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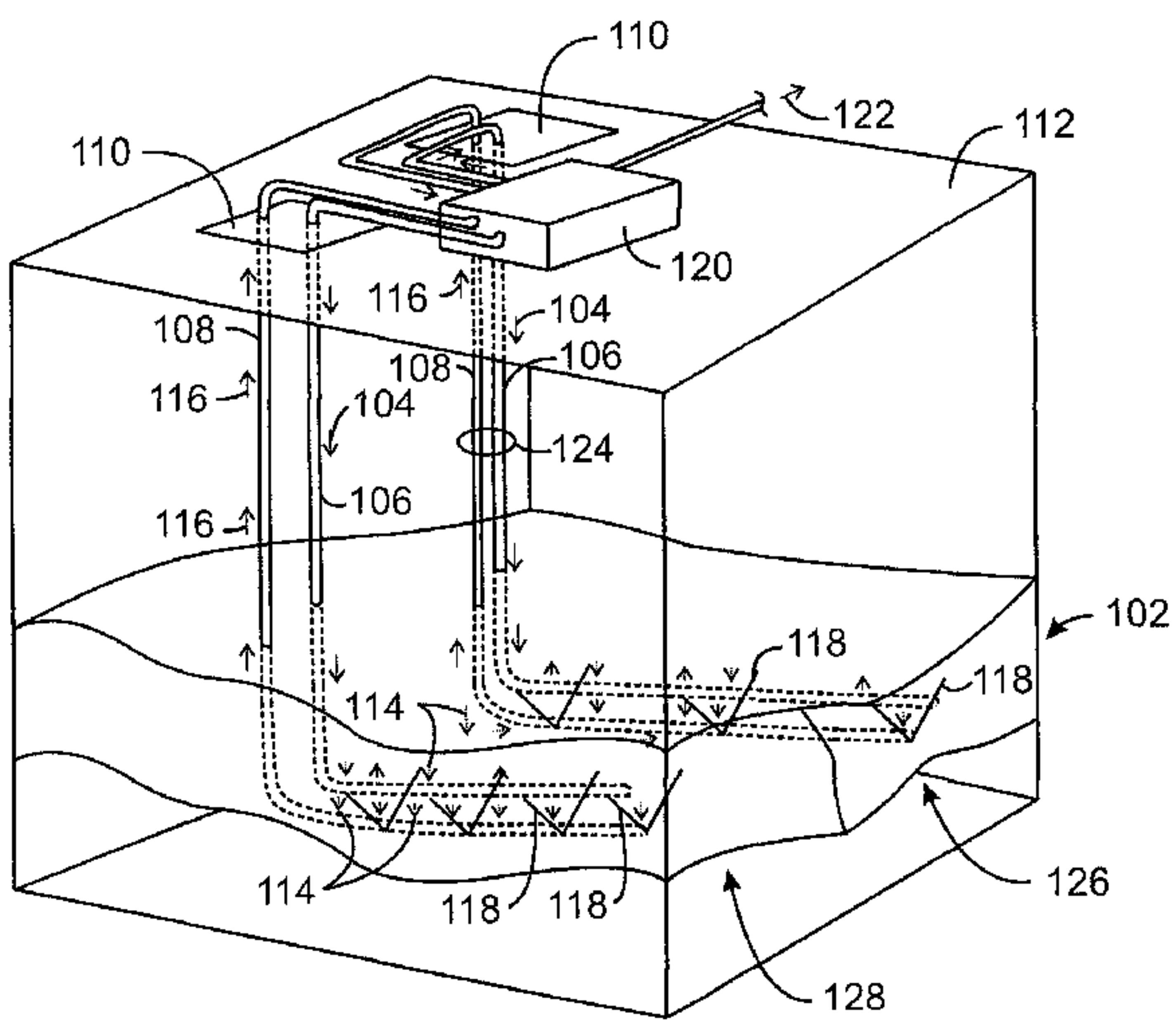

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(57) Abrégé/Abstract:
Embodiments described herein provide systems and methods for improving production of hydrocarbon resources. A method for improving recovery from a subsurface hydrocarbon reservoir includes generating a productivity map for a plurality of wells in a contiguous region of a reservoir and injecting different mixtures of non-condensable gas (NCG) and steam into at least two injection wells in the plurality of wells based, at least in part, on the productivity map.

2011EM332

ABSTRACT

Embodiments described herein provide systems and methods for improving production of hydrocarbon resources. A method for improving recovery from a subsurface hydrocarbon reservoir includes generating a productivity map for a plurality of wells in a contiguous region of a reservoir and injecting different mixtures of non-condensable gas (NCG) and steam into at least two injection wells in the plurality of wells based, at least in part, on the productivity map.

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IMPROVING RECOVERY FROM A HYDROCARBON RESERVOIR

FIELD

[0001] The present techniques relate to harvesting resources using gravity drainage processes. Specifically, techniques are disclosed for injecting mixtures of steam and non-condensable gases during thermal recovery processes.

BACKGROUND

[0002] This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present techniques. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present techniques. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0003] Modern society is greatly dependant on the use of hydrocarbons for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface formations that can be termed "reservoirs." Removing hydrocarbons from the reservoirs depends on numerous physical properties of the rock formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the rock formations, and the proportion of hydrocarbons present, among others.

[0004] Easily harvested sources of hydrocarbon are dwindling, leaving less accessible sources to satisfy future energy needs. However, as the costs of hydrocarbons increase, these less accessible sources become more economically attractive. For example, the harvesting of oil sands to remove hydrocarbons has become more extensive as it has become more economical. The hydrocarbons harvested from these reservoirs may have relatively high viscosities, for example, ranging from 8 API, or lower, up to 20 API, or higher. Accordingly, the hydrocarbons may include heavy oils, bitumen, or other carbonaceous materials, collectively referred to herein as "heavy oil," which are difficult to recover using standard techniques.

[0005] Several methods have been developed to remove hydrocarbons from oil sands. For example, strip or surface mining may be performed to access the oil sands, which can then be treated with hot water or steam to extract the oil. However, deeper formations may not be accessible using a strip mining approach. For these formations, a well can be drilled to the reservoir and steam, hot air, solvents, or combinations thereof, can be injected to release the hydrocarbons. The released hydrocarbons may then be collected by the injection well or by other wells and brought to the surface. Thermal recovery operations are used around the world to recover liquid hydrocarbons from both sandstone and carbonate reservoirs.

[0006] A number of techniques have been developed for harvesting heavy oil from subsurface formations using thermal recovery techniques. These operations include a suite of steam based in situ thermal recovery techniques, such as cyclic steam stimulation (CSS), steam flooding, and steam assisted gravity drainage (SAGD).

[0007] For example, CSS techniques includes a number of enhanced recovery methods for harvesting heavy oil from formations that use steam heat to lower the viscosity of the heavy oil. The steam is injected into the reservoir through a well and raises the temperature of the heavy oil during a heat soak phase, lowering the viscosity of the heavy oil. The same well may then be used to produce heavy oil from the formation. Solvents may be used in combination with steam in CSS processes, such as in mixtures with the steam or in alternate injections between steam injections. These techniques are described in U.S. Patent No. 4,280,559 to Best, U.S. Patent No. 4,519,454 to McMillen, and U.S. Patent No. 4,697,642 to Vogel, among others.

[0008] Another group of techniques is based on a continuous injection of steam through a first well to lower the viscosity of heavy oils and a continuous production of the heavy oil from a lower-lying second well. Such techniques may be termed "steam assisted gravity drainage" or SAGD. Various embodiments of the SAGD process are described in Canadian Patent No. 1,304,287 to Butler and its corresponding U.S. Patent No. 4,344,485.

[0009] In SAGD, two horizontal wells are completed into the reservoir. The two wells are first drilled vertically to different depths within the reservoir. Thereafter, using directional drilling technology, the two wells are extended in the horizontal direction that result in two horizontal wells, vertically spaced from, but otherwise vertically aligned with the other. Ideally, the production well is located above the base of the reservoir but as close as practical to the bottom of the reservoir, and the injection well is located vertically 10 to 30 feet (3 to 10 meters) above the horizontal well used for production.

[0010] The upper horizontal well is utilized as an injection well and is supplied with steam from the surface. The steam rises from the injection well, permeating the reservoir to form a vapor chamber that grows over time towards the top of the reservoir, thereby increasing the temperature within the reservoir. The steam, and its condensate, raise the temperature of the reservoir and consequently reduce the viscosity of the heavy oil in the reservoir. The heavy oil and condensed steam will then drain downward through the reservoir under the action of gravity and may flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface of the well, the condensed steam and heavy oil are separated, and the heavy oil may be diluted with appropriate light hydrocarbons for transport by pipeline. Solvents may be used alone or in combination with steam addition to increase the efficiency of the steam in removing the heavy oils.

[0011] As initial produced sections of a field mature and decrease in production, newer sections of the field may be opened up. However, there is a tendency for steam to escape from the newer sections into sections that are no longer being produced. To mitigate this problem, non-condensable gas (NCG) may be used to pressurize the older sections to allow the newer sections to be produced. For example, Canadian Patent Publication No. 2,251,157 discloses a process for sequentially applying SAGD to adjacent sections of a reservoir. The SAGD is performed in a first section until it is no longer economical, at which point, steam injection into the first section is terminated, and the section is pressurized with a non-condensable gas. Production is started from an adjacent section of the reservoir when the section is pressurized, minimizing the loss of steam to the first section of the reservoir.

[0012] The injection of non-condensable gases may be useful in other applications for SAGD. For example, when the steam demand for a reservoir or field exceeds the productive size of the steam generation system, the pressure in a field may fall, lowering production. To combat this, some amount of a non-condensable gas may be mixed with the steam that is injected to maintain the pressure in the field. Various techniques for performing the injection are discussed in Canadian Patent Publication No. 2,591,498.

[0013] However, the references discussed above treat contiguous sections of wells in the same way. More specifically, when a mixture of non-condensable gases is injected into a contiguous region, all of the wells in that region are injected with the same mixture.

SUMMARY

[0014] An embodiment described herein provides a method for improving recovery from a subsurface hydrocarbon reservoir, comprising: measuring a productivity for each well in a plurality of wells in a contiguous region of a reservoir, wherein the productivity is measured as a volume of oil produced per unit of steam consumed for each of the plurality of wells; generating a productivity map for the plurality of wells in the contiguous region of a reservoir; and injecting different mixtures of non-condensable gas (NCG) and steam into at least two injection wells in the plurality of wells based, at least in part, on the productivity map.

[0015] Another embodiment described herein provides a system for improving the recovery of resources from a reservoir, comprising: a reservoir; a plurality of production wells, wherein each production well is associated with an injection well in the plurality of injection wells; a plurality of injection wells drilled through the reservoir, wherein at least two different injection wells in the plurality of injection wells are configured to inject different mixtures of non-condensable gas (NCG) and steam; means for measuring a productivity of each of the plurality of production wells, wherein productivity is measured as a volume of oil produced per unit of steam consumed for each of the plurality of production wells; and a productivity map created by mapping the measured productivity for each of the plurality of production wells, wherein the different mixtures injected into the at least two different injection wells is based on the productivity map.

[0016] Another embodiment described herein provides a method for harvesting hydrocarbons from an oil sands reservoir, comprising: drilling a plurality of steam assisted gravity drainage (SAGD) well pairs through the oil sands reservoir; measuring a productivity for each SAGD well pair in the oils sand reservoir, wherein the productivity is measured as a volume of oil produced per unit of steam consumed for each of the plurality of SAGD wells; generating a map of the productivity of each of the plurality of SAGD well pairs; injecting a mixture comprising steam into a well pair with a high productivity; and injecting a mixture comprising a non-condensable gas into a well pair with a low productivity.

DESCRIPTION OF THE DRAWINGS

[0017] The advantages of the present techniques are better understood by referring to the following detailed description and the attached drawings, in which:

[0018] Fig. 1 is a drawing of a steam assisted gravity drainage (SAGD) process used for accessing hydrocarbon resources in a reservoir;

[0019] Fig. 2 is a top view of a reservoir showing a contiguous pattern of well pairs;

[0020] Fig. 3 is a top view of a reservoir showing multiple phases of development using well pairs of differing ages, orientations, lengths, and spacing, among others;

[0021] Figs. 4(A),(B), and (C) are cross sectional views of a reservoir showing the use of differing NCG injections to sweep solvent or other NCGs from the reservoir; and

[0022] Fig. 5 is a process flow diagram of a method for improving hydrocarbon recovery through the targeted injection of NCG and Steam mixtures.

DETAILED DESCRIPTION

[0023] In the following detailed description section, specific embodiments of the present techniques are described. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present techniques, this is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the techniques are not limited to the specific embodiments described below, but rather, include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

[0024] At the outset, for ease of reference, certain terms used in this application and their meanings as used in this context are set forth. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments, and terms or techniques that serve the same or a similar purpose are considered to be within the scope of the present claims.

[0025] "Bitumen" is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition depending upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

19 wt. % aliphatics (which can range from 5 wt. %-30 wt. %, or higher);

19 wt. % asphaltenes (which can range from 5 wt. %-30 wt. %, or higher);

30 wt. % aromatics (which can range from 15 wt. %-50 wt. %, or higher);

32 wt. % resins (which can range from 15 wt. %-50 wt. %, or higher); and

some amount of sulfur (which can range in excess of 7 wt. %).

In addition bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt. % to in excess of 0.7 wt. %. The percentage of the hydrocarbon types found in bitumen can vary. As used herein, the term "heavy oil" includes bitumen, as well as lighter materials that may be found in a sand or carbonate reservoir.

[0026] As used herein, two locations in a reservoir are in "fluid communication" when a path for fluid flow exists between the locations. For example, the establish of fluid communication between a lower-lying production well and a higher injection well may allow material mobilized from a drainage chamber above the injection well to flow down to the production well for collection and production. As used herein, a fluid includes a gas or a liquid and may include, for example, a produced hydrocarbon, an injected mobilizing fluid, or water, among other materials. Further, adjacent drainage chambers can establish paths for fluid communication, essentially coalescing to form larger drainage chambers.

[0027] "Facility" as used in this description is a tangible piece of physical equipment through which hydrocarbon fluids are either produced from a reservoir or injected into a reservoir, or equipment which can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, steam generation plants, processing plants, and delivery outlets. In some instances, the term "surface facility" is used to distinguish those facilities other than wells.

[0028] "Heavy oil" includes oils which are classified by the American Petroleum Institute (API), as heavy oils, extra heavy oils, or bitumens. In general, a heavy oil has an API gravity between 22.3° (density of 920 kg/m^3 or 0.920 g/cm^3) and 10.0° (density of 1,000 kg/m^3 or 1 g/cm^3). An extra heavy oil, in general, has an API gravity of less than 10.0° (density greater than 1,000 kg/m^3 or greater than 1 g/cm^3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water, and bitumen. The recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature or solvent concentration. Once the viscosity is reduced, the mobilization of fluids by steam, hot water flooding, or gravity is possible. The reduced viscosity makes the drainage quicker and therefore directly contributes to the recovery rate.

[0029] A "hydrocarbon" is an organic compound that primarily includes the elements hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. As used herein, hydrocarbons generally refer to components found in heavy oil, or other oil sands.

[0030] As used herein, a "liner" is a portion of a well used for recovering resources from a reservoir. To allow fluids to flow between the reservoir and the well, the liner will contain screen assemblies that contain multiple cut slots, externally mounted wire-wrap screens or meshrite screens. Beneath the screen assemblies, the liner will generally include a base pipe. During the screen assembly process, holes are drilled in the base pipe beneath where the screen assemblies are to be attached to allow fluid flow into and out of the base pipe.

[0031] "Pressure" is the force exerted per unit area by the gas on the walls of the volume. Pressure can be shown as pounds per square inch (psi). "Atmospheric pressure" refers to the local pressure of the air. The term "vapor pressure" has the usual thermodynamic meaning. For a pure component in an enclosed system at a given pressure, the component vapor pressure is essentially equal to the total pressure in the system.

[0032] As used herein, a "reservoir" is a subsurface rock or sand formation from which a production fluid, or resource, can be harvested. The rock formation may include sand, granite, silica, carbonates, clays, and organic matter, such as bitumen, heavy oil, oil, gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 m) to hundreds of feet (hundreds of m). The resource is generally a hydrocarbon, such as a heavy oil impregnated into a sand bed.

[0033] As discussed in detail above, "Steam Assisted Gravity Drainage" (SAGD), is a thermal recovery process in which steam, or combinations of steam and solvents, is injected into a first well to lower a viscosity of a heavy oil, and fluids are recovered from a second well. Both wells are generally horizontal in the formation and the first well lies above the second well. Accordingly, the reduced viscosity heavy oil flows down to the second well under the force of gravity, although pressure differential may provide some driving force in various applications. Although SAGD is used as an exemplary process herein, it can be understood that the techniques described can include any gravity driven process, such as those based on steam, solvents, or any combinations thereof.

[0034] "Substantial" when used in reference to a quantity or amount of a material, or a specific characteristic thereof, refers to an amount that is sufficient to provide an effect that the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context.

[0035] As used herein, "thermal recovery processes" include any type of hydrocarbon recovery process that uses a heat source to enhance the recovery, for example, by lowering the viscosity of a hydrocarbon. These processes may use injected mobilizing fluids, such as hot water, wet steam, dry steam, or solvents alone, or in any combinations, to lower the viscosity of the hydrocarbon. Such processes may include subsurface processes, such as cyclic steam stimulation (CSS), cyclic solvent stimulation, steam flooding, solvent injection, and SAGD, among others, and processes that use surface processing for the recovery, such as sub-surface mining and surface mining. Any of the processes referred to herein, such as SAGD, may be used in concert with solvents.

[0036] A "well" is a hole in the subsurface made by drilling or inserting a conduit into the subsurface. A well may have a substantially circular cross section or any other cross-sectional shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

Overview

[0037] The current industry practice for producing from reservoirs using gravity drainage processes utilizes a uniform horizontal spacing between wells, even though regions of the reservoir have different pay thickness. As a result, well pairs within the thinnest pay regions will generally reach their economic limit earlier than adjacent well pairs accessing thicker pay regions. The productivity, or volume of oil produced per unit of steam consumed, can be determined from the steam-to-oil ratio (SOR), with less productive zones determined by a higher steam-to-oil ratio than more productive zones. Other techniques can be used to measure productivity, such as oil rate, and it can be understood that these techniques may be used in place of SOR at any point SOR is referenced, herein.

[0038] Embodiments described herein provide methods for injecting combinations of steam and non-condensable gases in individual well pairs or regions within a reservoir. The methods may be used to manage periods of limited steam availability during normal operations, to manage performance during a wind-down phase of a mature operation, to manage the lateral growth at the edges of patterns, and to recover solvents and gases from the reservoir. For example, the well pairs with the poorest economic performance, e.g., the highest SOR, may be identified. During periods of limited steam availability, these well pairs may be preferentially injected with a NCG, or a mixture of an NCG and steam, in order to maintain pressure in the drainage chamber near these well pairs. The selective injection of the NCG will result in the largest benefit to both thermal efficiency and overall project recovery. Using these techniques, steam production can be reserved for areas having a higher economic performance, e.g., lower SORs.

[0039] Furthermore, once economic production is ending and as steam injection is being curtailed in the mature patterns, the relative SOR performance of the well pair, or in the case of significant steam transfer between coalesced well patterns the water oil ratio (WOR) performance of the production wells, can be used to expand the selective injection of NCG injection into the mature area, lowering the overall SOR and increasing the overall project's oil production rate, versus injecting a uniform mixture of a NCG and steam into all wells in a pattern.

[0040] The methods may also be used to manage the lateral growth of the edges of a pattern. For example, once a desired drainage width is close to being achieved, the NCG can be selectively injected into the injection wells at the perimeter of the pattern, while steam injection can continue at the interior injection wells. Time lapse 3D (also known as 4D) seismic data, any temperature observation wells in the vicinity and the production temperatures and fluid and gas production rates can be monitored at the perimeter production wells, and at adjacent production wells, to regulate the NCG injection and, thus, the lateral placement of the NGC in the drainage chamber.

[0041] The methods described herein may also be used to reclaim mobilizing fluids, such as condensable and non-condensable hydrocarbons. When using a thermal solvent or solvent based recovery process, either cyclic or gravity drainage based, a significant quantity of solvent will remain in the reservoir in the vapor phase and dissolved in residual oil as the process is reaching its economic limit. As described in further detail with respect to Figs. 4(A) – (C), selective injection of NCGs of varying value can be used to recover higher value NCGs and solvents.

[0042] For the purposes of this description, SAGD is used as the recovery process. However, those ordinarily skilled in the art will recognize that the approaches disclosed here are applicable to all thermal, thermal-solvent and solvent based recovery processes in which gravity drainage is the dominant recovery mechanism. Consistent with the use of SAGD to explain the techniques, injection and production are described with respect to well pairs. It can be understood that if different gravity recovery techniques are used, injection may be performed through injection wells that are not associated with any specific production well and that production may be performed from production wells that are not associated with any particular injection well.

[0043] Fig. 1 is a drawing of a steam assisted gravity drainage (SAGD) process **100** used for accessing hydrocarbon resources in a reservoir **102**. In the SAGD process **100**, steam **104** can be injected through injection wells **106** to the reservoir **102**. The injection wells **106** may be horizontally drilled through the reservoir **102**. Production wells **108** may be drilled horizontally through the reservoir **102**, with a production well **108** underlying each injection well **106**. Generally, the injection wells **106** and production wells **108** will be drilled from the same pads **110** at the surface **112**. This may make it easier for a production well **108** to track a corresponding injection well **106**. However, in some embodiments the wells **106** and **108** may be drilled from different pads **110**. Further, a number of well pairs can be drilled from a single pad **110** to facilitate injection and production.

[0044] The injection of steam **104** into the injection wells **106** may result in the mobilization of hydrocarbons **114**, which may drain to the production wells **108** and be removed to the surface **112** in a mixed stream **116** that can contain hydrocarbons, condensate and other materials, such as water, gases, and the like. As described herein, screen assemblies may be used on the injection wells **106**, for example, to enable the inflow of injectant vapor to the reservoir **102**. Similarly, screen assemblies may be used on the production wells **108**, for example, to decrease sand entrainment.

[0045] The hydrocarbons **114** may form a triangular shaped drainage chamber **118** that has the production well **108** at located at a lower apex. The mixed stream **116** from a number of production wells **108** may be combined and sent to a processing facility **120**. At the processing facility **120**, the water and hydrocarbons **122** can be separated, and the hydrocarbons **122** sent on for further refining. Water from the separation may be recycled to a steam generation unit within the facility **120**, with or without further treatment, and used to generate the steam **104** used for the SAGD process **100**.

[0046] As noted above, the horizontal spacing between well pairs is generally uniform, which can land a well pair **124** in a thinner region **126** of a reservoir **102**. The thinner region **126** may be less productive than in a thicker region **128** of the reservoir **102**, as reflected by a higher steam-to-oil ratio (SOR). Further, the thinner region **126** may be drained at a faster rate, measured as a fraction of the original oil in place, than the thicker region **128**.

[0047] In an embodiment, the injection wells **106** may be configured to allow separate injection for each well. Thus, if the steam demand of the reservoir **102** increases, for example, when as the individual drainage chambers **118** continue to expand and eventually coalesce to form larger drainage chambers, the steam **104** that is injected into the thinner region **126** through the injection well **106** of the well pair **124** may be partially or completely replaced with a non-condensable gas (NCG). The NCG may be a hydrocarbon, such as methane, or any number of other inert or non-inert gases, including nitrogen, CO_2, and air, among others. The injection of a NCG or NCG/Steam mixture into selected wells reserves the steam for more productive regions in the reservoir and may improve hydrocarbon production.

[0048] Fig. 2 is a top view **200** of a reservoir **202** showing a contiguous pattern **204** of well pairs **206**. For simplicity, only a portion of the well pairs **206** are labeled. As described herein, each well pair **206** includes a production well at a first level in the reservoir **202** and an injection well at a higher level in the reservoir **202**. The vertical separation between the wells is about five meters, which allows a drainage chamber to form above the production well. The production from each of the producing well pairs **206** can be monitored to create a productivity map of the contiguous pattern **204**.

[0049] Five pads **208** are shown, each pad **208** having seven well pairs **206** drilled out from the pad **208** into the reservoir. As all of the well pairs **206** are drilled in close proximity and time to each other, the pattern **204** in Fig. 2 can be considered a contiguous pattern **204** of well pairs **206**. Thus, as the reservoir **202** develops, the drainage chambers for the individual well pairs **206** can coalesce, creating a larger drainage chamber.

[0050] If the steam production is no longer sufficient to fully pressurize the large drainage chamber, less productive well pairs **210** in the productivity map may be selected for injection of NCG or a mixture of NCG and steam. In this example, the less productive well pairs **210** may have a higher SOR, indicating that less oil is being recovered for each unit of steam used. Since more productive well pairs **212** may be immediately adjacent to the less productive well pairs **210**, and may be drilled from the same pad **208** as the more productive well pairs **212**, the pads **208** may be plumbed to allow individual injection to and production from each of the well pairs **206**. Similarly, during a partial loss of steam production, the less productive well pairs **210** could be targeted for injection of NCG or mixtures of NCG with steam until full steam production is restored.

[0051] At end of the life of a contiguous pattern **204** in a reservoir **202**, the less productive wells **210**, which may not be producing hydrocarbons at economic rates by this point, can be targeted for injection of NCGs to hold pressure and restrict steam flow from more production regions. As the contiguous pattern **204** further falls in productivity, more and more wells may no longer be productive. As NCG replaces more of the steam from these wells, the steam may be shifted to more productive regions of the reservoir **202**.

[0052] Fig. 3 is a top view **300** of a reservoir **302** showing multiple phases of development **304** using well pairs **306** of differing ages, orientations, lengths, and spacing, among others. Each surface pad may be used to drill well pairs **306** in two different directions. While not shown, the area directly below a surface pad is accessed using wells drilled from an adjacent surface pad.

[0053] In this example, a first phase **308** of development **304** of the reservoir **302** may have been in place for several years, leading to the use of infill wells **310** (shown as dotted lines) to maintain production through harvesting assets left behind by well pairs **306**. A second phase **312** may be newer, allowing harvesting of hydrocarbons without the addition of infill wells. A third phase **314** of the development **304** has been drilled, but is not yet active. Over time, as the hydrocarbons are harvested, the drainage chambers of the well pairs **306** across the three phases **308**, **312**, and **314** may combine, creating a contiguous pattern across the entire field. Thus, steam injected into any well pair **306** may contribute to pressurization of the entire field. However, the use of steam may no longer be beneficial in part or all of the first phase **308**, for example, as the SOR increases with the decrease in hydrocarbon production.

[0054] Accordingly, a NCG or an NCG/steam mixture may be injected into a portion of the well pairs **306** within the first phase **308**, for example to maintain the pressure and prevent steam from leaking into the first phase **308** from the second phase **312**. In some embodiments, the NCG injection can be carried out in well pairs **306** along the border **316** between the first phase **308** and the second phase **314** of the development, while steam injection and hydrocarbon productions continues at well pairs located in the center of the development.

[0055] As mature portions of the development **304** are depleted, the techniques described herein may be used to finalize production from a phase, such as the first phase **308**, prior to terminating production in that phase. For example, as discussed with respect to Fig. 2, NCG/steam mixtures may injected into less productive well pairs **306**. The NCG content in the mixtures may be increased as the productivity falls, until only NCG is being injected into non-producing well pairs **306** in order to maintain pressure in the drainage chamber that surrounds those well pairs **306**, preventing steam coning and production. As production falls from more well pairs **306**, the process can continue until the phase is no longer producing hydrocarbons and the NCG injection is merely being used to maintain the pressure in the phase, for example, to lower the amount of steam that can flow from other phases in the development.

[0056] Once the phase is no longer economically producing hydrocarbons, or at other selected time periods in the development, lower value NCGs, such as nitrogen or air, can be used to recover higher value NCGs, such as methane. Further, if solvents were used to assist in the recovery of hydrocarbons from the phase, sequential injections of different NCGs can be used to recover both the solvents and the higher value NCGs. The use of sequential injections is discussed further with respect to Fig. 4

[0057] Figs. 4(A),(B), and (C) are cross sectional views of a reservoir **402** showing the use of differing NCG injections to sweep solvent or other NCGs from the reservoir **402**. The recovery may be performed across an entire reservoir **402**, or may be used to recover solvent and higher value NCGs from older phases of a development, such as described with respect to Fig. 3. As used herein, a well pattern is a subset of well pairs that have established a continuous flow path or drainage chamber. The well pattern may be a portion of a single phase, an entire phase, or, in the case of a mature field, may correspond to the entire reservoir.

[0058] Generally, the recovery may be performed by injecting a NCG, such as methane, in one portion of the well pattern and using the NCG to displace or sweep more valuable solvent laterally to another well pair, which may be drilled from the same pad or from a different pad. The well pairs selected for the injection may be in a poorer performing portion of the well pattern or located on a side of the development. The injection maintains the pressure in the drainage chamber, which allows the solvent concentration in the other portions of the drainage chamber to remain high. This allows the solvent to condense and recover additional oil during the process of being recovered.

[0059] As shown in Fig. 4(A), the drainage chambers of a number of individual well pairs **404** have coalesced into a single drainage chamber **406**. In this example, a solvent has been used to assist in the mobilization of fluids to the production wells **408** in each of the well pairs **404**. Solvents that may be used include linear hydrocarbons, such as propane, butane, pentanes, hexanes, and many others. Once oil production is no longer economical, the solvent can be recovered using the techniques described herein.

[0060] In Fig. 4(B), a first NCG, such as methane, is injected into the drainage chamber **406** through a first well pair **410**. As discussed herein, the first well pair **410**, or any well pairs that are be selected for the NCG injection, can include those in the most depleted region of the reservoir. Further, the well pairs **404** selected for injection can include the least productive well pairs **404**, or the well pairs **404** located on the edge of the well pattern, as well as any combinations thereof. The number of well pairs **404** used for the injection of the NCG will be driven by the level of interconnection that exists across the drainage chamber **406**, as well as by operator preferences.

[0061] As the NCG sweeps through the drainage chamber **406**, as indicated by arrows **412**, the partial pressure of the solvent in the vapor phase is decreased, allowing some of the solvent dissolved in remaining oil to vaporize. As additional NCG passed through the drainage chamber **406**, dissolved solvent will continue to be vaporized.

[0062] Once the NCG has swept across the entire drainage chamber **406**, and the oil recovery rates have diminished, the NCG itself may be recovered. For example, using the well pair **414** located furthest away from the well pair **410** that has been used for the injection of the NCG, the NCG can be produced. During this procedure, the pressure of the drainage chamber **406** can be maintained by the injection of other NCGs, as discussed with respect to Fig. 4(C), or it can be allowed to decline with the production of the NCG. This can be continued until the quantity of solvent being recovered is no longer economically justifiable.

[0063] As shown in Fig. 4(C), a lower value NCG, such as N_2, $C0_2$, exhaust gases, or air, can be used to displace the initial NCG from the chambers. This may be performed, for example, by introducing the lower value NCG into the well pair **410** used for the first NCG injection. The lower value NCG is then flowed through the drainage chamber **406**, as indicated by arrows **416**. The gases can then be produced at the well pair **414** located farthest from the well pair **412** used for injection. The sweeping of the drainage chamber **406** with progressively leaner NCG mixtures may enable additional solvent to vaporize and be recovered.

[0064] Sweeping the drainage chamber **406** may be combined with a decline in chamber pressure to force remaining amounts of the first NCG, the second NCG, or the solvent to the surface. However, in some situations, it may be decided that the drainage chamber **406** should remain pressurized at the end of the recovery process, for example, to allow production to continue from adjacent well patterns, while decreasing the amount of steam lost to the swept drainage chamber **406**.

[0065] Fig. 5 is a process flow diagram of a method **500** for improving hydrocarbon recovery through the targeted injection of steam, NCGs, and mixtures thereof. The method **500** begins at block **502** with the production of hydrocarbons from the reservoir under stable conditions. For example, no new phases are ready to start up and no older phases are being phased out. From stable production, any number of other conditions can be monitored and used to indicate when changes should be made to the amount of steam injected into certain well pairs. These include the amount of steam production, steam demand in the field, maturation operations, and any solvent recovery operations.

[0066] At block **504**, the amount of steam production may be monitored to determine if the steam production has dropped, lowering the amount available for injection into the reservoir. If no drop is detected, process flow continues at block **502**. If a drop in steam production is identified at block **504**, process flow proceeds to block **506**.

[0067] At block **506**, well pairs for the injection of NCG or mixtures of steam and NCG are identified. The compositions for the injections are also determined at this block. As described above, the identification may be based in part on a previous determination of the productivity of each of the well pairs in a pattern. Further, the amount of steam available may determine whether less productive wells are completely converted to NCG or a mixture of NCG and steam is injected. In addition, well pairs and patterns in mature sections of the field may be used for the injection of NCG as a prelude to the termination of production.

[0068] At block **508**, the NCG or NCG mixture is injected into the targeted well pairs while the production from the well pattern is monitored. The production wells associated with the target well pairs may be shut-in or throttled back, if an unacceptable rate of coning of steam or NCG is detected. At block **510**, a determination is made as to whether a shift in the injection of the NCG or NCG/steam mixtures is indicated by the production patterns. Such a shift may include, for example, changing the amount of steam or NCG being injected into a particular well pair or group of well pairs. In an embodiment, the shift may be used to sweep a solvent or NCG from a well pattern, as discussed with respect to Fig. 3. If a change is indicated at block **510**, flow returns to block **506** to identify the well pairs for injection of steam, NCGs, or mixtures thereof.

[0069] At block **512**, a determination is made as to whether a return to normal production is warranted. The determination may be based on the production from the well pairs in the patterns, as well as on other factors, such as the amount of steam available for injection. If no changes are indicated, process flow returns to block **508** to continue the injection of the NCG or NCG/steam mixtures into the targeted wells.

[0070] If, at block **512**, a return to normal production is indicated, for example, by the restoration of steam available for injection or other conditions, process flow proceeds to block **514** to identify the well pairs and patterns to be used for production. After block **514**, the well pairs used for pure steam injection may not be the same as the initial well pairs that were being used for pure steam injection. As described herein, any number of other conditions may be used to determine if well pairs should be converted to the injection of NCG or mixtures of NCG and steam.

[0071] At block **516**, the monitoring may identify that steam demand has increased beyond current steam production levels, for example, by either a continuous decline, or a sudden decline, in field pressure. A continuous pressure decline may occur as the individual well pair chambers continue to expand in size and then coalesce into single chambers. Large changes could result when drainage chambers for different well patterns previously operating at different pressures coalesce, forming larger patterns. The techniques described herein may be used to compensate for these changes by reserving steam for injection into the most productive well pairs. If steam demand has increased at block **516**, process flow follows the blocks starting with block **506** to carry out the changes, as described above.

[0072] At block **518**, a decision can be made to shut down a pattern or a portion of field, for example, if the productivity of a phase drops below an economic limit. If no changes indicate that a portion of a field should be shut-in, process flow returns to block **502** to continue with normal production. If a pattern or well pair is indicated as no longer being productive, process flow proceeds to block **506**, and follows the method as described above.

[0073] At block **520**, a decision can be made to initiate solvent recovery for example, after solvent has been used to mobilize hydrocarbons in a field. If solvent recovery is indicated, process flow proceeds to block **506** to initiate the procedure, as described above. Similarly, a decision to recover a second, or subsequent, NCG, can be made at block **520**. If not, process flow returns to block **502** to continue with production.

Embodiments

[0074] Embodiments described herein provide a number of features as described in the following numbered paragraphs.

1. A method for improving recovery from a subsurface hydrocarbon reservoir that includes:

generating a productivity map for a plurality of wells in a contiguous region of a reservoir; and

injecting different mixtures of non-condensable gas (NCG) and steam into at least two injection wells in the plurality of wells based, at least in part, on the productivity map.

2. The method of paragraph 1, including injecting mixtures that range in composition from completely NCG to completely steam.

3. The method of paragraph 1 or 2, including injecting mixtures that are substantially NCG into injection wells in less productive regions of the reservoir.

4. The method of any one of paragraphs 1 through 3, including injecting mixtures that are substantially steam into injection wells in more productive regions of the reservoir.

5. The method of any one of paragraphs 1 through 4, including, if steam production decreases:

injecting steam into injection wells in highly productive regions; and

injecting NCG, NCG and steam mixtures, or both, into injection wells in less productive regions.

6. The method of any one of paragraphs 1 through 5, including, if steam demand increases:

injecting steam into injection wells in highly productive regions; and

injecting NCG, NCG and steam mixtures, or both, into injection wells in less productive regions.

7. The method of any one of paragraphs 1 through 6, including:

injecting a solvent into a series of injection wells to increase the production of hydrocarbons from the reservoir; and

injecting a NCG including a hydrocarbon in a sequential manner in the series of injection wells to push the solvent to a production well.

8. The method of paragraph 7, including injecting a low value NCG in a sequential manner in the series of injection wells to push the NCG including a hydrocarbon to a production well.

9. The method of any one of paragraphs 1 through 8, including:

injecting a mixture substantially including a NCG into a plurality of injection wells located along the edge of a reservoir; and

injecting a mixture substantially including steam into a plurality of injection wells located in a center region of a reservoir.

10. The method of any one of paragraphs 1 through 9, including injecting different mixtures of NCG and steam into two wells drilled from a single pad.

11. The method of any one of paragraphs 1 through 10, including injecting different mixtures of NCG and steam into wells drilled from adjacent pads.

12. A system for improving the recovery of resources from a reservoir, including:

a reservoir; and

a plurality of injection wells drilled through the reservoir, wherein at least two different injection wells in the plurality of injection wells are configured to inject different mixtures of non-condensable gas (NCG) and steam.

13. The system of paragraph 12, wherein at least two different injection wells in the plurality of injection wells are drilled from a single pad.

14. The system of paragraph 12 or 13, including a plurality of production wells, wherein each production well is associated with an injection well in the plurality of injection wells.

15. The system of any one of paragraphs 12 through 14, including a plurality of pads, wherein each pad has a plurality of steam assisted gravity drainage (SAGD) well pairs.

16. The system of any one of paragraphs 12 through 15, including a productivity map created by mapping the steam-to-oil rates for each of a plurality of production wells.

17. The system of paragraph 16, including an injection well associated with a low productivity production well, wherein the injection well is configured to inject either steam or a NCG.

18. A method for harvesting hydrocarbons from an oil sands reservoir, including:

drilling a plurality of steam assisted gravity drainage (SAGD) well pairs through the oil sands reservoir;

generating a map of the productivity of each of the plurality of SAGD well pairs;

injecting a mixture including steam into a well pair with a high productivity; and

injecting a mixture including a non-condensable gas into a well pair with a low productivity.

19. The method of paragraph 18, including injecting a mixture including a non-condensable gas into a well pair at an edge of a reservoir.

20. The method of paragraph 18 or 19, including injecting a mixture including steam into a well pair proximate to the center of the reservoir.

[0075] While the present techniques may be susceptible to various modifications and alternative forms, the embodiments discussed above have been shown only by way of example. However, it should again be understood that the techniques is not intended to be limited to the particular embodiments disclosed herein. Indeed, the present techniques include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

CLAIMS

What is claimed is:

1. A method for improving recovery from a subsurface hydrocarbon reservoir, comprising:

measuring a productivity for each well in a plurality of wells in a contiguous region of a reservoir, wherein the productivity is measured as a volume of oil produced per unit of steam consumed for each of the plurality of wells;

generating a productivity map for the plurality of wells in the contiguous region of a reservoir; and

injecting different mixtures of non-condensable gas (NCG) and steam into at least two injection wells in the plurality of wells based, at least in part, on the productivity map.

2. The method of claim 1, comprising injecting mixtures that range in composition from completely NCG to completely steam.

3. The method of claim 1, comprising injecting mixtures that are substantially NCG into injection wells in less productive regions of the reservoir.

4. The method of claim 1, comprising injecting mixtures that are substantially steam into injection wells in more productive regions of the reservoir.

5. The method of claim 1, comprising, if steam production decreases:

injecting steam into injection wells in highly productive regions; and

injecting NCG, NCG and steam mixtures, or both, into injection wells in less productive regions.

6. The method of claim 1, comprising, if steam demand increases:

injecting steam into injection wells in highly productive regions; and

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injecting NCG, NCG and steam mixtures, or both, into injection wells in less productive regions.

7. The method of claim 1, comprising:

injecting a solvent into a series of injection wells to increase the production of hydrocarbons from the reservoir; and

injecting a NCG comprising a hydrocarbon in a sequential manner in the series of injection wells to push the solvent to a production well.

8. The method of claim 7, comprising:

injecting a low value NCG in a sequential manner in the series of injection wells to push the NCG comprising a hydrocarbon to a production well.

9. The method of claim 1, comprising:

injecting a mixture substantially comprising a NCG into a plurality of injection wells located along the edge of a reservoir; and

injecting a mixture substantially comprising steam into a plurality of injection wells located in a center region of a reservoir.

10. The method of claim 1, comprising injecting different mixtures of NCG and steam into two wells drilled from a single pad.

11. The method of claim 1, comprising injecting different mixtures of NCG and steam into wells drilled from adjacent pads.

12. A system for improving the recovery of resources from a reservoir, comprising:

a reservoir;

a plurality of production wells, wherein each production well is associated with an injection well in the plurality of injection wells;

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a plurality of injection wells drilled through the reservoir, wherein at least two different injection wells in the plurality of injection wells are configured to inject different mixtures of non-condensable gas (NCG) and steam;

means for measuring a productivity of each of the plurality of production wells, wherein productivity is measured as a volume of oil produced per unit of steam consumed for each of the plurality of production wells; and

a productivity map created by mapping the measured productivity for each of the plurality of production wells,

wherein the different mixtures injected into the at least two different injection wells is based on the productivity map.

13. The system of claim 12, wherein at least two different injection wells in the plurality of injection wells are drilled from a single pad.

14. The system of claim 12, comprising a plurality of pads, wherein each pad has a plurality of steam assisted gravity drainage (SAGD) well pairs.

15. The system of claim 12, comprising an injection well associated with a low productivity production well, wherein the injection well is configured to inject either steam or a NCG.

16. A method for harvesting hydrocarbons from an oil sands reservoir, comprising:

drilling a plurality of steam assisted gravity drainage (SAGD) well pairs through the oil sands reservoir;

measuring a productivity for each SAGD well pair in the oils sand reservoir, wherein the productivity is measured as a volume of oil produced per unit of steam consumed for each of the plurality of SAGD wells;

generating a map of the productivity of each of the plurality of SAGD well pairs;

injecting a mixture comprising steam into a well pair with a high productivity;

and injecting a mixture comprising a non-condensable gas into a well pair with a low productivity.

17. The method of claim 16, comprising injecting a mixture comprising a non-condensable gas into a well pair at an edge of a reservoir.

18. The method of claim 16, comprising injecting a mixture comprising steam into a well pair proximate to the center of the reservoir.

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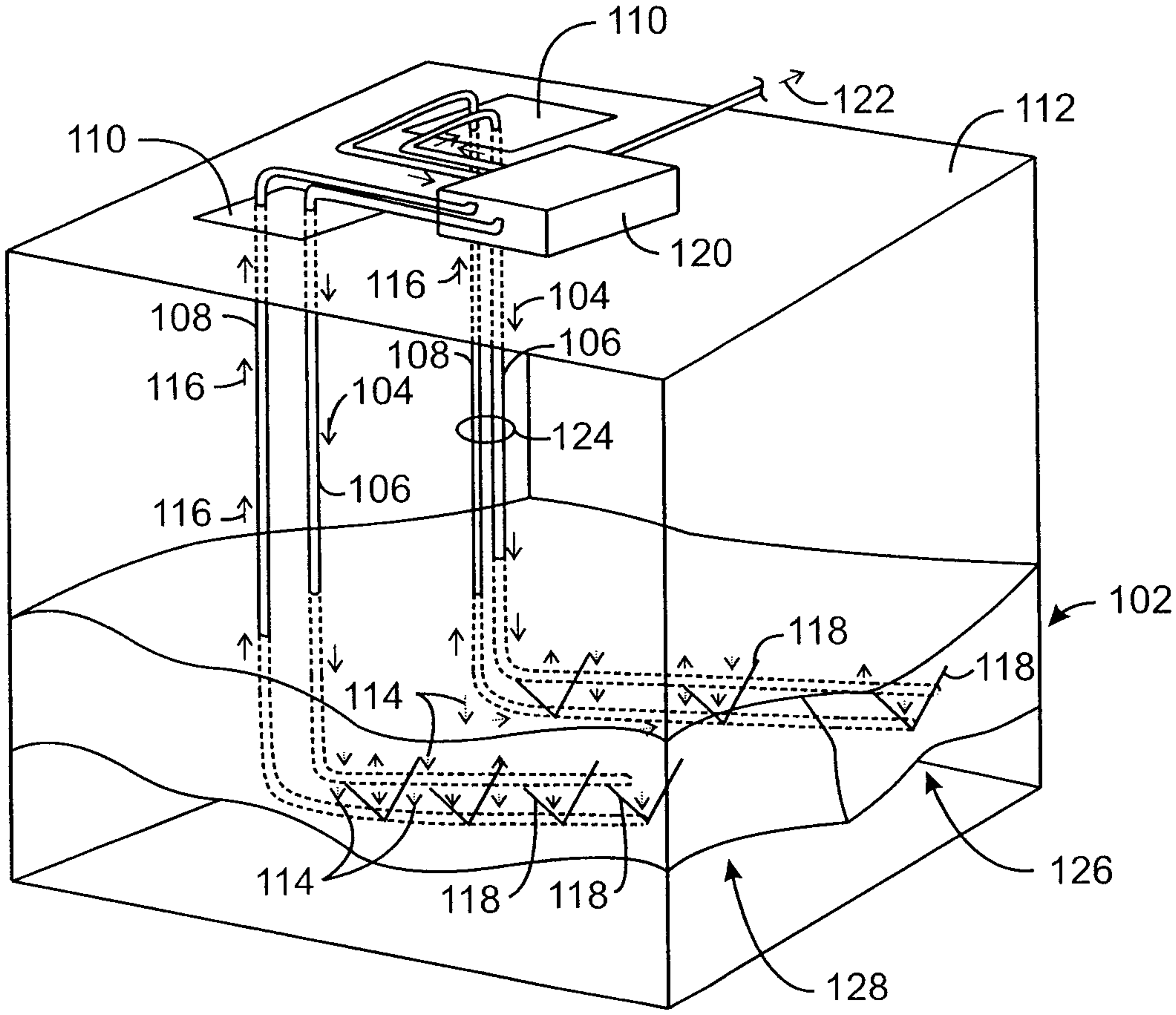

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FIG. 1

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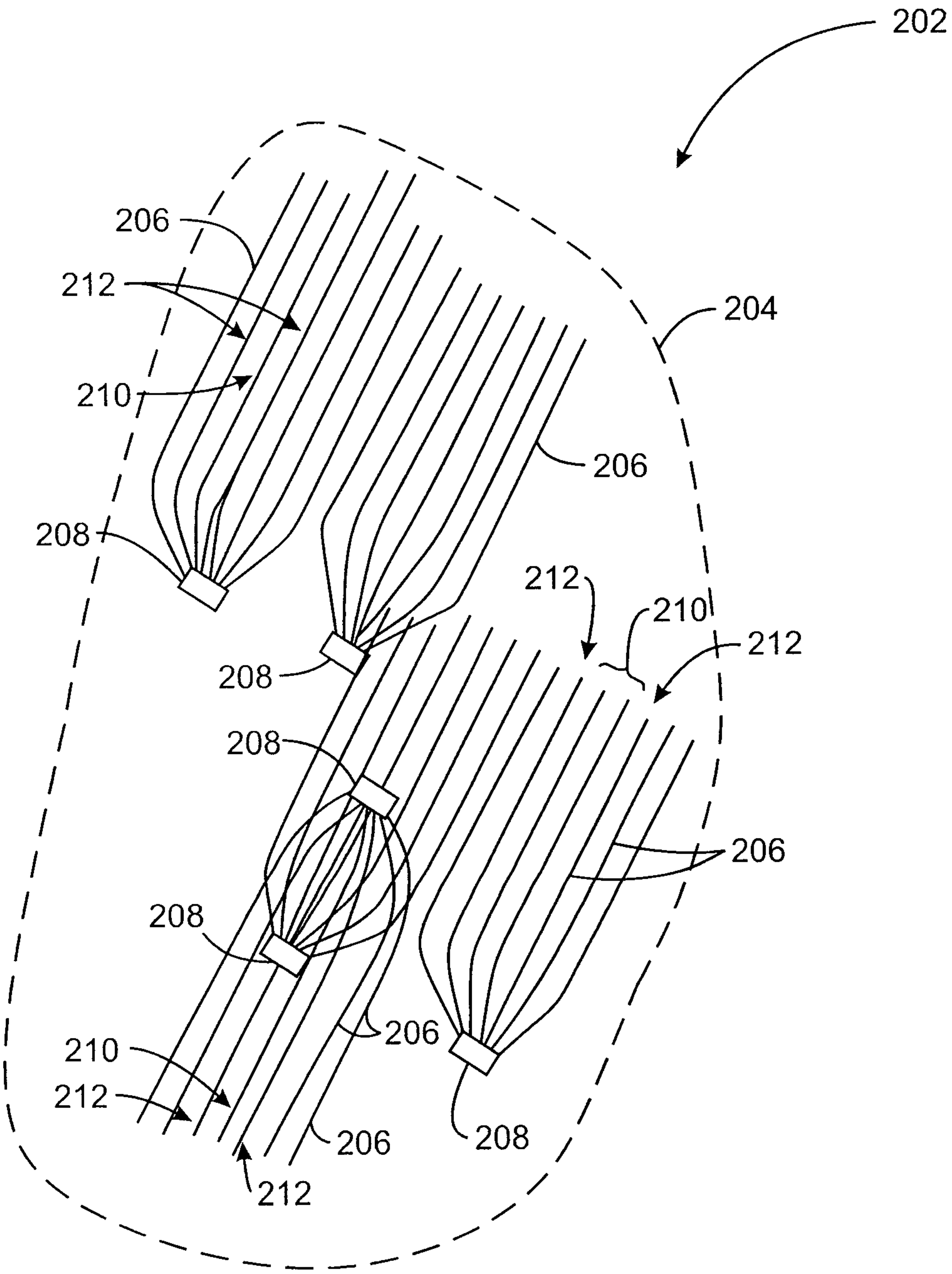

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FIG. 2

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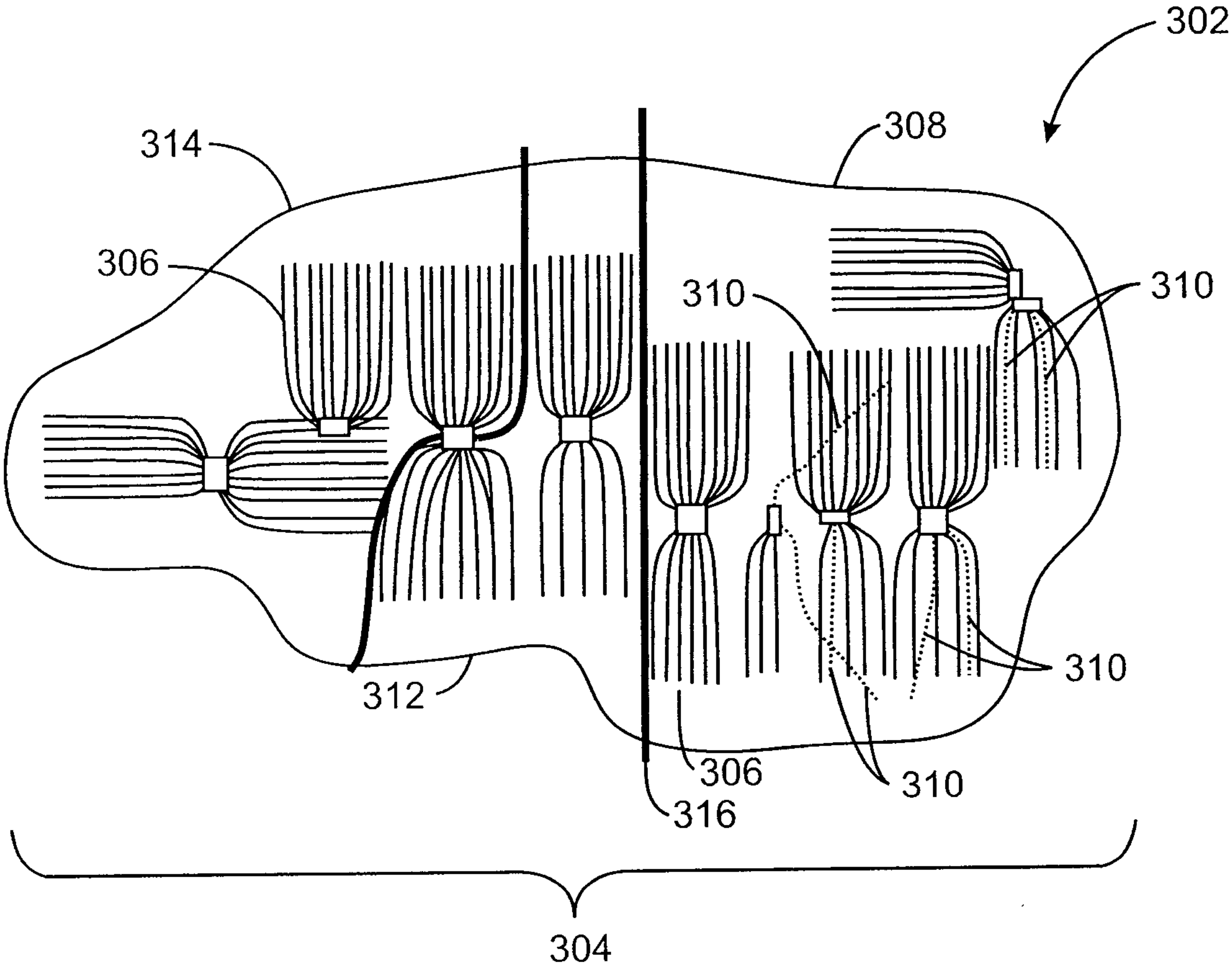

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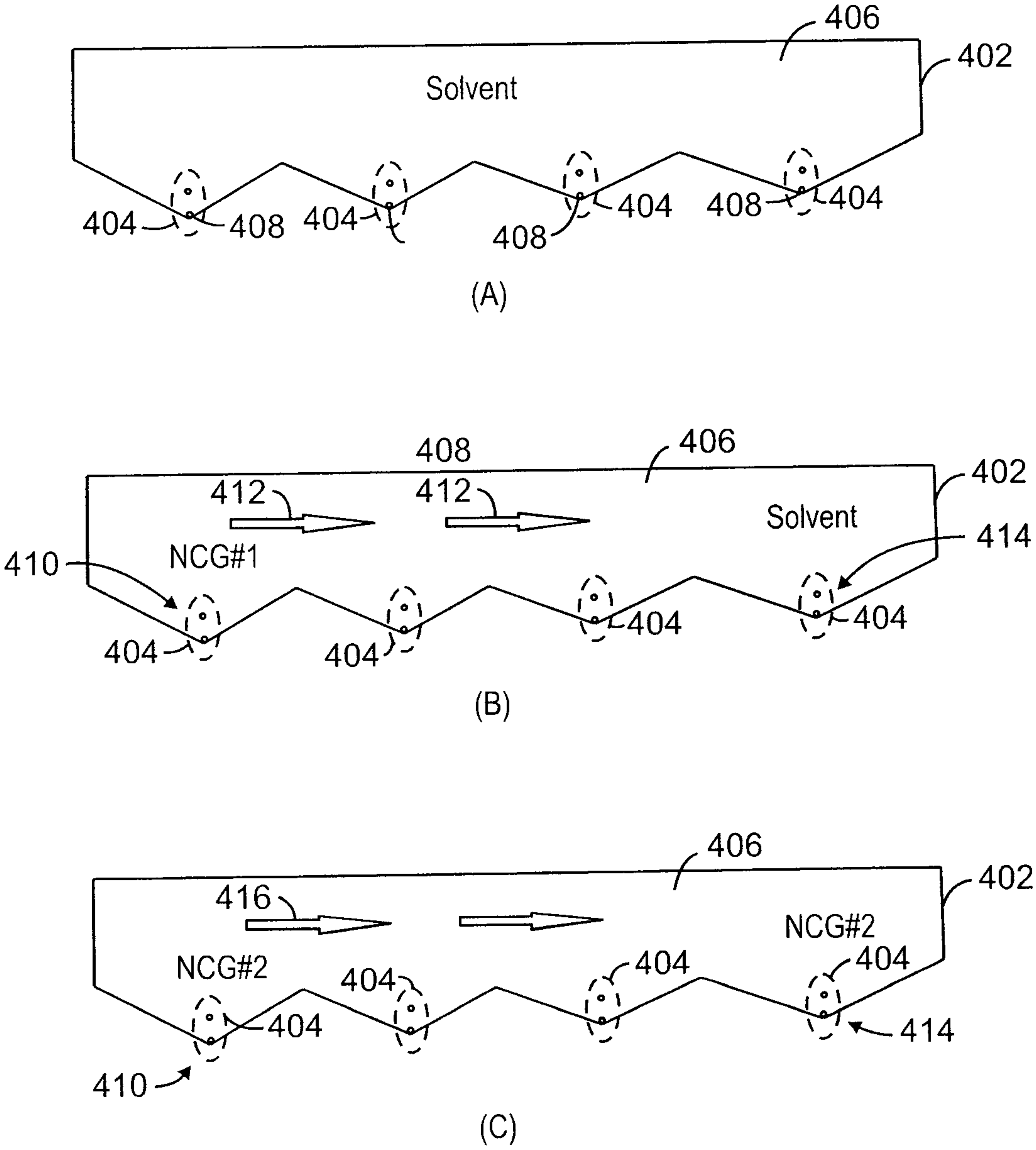
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FIG. 4

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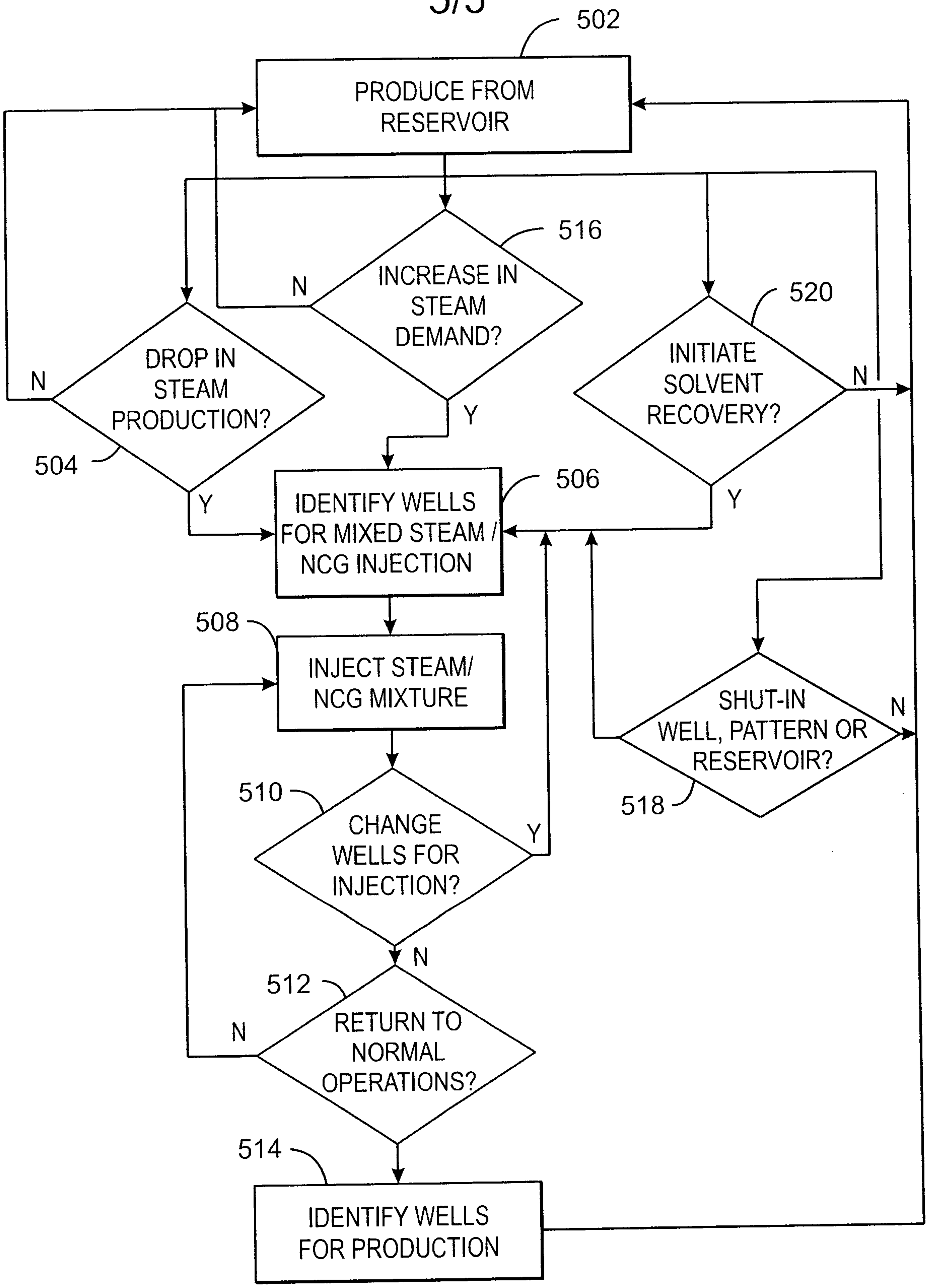

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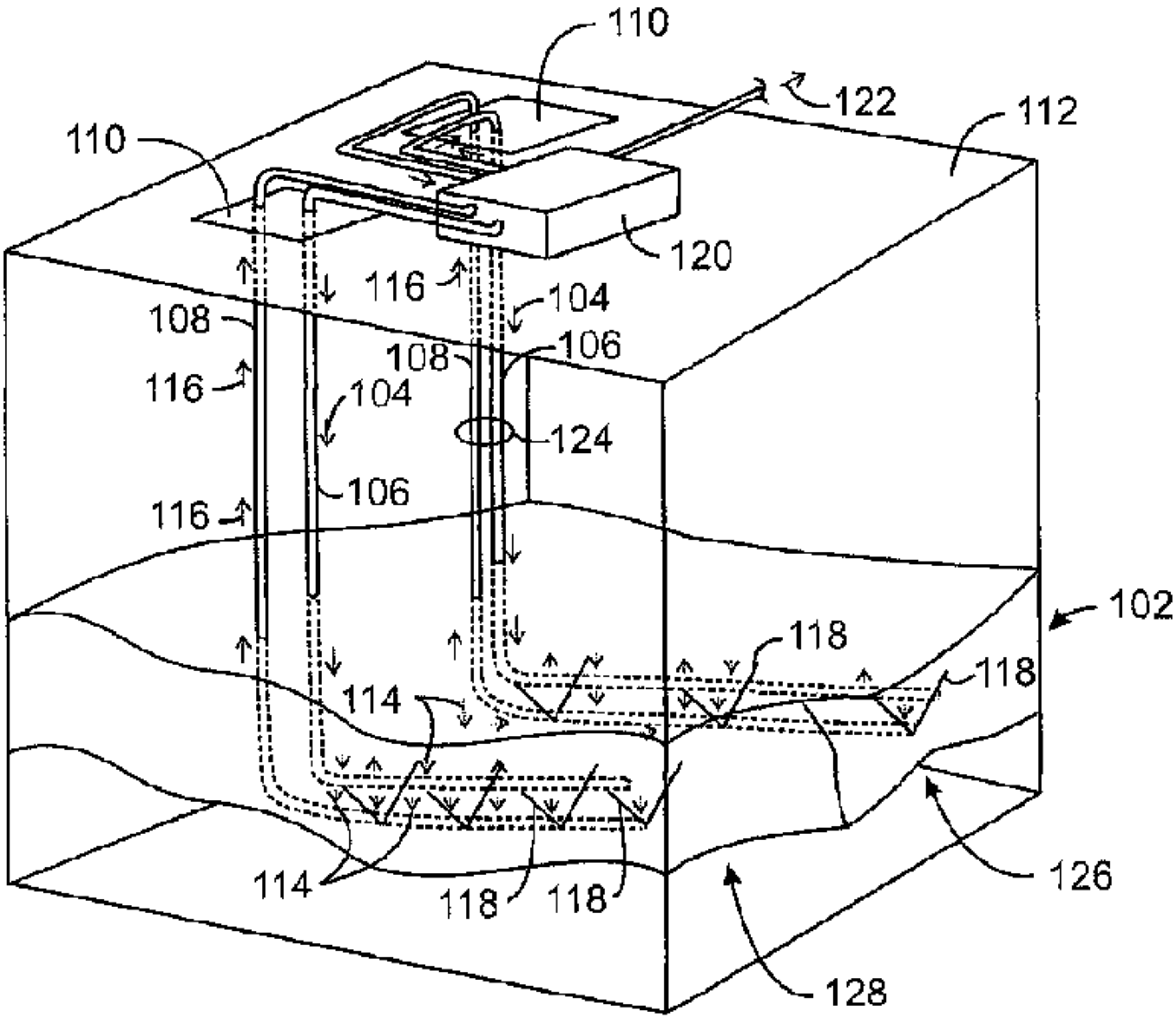
FIG. 5



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