Office de la Propriété Intellectuelle du Canada

Un organisme d'Industrie Canada

Canadian Intellectual Property Office

An agency of Industry Canada

CA 2912275 C 2018/01/09

(11)(21) **2 912 275**

(12) **BREVET CANADIEN CANADIAN PATENT**

(13) **C**

(22) **Date de dépôt/Filing Date:** 2015/11/18

(41) **Mise à la disp. pub./Open to Public Insp.:** 2016/07/23

(45) **Date de délivrance/Issue Date:** 2018/01/09

(30) **Priorité/Priority:** 2015/01/23 (US62/107,162)

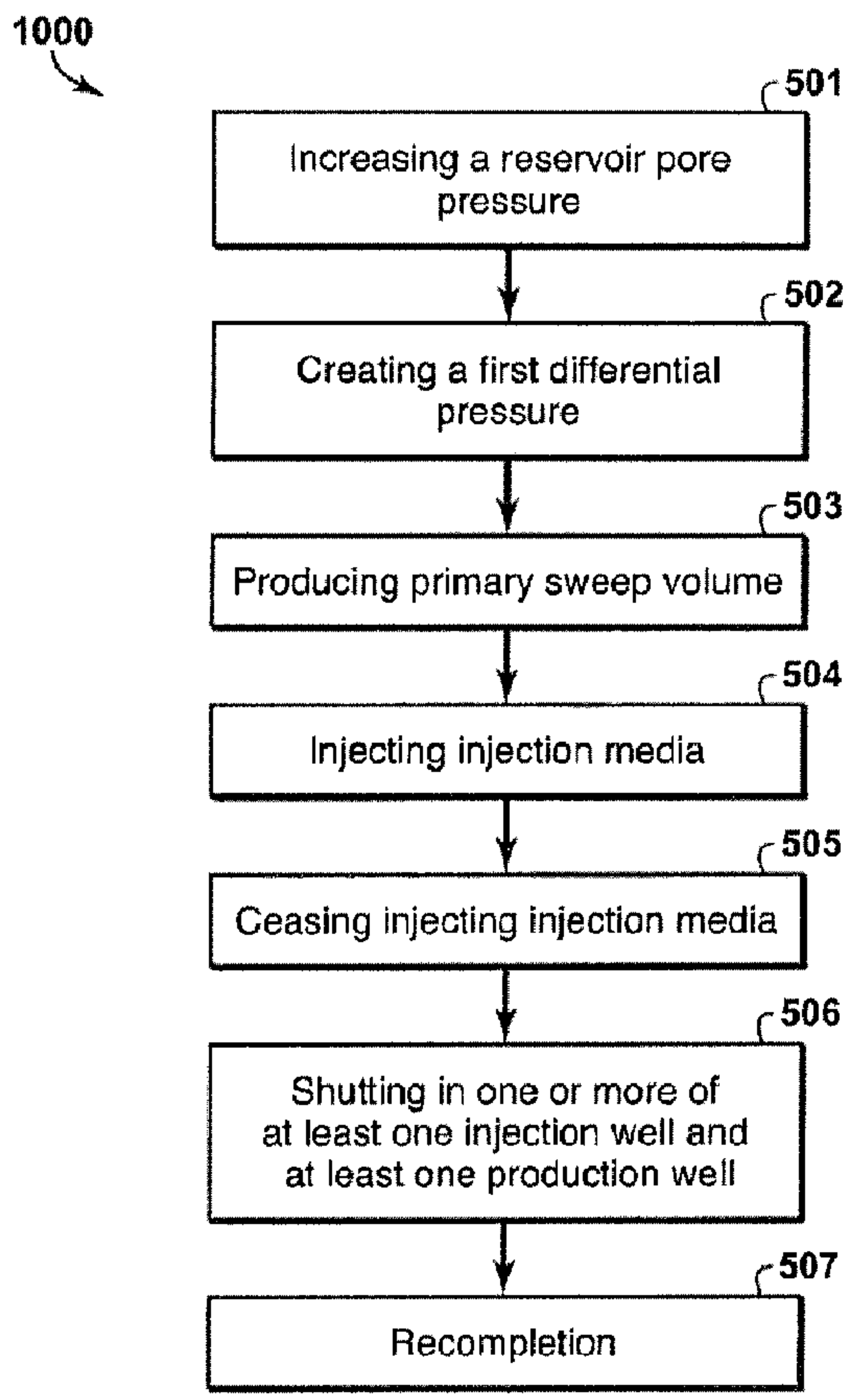
(51) **Cl.Int./Int.Cl.** ***E21B 43/18*** (2006.01), ***E21B 43/16*** (2006.01)

(72) **Inventeurs/Inventors:**
HSU, SHENG-YUAN, US;
HODA, NAZISH, US;
ZHANG, ZHENGYU, US;
YALE, DAVID P., US;
HERBOLZHEIMER, ERIC, US;
CHAIKIN, PAUL M., US

(73) **Propriétaire/Owner:**
EXXONMOBIL UPSTREAM RESEARCH COMPANY, US

(74) **Agent:** BORDEN LADNER GERVAIS LLP

(54) **Titre : METHODE ET DISPOSITIF PERMETTANT D'AMELIORER LA RECUPERATION DE PETROLE LOURD D'UN RESERVOIR**
(54) **Title: METHOD AND SYSTEM FOR ENHANCING THE RECOVERY OF HEAVY OIL FROM A RESERVOIR**



(57) **Abrégé/Abstract:**
The present disclosure provides a method and system for enhancing recovery of heavy oil from a reservoir that includes increasing a reservoir pore pressure, then; creating a first differential pressure, then; producing primary sweep volume; injecting an injection

(57) **Abrégé(suite)/Abstract(continued):**
media into the subsurface formation, then; ceasing injecting the injection media before the injection media is produced by the at least one production well and ceasing producing primary sweep volume from the subsurface formation before the injection media is produced, then; shutting in one or more of the at least one injection well and the at least one production well; and one of recompleting one or more of the at least one production well as a recompleted injection well and recompleting one or more of the at least one injection well as a recompleted production well.

ABSTRACT

The present disclosure provides a method and system for enhancing recovery of heavy oil from a reservoir that includes increasing a reservoir pore pressure, then; creating a first differential pressure, then; producing primary sweep volume; injecting an injection media into the subsurface formation, then; ceasing injecting the injection media before the injection media is produced by the at least one production well and ceasing producing primary sweep volume from the subsurface formation before the injection media is produced, then; shutting in one or more of the at least one injection well and the at least one production well; and one of recompleting one or more of the at least one production well as a recompleted injection well and recompleting one or more of the at least one injection well as a recompleted production well.

METHOD AND SYSTEM FOR ENHANCING THE RECOVERY OF HEAVY OIL FROM A RESERVOIR

BACKGROUND

Fields of Disclosure

[0002] The disclosure relates generally to the field of recovering heavy oil and, more particularly, to a method and system for enhancing the recovery of heavy oil from a reservoir within a subsurface formation.

Description of Related Art

[0003] This section is intended to introduce various aspects of the art, which may be associated with the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0004] Modern society is greatly dependent on the use of hydrocarbon resources 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 subsurface formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subsurface formations, and the proportion of hydrocarbons present, among other things. Easily harvested sources of hydrocarbons are dwindling, leaving less accessible sources to satisfy future energy needs. As the costs of hydrocarbons increase, the less accessible sources become more economically attractive.

CA 2912275 2017-06-13

[0005] Recently, the harvesting of oil sands to remove heavy oil has become more economical. Hydrocarbon removal from oil sands may be performed by several techniques. For example, a well can be drilled to an oil sand reservoir and steam, hot air, solvents, or a combination thereof, can be injected to release the hydrocarbons. The released hydrocarbons may be collected by wells and brought to the surface. In another technique, strip or surface mining may be performed to access the oil sands, which can be treated with hot water, steam or solvents to extract the heavy oil. Strip or surface mining when combined with the hot water or steam may produce a substantial amount of waste or tailings requiring disposal.

[0006] Another process for harvesting oil sands, which may generate less surface waste than other processes, is the slurrified reservoir hydrocarbon recovery process. The slurrified reservoir hydrocarbon recovery process may also be referred to as a slurrified hydrocarbon extraction process.

[0007] In a slurrified reservoir hydrocarbon recovery process, such as that described in U.S. Patent No. 5,823,631, hydrocarbons trapped in solid media, such as bitumen in oil sands, may be recovered from subsurface formations by relieving an overburden stress by injection of water to raise the pore pressure and causing the subsurface formation to flow from an injection well to a production well, for example, by fluid injection, recovering an oil sand/water mixture from the production well, separating the bitumen and reinjecting the remaining sand in a water slurry.

[0008] Another slurrified reservoir hydrocarbon recovery process, such as that described in U.S. Patent No. 8,360,157, may include a method for recovering heavy oil that comprises accessing, from two or more locations, a subsurface formation having an overburden stress disposed thereon. The subsurface formation comprises heavy oil and one or more solids. The subsurface formation is pressurized to a pressure sufficient to relieve the overburden stress. A differential pressure is created between the two or more locations to provide one or more high pressure locations and one or more low pressure locations. The differential pressure is varied within the subsurface formation between the one or more low pressure locations to mobilize at least a portion of the solids and a portion of heavy oil in the subsurface formation. The mobilized solids and heavy oil then flow toward one or more low pressure locations to provide a slurry comprising heavy oil and one or more solids. The slurry comprising the heavy oil and the one or more solids is flowed to the surface where the heavy oil is recovered from the one or more solids. The one or more solids are recycled to the subsurface formation.

[0009] A process that relates to a slurrified reservoir hydrocarbon recovery process may include methods and systems for recompacting a hydrocarbon reservoir to prevent override of a fill material, such as that described in U.S. Published Application No. 2012/0325461. An exemplary method may include detecting a slurry override condition and reducing a pressure within the reservoir so as to reapply overburden stress.

[0010] The slurrified reservoir hydrocarbon recovery processes discussed above convert the reservoir into a formation resembling a moving bed. When the reservoir moves toward a production well(s), void space is filled by a reinjected stream.

[0011] Although slurrified reservoir hydrocarbon recovery processes can recover a significant portion of the heavy oil present in a reservoir during primary production, an additional significant portion of heavy oil may remain unswept at the conclusion of primary production. Primary production may terminate when the heavy oil recovered from the production streams are economically insufficient to continue. To recover the significant portion of heavy oil that may remain unswept at the conclusion of primary production, secondary production may be undertaken. When secondary production is commenced after breakthrough occurs during primary production, injected sand or reinjected sand may be produced along with in situ oil sand. The production of injected or reinjected sand may lead to a reduced recovery efficiency of the heavy oil. The surface processing facilities may have been designed with a target heavy oil, sand, water, and fines content in mind. Since the injected or reinjected sand will have a lower portion of heavy oil content than the heavy oil, it is possible that the production of the injected or reinjected sand may lead to inefficiencies for processing the produced material.

[0012] A need exists for addressing the aforementioned disadvantages associated with commencing production after breakthrough occurs.

SUMMARY

[0013] The present disclosure provides a method and system for enhancing the recovery of heavy oil from a reservoir within a subsurface formation.

[0014] A method for enhancing recovery of heavy oil from a reservoir within a subsurface formation may comprise (a) increasing a reservoir pore pressure of the reservoir, then; (b) creating a first differential pressure between at least one injection well and at least one production well within the subsurface formation, then; (c) producing primary sweep volume from the subsurface formation via one or more of the at least one production well; (d) injecting an injection media into the subsurface formation via one or more of the at least one injection well, then; (e) ceasing injecting the injection media before the injection media is produced by the at least one production well and ceasing producing primary sweep volume from the subsurface formation before the injection media is produced, then; (f) shutting in one or more of the at least one injection well and the at least one production well and (g) one of recompleting one or more of the at least one production well as a recompleted injection well and recompleting one or more of the at least one injection well as a recompleted production well.

[0015] The foregoing has broadly outlined the features of the present disclosure so that the detailed description that follows may be better understood. Additional features will also be described.

BRIEF DESCRIPTION OF THE DRAWINGS

[0016] These and other features, aspects and advantages of the present disclosure will become apparent from the following description and the accompanying drawings, which are described briefly below.

[0017] Figure 1 is a diagram showing the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a subsurface formation.

[0018] Figure 2a is a diagram of the use of a slurrified reservoir hydrocarbon recovery process.

[0019] Figure 2b is a diagram of the use of a slurrified reservoir hydrocarbon recovery process.

[0020] Figure 3a is a diagram of the use of a slurrified reservoir hydrocarbon recovery process.

[0021] Figure 3b is a diagram of the use of a slurrified reservoir hydrocarbon recovery process.

[0022] Figure 4a is a diagram of the use of a slurrified reservoir hydrocarbon process.

[0023] Figure 4b is a diagram of the use of a slurrified reservoir hydrocarbon recovery process.

[0024] Figure 5 is a diagram showing a method of a slurrified reservoir hydrocarbon recovery process.

[0025] It should be noted that the figures are merely examples and that no limitations on the scope of the present disclosure are intended hereby. Further, the figures are generally not drawn to scale but are drafted for the purpose of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0026] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the features illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the disclosure is thereby intended. Any alterations and further modifications, and any further applications of the principles of the disclosure as described herein are contemplated as would normally occur to one skilled in the art to which the disclosure relates. It will be apparent to those skilled in the relevant art that some features that are not relevant to the present disclosure may not be shown in the drawings for the sake of clarity.

[0027] At the outset, for ease of reference, certain terms used in this application and their meaning as used in this context are set forth below. 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 processes are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments and terms or processes that serve the same or a similar purpose are considered to be within the scope of the present disclosure.

[0028] "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, semisolid 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 weight (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 found in bitumen can vary. The term “heavy oil” includes bitumen as well as lighter materials that may be found in a sand or carbonate reservoir.

[0029] “Breakthrough” refers to a description of reservoir conditions under which an injection material, previously isolated or separated from production as observed at the production well(s), gains access to one or more production wells. For breakthrough to occur, anywhere from greater than 0 to less than or equal to 100 percent of the material being produced at the production well(s) is injection media. The percentage of injection material may include any number within or bounded by the preceding material. For example, the percentage of injection material may be, but is not limited to, at least 50% or no more than 90%. In other words, breakthrough refers to a description of reservoir conditions when a material injected into the reservoir reaches one or more production wells after being reinjected into the reservoir. Breakthrough may occur at the end of primary production. Breakthrough may occur at the end of secondary production. When breakthrough occurs at the end of secondary production, the percentage of media being produced at the production well(s) is reinjection media and/or injection media. Breakthrough may occur at the end of any production (e.g., primary production, secondary production, tertiary production).

[0030] “Conditioning fluid” is fluid injected into a reservoir prior to primary production to increase the pore pressure of the reservoir. The conditioning fluid may be any suitable fluid. For example, the conditioning fluid may comprise at least one of water, fines, caustic, flocculants, coagulants, sodium silicate, polymeric compounds, salts, solvents, brine, hydrocarbons, polymers, and hydrocarbons.

[0031] "Facility" 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, sand processing plants, and delivery outlets. In some instances, the term "surface facility" is used to distinguish from those facilities other than wells.

[0032] "Heavy oil" includes oils which are classified by the American Petroleum Institute ("API"), as heavy oils, extra heavy oils, or bitumens. The term "heavy oil" includes bitumen. Heavy oil may have a viscosity of about 1,000 centipoise (cP) or more, 10,000 cP or more, 100,000 cP or more, or 1,000,000 cP or more. In general, a heavy oil has an API gravity between 22.3° API (density of 920 kilograms per meter cubed (kg/m^3) or 0.920 grams per centimeter cubed (g/cm^3)) and 10.0° API (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° API (density greater than 1,000 kg/m^3 or 1 g/cm^3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, silt, sand, water and bitumen.

[0033] A "hydrocarbon" is an organic compound that primarily includes the elements of hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. Hydrocarbons generally refer to components found in heavy oil or in oil sands. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0034] "Injection media" is media injected into the reservoir during primary production. The injection media may comprise, for example, at least one of water, clay, silt, sand, brine, salts, hydrocarbons, polymers, coagulants, flocculants, solvents and conditioning fluid. The injection media may comprise a portion of the conditioning fluid. The injection media may include reinjected sand.

[0035] An "injection well" refers to a well or wellbore that receives a material, such as but not limited to the conditioning fluid or the injection media.

[0036] A "line drive well pattern" refers to an injection pattern in which injection wells are located in a first straight line and production wells are located in a second straight line that is parallel to the first straight line.

[0037] "Overburden" refers to the material overlying a reservoir. The overburden may contain rock, soil, sand, clay, pore fluids, and ecosystem above the reservoir. The pore fluids may include, but are not limited to, water and/or hydrocarbons.

[0038] "Overburden stress" is the stress, or force exerted by unit area, that the overburden applies to the sands within the reservoir due to its weight. Overburden stress may be considered to be the effective stress applied by the overburden, e.g., the total stress of the overburden minus the fluid pressure within the reservoir. As such, overburden stress is a measure of the vertical component of the stress the solids in the reservoir exert on each other due to the weight of the overburden. "Overburden stress" may interchangeably be referred to as "overburden load." The solids in the reservoir may comprise sand grain, silt and/or clay particles, etc.

[0039] "Permeability" is the capacity of a rock to transmit fluids through the interconnected pore spaces of the structure. The customary unit of measurement for permeability is the milliDarcy (mD). The term "relatively permeable" is defined, with respect to formations or portions thereof (for example, 10 or 100 mD). The term "relatively low permeability" is defined, with respect to subsurface formations or portions thereof, as an average permeability of less than about 10 mD.

[0040] "Pressure" is a force exerted per unit area which is defined as being equal in all directions and is typically used here in reference to the pore fluids in the reservoir or to describe, in part, the fluid or material in the injection wells and production wells. Pressure can be shown as pounds per square inch (psi), kilopascals (kPa), or megapascals (MPa). "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. "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] "Pressure gradient" represents the pressure differences divided by the distance between the locations where those pressure differences are measured (e.g., the change in pore pressure per unit of depth). Depth may refer to length or width. Pressure gradient is a measure of driving force moving the sand through the subterranean reservoir or the pressure moving slurries through a pipe. The "pressure gradient" may interchangeably be referred to as a "pore pressure gradient" or, when the distance over which the pressure varies, a "differential pressure."

[0042] "Primary production," primary recovery or primary sweep is the first stage of hydrocarbon production by which the formation is displaced by an injection media injected at an injection well and produced via a production well. Primary production may terminate at or after breakthrough.

[0043] "Primary sweep volume" is material produced from the reservoir during primary recovery. Primary sweep volume may refer to the volume of the reservoir produced during primary production. For example, primary sweep volume may refer to anywhere between 20 to 70% inclusive volume of a reservoir total volume within a subsurface formation path of the total volume of reservoir produced during primary production within the subsurface formation path. The aforementioned ranges may include any number bounded by and/or within the preceding ranges. The primary sweep volume may comprise at least one of heavy oil, sand, silt, clay, connate or in situ water, and conditioning fluid. The primary sweep volume may comprise a portion of the conditioning fluid.

[0044] "Production well" refers to a well or wellbore that produces a material.

[0045] A "recompleted injection well" is a well that initially served as a production well but has been completed to serve as an injection well. In other words, such a well is a well that initially produced materials, such as but not limited to primary sweep volume and/or secondary sweep volume, and later receives materials, such as but not limited to injection media.

[0046] A "recompleted production well" is a well that initially served as an injection well but has been completed to serve as a production well. In other words, such a well is a well that initially received materials to be injected, such as but not limited to injection media, and later produces materials, such as but not limited to primary sweep volume and/or secondary sweep volume.

[0047] "Reconditioning fluid" is fluid injected into a reservoir prior to secondary production and/or tertiary production, etc. to increase the pore pressure of the reservoir. The reconditioning fluid may be any suitable fluid. For example, the reconditioning fluid may comprise at least one of water, fines, caustic, flocculants, coagulants, sodium silicate, polymeric compounds, salts, solvents, brine, hydrocarbons, polymers, and hydrocarbons. Reconditioning fluid may include conditioning fluid such as, for example, a portion of the conditioning fluid.

[0048] "Reinjected sand" may comprise sand, clay, and silt that was previously within the reservoir, was produced from the reservoir and is now being reinjected into the reservoir. Reinjected sand may comprise any part of the reservoir. For example, the reinjected sand may comprise clay, fluid, etc., in a proportion that may be the same or different than the makeup of clay, fluid, etc. in the reservoir.

[0049] "Reinjection media" is media injected into the reservoir during secondary production and/or tertiary production, etc. The reinjection media may comprise, for example, at least one of water, clay, silt, sand, brine, salts, hydrocarbons, polymers, coagulants, flocculants, solvents, conditioning fluid, reconditioning fluid and injection media. The reinjection media may comprise a portion of the conditioning fluid, reconditioning fluid and/or injection media. The reinjection media may include the reinjected sand.

[0050] A "reservoir" or "subterranean reservoir" is a subsurface rock or sand formation from which a production fluid or resource can be harvested. The subsurface rock or sand formation may include sand, granite, silica, carbonates, clays, and organic matter, such as bitumen, heavy oil (e.g., bitumen), gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 meter (m)) to hundreds of feet (hundreds of meters).

[0051] "Reservoir pore pressure" is the pressure of fluids within pores of a reservoir at a given time. "Reservoir pore pressure" may be interchangeably referred to as "pore pressure."

[0052] A "Sand breakthrough indicator" refers to a way of detecting breakthrough. For example, a sand breakthrough indicator may refer to a way of detecting the end of primary production and/or secondary production at a given production well along a subsurface formation path that material travels from one or more injection wells to the given production well. More specifically, if there is one production well and four injection wells, the sand breakthrough indicator may detect when breakthrough occurs along the subsurface formation path from each of the four injection wells to the production well such that if breakthrough occurs first along the subsurface formation path from a first one of the four injection wells to the production well, the one of the four injection wells can be shut in while material continues to travel from the other of the three injection wells to the production well. This process may continue until breakthrough has occurred for all of the injection wells. The sand breakthrough indicator may comprise any suitable mechanism. For example, the sand breakthrough indicator may comprise periodically conducting a well test (e.g. once a week), taking a sample (e.g., of the well) every well test to detect the bitumen flow rate, or using a tracer in the injection media to indicate when injected media is produced into the production well. If the sand breakthrough indicator comprises taking the sample, the sand breakthrough indicator may also comprise one or more well tests and using the tracer media in the injection media. If the sand breakthrough indicator comprises one of these additional steps, the sand breakthrough indicator may determine where breakthrough occurs. Merely taking the sample may indicate that breakthrough has occurred but may not indicate where breakthrough has occurred; performing one of these additional steps may determine where the breakthrough has occurred. The bitumen concentration variation at the production well may also be used. The tracer may be radioactive, ferrous, or otherwise labeled.

[0053] "Secondary production," secondary recovery or secondary sweep is the second stage of hydrocarbon recovery. Secondary production occurs after primary production.

[0054] "Secondary sweep volume" is material produced from the reservoir during secondary recovery. Secondary sweep volume may refer to the volume of the reservoir produced during secondary production. For example, secondary sweep volume may refer to anywhere between 20 to 70% inclusive volume of the reservoir total volume within a subsurface formation path of the total volume of reservoir produced during secondary production within the subsurface formation path. The aforementioned range may include any number bounded by or within the preceding range. The secondary sweep volume may include some of the volume produced during primary production as this volume may be reinjected into the reservoir and produced during secondary production The secondary sweep volume may comprise at least one of heavy oil, sand, silt, clay, conditioning fluid, reconditioning fluid, and injection media. The secondary sweep volume may comprise a portion of the conditioning fluid. The secondary sweep volume may comprise a portion of the reconditioning fluid. The secondary sweep volume may comprise a portion of the injection media.

[0055] "Shut in" refers to a shut in injection well or a shut in production well. A well that is shut in no longer injects or produces material, but may still be utilized for reservoir monitoring. For example, the well may be used to monitor a pore pressure in a reservoir or for sampling material in the reservoir. "Shutting in" may interchangeably be used to refer to a well that is shut in.

[0056] "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. For example, the exact degree of deviation allowable may range anywhere from less than or equal to a 10% exact degree in deviation.

[0057] A "subsurface formation" refers to the material existing below the Earth's surface. The subsurface formation may interchangeably be referred to as a formation, subsurface or a subterranean formation. The subsurface formation may comprise a range of components, e.g. minerals such as quartz, siliceous materials such as sand and clays, as well as the oil and/or gas that is extracted.

[0058] A "subsurface formation path" refers to the path within a subsurface formation that portions of the reservoir within the subsurface formation could travel when the portions of the reservoir are, for example but not limited to, produced from the subsurface formation. For example, the subsurface formation path may refer to a path between one or more injection wells and production wells that portions of the reservoir may travel by injecting into the one or more injection well and producing from the one or more production well.

[0059] A "wellbore" is a hole or access path 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-section shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. 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.

[0060] "Well pattern" refers to a configuration of wells within a single pattern. Examples of well patterns include, but are not limited to, a line drive well pattern, a 4-spot well pattern, an inverted 4-spot well pattern, a 5-spot well pattern, an inverted 5-spot well pattern, a 7-spot well pattern, an inverted 7-spot well pattern, a 9-spot well pattern and an inverted 9-spot well pattern.

[0061] A "4-spot well pattern" refers to a standard 4-spot well pattern. A standard 4-spot well pattern includes 3 injection wells at corners of a triangle and a production well at the center of the triangle.

[0062] An "inverted 4-spot well pattern" refers to a standard inverted 4-spot well pattern. An inverted 4-spot well pattern includes 3 production wells at corners of a triangle and an injection well at the center of the triangle.

[0063] A "5-spot well pattern" refers to a standard 5-spot well pattern. A standard 5-spot well pattern includes 4 injection wells at corners of a square and a production well at the center of the square.

[0064] An "inverted 5-spot well pattern" refers to a standard inverted 5-spot well pattern. An inverted 5-spot well pattern includes 5 production wells at corners of a square and an injection well at the center of the square.

[0065] A "7-spot well pattern" refers to a standard 7-spot well pattern. A standard 7-spot well pattern includes 6 injection wells at corners of a hexagon and a production well at the center of the hexagon.

[0066] An "inverted 7-spot well pattern" refers to a standard inverted 7-spot well pattern. An inverted 7-spot well pattern includes 6 production wells at corners of a hexagon and an injection well at the center of the hexagon.

[0067] A "9-spot well pattern" refers to a standard 9-spot well pattern. A standard 9-spot well pattern includes 8 injection wells at corners and midpoints of the sides of a square and a production well at the center of the square.

[0068] An "inverted 9-spot well pattern" refers to a standard inverted 9-spot well pattern. An inverted 9-spot well pattern includes 9 production wells at corners and side midpoints of a square and an injection well at the center of the square.

[0069] "At least one," in reference to a list of one or more entities should be understood to mean at least one entity selected from any one or more of the entity in the list of entities, but not necessarily including at least one of each and every entity specifically listed within the list of entities and not excluding any combinations of entities in the list of entities. This definition also allows that entities may optionally be present other than the entities specifically identified within the list of entities to which the phrase "at least one" refers, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, "at least one of A and B" (or, equivalently, "at least one of A or B," or, equivalently "at least one of A and/or B") may refer, to at least one, optionally including more than one, A, with no B present (and optionally including entities other than B); to at least one, optionally including more than one, B, with no A present (and optionally including entities other than A); to at least one, optionally including more than one, A, and at least one, optionally including more than one, B (and optionally including other entities). In other words, the phrases "at least one," "one or more," and "and/or" are open-ended expressions that are both conjunctive and disjunctive in operation. For example, each of the expressions "at least one of A, B and C," "at least one of A, B, or C," "one or more of A, B, and C," "one or more of A, B, or C" and "A, B, and/or C" may mean A alone, B alone, C alone, A and B together, A and C together, B and C together, A, B and C together, and optionally any of the above in combination with at least one other entity.

[0070] Where two or more ranges are used, such as but not limited to 1 to 5 or 2 to 4, any number between or inclusive of these ranges is implied.

[0071] The articles "the", "a" and "an" are not necessarily limited to mean only one, but rather are inclusive and open ended so as to include, optionally, multiple such elements.

[0072] As depicted in Figures 1-5 and set forth above and below, the present disclosure relates to a system and method for recovering heavy oil, and more particularly to a system and method for enhancing the recovery of heavy oil. The sytem and method make it possible to reduce the amount of sand injected and/or reinjected into the subterranean formation that would be produced from a subterranean formation during secondary production if the primary production is run to breakthrough. The system and method make it possible to increase sweep efficiency. The system and method, therefore, enhance the recovery of heavy oil. The system and method enhance the recovery of heavy oil by ceasing production before breakthrough, shutting in one or more of at least one injection well and at least one production well after ceasing production before breakthrough, and recompleting one of one or more of the at least one production well as a recompleted injection well and recompleting one or more of the at least one injection well as a recompleted production well after ceasing production before breakthrough.

[0073] The system 100 and method 1000 may include at least one injection well 104 and at least one production well 106 (Figures 1 and 5). The at least one injection well 104 may just be referred to as an injection well for simplicity. The at least one production well 106 may just be referred to as a production well for simplicity. The at least one injection well 104 and the at least one production well 106 may access a reservoir 102 within a subsurface formation 124. The at least one injection well 104 and the at least one production well 106 may extend through an overburden 108 of the subsurface formation 124 to access the reservoir 102. The overburden 108 may be above the reservoir 102. The overburden 108 may be closer to the Earth's surface 112 than the reservoir 102. The reservoir 102 may be at depths greater than or equal to about 50 meters from the Earth's surface 112. The depths may include any number within or inclusive of the preceeding range.

[0074] The at least one injection well 104 may extend through the reservoir 102. The at least one injection well 104 may include one or more injection wells 104. For example, the at least one injection well may include one injection well, two injection wells, three injection wells, etc. The at least one injection well 104 may include any number of injection wells that is greater than or equal to one. The number of injection wells may include any number within and/or inclusive of the preceding range.

[0075] The at least one production well 106 may extend through the reservoir 102. The at least one production well 106 may include one or more production wells 106. For example, the at least one production well may include one production well, two production wells, three injection wells, etc. The at least one production well 106 may include any number of production wells that is greater than or equal to one. The number of production wells may include any number within and/or inclusive of the preceding range.

[0076] The at least one injection well 104 may be configured to receive a conditioning fluid from the surface to be injected into the reservoir 102. The at least one injection well 104 has a structure that enables it to receive the conditioning fluid. Examples of the structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The conditioning fluid travels in the at least one injection well 104 in a direction 122 toward the reservoir 102. The conditioning fluid may be fed to the reservoir 102.

[0077] When the conditioning fluid is injected into the at least one injection well 104, a reservoir pore pressure of the reservoir 102 may increase, 501 (Figure 5). In other words, increasing the reservoir pore pressure may include injecting the conditioning fluid into the reservoir 102. The conditioning fluid is injected at one or more locations within the subsurface formation. The conditioning fluid may be injected into any suitable location within the subsurface formation. The pressure caused by the injection of the conditioning fluid may allow the conditioning fluid to permeate through the portion of the reservoir 102 that contains hydrocarbons. As the conditioning fluid is injected, the reservoir pore pressure increases and may thereby alleviate and/or substantially balance the stresses on the reservoir 102 that are caused by the overburden stress. The pressure of the conditioning fluid may be sufficient to develop a substantially steady-state pressure profile within the portion of the reservoir 102 that contains hydrocarbons at the end of injecting the conditioning fluid.

[0078] When the conditioning fluid is injected into the at least one injection well 104, the porosity of the subsurface formation 124 may increase. The porosity of the subsurface formation 124 may increase because the reservoir 102 may comprise a sand particle network. The sand particle network may dilate or expand in volume as the effective stress due to the overburden stress is alleviated and/or substantially balanced by the increase in reservoir pore pressure. The increase in porosity may be accompanied by a decrease in the mechanical strength of the material within the reservoir 102 to a state where the material within the reservoir 102 may slide in a direction of the one or more production well when a pressure gradient is imposed due to the flow of a fluid from the one or more injection well to the one or more production well. Increasing the initial porosity of the subsurface formation 124 may increase the permeability of the subsurface formation 124.

[0079] The injection of the conditioning fluid into the at least one injection well 104 or the at least one production well 106 may be referred to as the conditioning process. In other words, the conditoning fluid may be injected into the at least one production well 106 during the conditioning process. When the conditioning fluid is injected into the at least one production well 106, the at least one production well 106 acts like an injection well in that it receives a fluid that is fed to the reservoir 102.

[0080] Injecting the conditioning fluid may comprise injecting the conditioning fluid via one or more of the at least one injection well 104 and the at least one production well 106. When the conditioning fluid is injected into the at least one injection well 104 and the at least one production well 106, the stresses on the reservoir 102 may be balanced more quickly than if the conditioning fluid is only injected into the at least one injection well 104.

[0081] The conditioning process may end once the effective stresses on the reservoir 102 due to the overburden stress are alleviated and/or substantially balanced by the increased reservoir pore pressure. Whether or not the effective stresses on the reservoir 102 due to overburden stress has been alleviated and/or substantially balanced may be determined, but is not limited to being determined, by comparing the bottom hole pressures in the at least one injection well, the at least one production well, and/or at least one observation well to an estimated applied overburden stress due to its weight. The observation well may be a well that allows for the observation of parameters, such as but not limited to fluid levels and pressure changes, of one or more of the at least one injection well and the at least one production well. The magnitude of the effective stress applied by the overburden to the reservoir (e.g., overburden stress minus the reservoir pore pressure) at the end of the conditioning process is generally small (generally in the range of 10 to 500 kilopascals (kPa) out of the 1 megapascal (MPa) to 10MPa effective overburden stress that would have existed before the conditioning process, where the aforementioned ranges may include any number bounded by and/or within the preceding ranges depending on a depth of the reservoir, an initial pore pressure of the reservoir, and/or in situ stresses of the reservoir, of which the overburden stress may be one component).

[0082] Once the conditioning process ends, a first differential pressure between the at least one injection well 104 and the at least one production well 106 may be created, 502 (Figure 5). Creating the first differential pressure may impose a pressure gradient. The creation of the first differential pressure between the at least one injection well 104 and the at least one production well 106 may cause water or brine to flow in the subsurface formation 124. The water or brine may create fluid drag forces on solids in the subsurface formation 124. Once the first differential pressure in a given portion of the subsurface formation 124 between the at least one injection well 104 and the at least one production well 106 increases to a point where it overcomes the friction holding the reservoir 102 in place, some of a primary sweep volume 130 may move toward the at least one production well 106. In other words, the first differential pressure may move or flow the subsurface formation 124 toward the at least one production well 106.

[0083] The first differential pressure may be created by continuing to inject the conditioning fluid into the at least one injection well 104 and by starting to produce primary sweep volume 130 from the at least one production well 106 (Figures 2a, 3a and 4a). The first differential pressure may be created after the conditioning process ends. The flow of the conditioning fluid, fluid within the subterranean formation and/or a portion of the primary sweep volume 130 into the at least one production well 106 may create the first differential pressure near the at least one production well 106.

[0084] The first differential pressure may be created by increasing a rate or pressure at the least one injection well 104. The rate or pressure may be increased such that it is higher than the rate or pressure used during the conditioning process.

[0085] Once the first differential pressure alleviates and/or substantially balances the overburden stress opposing the motion or sliding of the material within the reservoir, which have been reduced from the initial in situ values due to raising the pore pressure by injecting the conditioning fluid, the primary sweep volume 130 may be produced via one or more of the at least one production well 106. The primary sweep volume 130 produced may be the rest of the primary sweep volume 130 that was not produced while creating the first differential pressure. Producing the primary sweep volume 130 may comprise mobilizing the primary sweep volume 130 along a first subsurface formation path within the subsurface formation 124. The primary sweep volume 130 moves along the first subsurface formation path away from one or more of the at least one injection well 104 to the one or more of the at least one production well 106. The primary sweep volume 130 may be only a portion of the reservoir.

[0086] The primary sweep volume may be produced via one or more of the at least one production well 106, 503 (Figure 5). The one or more of the at least one production well 106 may be configured to produce primary sweep volume 130 from the subsurface formation 124. The one or more of the at least one production well 106 has a structure that enables it to produce the primary sweep volume 130. Examples of the structure may include, but are not limited to, an uncased wellbore or a cased wellbore with an opening or perforations that allow the primary sweep volume to flow into a well. The primary sweep volume 130 travels in a direction 114 away from the reservoir 102 and toward the surface 112.

[0087] After being produced via the one or more of the at least one production well 106, the primary sweep volume 130 may be fed to a pumping station 116. From the pumping station 116, the primary sweep volume 130 may be processed in a facility 118 to remove at least a portion of the hydrocarbons 120 within the primary sweep volume 130 that may then be sold. The hydrocarbons 120 can be sent to other facilities for refining or further processing such as but not limited to upgrading to produce upgraded hydrocarbons. The upgraded hydrocarbons may be sold. The hydrocarbons 120 may be combined with a diluent stream and then sent to other facilities and/or or sold. The portion of the primary sweep volume 130 not sent to the other facilities for refining or further processing may enter a pumping station 110.

[0088] After creating the first differential pressure and to produce the primary sweep volume 130 not produced while creating the first differential pressure, injection media may be injected into the at least one injection well 104, 504 (Figure 5). The at least one injection well 104 may be configured to receive the injection media. The at least one injection well 104 has a structure that enables it to receive the injection media and inject that media through an opening or perforations into the reservoir. Examples of structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The injection media received by the at least one injection well travels in the at least one injection well 104 in the direction 122. The injection media may be fed to the reservoir 102.

[0089] The injection media may be injected while producing the primary sweep volume 130 and after creating the first differential pressure. As the injection media is injected into the subsurface formation 124 via the at least one injection well 104, the primary sweep volume 130 is swept toward one or more of the at least one production well 106 via the first subsurface formation path to be produced from the one or more of the at least one production well 106. The injection media may fill the void that the produced primary sweep volume 130 left in the reservoir 102.

[0090] The system 100 and method 1000 may comprise ceasing injecting the injection media into the subsurface formation 124 before the injection media is produced by the at least one production well 106 and ceasing producing the primary sweep volume 130 from the subsurface formation before the injection media is produced by the at least one production well 106, 505 (Figure 5). The injection media may be injected into the subsurface formation 124 at the same time that the primary sweep volume is produced from the subsurface formation 124. In other words, injecting the injection media into the subsurface formation 124 and producing the primary sweep volume 130 from the subsurface formation may occur simultaneously. The system 100 and method 1000 may comprise ceasing injecting the injection media into the subsurface formation 124 before breakthrough occurs at the least one production well 106. The system 100 and method 1000 may comprise ceasing producing the primary sweep volume 130 from the subsurface formation before the injection media is produced. The system 100 and method 1000 may comprise ceasing injecting the injection media into the subsurface formation 124 before the end of primary production. The system 100 and method 1000 may comprise ceasing producing the primary sweep volume 130 from the subsurface formation before the end of primary production.

[0091] Ceasing injecting the injection media into the subsurface formation 124 and ceasing producing the primary sweep volume 130 from the subsurface formation 124 before the injection media is produced by the at least one production well 106 may comprise measuring an injection well pressure of one or more of the at least one injection well 104. Ceasing injecting the injection media into the subsurface formation 124 and ceasing producing the primary sweep volume 130 from the subsurface formation 124 before the injection media is produced by the at least one production well 106 may comprise measuring a production well pressure of one or more of the at least one production well 106.

[0092] Measuring the injection well pressure of one or more of the at least one injection well 104 may comprise using at least one pressure sensor 138 (Figure 1). Each of the at least one injection well 104 from which the injection well pressure is being measured may include the at least one pressure sensor 138. The at least one pressure sensor 138 may be any suitable sensor. The at least one pressure sensor 138 may be at any location within the at least one injection well 104. For example, the at least one pressure sensor 138 may be one of at the bottom of the at least one injection well 104 and/or the at least one pressure sensor 138 may be at the top of the at least one injection well 104. The injection well pressure measured by the at least one pressure sensor 138 may be outputted to any suitable device, such as but not limited to a computer.

[0093] Measuring the production well pressure of one or more of the at least one production well 106 may comprise using at least one pressure sensor 139 (Figure 1). Each of the at least one production well 106 from which the production well pressure is being measured may include the at least one pressure sensor 139. The at least one pressure sensor 139 may be any suitable sensor. The at least one pressure sensor 139 may be at any location within the at least one production well 106. For example, the at least one pressure sensor 139 may be one of at the bottom of the at least one production well 106 and/or the at least one pressure sensor 139 may be at the top of the at least one production well 106. The production well pressure measured by the at least one pressure sensor 139 may be outputted to any suitable device, such as but not limited to a computer.

[0094] Ceasing injecting the injection media into the subsurface formation 124 and ceasing producing the primary sweep volume 130 from the subsurface formation 124 before the injection media is produced by the at least one production well 106 may comprise determining a pressure differential between one of the at least one injection well 104 and one of the at least one production well 106 by comparing the injection well pressure of the one of the at least one injection well 104 to the production well pressure of the one of the at least one production well 106. Any suitable mechanism may determine the pressure differential. For example, a computer may determine the pressure differential. The suitable mechanism may determine the pressure differential by comparing the injection well pressure to the production well pressure to determine the difference between the injection well pressure and the production well pressure.

[0095] Ceasing injecting the injection media into the subsurface formation 124 and ceasing producing the primary sweep volume 130 from the subsurface formation 124 before the injection media is produced by the at least one production well 106 may comprise identifying a maximum pressure differential with respect to time and determining whether the pressure differential has decreased from a maximum pressure differential. More specifically, ceasing injecting the injection media into the subsurface formation 124 and ceasing producing the primary sweep volume 130 from the subsurface formation 124 before the injection media is produced may comprise injecting the injection media into the subsurface formation while determining the pressure differential between one of the at least one injection well 104 and one of the at least one production well 106. The pressure differential may be determined at different times while injecting the injection media into the subsurface formation 124. The pressure differential may be determined at different times while injecting the injection media until the pressure differential has decreased from the maximum pressure differential. Each pressure differential may be compared to the immediately preceding pressure differential to see whether the pressure differential is lower than the immediately preceding pressure differential.

[0096] Ceasing injecting the injection media into the subsurface formation 124 and ceasing producing the primary sweep volume 130 from the subsurface formation 124 before the injection media is produced by the at least one production well 106 may comprise continuing to inject the injection media into the subsurface formation 124 until the pressure differential has decreased from the maximum pressure differential. In other words, when the pressure differential compared to the immediately preceding pressure differential is greater than the immediately preceding pressure differential, the immediately preceding pressure differential is determined not to be the maximum pressure differential and injection of the injection media into the subsurface formation 124 and production of the primary sweep volume 130 from the subsurface formation 124 continues. The pressure differential may be determined as an instantaneous value or a time-averaged value over a specified time period. The immediately preceding pressure differential may be determined as an instantaneous value or a time-averaged value over a specified time period. When the pressure differential compared to the immediately preceding pressure differential is lower than the immediately preceding pressure differential, the immediately preceding pressure differential is determined to be the maximum pressure differential and injection of the injection media into the subsurface formation 124 ceases.

[0097] After ceasing to inject the injection media into the subsurface formation and ceasing to produce the primary sweep volume 130 from the subsurface formation, the reservoir pore pressure may be reduced. Reducing the reservoir pore pressure may allow the overburden stress to be at least partially reapplied to the reservoir 102, thereby recompacting at least a portion of the reservoir 102, reducing the porosity or increasing the mechanical stiffness of a portion of the sand matrix comprising the reservoir 102. One or more of the at least one injection well 104 and the at least one production well 106 may allow for this recompaction of the reservoir 102 by being wells for withdrawing fluids from the reservoir in order to lower the reservoir pore pressure. The reservoir pore pressure may be reduced by ceasing the injection of the injection media into the at least one injection well 104. The reservoir pore pressure may be reduced by ceasing production of all but fluid (e.g., preferentially only producing the fluid) through the one or more of the at least one production well 106. The reservoir pore pressure may be reduced by ceasing injection of injection media into the at least one injection well 104 and allowing the reservoir pore pressure to drop due to leak off or equilibration of the reservoir pore pressure. The reservoir pore pressure may be reduced by ceasing injection of injection media into the at least one injection well 104 and by ceasing production of the primary sweep volume 130 by the at least one production well 106 and allowing the reservoir pore pressure to drop due to leak off or requilibration of the reservoir pore pressure. The reservoir pore pressure leaks off into one or more portions of the reservoir that are not being targeted for production.

[0098] Reducing the reservoir pore pressure to recompact at least the portion of the reservoir 102 may seal the first subsurface formation path, which is beneficial. Sealing the first subsurface formation path after the hydrocarbons are produced during for example, primary production, will promote production from the reservoir along other subsurface formation paths (e.g. where production has not yet occured). Sealing the first subsurface formation path helps make it possible to produce a portion of the reservoir 102 that was not previously produced, thereby helping make it possible to enhance heavy oil recovery. The process of reducing the reservoir pore pressure may be referred to as a recompaction process.

[0099] While producing the primary sweep volume 130 and/or injecting the injection media, the reservoir pore pressure may be reduced. This reduction may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the injection media includes too much water. When the injection media includes too much water, the primary sweep volume 130 may not be able to be mobilized or only a portion of the primary sweep volume 130 may be mobilized with a portion of the injection media bypassing the primary sweep volume 130. When the primary sweep volume is not able to be mobilized or only a portion of the primary sweep volume 130 is mobilized, the reservoir pore pressure may be reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompaction process. After recompacting the subsurface formation, injection media may again be injected so that primary sweep volume 130 may be produced.

[0100] While producing the primary sweep volume 130 and/or injecting the injection media, the reservoir pore pressure may be increased. This increase may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the reservoir pore pressure has not been increased enough to mobilize the primary sweep volume 130 when the injection media is injected. The reservoir pore pressure may not be increased enough if the conditioning process ends before the effective stresses on the reservoir 102, due to the overburden stress, are alleviated and/or substantially balanced by the increased reservoir pore pressure. The reservoir pore pressure may be increased in a similar manner to how the reservoir pore pressure is increased during the previously described conditioning process. Increasing the reservoir pore pressure may be stopped when it appears that the the effective stresses on the reservoir 102, due to the overburden stress, have been alleviated and/or substantially balanced by the increased reservoir pore pressure. After increasing the reservoir pore pressure has stopped, injection media may again be injected so that primary sweep volume 130 may be produced.

[0101] While producing the primary sweep volume 130 and/or injecting the injection media, the reservoir pore pressure may be reduced and then increased. This reduction and increase may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the injection media includes too much water, so the reservoir pore pressure is reduced in a manner similar to how previously described, and then the reservoir pore pressure is not high enough for the primary sweep volume 130 to be mobilized, so the reservoir pore pressure is increased in a similar manner to how the reservoir pore pressure is increased during the previously described conditioning process. After the reduction and increase stops, injection media may again be injected so that primary sweep volume 130 may be produced.

[0102] While producing the primary sweep volume 130 and/or injecting the injection media, the reservoir pore pressure may be increased and then reduced. This increase and reduction may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the reservoir pore pressure is not high enough for the primary sweep volume 130 to be mobilized, so the reservoir pore pressure is increased in a similar manner to how the reservoir pore pressure is increased during the previously described conditioning process, and then the injection media includes too much water, so the reservoir pore pressure is reduced in a manner similar to how previously described. After the increase and reduction stops, injection media may again be injected so that primary sweep volume 130 may be produced.

[0103] After the injection media ceases being injected into the subsurface formation 124 and the primary sweep volume 130 ceases being produced from the subsurface formation 124, the system 100 and method 1000 may comprise shutting in one or more of the at least one injection well 104 and the at least one production well 106, 506 (Figure 5). In other words, after the injection media ceases being injected into the subsurface formation 124 and the primary sweep volume 130 ceases being produced from the subsurface formation 124, the system 100 and method 1000 may comprise shutting in one or more of the at least one injection well 104 or shutting in one or more of the at least one production well 106.

[0104] After the injection media ceases being injected into the subsurface formation 124 and the primary sweep volume 130 ceases being produced from the subsurface formation 124, the system 100 and method 1000 may comprise one of recompleting one or more of the at least one production well 106 as a recompleted injection well 105 and recompleting one or more of the at least one injection well 104 as a recompleted production well 107, 507 (Figure 5). In other words, after the injection media ceases being injected into the subsurface formation 124 and the primary sweep volume 130 ceases being produced from the subsurface formation 124, the system 100 and method 1000 may comprise recompleting one or more of the at least one production well 106 as a recompleted injection well 105 or recompleting one or more of the at least one injection well 104 as a recompleted production well 107. The system 100 and method 1000 may comprise recompleting one or more of the at least one production well 106 as a recompleted injection well 105 if the system 100 and method 1000 comprises shutting in one or more of the at least one injection well 104. The system 100 and method 1000 may comprise recompleting one or more of the at least one injection well 104 as a recompleted production well 107 if the system 100 and method 1000 comprises shutting in one or more of the at least one production well 106. The system 100 and method 1000 may comprise one of recompleting one or more of the at least one production well 106 as a recompleted injection well 105 and recompleting one or more of the at least one injection well 104 as a recompleted production well 107 before, after or while shutting in one of one or more of the at least one injection well 104 and the at least one production well 106.

[0105] After one of recompleting one or more of the at least one production well 106 as a recompleted injection well 105 and recompleting one or more of the at least one injection well 104 as a recompleted production well 107, the system 100 and method 1000 may comprise injecting a reinjection media into the subsurface formation 124 via one or more of the at least one injection well 104 and the at least one recompleted injection well 105. The at least one recompleted injection well 105 and/or the one or more of the at least one injection well 104 has a structure that enables it to receive the reinjection media and inject that media through an opening or perforations into the reservoir. Examples of structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The reinjection media received by the at least one recompleted injection well 105 and/or the one or more of the at least one injection well 104 travels in the at least one recompleted injection well 105 or the one or more of the at least one injection well 104 in a direction. The reinjection media may be fed to the reservoir 102.

[0106] The reinjection media may be injected into the subsurface formation 124 via the at least one recompleted injection well 105 and/or the one or more of the at least one injection well 104 until the reinjection media is produced by the at least one recompleted production well 107 and/or the one or more of the at least one production well 106. Specifically, the reinjection media may be injected into the subsurface formation 124 until breakthrough occurs at the at least one recompleted production well 107 and/or the one or more of the at least one production well 106. The reinjection media being produced by the at least one recompleted production well 107 or the one or more of the at least one production well 106 marks the end of secondary production when the reinjection media being produced comprises the reinjected sand. The reinjected sand may start to be produced from the at least one recompleted production well 107 and/or the one or more of the at least one production well 106 when a portion of the reinjected sand reaches the at least one recompleted production well 107 and/or the one or more of the at least one production well 106, when the reinjected sand is travelling through the at least one recompleted production well 107 and/or the one or more of the at least one production well 106, when the reinjected sand is exiting the at least one recompleted production well 107 and/or the one or more of the at least one production well 106, or when the reinjected sand is moving through the surface processing facility 118.

[0107] The actual determination of when to stop injecting reinjection media via any of the at least one recompleted injection well 105 and/or the one or more of the at least one injection well

104 into the subsurface formation 124, because the reinjection media is being produced by the at least one recompleted production well 107 or the one or more of the at least one production well 106, may be determined by the sand breakthrough indicator.

[0108] After one of recompleting one or more of the at least one production well 106 as a recompleted injection well 105 and recompleting one or more of the at least one injection well 104 as a recompleted production well 107, the system 100 and method 1000 may comprise producing a secondary sweep volume 131 (Figures 2b, 3b and 4b) from the subsurface formation 124 via one or more of the at least one production well 106 and the at least one recompleted production well 107. The one or more of the at least one recompleted production well 107 and the at least one production well 106 may be configured to produce the secondary sweep volume 131 from the subsurface formation 124. The one or more of the at least one production well 106 and/or the at least one recompleted production well 107 may each have a structure that enable them to produce the secondary sweep volume 131. Examples of structure may include, but are not limited to, a caseless wellbore or a cased wellbore. The secondary sweep volume 131 travels in a direction 114 away from the reservoir 102 and toward the surface 112 such that a secondary sweep volume may be swept in a second subsurface formation path (Figure 1).

[0109] Injecting the reinjection media may result in the production of the secondary sweep volume 131. Producing the secondary sweep volume 131 may comprise mobilizing the secondary sweep 131 volume along a second subsurface formation path within the subsurface formation 124. The secondary sweep volume 131 may start to be produced some time after the reinjection media starts being injected. Once the secondary sweep volume 131 starts being produced, the secondary sweep volume 131 may be produced at the same time that the reinjection media is injected. As the reinjection media is injected into the subsurface formation 124, the secondary sweep volume 131 may be swept toward one or more of the at least one recompleted production well 107 and/or the one or more of the at least one production well 106 via a second subsurface formation path. The reinjection media may fill the void that the produced secondary sweep volume 131 leaves in the reservoir 102.

[0110] The second subsurface formation path may be different from the first subsurface formation path. When the second subsurface formation path is different from the first subsurface formation path, the recovery of heavy oil may be enhanced because a different portion of the reservoir 102 may be swept. The swept portion of the second subsurface formation path is the secondary sweep volume 131 that may be produced. The second subsurface formation path may be different from the first subsurface formation path because the subsurface formation 124 may undergo the recompaction after the primary sweep volume 130 is produced. The recompaction helps provide an alternative path for reinjection media to enter the subsurface formation 124 and for secondary sweep volume to be produced from the subsurface formation 124 so that a portion of the reservoir 102 not produced during primary production can be swept and produced. The secondary sweep volume 131 may only be a portion of the reservoir.

[0111] After being produced via the one or more of the at least one recompleted production well 107 and the at least one production well 106, the secondary sweep volume may be fed to a pumping station 116. From the pumping station 116, the secondary sweep volume may be processed in a facility 118 to remove at least a portion of the hydrocarbons 120 within the secondary sweep volume, which may then be sold. The hydrocarbons 120 can be sent to other facilities for refining or further processing, such as but not limited to for upgrading to produce upgraded hydrocarbons. The upgraded hydrocarbons may be sold. The hydrocarbons 120 may be combined with a diluent stream and then sent to other facilities and/or sold. The portion of the secondary sweep volume not sent to the other facilities for refining or further processing may enter a pumping station 110.

[0112] While producing the secondary sweep volume and/or injecting the reinjection media, the reservoir pore pressure may be reduced. This reduction may occur during a process upset. One example of a process upset includes, but is not limited to, when the reinjection media includes too much water. When the reinjection media includes too much water, the secondary sweep volume may not be able to be mobilized or only a portion of the secondary sweep volume may be mobilized with a portion of the reinjection media bypassing the the secondary sweep volume. When the secondary sweep volume is not able to be mobilized or only a portion of the secondary sweep volume is mobilized, the reservoir pore pressure may be reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompaction process. After recompacting the subsurface formation, reinjection media may again be injected so that secondary sweep volume may be produced.

[0113] While producing the secondary sweep volume and/or injecting the reinjection media, the reservoir pore pressure may be increased. This increase may occur during a process upset. One example of a process upset includes, but is not limited to, when the reservoir pore pressure has not been increased enough to mobilize the secondary sweep volume when the reinjection media is injected. The reservoir pore pressure may not be increased enough if the reconditioning process ends before the effective stresses on the reservoir 102, due to the overburden stress, are alleviated and/or substantially balanced by the increased reservoir pore pressure. The reservoir pore pressure may be increased in a similar manner to how the reservoir pore pressure is increased during the previously described reconditioning process. Increasing the reservoir pore pressure may be stopped when it appears that the the effective stresses on the reservoir 102, due to the overburden stress, have been alleviated and/or substantially balanced by the increased reservoir pore pressure. After increasing the reservoir pore pressure has stopped, reinjection media may again be injected so that secondary sweep volume may be produced.

[0114] While producing the secondary sweep volume and/or injecting the reinjection media, the reservoir pore pressure may be reduced and then increased. This reduction and increase may occur during a process upset. One example of a process upset includes, but is not limited to, when the reinjection media includes too much water, so the reservoir pore pressure is reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompaction process, and then the reservoir pore pressure is not high enough for the secondary sweep volume to be mobilized, so the reservoir pore pressure is increased in a similar manner to how the reservoir pore pressure is increased during the previously described reconditioning process. After the reduction and increase stops, reinjection media may again be injected so that secondary sweep volume may be produced.

[0115] While producing the primary sweep volume and/or injecting the reinjection media, the reservoir pore pressure may be increased and then reduced. This increase and reduction may occur during a process upset. One example of a process upset includes, but is not limited to, when the reservoir pore pressure is not high enough for the secondary sweep volume to be mobilized, so the reservoir pore pressure is increased in a similar manner to how the reservoir pore pressure is increased during the previously described reconditioning process, and then the reinjection media includes too much water, so the reservoir pore pressure is reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompaction process. After the increase and reduction stops, reinjection media may again be injected so that secondary sweep volume may be produced.

[0116] Figures 2a-4b show specific examples of some of the above description. Figures 2a-2b show inverted seven-spot well patterns. Figures 2a-2b are diagrams of the use of a slurrified reservoir hydrocarbon recovery process during primary production and secondary production, respectively. Figures 3a-3b show seven-spot well patterns. Figures 3a-3b are diagrams of the use of a slurrified reservoir hydrocarbon recovery process during primary production and secondary production, respectively. Figures 4a-4b show an inverted five-spot well patterns. Figures 4a-4b are diagrams of the use of a slurrified reservoir hydrocarbon recovery process during primary production and secondary production, respectively.

[0117] Figure 2a shows use of a slurrified reservoir hydrocarbon recovery process during primary production. As shown in Figure 2a, each inverted seven-spot well pattern includes a center injection well 104 surrounded by six production wells 106. Figure 2a shows seven inverted seven-spot well patterns but there may be any number of well patterns within a slurrified reservoir hydrocarbon recovery process having multiple inverted seven-spot well patterns. The seven inverted seven-spot well patterns in Figure 2a may be referred to as a first well pattern, a second well pattern, a third well pattern, a fourth well pattern, a fifth well pattern, a sixth well pattern and a seventh well pattern. During primary production, the center injection well 104 within each inverted seven-spot well pattern receives injection media while each production well 106 within each inverted seven-spot well pattern receives and produces primary sweep volume. Injection media ceases being injected into the injection well 104 within each inverted seven-spot well pattern before the injection media is produced by the production wells 106 within each inverted seven-spot well pattern. Primary sweep volume 130 ceases being produced from the subsurface formation 124 before the injection media is produced.

[0118] Figure 2b shows use of a slurrified reservoir hydrocarbon recovery process during secondary production. As shown in Figure 2b, the injection well 104 of each inverted seven-spot well pattern is shut-in 204. The injection well 104 of each inverted seven-spot well pattern is shut-in 204 after ceasing injecting the injection media and ceasing producing primary sweep volume 130. As shown in Figure 2b, every other production well 106 in each inverted seven-spot well pattern is recompleted as a recompleted injection well 105. Every other production well 106 in each inverted seven-spot well pattern is recompleted as a recompleted injection well 105 after ceasing injecting the injection media and ceasing producing the primary sweep volume 130. As a result, each inverted seven-spot well pattern contains three production wells 106 and three recompleted injection wells 105 after ceasing injecting the injection media and ceasing producing the primary sweep volume 130. During secondary production, therefore, reinjection media is injected into the subsurface formation via the three recompleted injection wells 105 in each inverted seven-spot well pattern and secondary sweep volume 131 is produced from the three production wells 106 in each inverted seven-spot well pattern. The reinjection media may be injected into the subsurface formation via the three recompleted injection wells 105 until the reinjection media is produced from one or more of the three production wells 106. The secondary sweep volume 131 of each of the inverted seven-spot well patterns is shown to be along the edge of each of the inverted seven-spot well patterns.

[0119] Figure 3a shows use of a slurrified hydrocarbon recovery process during primary production. As shown in Figure 3a, each seven-spot well pattern includes a center production well 106 surrounded by six injection wells 104. Figure 3a shows seven seven-spot well patterns but there may be any number of well patterns within a slurrified reservoir hydrocarbon recovery process having multiple seven-spot well patterns. The seven seven-spot well patterns in Figure 3a may be referred to as a first well pattern, a second well pattern, a third well pattern, a fourth well pattern, a fifth well pattern, a sixth well pattern and a seventh well pattern. During primary production, the six injection wells 104 surrounding the center production well 106 of each seven-spot well pattern receive injection media while the center production well 106 receives and produces primary sweep volume. Injection media ceases being injected into each injection well 104 within each seven-spot well pattern before the injection media is produced by the production well 106 within each seven-spot well pattern. Primary sweep volume 130 ceases being produced from the subsurface formation 124 before the injection media is produced.

[0120] Figure 3b shows use of a slurrifed hydrocarbon recovery process during secondary production. As shown in Figure 3b, the production well 106 of each seven-spot well pattern is shut-in 204. The production well 106 of each seven-spot well pattern is shut-in 204 after ceasing injecting the injection media and ceasing producing primary sweep volume 130. As shown in Figure 2b, every other injection well 104 in each seven-spot well pattern is recompleted as a recompleted production well 107. Every other injection well 104 in each seven-spot well pattern is recompleted as a recompleted production well 107 after ceasing injecting the injection media and ceasing producing the primary sweep volume 130. As a result, each seven-spot well pattern contains three injection wells 104 and three recompleted production wells 107 after ceasing injecting the injection media and ceasing producing the primary sweep volume 130. During secondary production, therefore, reinjection media is injected into the subsurface formation via the injection wells 104 in each seven-spot well pattern and secondary sweep volume 131 is produced from the three recompleted production wells 107 in each seven-spot well pattern. The reinjection media may be injected into the subsurface formation via the injection wells 104 until the reinjection media is produced from one or more of the three recompleted production wells 107. The secondary sweep volume 131 of each of the seven-spot well patterns is shown to be along the edge of each of the seven-spot well patterns.

[0121] Figure 4a shows use of a slurrified hydrocarbon recovery process during primary production. As shown in Figure 4a, each inverted five-spot well pattern includes a center injection well 104 surrounded by four production wells 106. Figure 4a shows four inverted five-spot well patterns but there may be any number of well patterns within a slurrified reservoir hydrocarbon recovery process having multiple inverted five-spot well patterns. The four inverted seven-spot well patterns in Figure 4a may be referred to as a first well pattern, a second well pattern, a third well pattern and a fourth well pattern. During primary production, the center injection well 104 within each inverted five-spot well pattern receives injection media while each production well 106 within each inverted five-spot well pattern receives and produces primary sweep volume. Injection media ceases being injected into the injection well 104 within each inverted five-spot well pattern before the injection media is produced by the production wells 106 within each inverted five-spot well pattern. Primary sweep volume 130 ceases being produced from the subsurface formation 124 before the injection media is produced.

[0122] Figure 4b shows use of a slurrified hydrocarbon recovery process during secondary production. As shown in Figure 4b, the production well 106 of each inverted five-spot well pattern is shut-in 204. The production well 106 of each inverted five-spot well pattern is shut-in 204 after ceasing injecting the injection media and ceasing producing primary sweep volume 130. As shown in Figure 4b, every other injection well 104 in each inverted five-spot well pattern is recompleted as a recompleted production well 107. Every other injection well 104 in each inverted five-spot well pattern is recompleted as a recompleted production well 107 after ceasing injecting the injection media and ceasing producing the primary sweep volume 130. As a result, each inverted five-spot well pattern contains four shut-in wells 204 and every other inverted five-spot well pattern contains an injection well 104 or a recompleted production well

107. During secondary production, therefore, reinjection media is injected into the subsurface formation via the injection well 104 in every other inverted five-spot well pattern and secondary sweep volume 131 is produced from the recompleted production well 107 in every other inverted five-spot well pattern. The reinjection media may be injected into the subsurface formation via the every other injection well 104 until the reinjection media is produced from the every other recompleted production well 107.

[0123] The configuration shown in Figures 2a-2b may be preferred to that shown in Figures 3a-3b because more primary sweep volume may be produced in the configuration shown in Figures 2a-2b than in that shown in Figures 3a-3b. In general, inverted well patterns (e.g., inverted five-spot well pattern, inverted seven-spot well pattern) may be preferred to well patterns that are not inverted (e.g., five-spot well pattern, seven-spot well pattern) when the injection well of each inverted well-pattern is shut-in and every other production well 106 of each inverted well-pattern is recompleted as a production well during secondary production because more primary sweep volume 130 may be produced than when this is not the case, such as shown in Figures 3a-4b. The configuration shown in Figures 2a-2b may be preferred to that shown in Figures 4a-4b because more secondary sweep volume may be produced in an inverted well-pattern where the injection well of each inverted well-pattern is shut-in and every other production well 106 of each inverted well-pattern is recompleted as a production well during secondary production, such as shown in Figures 2a-2b, than in an inverted well-pattern where all production wells 106 are shut-in and every other injection well 104 is recompleted as a recompleted production well 107 during secondary production, such as shown in Figures 4a-4b.

[0124] As illustrated in the examples depicted in Figures 2a-4b, one of recompleting one or more of the at least one production well 106 as a recompleted injection well 105 and recompleting one or more of the at least one injection well 104 as a recompleted production well 107 may comprise recompleting one or more of the at least one production well 106 in at least one of a first well pattern and a second well pattern as the recompleted injection well 105 or recompleting one or more of the at least one injection well 104 in at least one of a first well pattern and a second well pattern as the recompleted production well 107. As illustrated in the examples depicted in Figures 2a-4b, the first well pattern, the second well pattern, etc. may be any of a number of well patterns. For example, the first well pattern and the second well pattern may comprise one of a line-drive well pattern, a four-spot well pattern, an inverted four-spot well pattern, a five-spot well pattern, an inverted five-spot well pattern, a seven-spot pattern, an inverted seven-spot pattern, a nine-spot pattern and an inverted nine-spot pattern.

[0125] As illustrated in the examples depicted in Figures 2a-4b, shutting in one or more of the at least one injection well 104 and the at least one production well 106 may comprise shutting in one or more of the at least one injection well 104 or one or more of the at least one production well 106. For example, as shown in Figure 2b, shutting in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the injection well 104 in each well pattern; as shown in Figure 3b, shutting in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the production well 106 in each well pattern; as shown in Figure 4b, in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the production wells in each well pattern. Shutting in one or more of the at least one injection well 104 and the at least one production well 106 may comprise shutting in the injection wells in each pattern (not shown).

[0126] If shutting in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the injection well 104 in each pattern than recompleting the one or more of the at least one injection well 104 and the at least one production well 106 may comprise recompleting every other production well 106 in a pattern as a recompleted injection well 105 (Figures 2a-2b). If shutting in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the injection wells 104 in each pattern than recompleting the one or more of the at least one injection well 104 and the at least one production well 106 may comprise recompleting every other production well 106 as a recompleted injection well 107 where the production wells 106 and recompleted injection wells 107 are in a plurality of well patterns (not shown). If shutting in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the production well 106 in each pattern than recompleting the one or more of the at least one injection well 104 and the at least one production well 106 may comprise recompleting every other injection well 104 in a pattern as a recompleted production well 107 (Figures 3a-3b). If shutting in one or more of the at least one injection well 104 and the at least one production well 106 comprises shutting in the production wells 106 in each pattern than recompleting the one or more of the at least one injection well 104 and the at least one production well 106 may comprise recompleting every other injection well 104 as a recompleted production well 105 where the injection wells 104 and the recompleted production wells 107 are in a plurality of well patterns (Figures 4a-4b).

[0127] All of the above steps may be performed at a first elevation or depth first and then, after all the steps are completed, the above steps may be performed at a second elevation or depth. The second elevation may be above the first elevation. In other words, the second elevation may be closer to the Earth's surface than the first elevation. The second elevation may be farther from the Earth's surface than the first elevation; the first elevation may be closer to the Earth's surface than the second elevation. It may be advantageous to perform at a first elevation first and then a second elevation to increase the total production for a given set of wells. After performing the above steps at a second elevation, the steps could be performed at a third elevation and so on.

[0128] While the above steps discuss only primary production and secondary production, additional productions may be performed. For example, tertiary production may be performed. While the above steps discuss only one cycle of primary production and/or secondary production within primary production and secondary production, each production may include more than one cycle of primary production and/or secondary production. One of the cycles or tertiary production may include, but is not limited to, shutting in at least one production well used during primary production, converting the shut-in well during secondary production to an injection well and producing from the at least one production well and/or recompleted production well.

[0129] It is important to note that the steps depicted in Figure 5 are provided for illustrative purposes only and a particular step may not be required to perform the inventive methodology. The claims, and only the claims, define the inventive system and methodology.

[0130] Disclosed aspects may be used in hydrocarbon management activities. As used herein, "hydrocarbon management" or "managing hydrocarbons" includes hydrocarbon extraction, hydrocarbon production, hydrocarbon exploration, identifying potential hydrocarbon resources, identifying well locations, determining well injection and/or extraction rates, identifying reservoir connectivity, acquiring, disposing of and/ or abandoning hydrocarbon resources, reviewing prior hydrocarbon management decisions, and any other hydrocarbon-related acts or activities. The term "hydrocarbon management" is also used for the injection or storage of hydrocarbons or CO2, for example the sequestration of CO2, such as reservoir evaluation, development planning, and reservoir management. The disclosed methodologies and techniques may be used to extract hydrocarbons from a subsurface region. Hydrocarbon extraction may be conducted to remove hydrocarbons from the subsurface region, which may be accomplished by drilling a well using oil drilling equipment. The equipment and techniques used to drill a well and/or extract the hydrocarbons are well known by those skilled in the relevant art. Other hydrocarbon extraction activities and, more generally, other hydrocarbon management activities, may be performed according to known principles.

[0131] The system and method discussed above are different from waste injection. In the system and method discussed above, the goal is to displace the reservoir itself. In other words, in the system and method discussed above, the goal is to produce the reservoir itself, which includes producing hydrocarbons within the reservoir as well as other components, such as but not limited to sand, within a reservoir. The reservoir is produced by displacing the reservoir with injection media and/or reinjection media. In waste injection, the injection media does not displace the reservoir, but is rather injected into the reservoir with no accompanied production.

[0132] The system and method discussed above are different from hydrocarbons waterflooding. In waterflooding, water may be injected into the subsurface to cause a pressure differential between sets of injection wells and production wells to aid in the production of hydrocarbons from the production wells. Waterflooding is generally a "secondary" or "enhanced" hydrocarbons recovery concept as it increases the pressure in the reservoir locally to drive more hydrocarbons out of the reservoir through creation of a pressure differential between sets of injection wells or production wells.

[0133] The basic physics that govern waterflooding are the flow of fluids through a porous and/or permeable media. The physics of flow through porous and/or permeable media show that the pressures between injection wells and production wells is governed by the rate at which fluids are injected and produced and the mobility of those fluids through the porous and/or permeable media. That mobility is controlled by the permeability of the media divided by the viscosity of the fluid flowing in the media. Thus for the single media (i.e. single permeability), water with it viscosity of 1 (centipoise) cP will have a higher mobility than hydrocarbons which generally have a higher to much higher viscosity than water (generally 5-500 cP). It is this physics that dictates that when the injected fluid (most often water) "breaks through" to a production well during a waterflood, the production rate of hydrocarbons drops dramatically due both to the higher mobility of the water versus the hydrocarbons and to the drop in pressure differential between injection wells and production wells due to the ease for water now to flow between the injection wells and production wells. This break through of water may substantially decrease the effectiveness of an injection well to aid in the production of hydrocarbons from production wells in the area as for the same injection rate, as its injection pressure now is much lower and thus its pressure differential even with non-break through production wells is much less.

[0134] The system and method described above involve the flow of the porous and/or permeable media itself as opposed to the flow of fluids through a porous and/or permeable media. The flow of fluid relative to the porous and/or permeable media exerts a drag. When the drag balances or overcomes the frictional stresses holding the porous and/or permeable media in the reservoir in place, the reservoir will begin to flow. When the reservoir flows, the pressure differential is proportional to the frictional stresses rather than being proportional to the flow rate of fluid as it is in waterflood. This completely changes the physics of the process from that of waterflooding. As the pressure differential is proportional to the frictional stresses opposing the flow of the reservoir, it is also proportional to those stresses normal to the direction of flow. Those normal stresses are the effective overburden stresses applied to that porous and/or permeable media. The effective overburden stresses applied to the porous and/or permeable media are inversely proportional to the pore pressure. During reservoir flow, the effective overburden stresses applied to both the flowing and nonflowing porous and/or permeable media evolve and vary. This is different from waterflooding where production is fairly independent of stresses and stress evolution. The effective overburden stress in the system and method described above may impact the pressure gradient needed to flow the porous and/or permeable media between the wells. Specifically, for a given portion of porous and/or permeable media, the higher the effective overburden stress – the higher the required pressure differential for reservoir flow. If the overall pressure differential is dominated by the flow of porous and/or permeable media via a low stress path, the higher stressed porous and/or permeable media will not flow.

[0135] The different physics of fluid flow with porous and/or permeable media flow envisioned for the system and method described above relative to waterflooding makes it extremely unlikely that one of ordinary skill in the art of flow through porous and/or permeable media would extrapolate waterflooding to the flow of porous and/or permeable media as described for the above system and method.

[0136] It should be noted that the orientation of various elements may differ, and that such variations are intended to be encompassed by the present disclosure. It is recognized that features of the disclosure may be incorporated into other examples.

[0137] It should be understood that the preceding is merely a detailed description of this disclosure and that numerous changes, modifications, and alternatives can be made in accordance with the disclosure here without departing from the scope of the disclosure. The preceding description, therefore, is not meant to limit the scope of the disclosure. Rather, the scope of the disclosure is to be determined only by the appended claims and their equivalents. It is also contemplated that structures and features embodied in the present examples can be altered, rearranged, substituted, deleted, duplicated, combined, or added to each other.

CLAIMS:

1. A method for enhancing recovery of heavy oil from a reservoir within a subsurface formation, comprising:

(a) increasing a reservoir pore pressure of the reservoir, then;

(b) creating a first differential pressure between at least one injection well and at least one production well within the subsurface formation, then;

(c) producing primary sweep volume from the subsurface formation via one or more of the at least one production well;

(d) injecting an injection media into the subsurface formation via one or more of the at least one injection well, then;

(e) ceasing injecting the injection media before the injection media is produced by the at least one production well and ceasing producing primary sweep volume from the subsurface formation before the injection media is produced, then;

(f) shutting in one or more of the at least one injection well and the at least one production well; and

(g) one of recompleting one or more of the at least one production well as a recompleted injection well and recompleting one or more of the at least one injection well as a recompleted production well.

2. The method of claim 1, wherein increasing the reservoir pore pressure in (a) further comprises injecting a conditioning fluid into the reservoir at one or more locations within the subsurface formation.

3. The method of claim 2, wherein injecting the conditioning fluid comprises injecting the conditioning fluid via one or more of the at least one injection well and the at least one production well.

4. The method of claim 1, wherein (c) and (d) occur simultaneously.

5. The method of claim 1, further comprising during at least one of (c) and (d), one of reducing the reservoir pore pressure, increasing the reservoir pore pressure, reducing the reservoir pore

pressure and then increasing the reservoir pore pressure, and increasing the reservoir pore pressure and then increasing the reservoir pore pressure.

6. The method of claim 1, wherein (c) comprises mobilizing the primary sweep volume along a first subsurface formation path within the subsurface formation.

7. The method of claim 1, wherein (f) occurs before (g).

8. The method of claim 1, wherein (g) comprises recompleting one or more of the at least one production well in at least one of a first well pattern and a second well pattern as the recompleted injection well.

9. The method of claim 1, wherein (g) comprises recompleting one or more of the at least one injection well in at least one of a first well pattern and a second well pattern as the recompleted production well.

10. The method of claim 1, wherein (f) comprise shutting in the one or more of the at least one injection well and (g) comprises recompleting the one or more of the at least one production well as the recompleted injection well.

11. The method of claim 1, wherein (f) comprises shutting in the one or more of the at least one production well and (g) comprises recompleting the one or more of the at least one injection well as the recompleted production well.

12. The method of claim 1, further comprising (h) injecting a reinjection media into the subsurface formation via one or more of the at least one recompleted injection well.

13. The method of claim 1, further comprising (i) producing secondary sweep volume from the subsurface formation via one or more of the at least one production well.

14. The method of claim 1, wherein (i) comprises mobilizing the secondary sweep volume along a second subsurface formation path within the subsurface formation that is different from a first subsurface formation path within the subsurface formation.

15. The method of claim 14, further comprising during (i), one of reducing the reservoir pore pressure, increasing the reservoir pore pressure, and reducing the reservoir pore pressure and then increasing the reservoir pore pressure, and increasing the reservoir pore pressure and then increasing the reservoir pore pressure.

16. The method of claim 13, further comprising first performing steps (a) through (i) at a first elevation and then performing steps (a) through (i) at a second elevation that is above the first elevation.

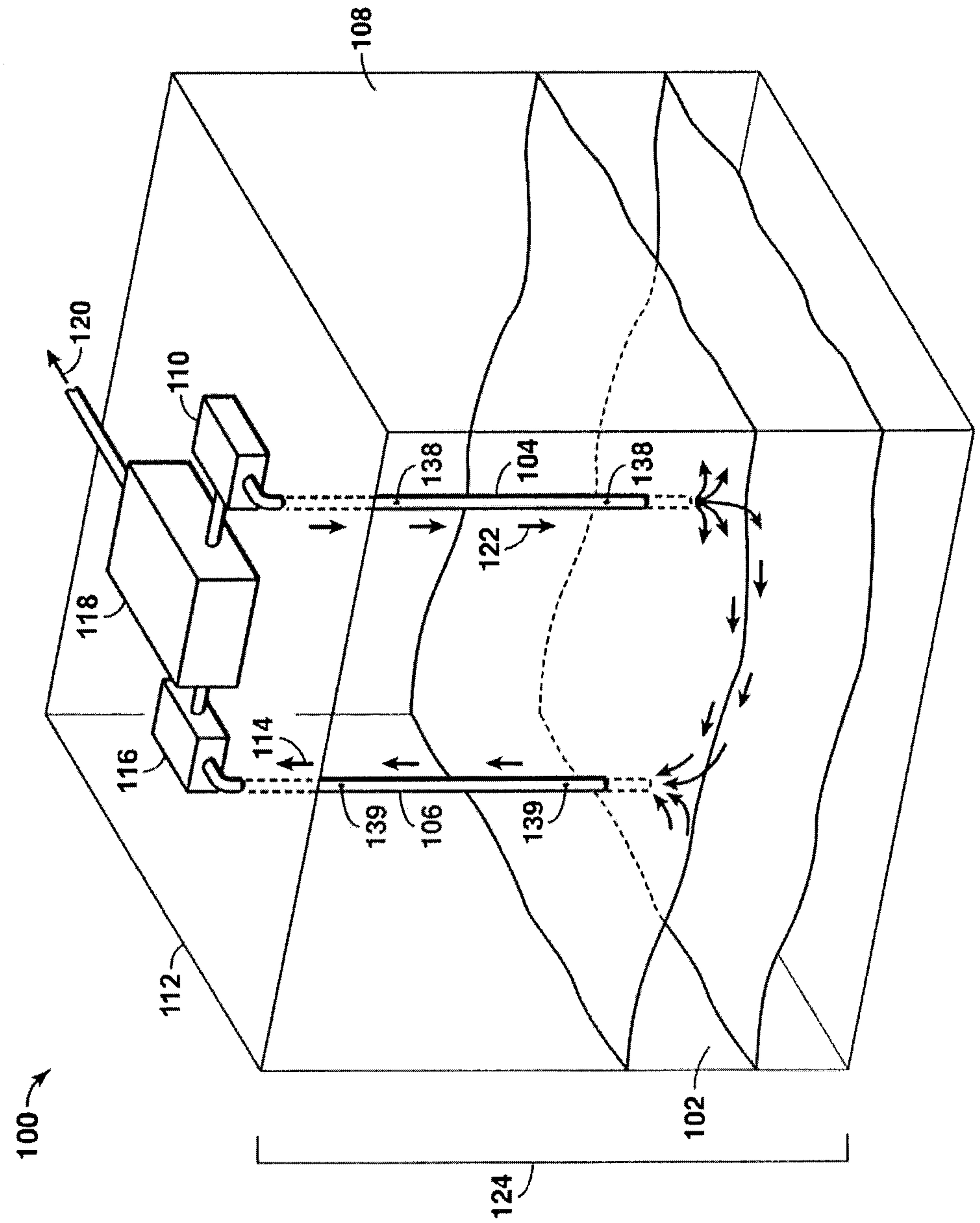

100
102
104
106
108
110
112
114
116
118
120
122
124
138
138
139
139

FIG. 1

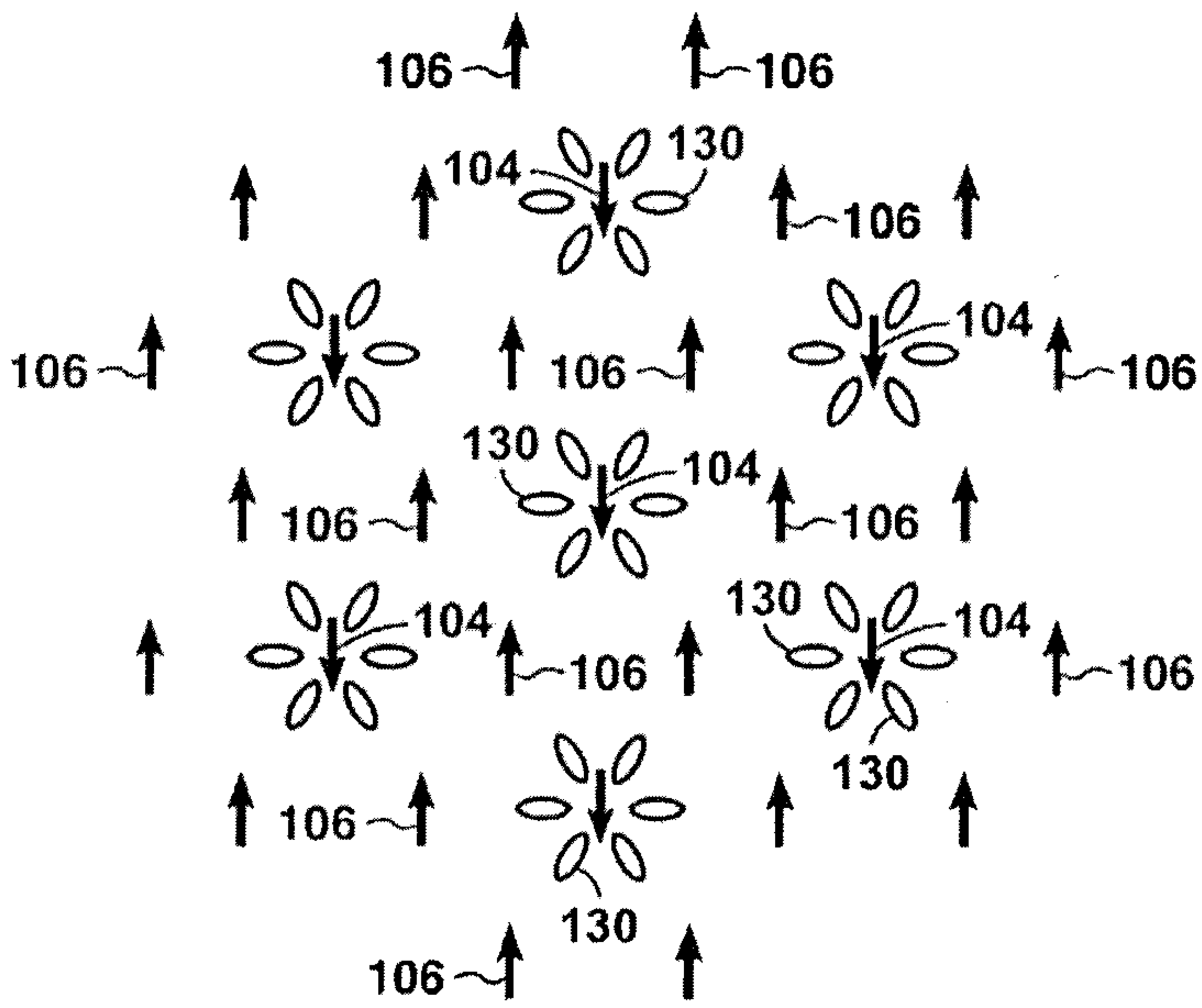

106
106
104
130
106
106
104
106
106
130
104
106
106
106
104
106
130
104
106
130
106
130
106

FIG. 2A

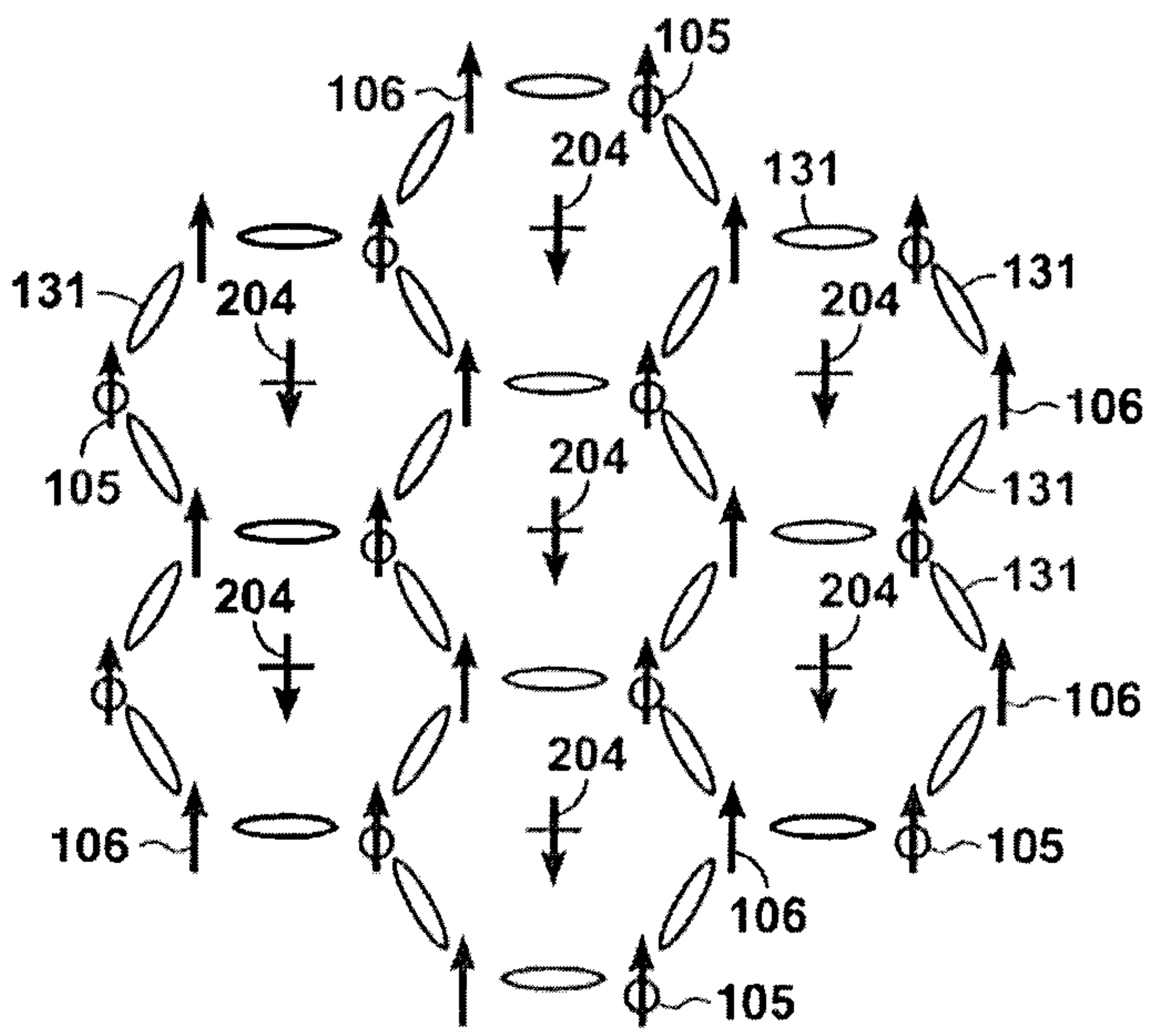

106
105
204
131
131
204
204
131
106
105
131
204
131
204
204
106
204
106
105
106
105

FIG. 2B

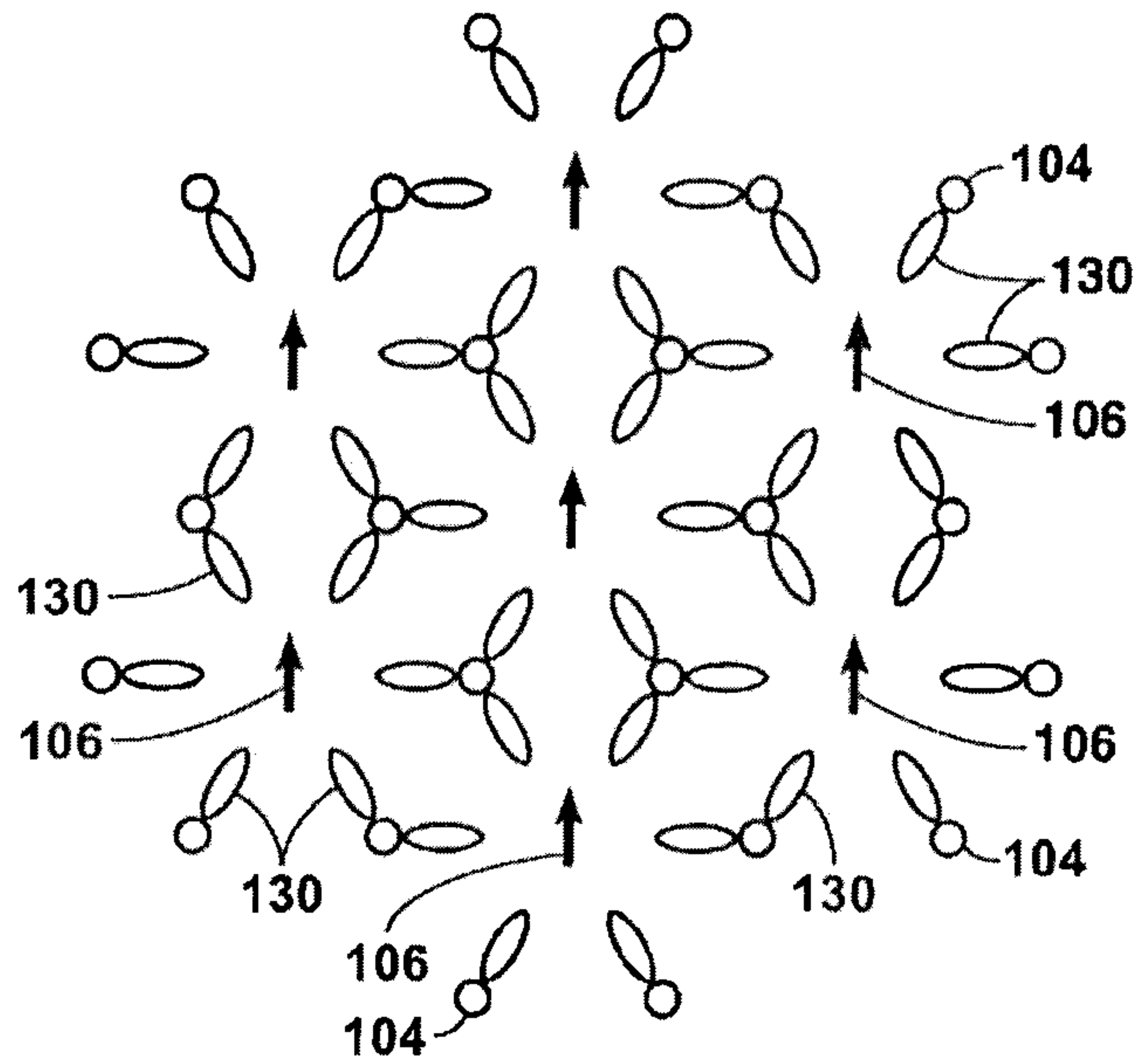

104
130
106
130
106
106
130
130
106
104
104

FIG. 3A

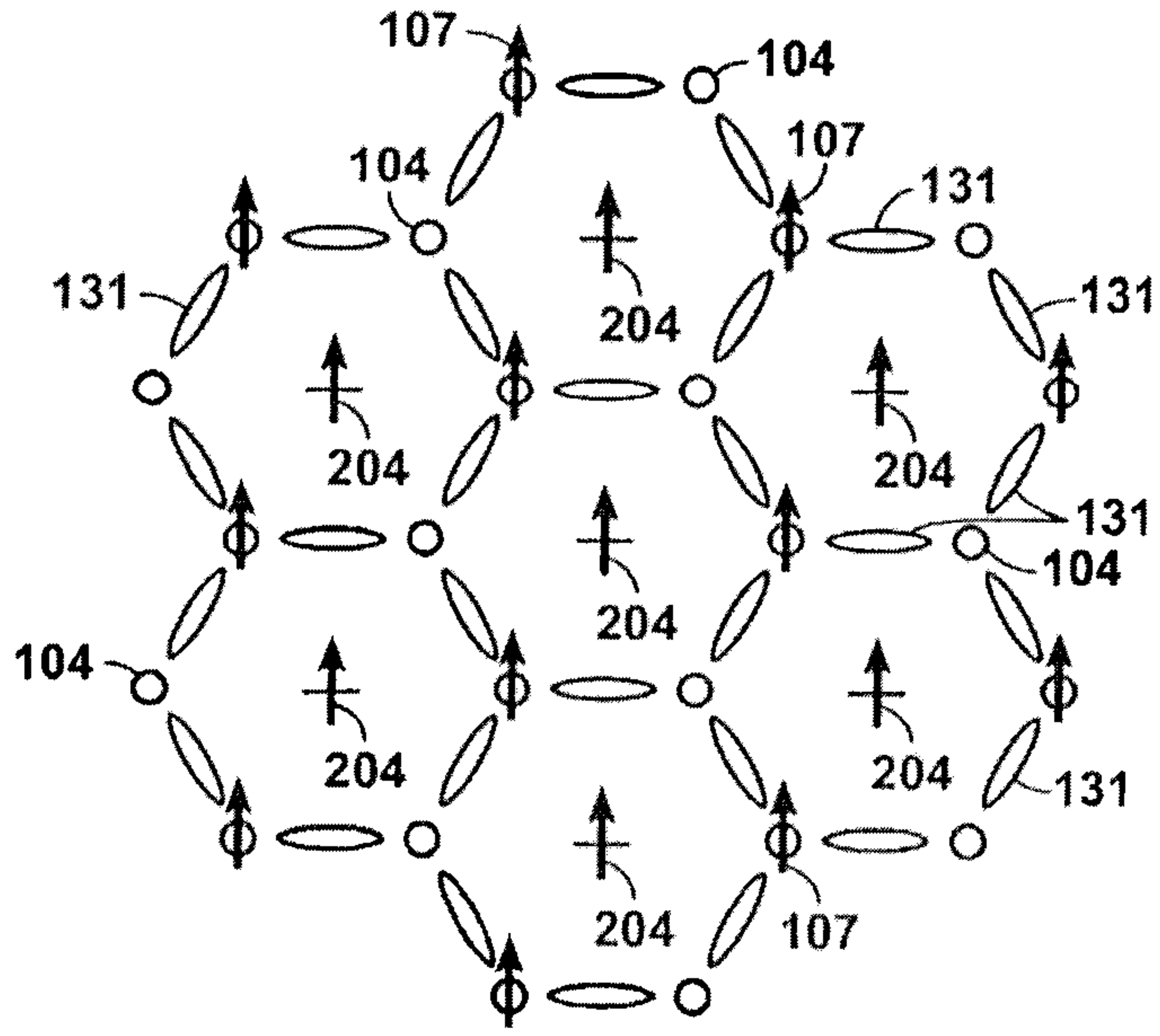

107
104
104
107
131
131
131
204
204
204
131
104
204
104
204
204
131
204
107

FIG. 3B

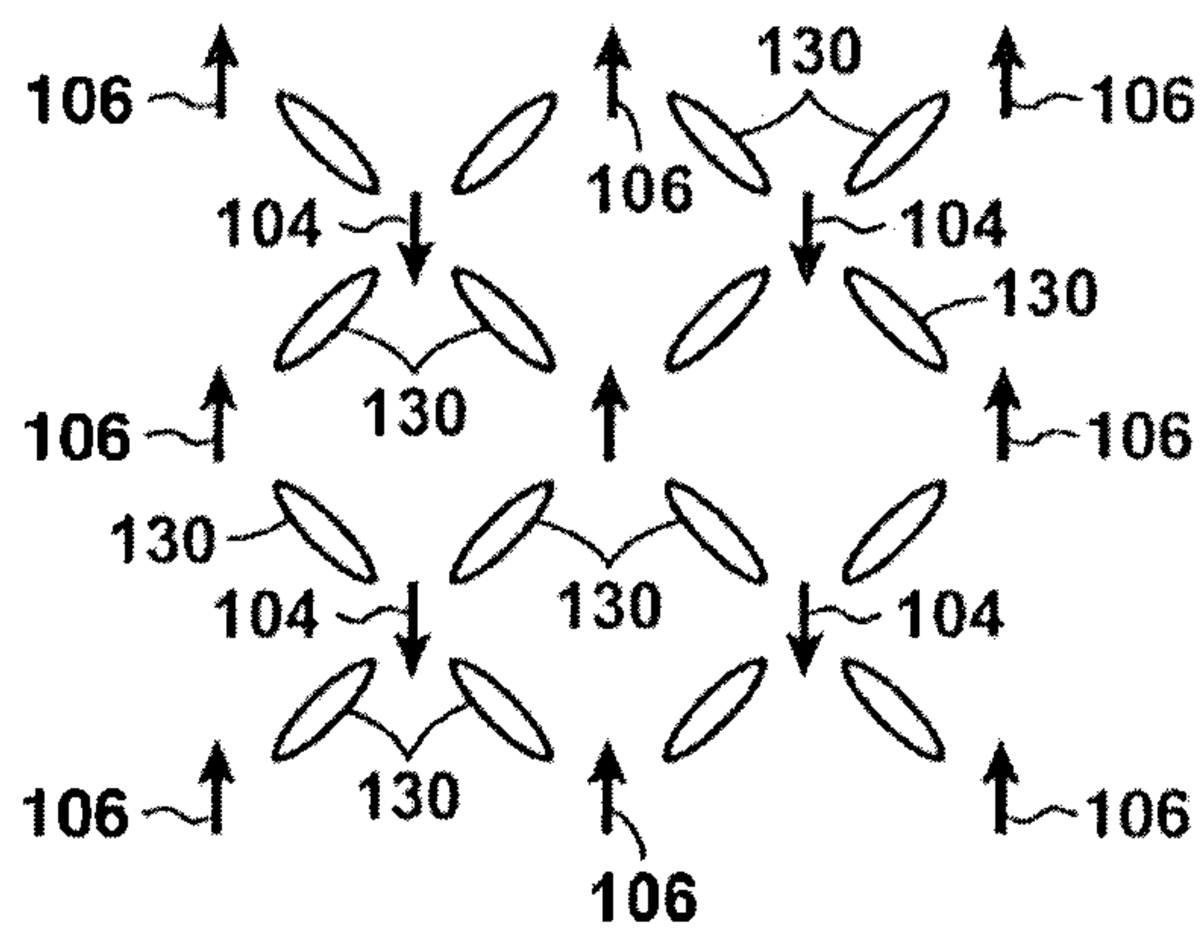

106
106
130
106
104
104
130
130
106
106
130
104
130
104
106
130
106
106

FIG. 4A

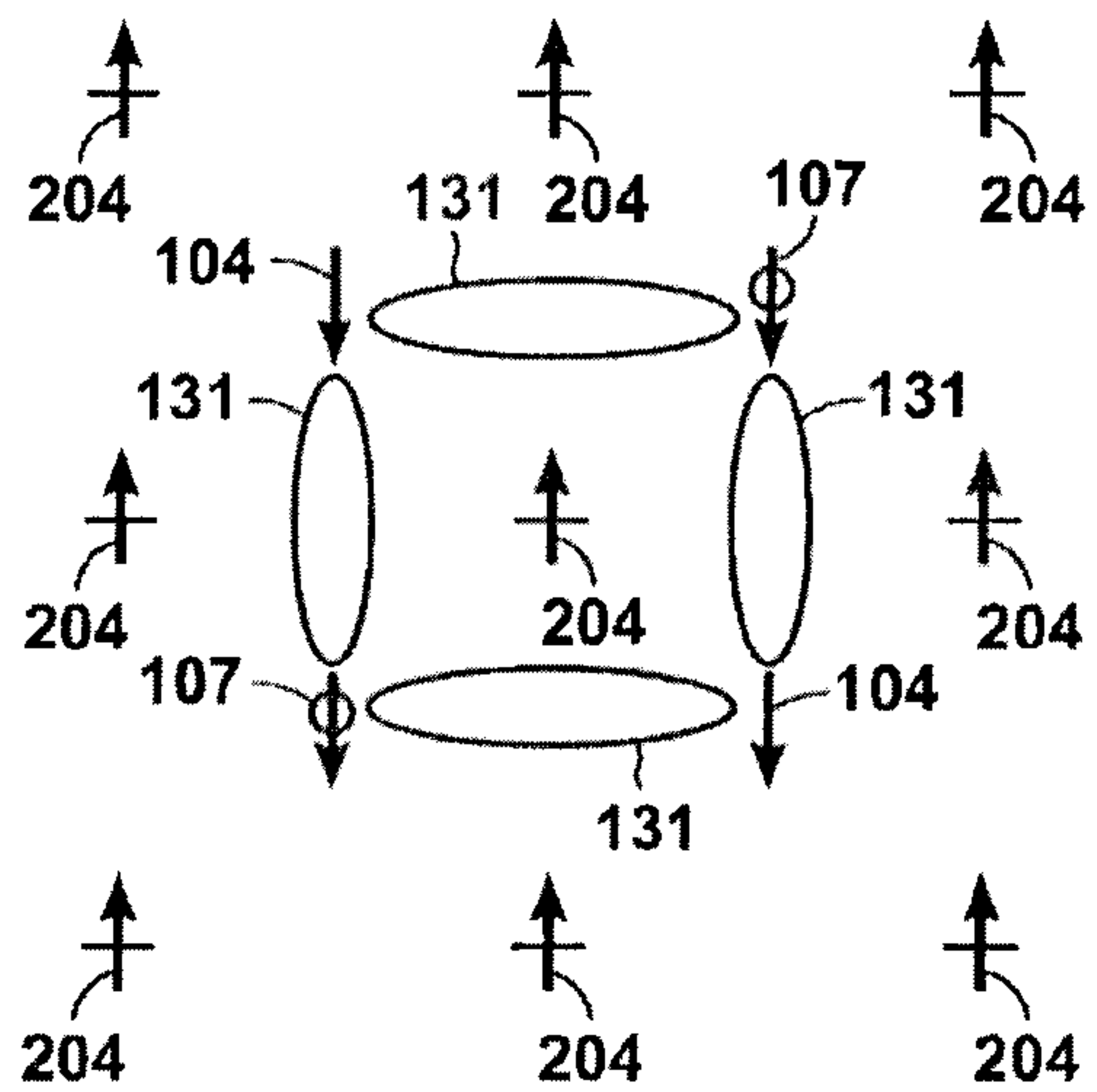

204
204
204
131
107
104
131
131
204
204
204
204
107
104
131
204
204
204

FIG. 4B

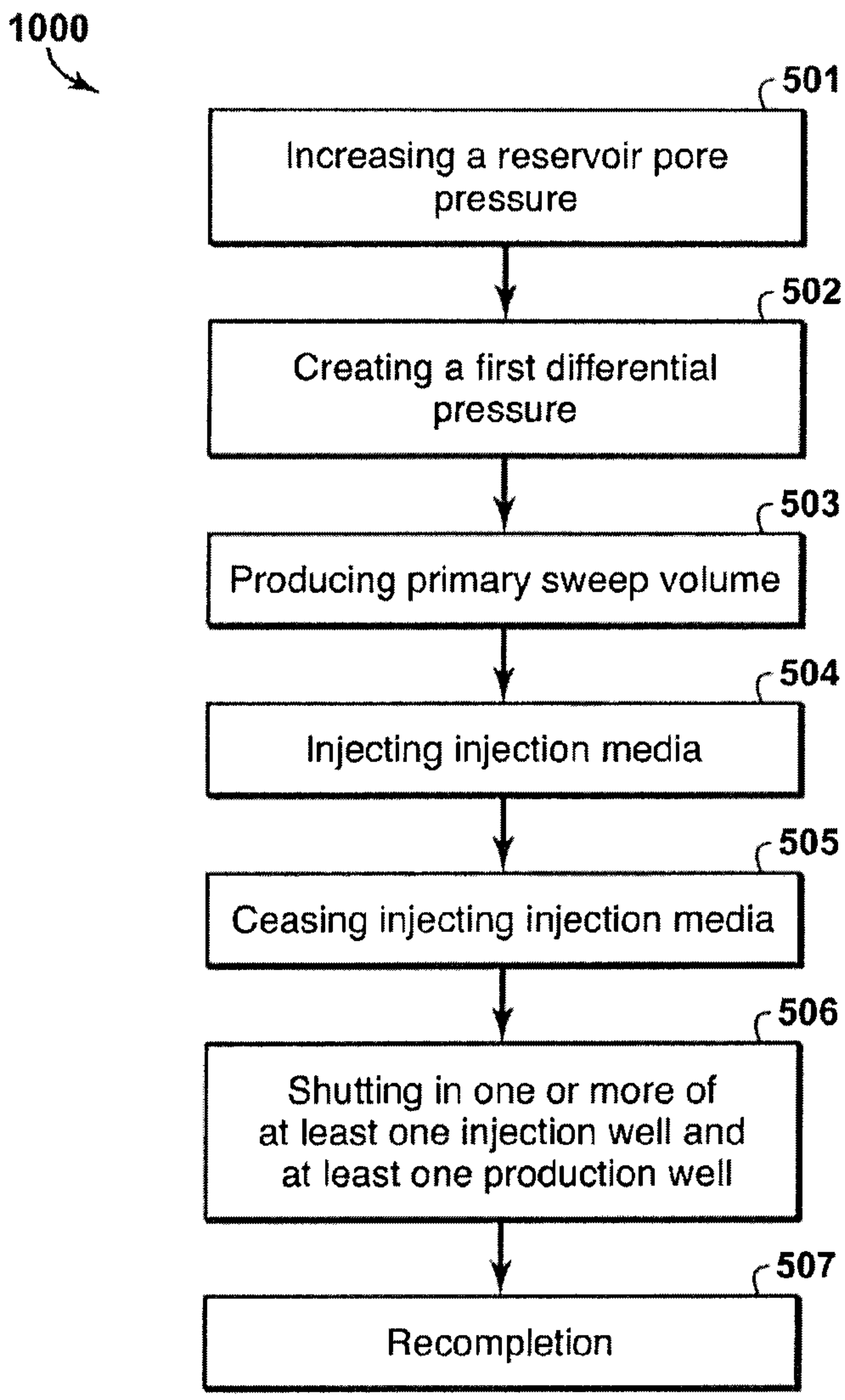
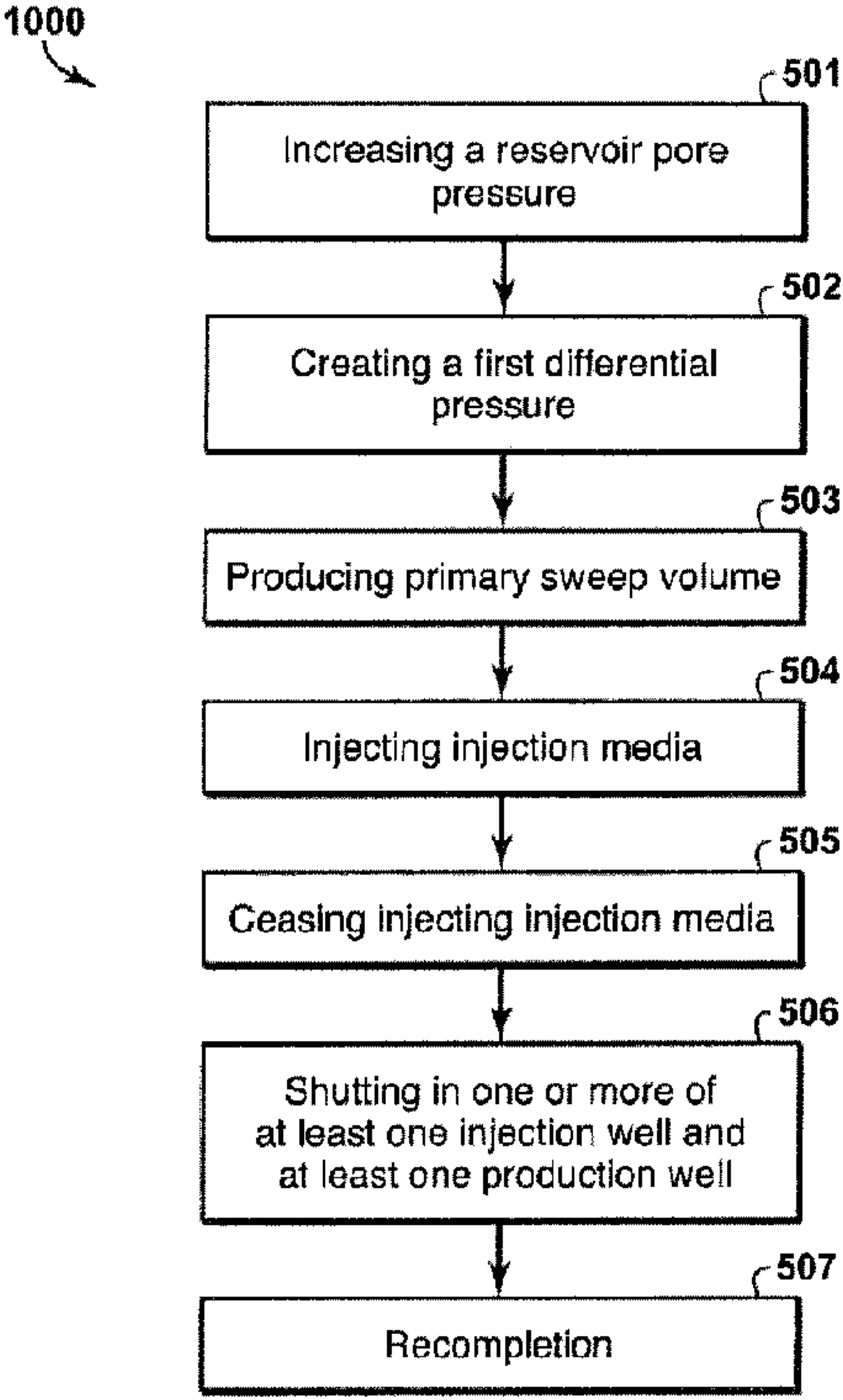

1000
501
Increasing a reservoir pore pressure
502
Creating a first differential pressure
503
Producing primary sweep volume
504
Injecting injection media
505
Ceasing injecting injection media
506
Shutting in one or more of at least one injection well and at least one production well
507
Recompletion

FIG. 5


1000
501
Increasing a reservoir pore pressure
502
Creating a first differential pressure
503
Producing primary sweep volume
504
Injecting injection media
505
Ceasing injecting injection media
506
Shutting in one or more of at least one injection well and at least one production well
507
Recompletion