



(22) Date de dépôt/Filing Date: 2011/12/16

(41) Mise à la disp. pub./Open to Public Insp.: 2013/06/16

(45) Date de délivrance/Issue Date: 2019/03/05

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

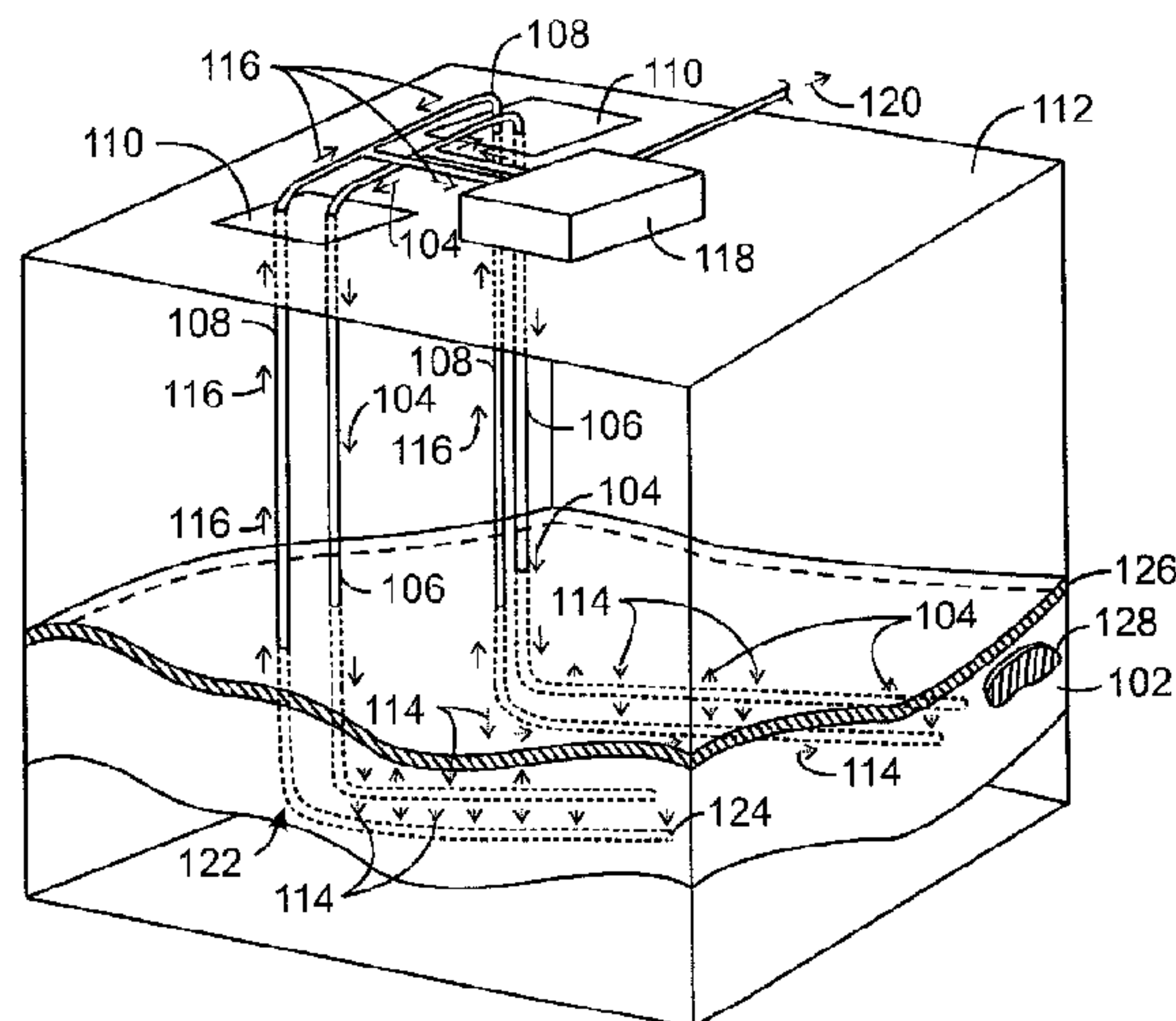
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(54) Titre : AMELIORATION DE LA RECUPERATION D'UN RESERVOIR D'HYDROCARBURE

(54) Title: IMPROVING RECOVERY FROM A HYDROCARBON RESERVOIR



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(57) **Abrégé/Abstract:**

A method and systems for improving recovery from a hydrocarbon reservoir are described. A method includes identifying an interval within the reservoir that comprises a reduced reservoir quality, wherein the interval includes hydrocarbons. A production chamber is formed in a reservoir interval below the interval of reduced reservoir quality, wherein the production chamber is in contact with the interval of reduced reservoir quality. Hydrocarbons are mobilized in the interval of reduced reservoir quality by contact with a mobilizing agent and a pressure is changed within the interval of reduced reservoir quality to allow hydrocarbon flow from the interval of reduced reservoir quality.

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## ABSTRACT

A method and systems for improving recovery from a hydrocarbon reservoir are described. A method includes identifying an interval within the reservoir that comprises a reduced reservoir quality, wherein the interval includes hydrocarbons. A production chamber is formed in a reservoir interval below the interval of reduced reservoir quality, wherein the production chamber is in contact with the interval of reduced reservoir quality. Hydrocarbons are mobilized in the interval of reduced reservoir quality by contact with a mobilizing agent and a pressure is changed within the interval of reduced reservoir quality to allow hydrocarbon flow from the interval of reduced reservoir quality.

## IMPROVING RECOVERY FROM A HYDROCARBON RESERVOIR

### FIELD

5 [0001] The present techniques relate to harvesting resources using gravity drainage processes. Specifically, techniques are disclosed for harvesting resource from poor quality reservoir intervals.

### BACKGROUND

10 [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.

15 [0003] Modern society is greatly dependant on the use of hydrocarbons for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface rock 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  
20 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  
25 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  
30 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.

5 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.

**[0006]** A number of techniques have been developed for harvesting heavy oil from subsurface formations using thermal recovery techniques. Thermal recovery operations are used around the world to recover liquid hydrocarbons from both sandstone and carbonate reservoirs. 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).

15 **[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. These steam assisted hydrocarbon recovery methods are described in U.S. Patent No. 3,292,702 to Boberg, and U.S. Patent No. 3,739,852 to Woods, et al., among others. CSS and other steam flood techniques have been  
20 utilized worldwide, beginning in about 1956 with the utilization of CSS in the Mene Grande field in Venezuela and steam flood in the early 1960s in the Kern River field in California.

**[0008]** The CSS process may raise the steam injection pressure above the formation fracturing pressure to create fractures within the formation and enhance  
25 the surface area access of the steam to the heavy oil, although CSS may also be practiced at pressures that do not fracture the formation. The steam raises the temperature of the heavy oil during a heat soak phase, lowering the viscosity of the heavy oil. The injection well may then be used to produce heavy oil from the formation. The cycle is often repeated until the cost of injecting steam becomes  
30 uneconomical, for instance if the cost is higher than the money made from producing the heavy oil. However, successive steam injection cycles reenter earlier created

fractures and, thus, the process becomes less efficient over time. CSS is generally practiced in vertical wells, but systems are operational in horizontal wells.

**[0009]** 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.

5 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.

**[0010]** 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  
10 "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.

**[0011]** In SAGD, two horizontal wells are completed into the reservoir. The two wells are first drilled vertically to different depths within the reservoir. Thereafter,  
15 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  
20 well used for production.

**[0012]** 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  
25 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  
30 heavy oil may be diluted with appropriate light hydrocarbons for transport by pipeline.

**[0013]** Solvents may be used alone or in combination with steam addition to increase the efficiency of the steam in removing the heavy oils. As the solvents blend with the heavy oils and bitumens, they lower the viscosity, allowing the materials to flow towards a production well. The mobility of the heavy oil obtained with the steam and solvent combination is greater than that obtained using steam alone under substantially similar formation conditions.

**[0014]** The techniques discussed above may leave a substantial remainder of hydrocarbons in the reservoir. For example, poor quality reservoir layers may have slow oil drainage under the force of gravity.

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## SUMMARY

**[0014a]** An embodiment described herein provides a method for improving recovery from a hydrocarbon reservoir, comprising: identifying an under developed interval within the reservoir that includes an under developed steam chamber, wherein the under developed interval comprises hydrocarbons; forming a production chamber in a reservoir interval below the under developed interval, wherein the production chamber is in contact with the under developed interval; mobilizing hydrocarbons in the under developed interval by contact with a mobilizing agent; and cycling a pressure between an operating pressure and a reduced pressure within the production chamber to allow hydrocarbon flow from the under developed interval; wherein cycling of the pressure is such that at the reduced pressure at least a portion of at least one of water and a solvent in a liquid phase within the under developed interval is flashed to the vapor phase.

**[0014b]** Another embodiment described herein provides a system for increasing hydrocarbon production from an under developed interval in a reservoir that includes an under developed steam chamber, comprising: an injection well configured to inject an injectant into the reservoir; a production well configured to produce fluids from the reservoir, wherein the fluids comprise a hydrocarbon; and a pressure system configured to cycle a pressure within a production chamber between an operating pressure and a reduced pressure to increase a flow of hydrocarbon from the under developed interval in contact with the production chamber; wherein the system is configured such that the cycling of the pressure is such that at the reduced

pressure at least a portion of at least one of water and a solvent in a liquid phase within the under developed interval is flashed to the vapor phase.

**[0015]** Another embodiment described herein provides a method for improving recovery from a hydrocarbon reservoir. The method includes identifying an interval  
5 within the reservoir that comprises a reduced reservoir quality, wherein the interval comprises hydrocarbons. A production chamber is formed in a reservoir interval below the interval of reduced reservoir quality, wherein the production chamber is in contact with the interval of reduced reservoir quality. Hydrocarbons are mobilized in the interval of reduced reservoir quality by contact with a mobilizing agent. A  
10 pressure is changed within the interval of reduced reservoir quality to allow hydrocarbon flow from the interval of reduced reservoir quality.

**[0016]** Another embodiment provides a system for increasing hydrocarbon production from an interval of low quality reservoir. The system includes an injection well configured to inject an injectant into a reservoir and a production well configured  
15 to produce fluids from the reservoir, wherein the fluids comprise a hydrocarbon. A pressure system is configured to change a pressure within a production chamber to increase a flow of hydrocarbon from an interval of low quality reservoir in contact with the production chamber.

**[0017]** Another embodiment provides a system for harvesting resources in a low  
20 quality interval of a reservoir. The system includes a gravity drainage system configured to drain a first portion of resources from a high quality interval of a reservoir. The system also includes a pressure control system configured to change

a pressure on a production chamber to drain a second portion of resources from a low quality interval of a reservoir.

#### DESCRIPTION OF THE DRAWINGS

5 [0018] The advantages of the present techniques are better understood by referring to the following detailed description and the attached drawings, in which:

[0019] Fig. 1 is a drawing of a steam assisted gravity drainage (SAGD) process used for harvesting hydrocarbons in a reservoir;

10 [0020] Fig. 2 is a drawing of a steam assisted gravity drainage (SAGD) process, showing a interval of reduced reservoir quality above a interval of high quality reservoir layer;

[0021] Fig. 3 is the cross-section of Fig. 2, showing the interception of the steam chamber with the interval of reduced reservoir quality;

[0022] Fig. 4 is the cross-section of Fig. 2, showing drainage from the interval of reduced quality reservoir as the reservoir pressure is lowered;

15 [0023] Fig. 5 is the cross-section of Fig. 2, showing steam infiltration into the interval of reduced quality reservoir as the reservoir pressure is increased;

[0024] Fig. 6 is the cross-section of Fig. 2, showing a lateral section drilled through the interval of reduced reservoir quality;

20 [0025] Fig. 7 is a schematic of four SAGD well pairs showing pressure patterns to keep total steam injection constant; and

[0026] Fig. 8 is a method of harvesting hydrocarbons from an interval of reduced reservoir quality.

#### DETAILED DESCRIPTION

25 [0027] 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.

**[0028]** 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  
 5 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  
 10 scope of the present claims.

**[0029]** As used herein, the term "base" indicates a lower boundary of the resources in a reservoir that are practically recoverable, by a gravity-assisted drainage technique, for example, using an injected mobilizing fluid, such as steam, solvents, hot water, gas, and the like. The base may be considered a lower  
 15 boundary of the payzone. The lower boundary may be an impermeable rock layer, including, for example, granite, limestone, sandstone, shale, and the like. The lower boundary may also include layers that, while not completely impermeable, impede the formation of fluid communication between a well on one side and a well on the other side. Such layers, which may include inclined heterolithic strata (IHS) of  
 20 broken shale, mud, silt, and the like. The resources within the reservoir may extend below the base, but the resources below the base may not be recoverable with gravity assisted techniques.

**[0030]** "Bitumen" is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition  
 25 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);
- 30 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 metals content, while small, must  
5 be removed to avoid contamination of the product synthetic crude oil (SCO). Nickel can vary from less than 75 ppm (part per million) to more than 200 ppm. Vanadium can range from less than 200 ppm to more than 500 ppm. 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  
10 carbonate reservoir.

**[0031]** As used herein, a pressure "cycle" represents a sequential increase to peak operating pressure in a reservoir, followed by a release of the pressure to a minimum operating pressure. The elapsed time between two periods of peak operating pressure does not have to be the same between cycles, nor do the peak  
15 operating pressures and minimum operating pressures.

**[0032]** As used herein, two locations in a reservoir are in "fluid communication" when a path for fluid flow exists between the locations. For example, fluid communication between a production well and an overlying steam chamber can allow mobilized material to flow down to the production well for collection and  
20 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.

**[0033]** As used herein, a "cyclic recovery process" uses an intermittent injection of injected mobilizing fluid selected to lower the viscosity of heavy oil in a  
25 hydrocarbon reservoir. The injected mobilizing fluid may include steam, solvents, gas, water, or any combinations thereof. After a soak period, intended to allow the injected material to interact with the heavy oil in the reservoir, the material in the reservoir, including the mobilized heavy oil and some portion of the mobilizing agent may be harvested from the reservoir. Cyclic recovery processes use multiple  
30 recovery mechanisms, in addition to gravity drainage, early in the life of the process. The significance of these additional recovery mechanisms, for example dilation and

compaction, solution gas drive, water flashing, and the like, declines as the recovery process matures. Practically speaking, gravity drainage is the dominant recovery mechanism in all mature thermal, thermal-solvent and solvent based recovery processes used to develop heavy oil and bitumen deposits, such as steam assisted gravity drainage (SAGD). For this reason the approaches disclosed here are equally applicable to all recovery processes in which at the current stage of depletion gravity drainage is the dominant recovery mechanism.

**[0034]** "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.

**[0035]** "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<sup>3</sup> or 0.920 g/cm<sup>3</sup>) and 10.0° (density of 1,000 kg/m<sup>3</sup> or 1 g/cm<sup>3</sup>). An extra heavy oil, in general, has an API gravity of less than 10.0° (density greater than 1,000 kg/m<sup>3</sup> or greater than 1 g/cm<sup>3</sup>). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water, and bitumen. The thermal 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.

**[0036]** 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 in oil sands.

However, the techniques described herein are not limited to heavy oils, but may also be used with any number of other reservoirs to improve gravity drainage of liquids.

**[0037]** "Inclined heterolithic strata" or IHS are layers of rock containing hydrocarbons that can form above or below sand layers in an oil sands reservoir.

- 5 The layers of rock in IHS are often shale layers formed from clay or other sediments layered over or under sand beds. The hydrocarbons may be trapped between the layers of rock. As IHS layers may be poorly drained, it may be problematic to produce hydrocarbons by gravity drainage from an IHS layer over a sand layer.

- [0038]** As used herein, "poorer quality facies" are intervals in a reservoir that can have poor drainage, often due to a difficulty in establishing a counter-current flow. In an oil sands reservoir, poorer quality facies may include IHS layers above the higher quality sands of a clean pay interval.

- [0039]** "Permeability" is the capacity of a rock to transmit fluids through the interconnected pore spaces of the rock. The customary unit of measurement for permeability is the millidarcy.

- [0040]** "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. "Absolute pressure" (psia) refers to the sum of the atmospheric pressure (14.7 psia at standard conditions) plus the gauge pressure (psig). "Gauge pressure" (psig) refers to the pressure measured by a gauge, which indicates only the pressure exceeding the local atmospheric pressure (i.e., a gauge pressure of 0 psig corresponds to an absolute pressure of 14.7 psia). 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.

- [0041]** 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.

**[0042]** 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.

**[0043]** "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.

**[0044]** 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.

**[0045]** A "wellbore" is a hole in the subsurface made by drilling or inserting a conduit into the subsurface. A wellbore 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." Further, multiple pipes may be inserted into a single wellbore, for example, as a liner configured to allow flow from an outer chamber to an inner chamber.

*Overview*

**[0046]** For mobilized oil to drain in a gravity drainage process, another material, such as steam or solvent vapor, must occupy the space currently occupied by the oil. In a clean reservoir, such as a sand bed, this readily occurs as counter-current flow can easily be established. However, in an interval of a reservoir containing rock with multiple close spaced layers, such as shale lamina found in inclined heterolithic strata (IHS), counter-current flow slows dramatically. For example, it is possible to heat oil present on one side of a shale lamina, but for the oil to drain, steam needs to find a continuous path around the shale. If the recovery process relies on a cold solvent, the contact area is limited to the sand interface between the individual shale lamina.

**[0047]** Field data has shown that some oil drainage occurs from an interval of poorer quality reservoir, such as an IHS facies overlying a sand bed, during thermal gravity drainage operations. Conduction heating of the IHS facies causes some of the solution gas dissolved in the oil to exsolve, and the gas displaces a portion of the heated oil into the underlying steam chamber. However, minimal steam chamber development is observed in the IHS facies. This is due to the difficulty to establishing a counter-current flow of draining liquids and rising steam in the thin sand lenses present in the lamina of the IHS. As a result, oil recovery from the IHS is suboptimal.

**[0048]** Generally, after the establishment of communication between injector wells and producer wells in gravity drainage recovery processes, the injection rate of the injectant, such as steam, hot solvent, cold solvent, or mixtures thereof, can be regulated to maintain an operating pressure determined by an operator. The operating pressure will be less than the fracture pressure of the formation, but more than the minimum operation pressure of the installed production lift system. In gravity drainage processes the production chamber pressure is kept substantially constant over the duration of the life of the well pattern. More recently, steam chambers have been operated at higher pressures initially and then allowed to slowly decline over time, for example, as the chambers expand in size. The criteria for when to decrease the steam chamber pressure is typically dictated by when the

total steam demand in the field to maintain a constant operating pressure exceeds the installed capacity for supplying the steam to the field.

**[0049]** In embodiments described herein, the drainage of the mobilized oil is accelerated by varying the pressure in the thin sand lenses present between the shale lamina. This may be performed by cycling the chamber pressures, such as by varying an injection rate or a production rate over time during the gravity drainage process. For a gravity drainage process that involves heating, dropping the chamber pressure will also drop the pressure in the partially heated region surrounding the chamber. As a result, some of the heated water present in a pore space in the thin sand lenses between the shale lamina, as well as within the shale lamina, can flash to steam. Further, partial pressure changes will cause some of the dissolved gas present in the heated oil to be liberated. These expanding vapors will displace some of the heated oil from the thin sand lenses located between the shale lamina into the chamber.

**[0050]** When an injection rate is increased or a production rate is decreased, the chamber pressures will increase. The increasing pressure can cause the vapor saturation in the conductively heated region to collapse as gases condense or are reabsorbed, enabling the steam to penetrate faster and deeper into the conductively heated region than would occur without a pressure reduction phase. Thus, the cycling of the chamber pressure can accelerate the heat penetration and recovery from both good and poor quality facies within the reservoir.

**[0051]** For a gravity drainage process that does not involve heating, such as a solvent driven recovery process, dropping the chamber pressure will also drop the pressure in the partially mobilized oil region surrounding the chamber. As a result, some of the dissolved solvent present in the thin sand lenses located between the shale lamina will flash to vapor. Due to partial pressure effects, some of the solution gas present will also be liberated. The expanding vapors will displace some of the mobilized oil into the chamber and increase the available surface area between the oil and vapor phases. When the injection rate is increased or fluid production decreased, the chamber pressures will increase and the vapor saturation surrounding the chamber will collapse. The collapse will create accommodation space, allowing the injectant to penetrate deeper into the partially mobilized oil

region. The increased penetration and the increase in surface area available between the solvent and oil phases accelerates the mixing of the solvent with the oil. As with the cycling of the steam chamber pressure, the pressure cycling process is very effective in accelerating the solvent penetration and recovery from both good  
5 and poorer quality facies within the reservoir.

**[0052]** In another embodiment, a pressure in the poorer quality facies can be changed by drilling a lateral well through the poorer quality facies, such as in an IHS. The lateral well enables steam flow into the lamina of the IHS, relieving the pressure and enabling uni-directional flow, versus counter current flow. The lateral well may  
10 include a horizontal section that is drilled through the IHS and is aligned with dominant dip direction of an IHS bed. This well path can be an initial sidetrack drilled when the gravity drainage well pair is drilled. Depending on the integrity of the formation, the side track can either be left open or completed with a liner, that includes slotted sections or sections of wire-wrap screen, that is plugged at both  
15 ends. The well path can also be the result of a separate well that is tied to surface via a cased wellbore. This well path is referred to, herein, as an IHS well.

**[0053]** A portion of the horizontal section of the IHS well can be placed in a clean interval of the reservoir that is expected to be part of the main steam chamber. Once the oil within the IHS facies that is adjacent to the well path is heated, it may be able  
20 to drain along the IHS beds into the underlying steam chamber. The drainage results as vapor, such as steam or solvent, cross-flows along the lateral or IHS well and occupies the space being vacated by the draining oil.

**[0054]** The IHS well's ability to create a sustainable unidirectional flow path allows steam or solvent to replace any bitumen and condensed steam or solvent that drains  
25 from the IHS, allowing additional mobilization and drainage to occur. If the IHS well is drilled from the surface, as the chamber matures the IHS well can be used to inject non-condensable gas (NCG) into the IHS facies, further reducing overburden heat losses. The shale laminate present in the IHS can stabilize the location and integrity of the gas blanket.

30 **[0055]** For the purposes of this description, SAGD is used as the recovery process. Those ordinarily skilled in the art will recognize that the approaches disclosed here are equally applicable to all thermal, thermal-solvent and solvent

based recovery processes in which gravity drainage is the dominant recovery mechanism.

**[0056]** 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**. As previously noted, 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 pad **110** at the surface **112**. This may make it easier for the production well **108** to track the injection well **106**. However, in some embodiments the wells **106** and **108** may be drilled from different pads **110**.

#### *Steam Assisted Gravity Drainage*

**[0057]** 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. Sand filters may be used in the production wells **108** to decrease sand entrainment.

**[0058]** The mixed stream **116** from a number of production wells **108** may be combined and sent to a processing facility **118**. At the processing facility **118**, the water and hydrocarbons **120** can be separated, and the hydrocarbons **120** sent on for further refining. Water from the separation may be recycled to a steam generation unit within the facility **118**, with or without further treatment, and used to generate the steam **104** used for the SAGD process **100**.

**[0059]** The production wells **108** may have a segment that is relatively flat, and in some development, have a slight upward slope from the heel **122**, at which the pipe branches to the surface, to the toe **124**, at which the pipe ends. When present, an upward slope of this horizontal segment may result in the toe **124** being around one to five meters higher than the heel **122**, depending on the length of the horizontal segment. When present, the slight slope assists in draining fluids that enter the horizontal segment to the heel **122** for removal.

**[0060]** An interval **126** of the reservoir **102** may include poorer quality facies, such as an IHS layer, which drains poorly. The poorer quality facies are not limited to intervals **126** at the top of a reservoir **120**, but may be in lenses **128** or other places in the reservoir **102**. As described herein, cycling the pressure of the reservoir **102** may increase the drainage from the interval **126** and lenses **128**, allowing increases in production of hydrocarbons from these locations.

**[0061]** Fig. 2 is a cross section **200** of a steam assisted gravity drainage (SAGD) process, showing a interval **202** of reduced reservoir quality overlaying an interval **204** of high quality reservoir **204**. The interval **202** of reduced reservoir quality may be an IHS facies that contains alternating dipping beds of sand **206** and shale **208**. The horizontal sections of an injection wellbore **210** and production wellbore **212** are also shown.

**[0062]** Fig. 3 is a drawing **300** of the cross-section of Fig. 2 after a production chamber **302** has contacted the base **304** of the interval **202** of reduced reservoir quality. The production chamber **302** is a free flowing area of mobilized hydrocarbon that can be formed from steam injection, termed a steam chamber, or through the injection of solvents or both steam and solvents. As the production chamber **302** approaches base **304** of the interval **202**, the materials in a region **306** of the interval **202** will be affected by the injectant. For example, the materials in the affected region **306** can be conductively heated by steam in the production chamber. Similarly, solvent vapor may begin to diffuse into the materials in the affected region **306**.

#### *Pressure Cycling*

**[0063]** Fig. 4 is a drawing **400** of the cross-section of Fig. 2, showing drainage of oil **402** from the affected region **306**. As the pressure in the reservoir **204** is lowered, hot water or solvent in the affected region **306** can flash to vapor, helping to displace some of the oil **402** contained in the affected region **306** into the production chamber **302**. Further, gases dissolved in the oil can exsolve, further displacing oil **402** from the affected region **306**.

**[0064]** Fig. 5 is a drawing **500** of the cross-section of Fig. 2, showing injectant **502** infiltrating into the affected region **306** of the interval **202** of reduced quality reservoir.

As the pressure in the production chamber **302** is increased, vapor in the affected region **306** can collapse, for example, steam can condense to water and gases can be compressed or redissolved into the oil. This creates voids that allow injectant **502** to penetrate the affected region **306**. As each of the pressure cycles is performed, the affected region **306** can increase in size, increasing the penetration and the amount of oil recovered from the interval **202** of reduced quality reservoir. While the technique described above permit harvesting hydrocarbons from intervals **202** of reduced quality reservoir using standard SAGD equipment arrangements, some techniques for changing the pressure in intervals may permit faster harvesting.

**[0065]** To increase the effectiveness of the pressure cycling process in accelerating oil recovery from an interval **202** with dipped shale lamina, such as an IHS, the well pair trajectories can be aligned with the general direction of the IHS bed dip when using a thermal or a thermal-solvent recovery process. The IHS bed dip is the direction along which the lamina are oriented. In other words, the injection well **210** and production well **212** can be drilled along the direction of the bed dip of the interval **202** of reduced quality reservoir. For a thermal process, this orientation allows the conductively heated oil displaced along the IHS beds to drain down into the chamber at a different point along the same well pair's trajectory.

**[0066]** However, when pressure cycling is being used in a solvent based process; well orientation relative to the bed dip of the shale lamina is not as significant. This is because the mobilization process relies the solvent migrating up along the sand layers and physically contacting the oil. Further, more frequent pressure cycling may be useful when using a solvent based recovery process than with a steam based recovery process.

**[0067]** Where the interval **202** of poorer quality reservoir is thick, an environment that enables uni-directional flow, versus counter current, may be created. To achieve this, a lateral section can be drilled through the interval **202** at an angle to the bed dip, as discussed with respect to Fig. 6.

#### *Lateral Well*

**[0068]** Fig. 6 is a drawing **600** of the cross-section of Fig. 2, showing a lateral well **602** located in the interval **202** of reduced reservoir quality. The lateral well **602** is

drilled through the interval **202** at an obtuse, or shallow, angle **604** to the bed dip angle **606**. This allows the horizontal segment of the lateral well to intercept a large number of individual thin sand lenses present between the shale lamina. In some embodiments, the lateral is drilled at a shallow angle relative to horizontal. This will help prevent fluids from accumulating in the lateral well, which may reduce its effectiveness. The lateral well **602** can be left as an open hole or can be completed, for example, with a slotted liner, wirewrap, or mesh screen.

**[0069]** The lateral well **602** can be drilled as a side track lateral during the drilling of the well pair **210** and **212** or as a separate well drilled from the surface. Once the oil within the interval **202** of reduced reservoir quality that is adjacent to the lateral well **602** is heated, it will be able to drain along the IHS beds into the underlying steam chamber because vapor **608**, such as steam or gas, will be able to cross-flow along the lateral section and easily access and occupy the space as it is being vacated by the draining oil. Thus, the lateral well **602** can function as a vacuum breaker to relieve pressure behind the oil within the interval **202** of reduced reservoir quality, allowing the oil to flow out.

**[0070]** A portion **610** of the lateral well **602** can be placed in the high quality reservoir **204**, for example, within the production chamber **302**. As the recovery process matures, and the ability to independently cycle the chamber pressures declines, the presence of the lateral well **602** through the interval **202** will act as a very high permeability conduit to allow vapor **608** to enter the IHS. This flow path for the vapor **608** will progressively increase the recovery of the oil from these poorer quality reservoir facies.

**[0071]** Fig. 7 is a drawing **700** of four representative SAGD well pairs in various phases of the pressure cycling of production chambers. In the drawing **700**, the pressure in a first production chamber **702** is declining, allowing water (or solvent) to flash and solution gas to exsolve, displacing oil **402** from the interval **202** of reduced reservoir quality into the first production chamber **702**. The second production chamber **704** and fourth production chamber **706** are operating at a constant pressure, enabling the injectant to affect the material in the interval **202** of reduced reservoir quality, for example, allowing conductive heating of the interval **202** from the chambers **704** and **706**. In the drawing **700**, the pressure in the third production

chamber **708** is increasing, allowing steam, solvent vapor, or exsolved gas to compress, thereby allowing the injectant **502** to invade the interval **202** of reduced reservoir quality.

5 [0072] As shown in the drawing **700**, the pressure cycling process can be staggered between the well patterns, prior to coalesce of the production chambers **702**, **704**, **706**, and **708**. This allows an injectant **502**, such as steam, solvent, or mixtures thereof, to be used in individual production chambers, such as production chamber **708**, during a pressure increase phase. From a facilities perspective, the sequential approach can lower, or entirely mitigate, swings in demand for the  
10 injectant **502**.

[0073] As adjacent production chambers coalesce, the coalesced production chambers can be treated as single entities. Accordingly, the pressure cycling practice can be maintained, but with the cycle times progressively becoming longer as the chambers increase in size. The pressure cycling can be continued after all of  
15 the production chambers have coalesced, and a decision has been made to allow overall pressures in the production chambers to slowly fall with time. However, in this circumstance, the overall demand for injectant being supplied from the central facility will swing.

[0074] During the pressure cycles, production from the production wells **710** can  
20 be controlled to lower production of the injectant **502** in a vapor phase. The maximum pressure can be kept below the reservoir fracture pressure to prevent fracturing of the surrounding rock. The minimum pressure can be kept at or above the lowest pressure required for the installed production system to efficiently lift the fluids to surface. The lowest pressure may be lower than the initial reservoir  
25 pressure in order to capture the benefits of the expansion of solution gas exsolving from the oil. The pressure differences do not have to be large. For example, in an embodiment, the minimum pressure may be only 10 % less than the maximum pressure. In other embodiments, the pressure differential may be 50 %, 90 %, or even greater. A larger pressure differential may be more effective at harvesting the  
30 hydrocarbons from the interval **202** of reduced reservoir quality, but may place greater stress on a central facility.

**[0075]** Fig. 8 is a method **800** of improving the hydrocarbon yield from an interval of reduced reservoir quality. The method **800** begins at block **802** with a mapping of the locations of resources in a reservoir and a plan for harvesting those resources. The mapping can include locating high quality, such as sand beds, and poorer  
5 quality reservoir regions, such as IHS facies. Generally, the mapping will be performed in the initial planning stages of the recovery scheme. For example, prior to the start of recovery operations, a geologic model can be created for the development area. This geologic model is usually constructed using a geologic modeling software program. Available open hole and cased hole log, core, 2D and  
10 3D seismic data, and knowledge of the depositional environment setting can all be used in the construction the geologic model. The geologic model and knowledge of surface access constraints can then be used to complete the layout of the recovery process wells, e.g., the injection and production wells and the surface pads.

**[0076]** At block **804**, a series of performance predictions can be made using a  
15 reservoir simulation program, such as Computer Modeling Group's STARS program, in order to identify a useful combination of absolute pressure changes, pressure cycle frequency, or side track lateral trajectories. The simulations can also help identify how the combinations should change over time as the recovery process matures.

**[0077]** The optimization process needs to consider both the needs of individual  
20 well pairs and the overall pattern needs. For example, changes in geology and well design may result in different approaches for different wells within the development. It may also be possible to use simple empirical or analog based models for performance prediction. Further, in many developments, one or more follow-up  
25 recovery processes, such as the drilling of in-fill wells, can be used to further enhance the recovery of the hydrocarbons. The options to extend recovery can be considered during the pressure cycling planning phase, in addition to any operating pressure and production rate limitations associated with the installed lift system to be used in the production wells.

**[0078]** The pressure cycling described herein can be included as part of the start-up  
30 procedures, such as steam circulation and continuous solvent injection. To achieve a beneficial impact on one or both well pair wells it is necessary for the

pressure decline to be sufficient to allow some of the injectant to vaporize and, thus, displace oil from the reservoir into the well and produced. Again, a series of performance predictions can be made using a reservoir simulation program, such as Computer Modeling Group's STARS program in order to identify the optimal combination of absolute pressure change, pressure cycle frequency and how these should evolve over time as the start-up process matures.

**[0079]** At block **806**, the SAGD well pairs used to harvest the hydrocarbon from the reservoir can be drilled. As noted above, if a thermal process is used, the well pairs may follow the direction of the dip to maximize the yield of hydrocarbons. At this same time, or at any time during the field operation, one or more lateral wells may be drilled into the interval of lower quality reservoir to relieve pressure and establish unidirectional flow. After the well pairs have been drilled, data collected during their drilling as well as data collected during the operation of the recovery process, such as cased hole logs including temperature logs, observation wells, additional time lapse seismic or other remote surveying data, can be used to update the geologic model and to map the evolution of the depletion patterns as the recovery process matures. The depletion patterns within the reservoir will be influenced by well placement decisions, geological heterogeneity, well failures, and day to day operating decisions.

**[0080]** At block **808**, steam, solvent, or combinations of these agents can be injected into the injection well. At block **810**, fluids including hydrocarbons, injectants, water, and the like, may be produced from the production well. As the injection and production continues, at block **812**, a production chamber can be formed that is in contact with the interval of low quality reservoir, such as an IHS facies above a sand bed.

**[0081]** At block **814**, the pressure in the production chamber and interval of low quality reservoir can be changed to enhance production of hydrocarbons. In an embodiment, this is performed by cycling the pressure in the production chamber. In another embodiment, the pressure is changed by a lateral well that releases pressure in an interval of low quality reservoir, such as an IHS facies. Following the operation of the thermal, thermal-solvent, or solvent based recovery process for a suitable period of time, intervals of high hydrocarbon depletion will create a series of

discrete connections between adjacent wells or well pairs, depending on the recovery process. Knowledge of these connections is gained through observances of interwell or interpattern communication of fluids, convergence of operating pressures, as well as via ongoing reservoir depletion monitoring with tools such as time lapse 3D seismic. The connections may be used to determine the cycle time and total pressure range of the cycles used for the recovery during each stage of the development.

**[0082]** Production rates may be controlled to help minimize the co-production of the injectant used to mobilize the hydrocarbon. Depending on whether the injectant is steam, a steam-gas mixture, a steam-solvent mixture, solvent or gas, such procedures for controlling the amount of injectant co-production can include monitoring the bottom hole temperature or pressure, as well as the production rates of injectant observed at surface. In addition, the injectant amount and type may also be modified to keep the measurements within control ranges. The control measures can be modified to reflect changes in the injectant type and composition that may occur over the life of the project. In addition, the liner could be completed with inflow control devices to restrict the production of injectant vapour.

### *Embodiments*

**[0083]** An embodiment provides a method for improving recovery from a hydrocarbon reservoir. The method includes identifying an interval within the reservoir that comprises a reduced reservoir quality, wherein the interval comprises hydrocarbons. A production chamber is formed in a reservoir interval below the interval of reduced reservoir quality, wherein the production chamber is in contact with the interval of reduced reservoir quality. Hydrocarbons are mobilized in the interval of reduced reservoir quality by contact with a mobilizing agent. A pressure is changed within the interval of reduced reservoir quality to allow hydrocarbon flow from the interval of reduced reservoir quality.

**[0084]** The method may include cycling a steam pressure within the production chamber. A solvent pressure can be cycled with the production chamber. The pressure can be cycled over a period of at least one month. Different areas of a reservoir can be cycled using offset pressure phases to keep the total injection rate of the mobilizing fluid substantially constant over time.

**[0085]** In an embodiment, the method includes drilling a lateral segment through the interval of reduced reservoir quality, wherein the lateral segment is configured to allow mobilizing agent flow into the interval of reduced reservoir quality. The lateral section can be drilled through the intervals of reduced reservoir quality at an angle to a bed dip. The lateral section may be drilled as a side track drilled from one of the gravity drainage wellbores. The lateral section may be left open to the production chamber. The portion of the lateral segment that is within the interval of reduced reservoir quality can be completed with a slotted liner, a wirewrap screen, or a mesh rite screen. The lateral segment can be drilled from the surface.

**[0086]** Another embodiment provides a system for increasing hydrocarbon production from an interval of low quality reservoir. The system includes an injection well configured to inject an injectant into a reservoir and a production well configured to produce fluids from the reservoir, wherein the fluids comprise a hydrocarbon. A pressure system is configured to change a pressure within a production chamber to increase a flow of hydrocarbon from an interval of low quality reservoir in contact with the production chamber.

**[0087]** In the system, a maximum operating pressure for the production chamber can be less than a reservoir failure pressure. A minimum operating pressure for the production chamber can be at least 10% lower than a maximum operating pressure.

**[0088]** The pressure system can include an injection system configured to lower the pressure by slowing an injection rate. The can include a production system configured to lower the pressure by increasing fluid withdrawal.

**[0089]** The system can include a number of injection and production well pairs, wherein the pressure of a production chamber associated with a single one of the plurality of injection and production well pairs is cycled. The system can be configured to independently cycle the pressure in two or more production chambers, wherein each production chamber is associated with one of the plurality of injection and production well pairs. In the system, the injection well and production well can be drilled parallel to the direction of a bed dip in the lower quality resource.

**[0090]** Another embodiment provides a system for harvesting resources in a low quality interval of a reservoir. The system includes a gravity drainage system

configured to drain a first portion of resources from a high quality interval of a reservoir. The system also includes a pressure control system configured to change a pressure on a production chamber to drain a second portion of resources from a low quality interval of a reservoir.

- 5   **[0091]**   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 are not intended to be limited to the particular embodiments disclosed herein. Indeed, the present techniques include all alternatives, modifications, and equivalents falling
- 10   within the true spirit and scope of the appended claims.

## CLAIMS

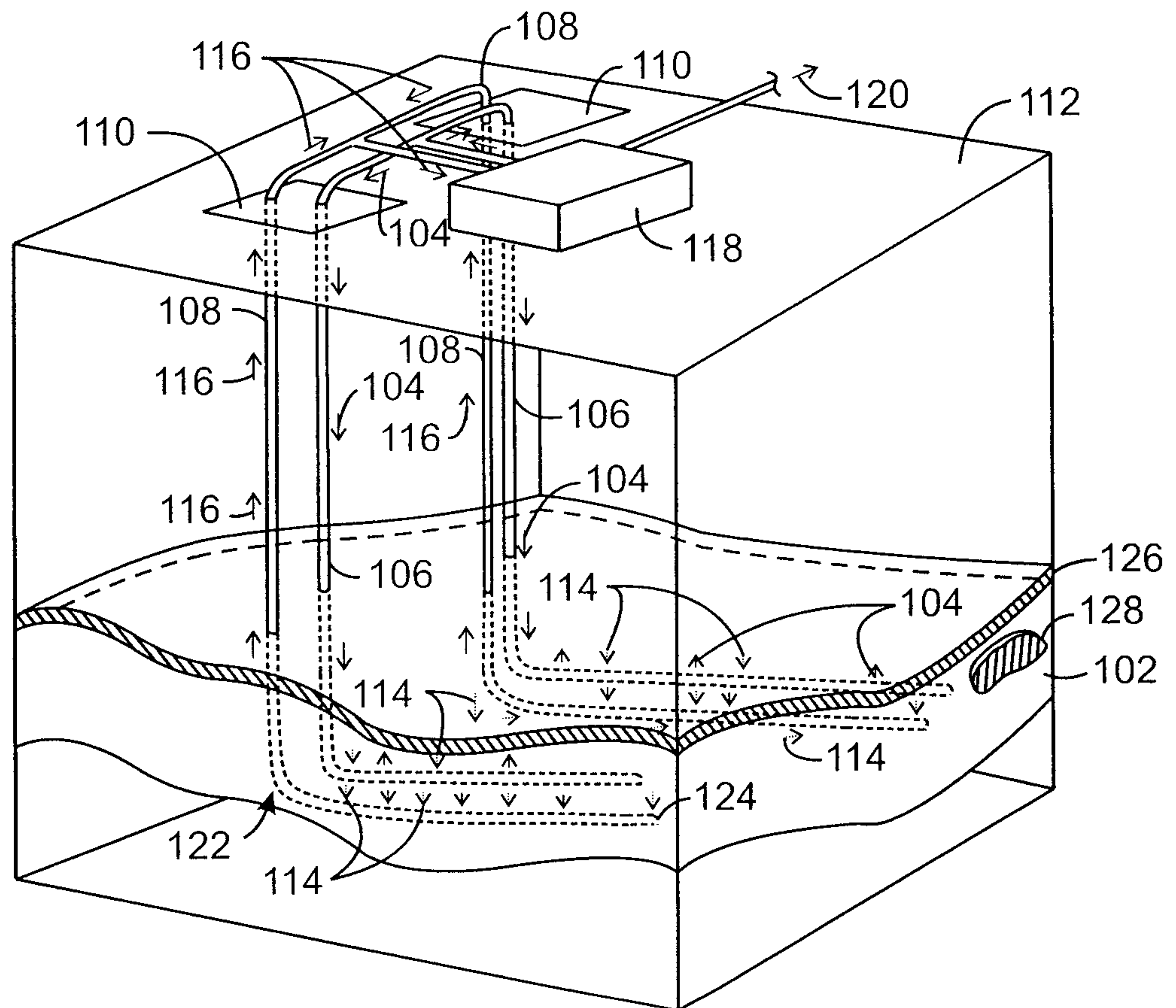
What is claimed is:

1. A method for improving recovery from a hydrocarbon reservoir, comprising:  
identifying an under developed interval within the reservoir that includes an under developed steam chamber, wherein the under developed interval comprises hydrocarbons;  
forming a production chamber in a reservoir interval below the under developed interval, wherein the production chamber is in contact with the under developed interval;  
mobilizing hydrocarbons in the under developed interval by contact with a mobilizing agent; and  
cycling a pressure between an operating pressure and a reduced pressure within the production chamber to allow hydrocarbon flow from the under developed interval;  
wherein cycling of the pressure is such that at the reduced pressure at least a portion of at least one of water and a solvent in a liquid phase within the under developed interval is flashed to the vapor phase.
2. The method of claim 1, comprising cycling a steam pressure within the production chamber.
3. The method of claim 1, comprising cycling a solvent pressure within the production chamber.
4. The method of claim 1, comprising cycling the pressure over a period of at least one month.
5. The method of claim 1, comprising cycling different areas of the reservoir using offset pressure phases to keep a total injection rate of the mobilizing agent substantially constant over time.

6. The method of claim 1, comprising drilling a lateral segment through the under developed interval, wherein the lateral segment is configured to allow flow of the mobilizing agent into the under developed interval.
7. The method of claim 6, comprising drilling the lateral segment through the under developed interval at an angle to a bed dip.
8. The method of claim 6, comprising drilling the lateral segment as a side track drilled from a gravity drainage wellbores.
9. The method of claim 6, comprising leaving the lateral segment open to the production chamber.
10. The method of claim 6, comprising completing a portion of the lateral segment that is within the under developed interval with a slotted liner, a wirewrap screen, or a mesh rite screen.
11. The method of claim 6, comprising drilling the lateral segment from the surface.
12. A system for increasing hydrocarbon production from an under developed interval in a reservoir that includes an under developed steam chamber, comprising:
  - an injection well configured to inject an injectant into the reservoir;
  - a production well configured to produce fluids from the reservoir, wherein the fluids comprise a hydrocarbon; and
  - a pressure system configured to cycle a pressure within a production chamber between an operating pressure and a reduced pressure to increase a flow of hydrocarbon from the under developed interval in contact with the production chamber;wherein the system is configured such that the cycling of the pressure is such that at the reduced pressure at least a portion of at least one of water and a solvent in a liquid phase within the under developed interval is flashed to the vapor phase.

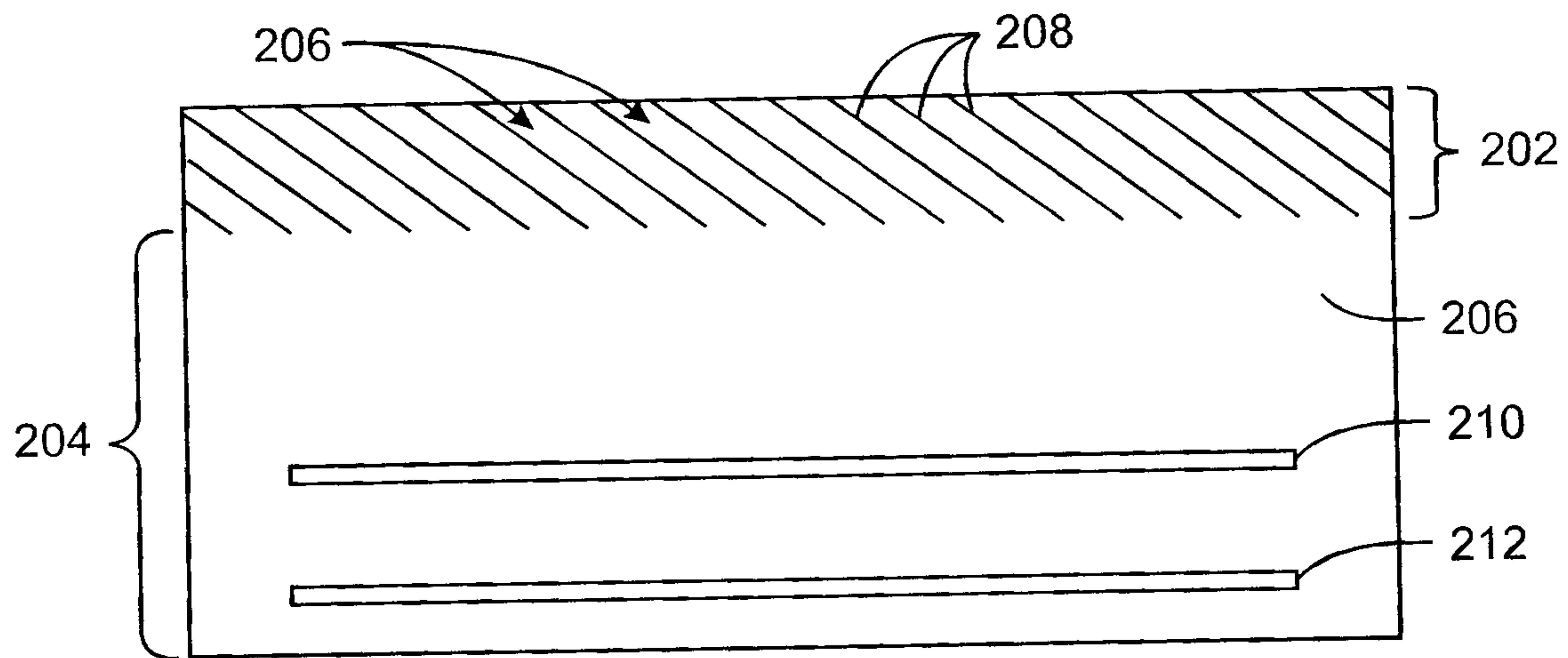
13. The system of claim 12, wherein a maximum operating pressure for the production chamber is less than a reservoir failure pressure.
14. The system of claim 12, wherein a minimum operating pressure for the production chamber is at least 10% lower than a maximum operating pressure.
15. The system of claim 12, wherein the pressure system comprises an injection system configured to lower the pressure by slowing an injection rate.
16. The system of claim 12, wherein the pressure system comprises a production system configured to lower the pressure by increasing fluid withdrawal.
17. The system of claim 12, comprising a plurality of injection and production well pairs, and wherein the pressure of a production chamber associated with a single one of the plurality of injection and production well pairs is cycled.
18. The system of claim 17, wherein two or more production chambers are independently pressure cycled, wherein each production chamber is associated with one of the plurality of injection and production well pairs.
19. The system of claim 12, wherein the injection well and production well are drilled parallel to a direction of a bed dip in the reservoir.

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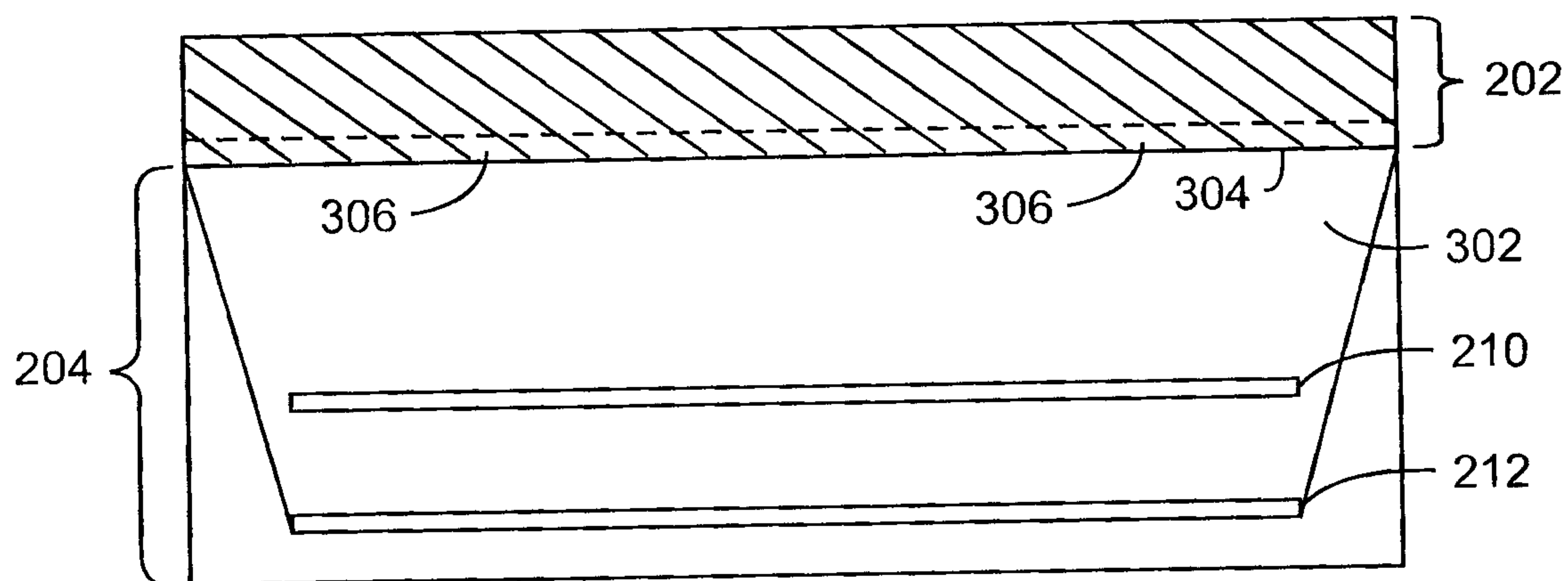


100  
FIG. 1

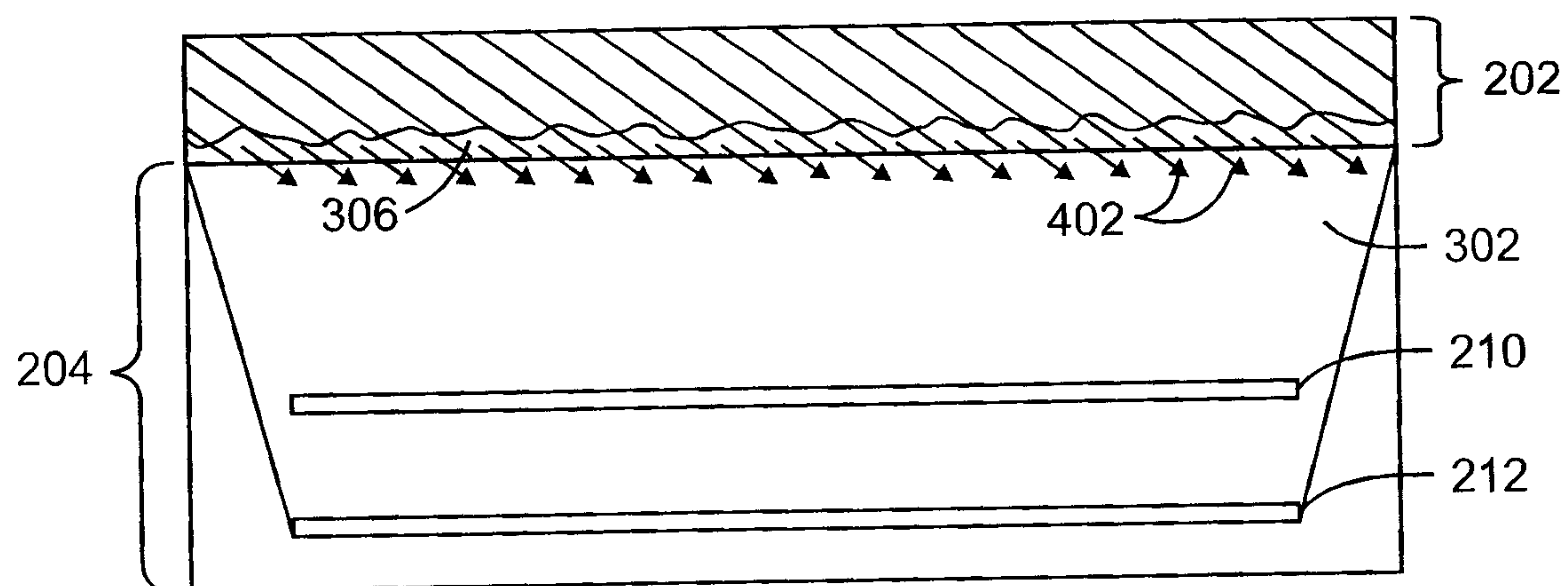
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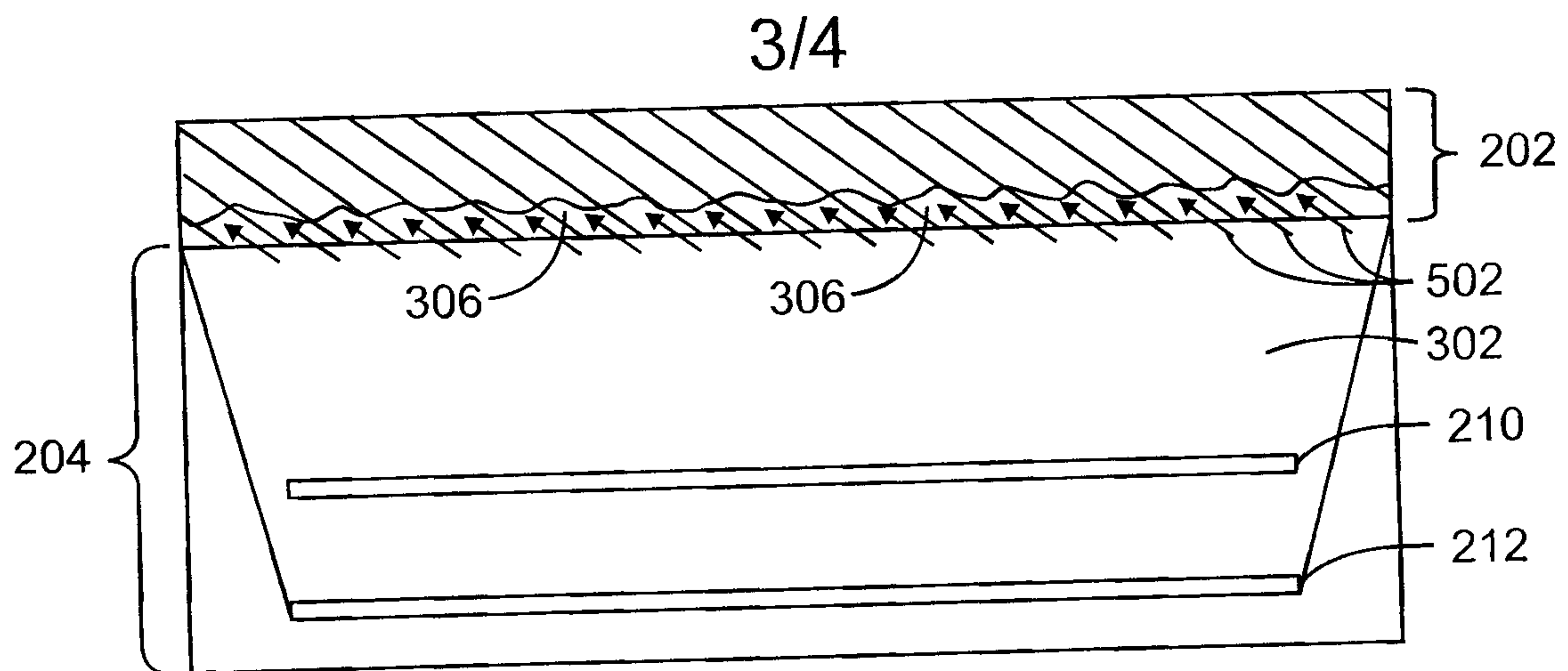
200  
FIG. 2



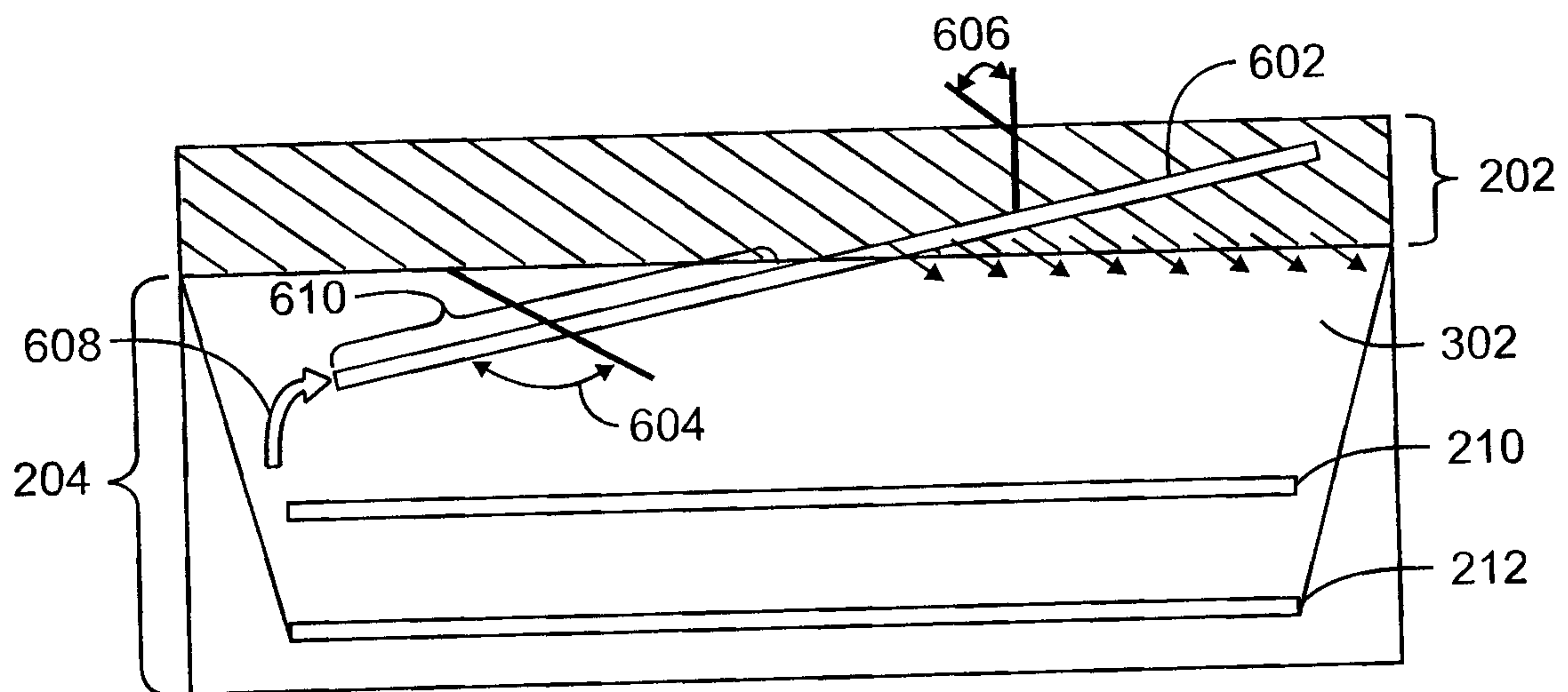
300  
FIG. 3



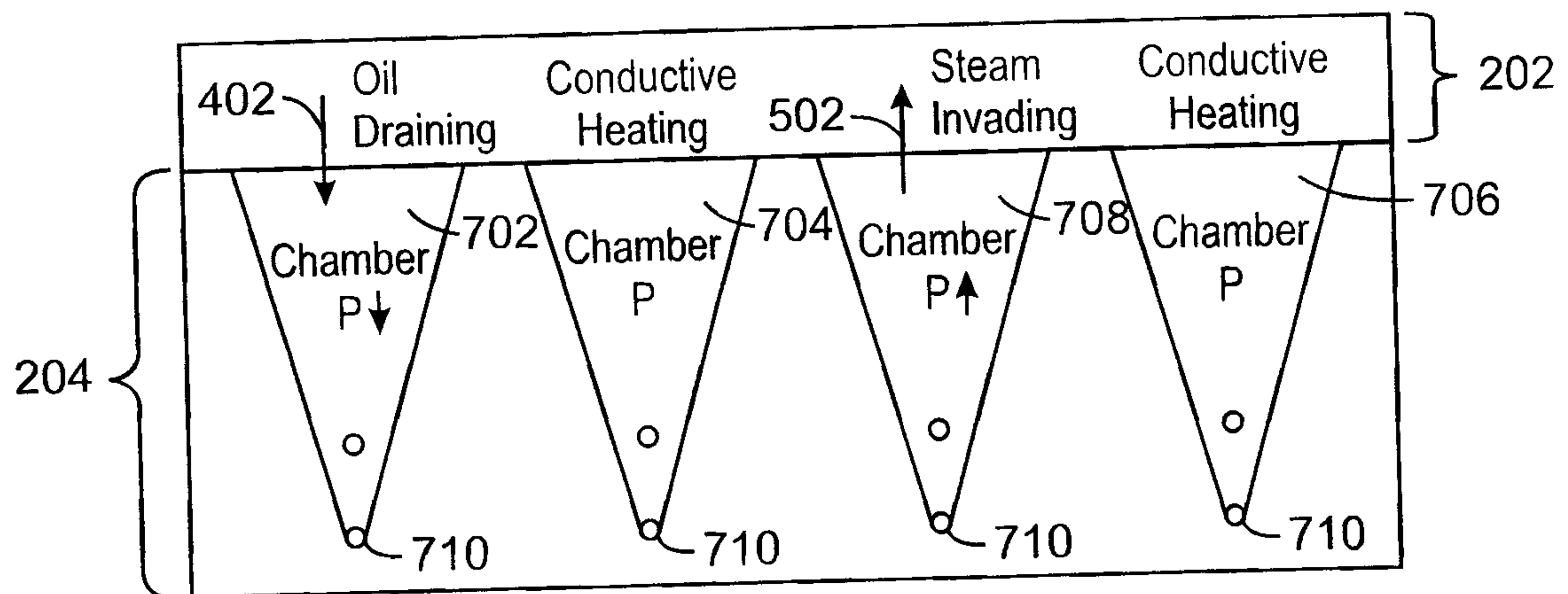
400  
FIG. 4



500  
FIG. 5

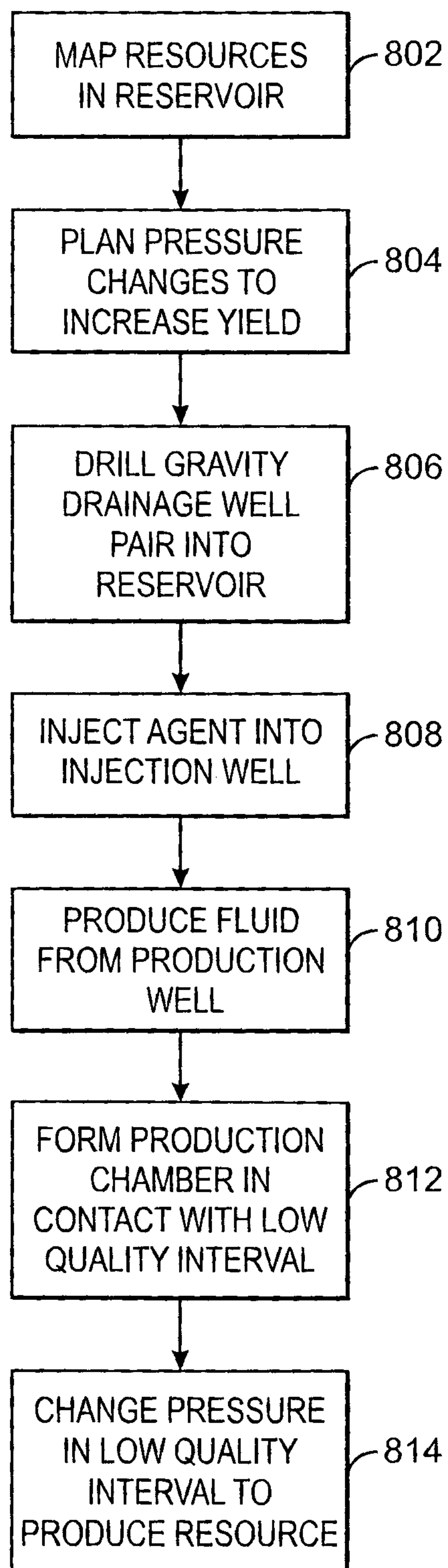


600  
FIG. 6

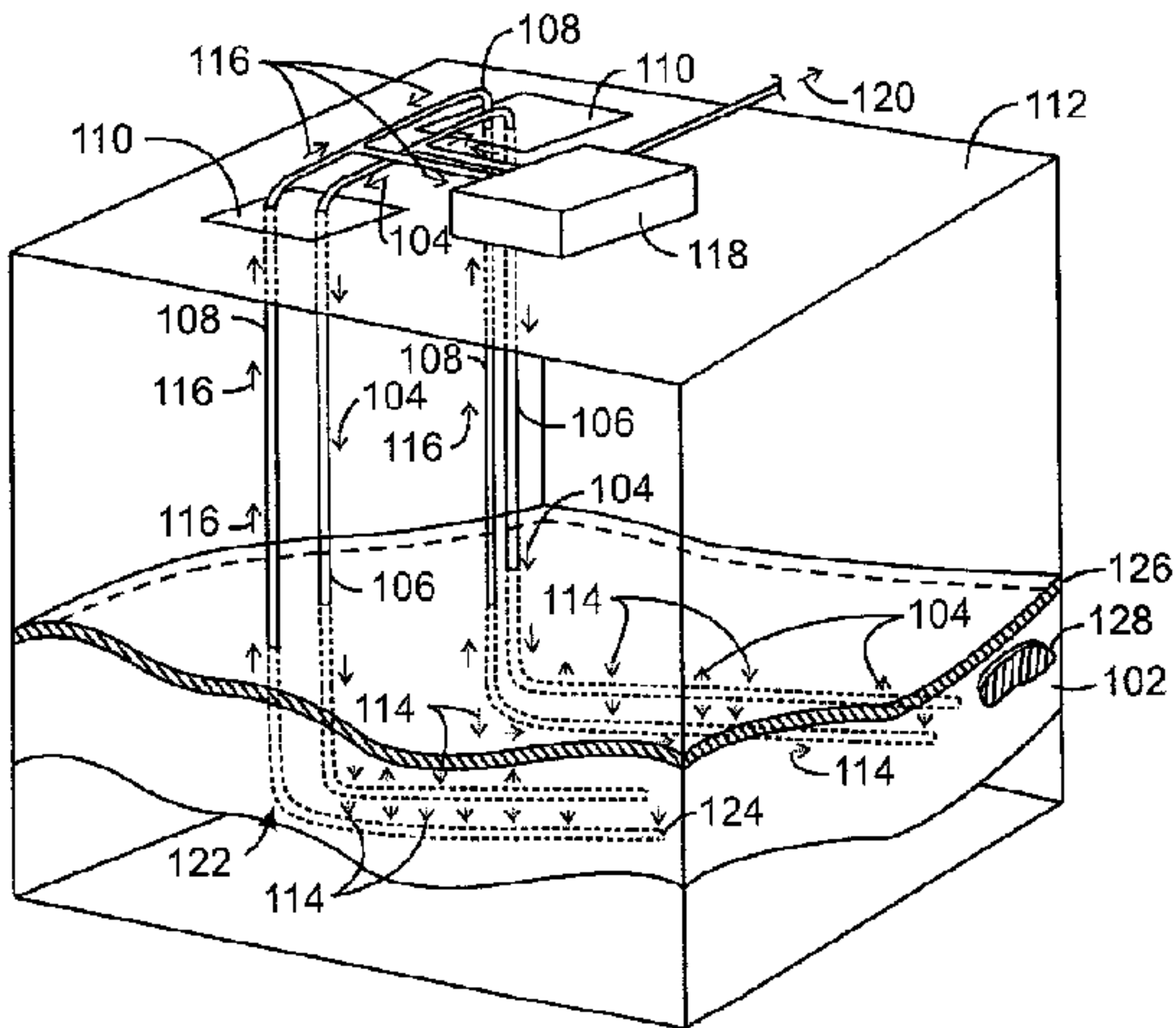


700  
FIG. 7

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800  
FIG. 8



100