the formation being treated (for example, temperature and/or pressure in the formation). In certain embodiments, the operating conditions may be selected, varied, and/or maintained to produce desirable properties in hydrocarbons in the produced mixture. For example, the produced mixture may include hydrocarbons that have properties that allow the mixture to be easily transported (for example, sent through a pipeline without adding diluent or blending the mixture and/or resulting hydrocarbons with another fluid).

[0082] In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures, the amount of fluids produced at visbreaking temperatures, the amount of fluids produced before reducing the pressure in the formation, and/or the amount of upgraded or pyrolyzed fluids produced may be varied to control the quality and amount of fluids produced from the formation and the total recovery of hydrocarbons from the formation. For example, producing more fluid during the early stages of treatment (for example, producing fluids before reducing the pressure in the formation) may increase the total recovery of hydrocarbons from the formation while reducing the overall quality (lowering the overall API gravity) of fluid produced from the formation. The overall quality is reduced because more heavy hydrocarbons are produced by producing more fluids at the lower temperatures. Producing less fluids at the lower temperatures may increase the overall quality of the fluids produced from the formation but may lower the total recovery of hydrocarbons from the formation. The total recovery may be lower because more coking occurs in the formation when less fluids are produced at lower temperatures.

[0083] In some embodiments, production of fluids is continued after reducing and/or turning off heating of the formation. The formation may be heated for a selected time. For example, the formation may be heated until it reaches a selected average temperature. Production from the formation may continue after the selected time. Continuing production may produce more fluid from the formation as fluids drain towards the bottom of the formation and/or as fluids are upgraded by passing by hot spots in the formation. In some embodiments, a horizontal production well is located at or near the bottom of the formation (or a zone of the formation) to produce fluids after heating is turned down and/or off.

[0084] In certain embodiments, initially produced fluids (for example, fluids produced below visbreaking temperatures), fluids produced at visbreaking temperatures, and/or other viscous fluids produced from the formation are blended with diluent to produce fluids with lower viscosities. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from the formation. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from another portion of the formation or another formation. In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures and/or fluids produced at visbreaking temperatures that are blended with upgraded fluids from the formation is adjusted to create a fluid suitable for transportation and/or use in a refinery. The amount of blending may be adjusted so that the fluid has chemical and physical stability. Maintaining the chemical and physical stability of the fluid may allow the fluid to be transported, reduce pre-treatment processes at a refinery and/or reduce or eliminate the need for adjusting the refinery process to compensate for the fluid.

[0085] In certain embodiments, formation conditions (for example, pressure and temperature) and/or fluid production are controlled to produce fluids with selected properties. For example, formation conditions and/or fluid production may be controlled to produce fluids with a selected API gravity and/or a selected viscosity. The selected API gravity and/or selected viscosity may be produced by combining fluids produced at different formation conditions (for example, combining fluids produced at different temperatures during the treatment as described above). As an example, formation conditions and/or fluid production may be controlled to produce fluids with an API gravity of about 19° and a viscosity of about 0.35 Pa·s (350 cp) at 5 °C.

[0086] In certain embodiments, a drive process (for example, a steam injection process such as cyclic steam injection, a steam assisted gravity drainage process (SAGD), a solvent injection process, a vapor solvent and SAGD process, or a carbon dioxide injection process) is used to treat the tar sands formation in addition to the in situ heat treatment process. In some embodiments, heaters are used to create high permeability zones (or injection zones) in the formation for the drive process. Heaters may be used to create a mobilization geometry or production network in the formation to allow fluids to flow through the formation during the drive process. For example, heaters may be used to create drainage paths between the heaters and production wells for the drive process. In some embodiments, the heaters are used to provide heat during the drive process. The amount of heat provided by the heaters may be small compared to the heat input from the drive process (for example, the heat input from steam injection).

[0087] In some embodiments, the steam injection (or drive) process (for example, SAGD, cyclic steam soak, or another steam recovery process) is used to treat the formation and produce hydrocarbons from the formation. The steam injection process may recover a low amount of oil in place from the formation (for example, less than 20% recovery of oil in place from the formation). The in situ heat treatment process may be used following the steam injection process to increase the recovery of oil in place from the formation. In certain embodiments, the steam injection process is used until the steam injection process is no longer efficient at removing hydrocarbons from the formation (for example, until the steam injection process is no longer economically feasible). The in situ heat treatment process is used to produce hydrocarbons remaining in the formation after the steam injection process. Using the in situ heat treatment process after the steam injection process may allow recovery of at least about 25%, at least about 50%, at least about 55%, or at least about 60% of oil in place in the formation.

[0088] In some embodiments, the formation has been at least somewhat heated by the steam injection process before treating the formation using the in situ heat treatment process. For example, the steam injection process may heat the formation to an average temperature between about 200 °C and about 250 °C, between about 175 °C and about 265 °C, or between about 150 °C and about 270 °C. In certain embodiments, the heaters are placed in the formation after the steam injection process is at least 50% completed, at least 75%, completed, or near 100% completion of the steam injection process. The heaters provide heat for treating the formation using the in situ heat treatment process. In some embodiments, the heaters are already in place in the formation during the steam injection process. In such embodiments, the heaters may be energized after the steam injection process is completed or when production of hydrocarbons using the steam injection process is reduced below a desired level. In some embodiments, steam injection wells from the steam injection process are converted to heater wells for the in situ heat treatment process.

[0089] Treating the formation with the in situ heat treatment process after the steam injection process may be more efficient than only treating the formation with the in situ heat treatment process. The steam injection process may provide some energy (heat) to the formation with the steam. Any energy added to the formation during the steam injection process reduces the amount of energy needed to be supplied by heaters for the in situ heat treatment process. Reducing the amount of energy supplied by heaters reduces costs for treating the formation using the in situ heat treatment process.

[0090] In certain embodiments, treating the formation using the steam injection process does not treat the formation uniformly. For example, steam injection may not be uniform throughout the formation. Variations in the properties of the formation (for example, fluid injectivities, permeabilities, and/or porosities) may result in non-uniform injection of the steam through the formation. Because of the non-uniform injection of the steam, the steam may remove hydrocarbons from different portions of the formation at different rates or with different results. For example, some portions of the formation may have little or no steam injectivity, which inhibits the hydrocarbon production from these portions. After the steam injection process is completed, the formation may have portions that have lower amounts of hydrocarbons produced (more hydrocarbons remaining) than other parts of the formation.

[0091] FIG. 7 depicts a side view representation of an embodiment of a tar sands formation subsequent to a steam injection process. Injection well 220 is used to inject steam into hydrocarbon layer 214 below overburden 212. Portion 222 may have little or no steam injectivity and have small amounts of hydrocarbons or no hydrocarbons at all removed by the steam injection process. Portions 224 may include portions that have steam injectivity and measurable amounts of hydrocarbons are removed by the steam injection process. Thus, portion 222 may have a greater amount of hydrocarbons remaining than portions 224 following treatment with the steam injection process. In some embodiments, hydrocarbon layer 214 includes two or more portions 222 with more hydrocarbons remaining than portions 224.

[0092] In some embodiments, the portions with more hydrocarbons remaining (such as portion 222, depicted in FIG. 7) are large portions of the formation. In some embodiments, the amount of hydrocarbons remaining in these portions is significantly higher than other portions of the formation (such as portions 224, depicted in FIG. 7). For example, portions 222 may have a recovery of at most about 10% of the oil in place and portions 224 may have a recovery of at least about 30% of the oil in place. In some embodiments, portions 222 have a recovery of between about 0% and about 10% of the oil in place, between about 0% and about 15% of the oil in place, or between about 0% and about 20% of the oil in place. The portions 224 may have a recovery of between about 20% and about 25% of the oil in place, between about 20% and about 40% of the oil in place, or between about 20% and about 50% of the oil in place. Coring, logging techniques, and/or seismic imaging may be used to assess hydrocarbons remaining in the formation and assess the location of one or more of the first and/or second portions.

[0093] In certain embodiments, during the in situ heat treatment process, more heat is provided to the first portions of the formation that have more hydrocarbons remaining than the second portions with less hydrocarbons remaining. In some embodiments, heaters are located in the first portions but not in the second portions. In some embodiments, heaters are located in both the first portions and the second portions but the heaters in the first portions are designed or operated to provide more heat than the heaters in the second portions. In some embodiments, heaters pass through both first portions and second portions and the heaters are designed or operated to provide more heat in the first portions than the second portions.

[0094] In some embodiments, steam injection is continued during the in situ heat treatment process. For example, steam injection may be continued while liquids are being produced from the formation. The steam injection may increase the production of liquids from the formation. In certain embodiments, steam injection may be reduced or stopped when gas production from the formation begins.

[0095] In some embodiments, the formation is treated using the in situ heat treatment process a significant time after the formation has been treated using the steam injection process. For example, the in situ heat treatment process is used 1 year, 2 years, 3 years, or longer (for example, 10 years to 20 years) after a formation has been treated using the steam injection process. During this dormant period, heat from the steam injection process may diffuse to cooler parts of the formation and result in a more uniform preheating of the formation prior to in situ heat treatment. The in situ heat treatment process may be used on formations that have been left dormant after the steam injection process treatment because further hydrocarbon production using the steam injection process is not possible and/or not economically feasible. In some embodiments, the formation remains at least somewhat heated from the steam injection process even after the significant time.

[0096] 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 treating a tar sands formation, comprising:

providing a drive fluid to a hydrocarbon containing layer of the tar sands formation to mobilize at least some hydrocarbons in the layer;

producing at least some first hydrocarbons from the layer;

providing heat to the layer from one or more heaters located in the formation; and

producing at least some second hydrocarbons from the layer of the formation, the second hydrocarbons comprising at least some hydrocarbons that are upgraded compared to the first hydrocarbons produced by using the drive fluid.

2. The method of claim 1, wherein the drive fluid is steam.

3. A method for treating a tar sands formation, comprising:

providing heat to a hydrocarbon containing layer in the tar sands formation from one or more heaters located in the formation, wherein the hydrocarbon containing layer has been previously treated using a steam injection and production process; and

producing at least some hydrocarbons from the layer of the formation, the produced hydrocarbons comprising at least some hydrocarbons that are upgraded compared to hydrocarbons produced by the steam injection and production process.

4. The method of claim 3, wherein at most 20% of the oil in place is produced from the formation as first hydrocarbons using the provided drive fluid and/or using the steam injection and production process.

5. The method of any of claims 3 or 4, wherein at least 25% of the oil in place is produced after providing heat to the formation from the one or more heaters.

6. The method of any of claims 3 or 4, further comprising heating the layer to a temperature between 150 °C and 270 °C using the drive fluid and/or the steam injection and production process.

7. The method of any of claims 3 or 4, wherein the heaters used to provide heat are placed in the formation after the production of the first hydrocarbons using the drive fluid and/or the steam injection and production process are at least 50% complete.

8. The method of any of claims 3 or 4, further comprising activating the heaters after the production of hydrocarbons using the drive fluid and/or the steam injection and production process are at least 50% complete.

9. The method of any of claims 3 or 4, wherein hydrocarbons in the layer are not uniformly removed using the drive fluid and/or during the steam injection and production process.

10. The method of any of claims 3 or 4, further comprising continuing to provide the drive fluid and/or resuming the steam injection and production process while providing heat to the formation from the one or more heaters.

11. The method of any of claims 3 or 4, wherein the layer comprises at least two portions with different recoveries after producing the first hydrocarbons using the drive fluid and/or using the steam injection and production process.

12. The method of claim 11, wherein at least one of the portions has a recovery of at most 10% of the oil in place and at least a second one of the portions has a recovery of at least 30% of the oil in place.

13. The method of claim 12, further comprising providing more heat to the portion with the lower recovery than to the portion with the higher recovery.

14. The method of any of claims 3 or 4, wherein the layer is left dormant for at least 1 year after production of the first hydrocarbons using the drive fluid and/or the steam injection and production process, and before heat is provided from the one or more heaters.

15. The method of any of claims 3 or 4, further comprising installing at least one of the heaters in a wellbore that has previously been used to provide the drive fluid or steam into the layer.

16. The method of any of claims 3 or 4, further comprising heating the layer to a first average temperature using the drive fluid or steam, and then heating the layer to a second average temperature using the one or more heaters, wherein the second average temperature is higher than the first average temperature.

17. The method of claim 16, wherein the second average temperature is at least 250°C.

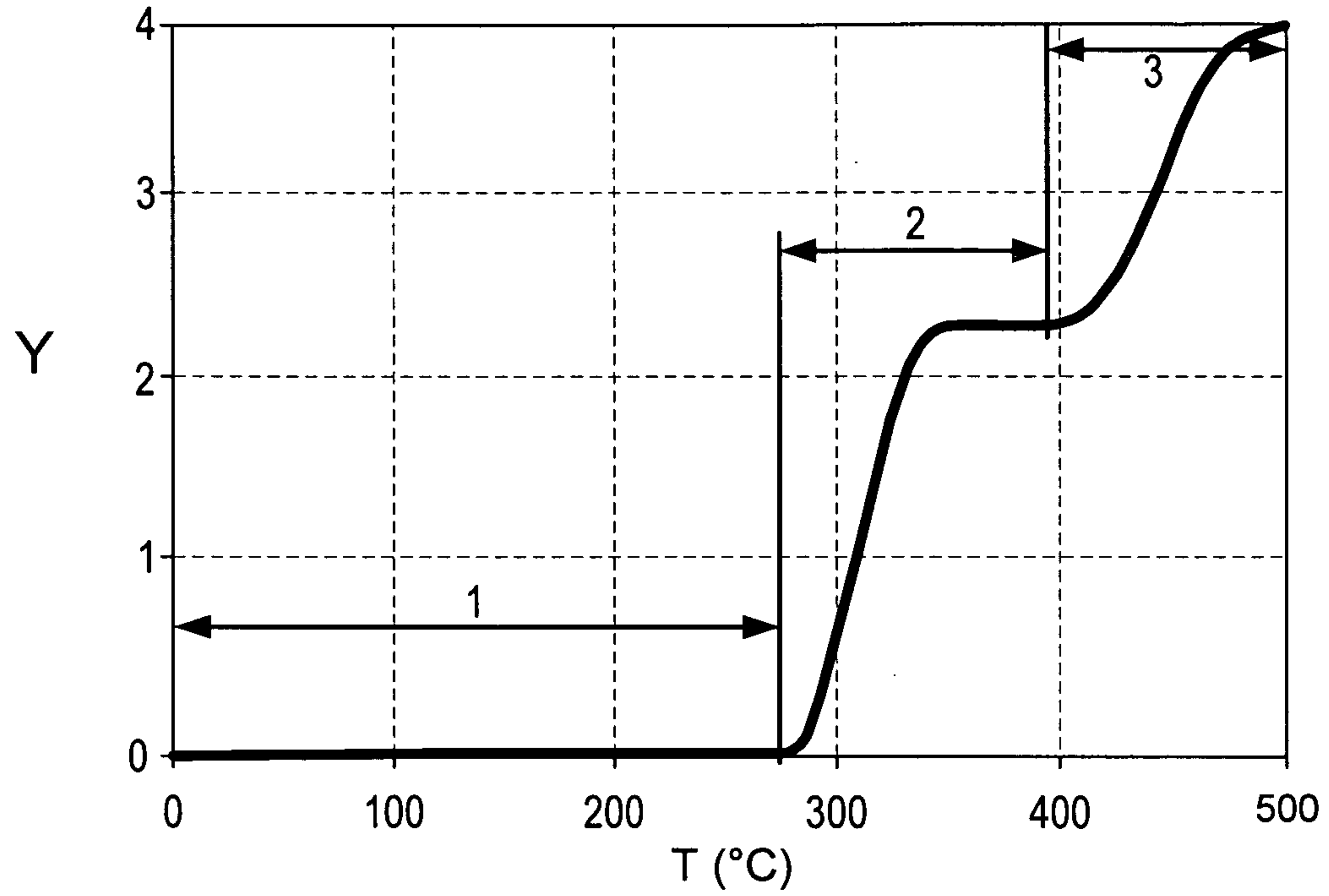
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FIG. 1

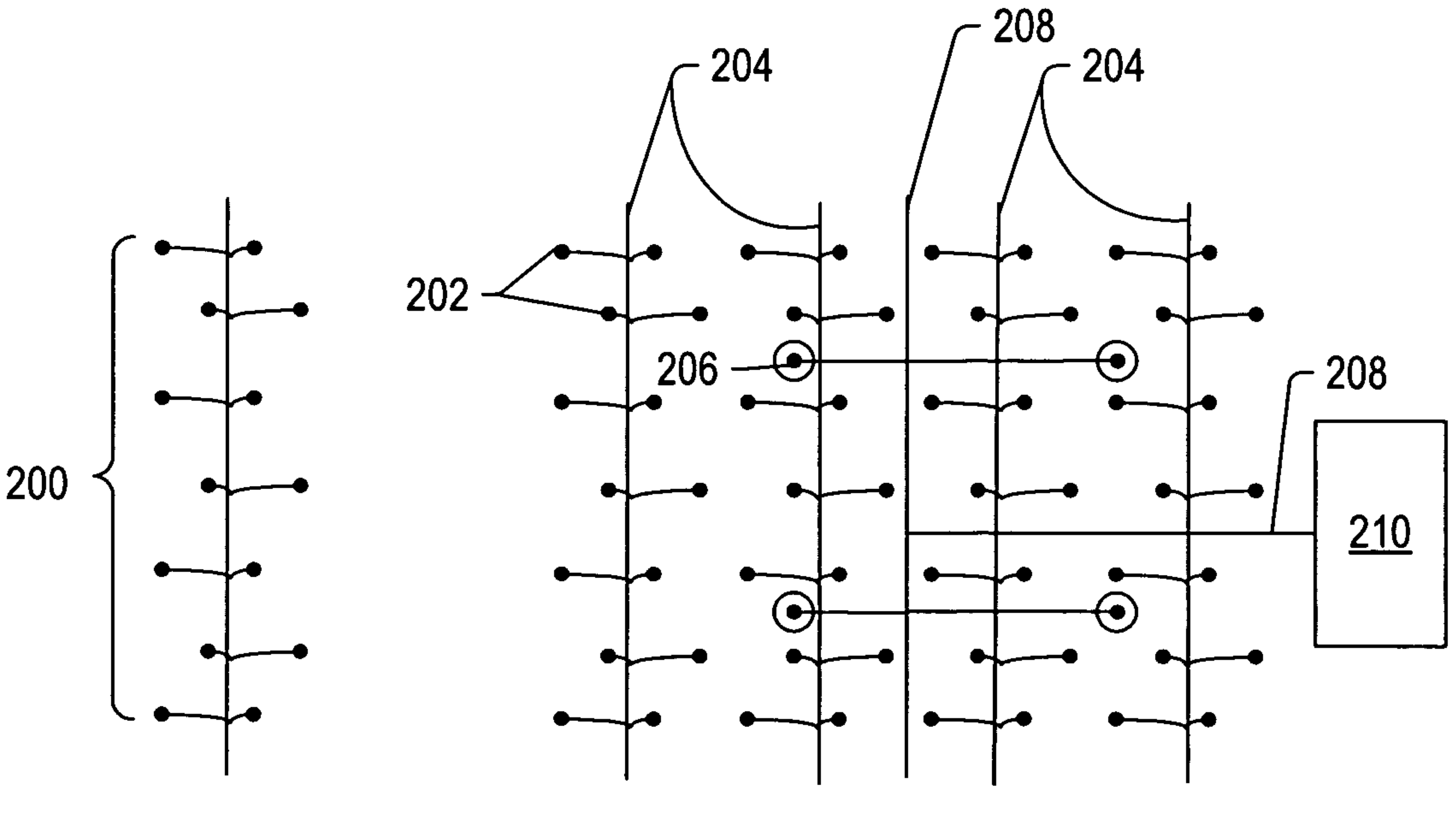
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FIG. 2

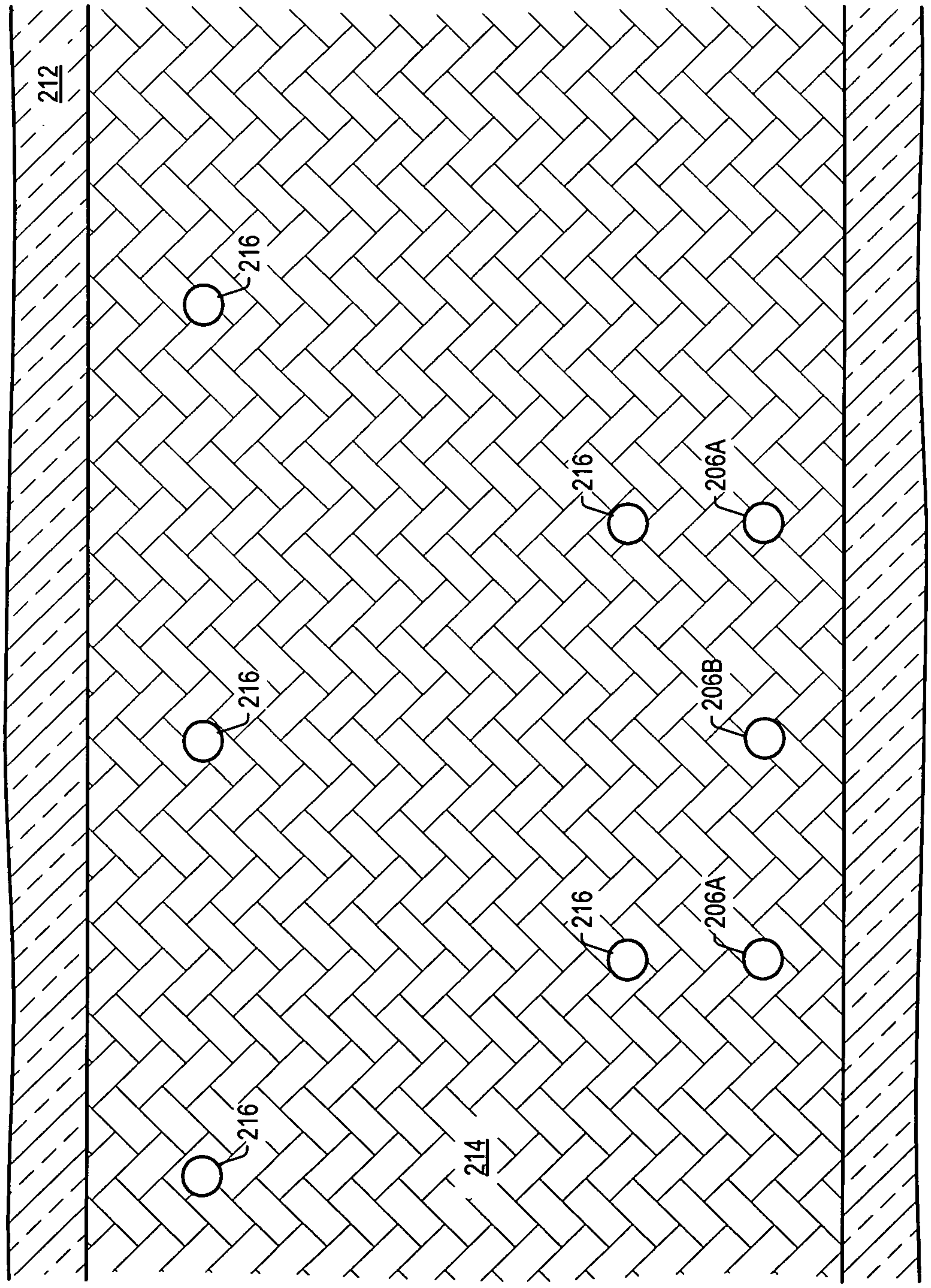


FIG. 3

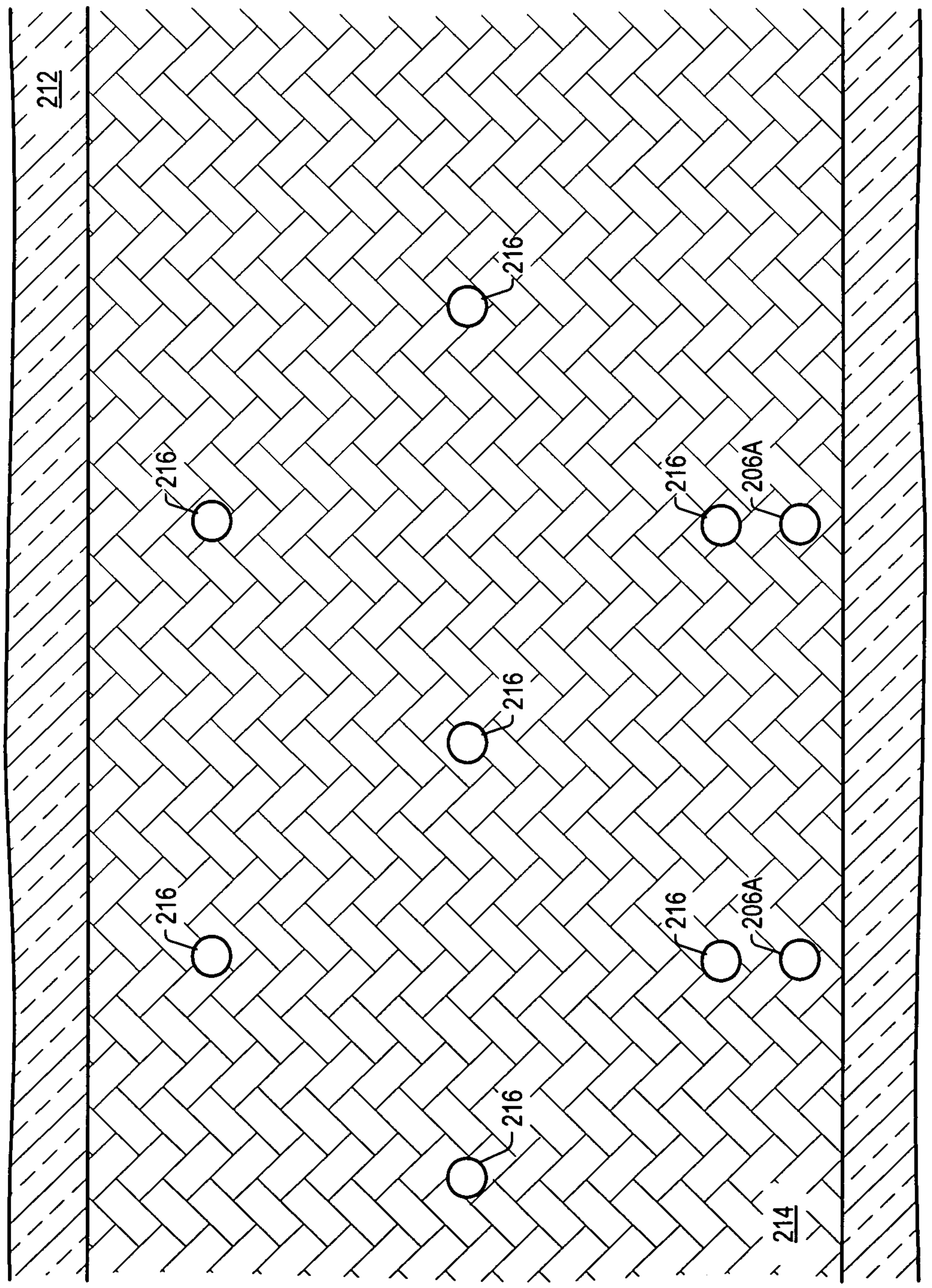
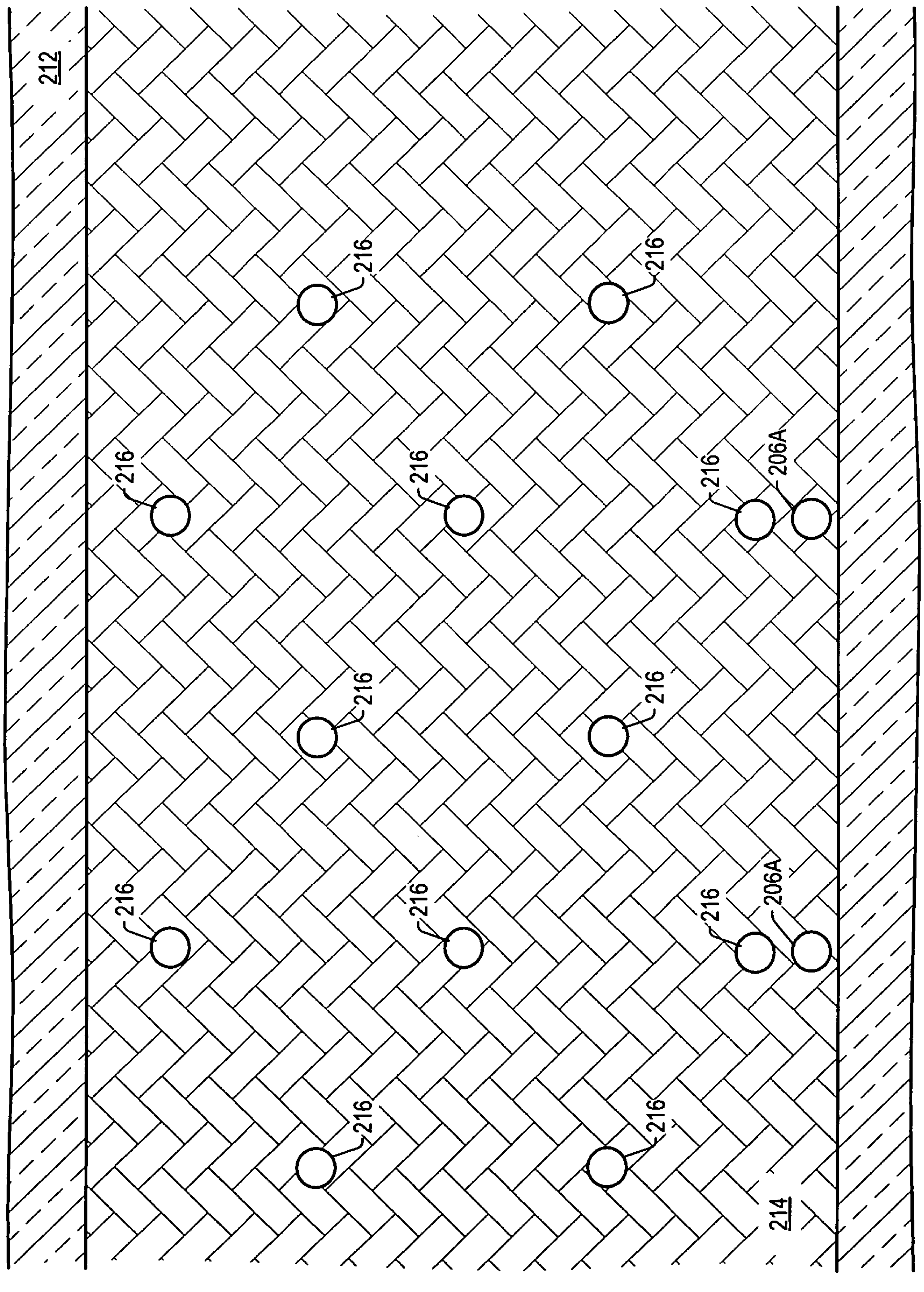


FIG. 4

FIG. 5


212
216
216
216
216
216
206A
216
216
216
216
216
206A
216
216
214

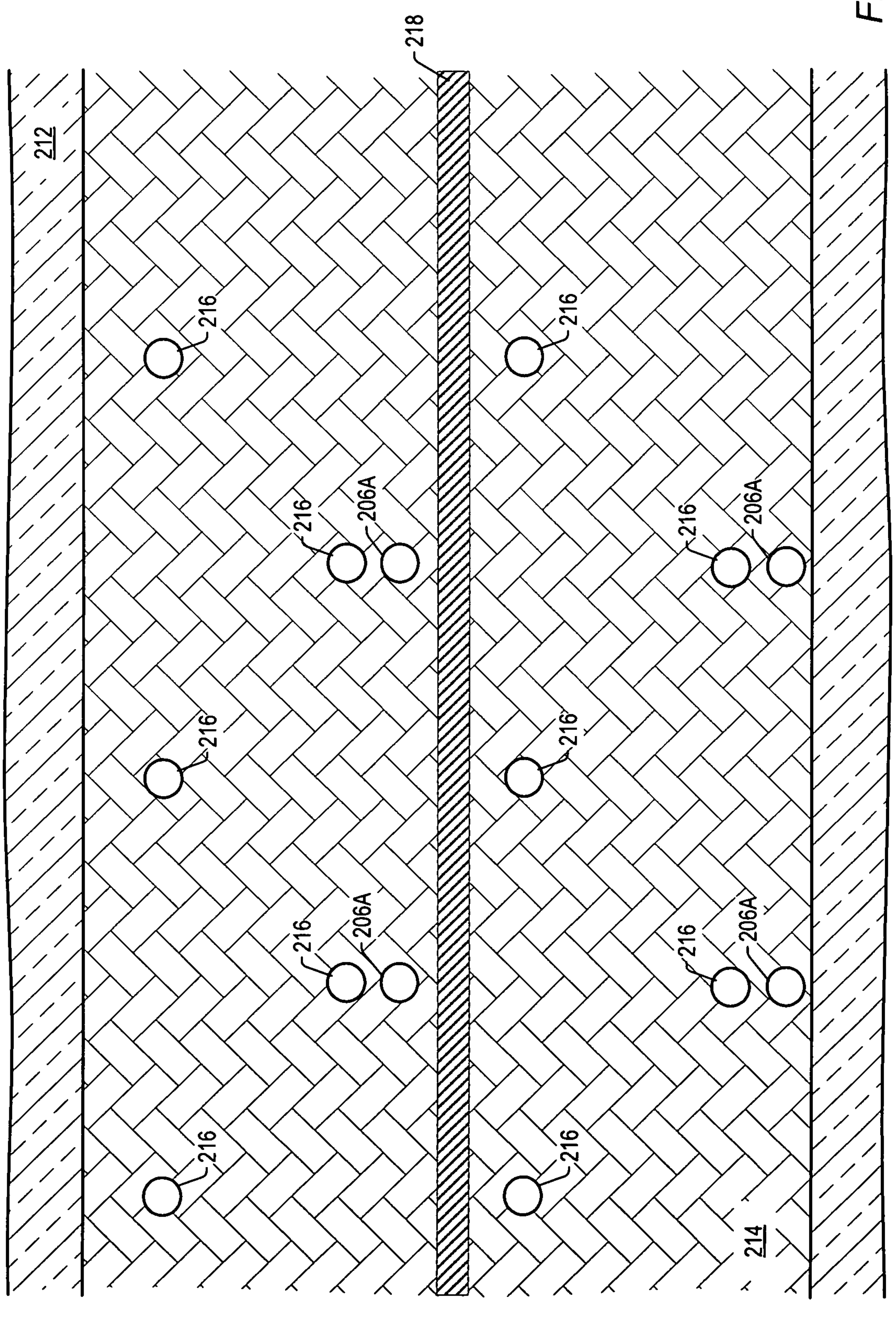

218
212
216
216
216
206A
216
206A
216
216
216
206A
216
206A
216
216
214

FIG. 6

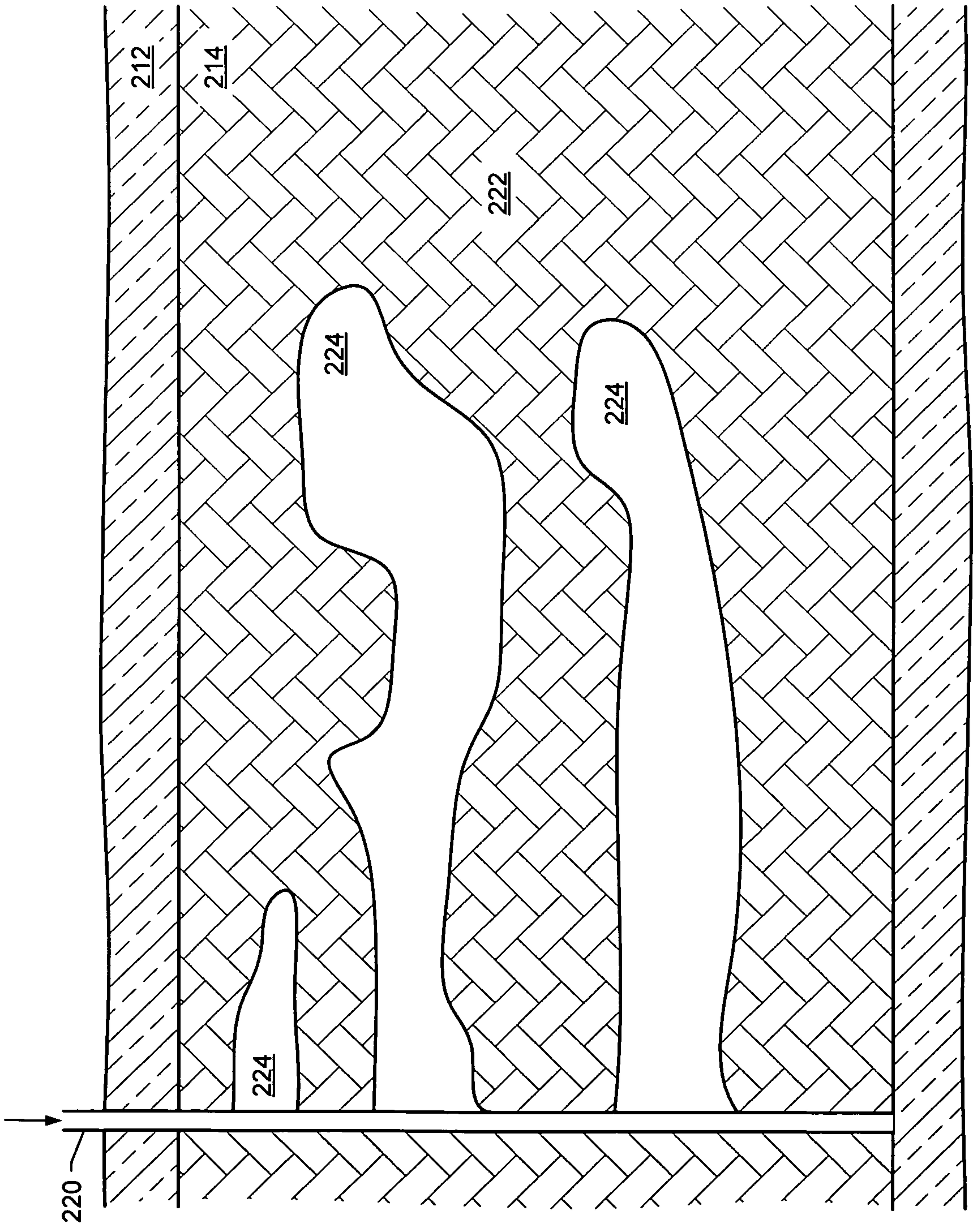


FIG. 7

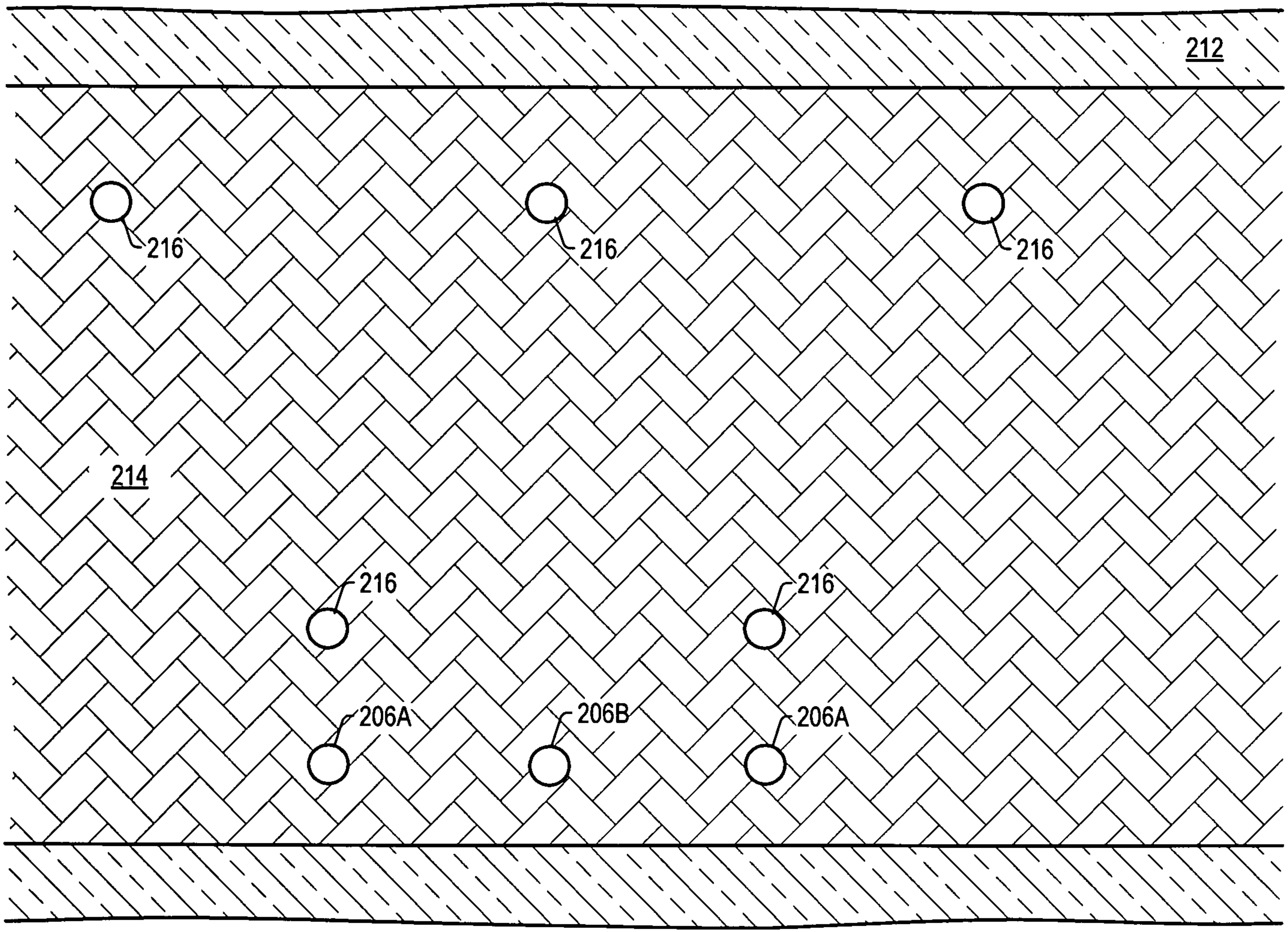


FIG. 3