Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 2744767 C 2020/10/20

(11)(21) 2 744 767

(12) BREVET CANADIEN
CANADIAN PATENT

(13) C

(22) **Date de dépôt/Filing Date:** 2011/06/30

(41) **Mise à la disp. pub./Open to Public Insp.:** 2012/12/30

(45) **Date de délivrance/Issue Date:** 2020/10/20

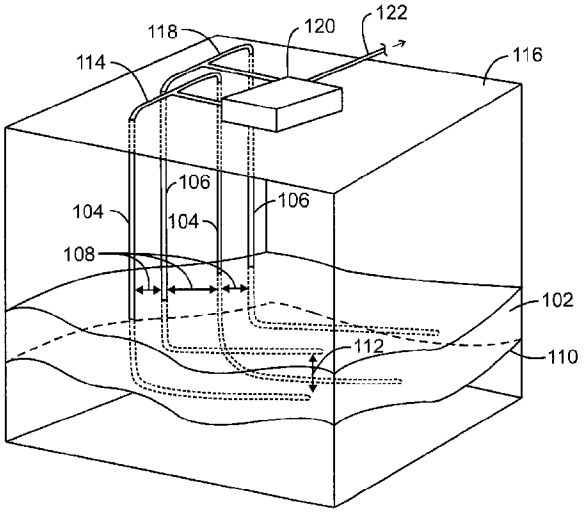
(51) **Cl.Int./Int.Cl.** ***E21B 43/24*** (2006.01),
E21B 43/34 (2006.01)

(72) **Inventeur/Inventor:**
BOONE, THOMAS J., CA

(73) **Propriétaire/Owner:**
IMPERIAL OIL RESOURCES LIMITED, US

(74) **Agent:** KIRBY EADES GALE BAKER

(54) **Titre : AGENTS MOBILISATEURS DOUBLES DANS LE DRAINAGE PAR GRAVITE PLANAIRE INFERIEURE**
(54) **Title: DUAL MOBILIZING AGENTS IN BASAL PLANAR GRAVITY DRAINAGE**



100

(57) **Abrégé/Abstract:**
Systems and methods are provided for producing hydrocarbons from reservoirs. A provided method includes drilling a first horizontal well substantially proximate to a base of a reservoir and drilling a second horizontal well at a horizontal offset from the first horizontal well. Fluid communication is established between the first horizontal well and the second horizontal well through cyclic production processes. A vertical mobilizing agent is injected into the reservoir and a lateral mobilizing agent is imposed on the reservoir. Fluids are produced from the first horizontal well.

ABSTRACT

Systems and methods are provided for producing hydrocarbons from reservoirs. A provided method includes drilling a first horizontal well substantially proximate to a base of a reservoir and drilling a second horizontal well at a horizontal offset from the first horizontal well. Fluid communication is established between the first horizontal well and the second horizontal well through cyclic production processes. A vertical mobilizing agent is injected into the reservoir and a lateral mobilizing agent is imposed on the reservoir. Fluids are produced from the first horizontal well.

DUAL MOBILIZING AGENTS IN BASAL PLANAR GRAVITY DRAINAGE

FIELD

[0001] The present techniques relate to the use of steamflooding to recover hydrocarbons. Specifically, techniques are disclosed for utilizing dual mobilizing agents between spaced horizontal wells at different levels in a reservoir.

BACKGROUND

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

[0003] Modern society is greatly dependant on the use of hydrocarbons for fuels and chemical feedstocks. However, easily harvested sources of hydrocarbon are dwindling, leaving less accessible sources to satisfy future energy needs. As the costs of hydrocarbons increase, these less accessible sources become more economically attractive. For example, the harvesting of oil sands to remove hydrocarbons has become more extensive as it has become more economical. The hydrocarbons harvested from these reservoirs may have relatively high viscosities, for example, ranging from 8 API, or lower, up to 20 API, or higher. Accordingly, the hydrocarbons may include heavy oils, bitumen, or other carbonaceous materials, collectively referred to herein as "heavy oil," which are difficult to recover using standard techniques.

[0004] Several methods have been developed to remove hydrocarbons from oil sands. For example, strip or surface mining may be performed to access the oil sands, which can then be treated with hot water or steam to extract the oil. However, deeper formations may not be accessible using a strip mining approach. For these formations, a well can be drilled to the reservoir and steam, hot air, solvents, or combinations thereof, can be injected to release the hydrocarbons. The released hydrocarbons may then be collected by the injection well or by other wells and brought to the surface.

[0005] A number of techniques have been developed for harvesting heavy oil from subsurface formations using thermal recovery techniques. Thermal recovery operations are used around the world to recover liquid hydrocarbons from both sandstone and carbonate reservoirs. These operations include a suite of in-situ recovery techniques that may be based on steam injection, solvent injection, or both. These techniques may include cyclic steam stimulation (CSS), steamflooding, and steam assisted gravity drainage (SAGD), as well as their corresponding solvent based techniques.

[0006] For example, CSS techniques include a number of enhanced recovery methods for harvesting heavy oil from formations that use steam heat to lower the viscosity of the heavy oil. The CSS process may raise the steam injection pressure above the formation fracturing pressure to create fractures within the formation and enhance the surface area access of the steam to the heavy oil, although CSS may also be practiced at pressures that do not fracture the formation. The steam raises the temperature of the heavy oil during a heat soak phase, lowering the viscosity of the heavy oil. The injection well may then be used to produce heavy oil from the formation. The cycle is often repeated until the cost of injecting steam becomes uneconomical, for instance if the cost is higher than the money made from producing the heavy oil. However, successive steam injection cycles reenter earlier created fractures and, thus, the process becomes less efficient over time. CSS is generally practiced in vertical wells, but systems are operational in horizontal wells.

[0007] Solvents may be used in combination with steam in CSS processes, such as in mixtures with the steam or in alternate injections between steam injections. The liquid hydrocarbons may be directly mixed and flashed into the injected steam lines or injected into the CSS wellbores and further transported as vapours to contact heavy oil surrounding steamed areas between adjacent wells. The injected hydrocarbons may be produced as a solution in the heavy oil phase. The loading of the liquid hydrocarbons injected with the steam can be chosen based on pressure drawdown and fluid removal from the reservoir using lift equipment in place for the CSS.

[0008] As a field ages, the use of CSS may gradually be replaced with non-cyclic techniques, for example, in which steam is continuously injected into a first well, and fluids are continuously produced from a second well. These techniques may

generally be termed steamflooding, and are generally based on vertical wells. However, steam and injected fluids have a tendency to override the hydrocarbons in the formation, and directly travel from injector to producer, lowering the potential recovery.

[0009] Another group of techniques is based on a continuous injection of steam through a first well to lower the viscosity of heavy oils and a continuous production of the heavy oil from a lower-lying second well. Such techniques may be termed "steam assisted gravity drainage" or SAGD.

[0010] In SAGD, two horizontal wells are completed into the reservoir. The two wells are first drilled vertically to different depths within the reservoir. Thereafter, using directional drilling technology, the two wells are extended in the horizontal direction that result in two horizontal wells, vertically spaced from, but otherwise vertically aligned with the other. Ideally, the production well is located above the base of the reservoir but as close as practical to the bottom of the reservoir, and the injection well is located vertically 3 to 10 metres (10 to 30 feet) above the horizontal well used for production.

[0011] The upper horizontal well is utilized as an injection well and is supplied with steam from the surface. The steam rises from the injection well, permeating the reservoir to form a vapour chamber that grows over time towards the top of the reservoir, thereby increasing the temperature within the reservoir. The steam, and its condensate, raise the temperature of the reservoir and consequently reduce the viscosity of the heavy oil in the reservoir. The heavy oil and condensed steam will then drain downward through the reservoir under the action of gravity and may flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface, the liquids flow into processing facilities where the condensed steam and heavy oil are separated, and the heavy oil may be diluted with appropriate light hydrocarbons for transport by pipeline.

[0012] The techniques discussed above may leave a substantial remainder of hydrocarbons in the reservoir. For example, each SAGD well pair may harvest hydrocarbons from a limited area of a reservoir, requiring a substantial number of wells. Infill wells are generally designed in a similar fashion to the lower, drainage wells in SAGD having a horizontal run placed between two SAGD pairs. Further, current steamflooding techniques may allow steam to override the hydrocarbons

SUMMARY

[0013] An embodiment provides a method for harvesting resources in a reservoir. The method includes drilling a first horizontal well substantially proximate to a base of a reservoir and drilling a second horizontal well at a horizontal offset from the first horizontal well. Fluid communication is established between the first horizontal well and the second horizontal well through a cyclic production process. A vertical mobilizing agent is injected into the reservoir and a lateral mobilizing agent is used in the reservoir. Fluids are produced from the first horizontal well.

[0014] Another embodiment provides a system for harvesting resources in a reservoir. The system includes a first horizontal well substantially proximate to the base of the reservoir and a second horizontal well at a horizontal offset from the first horizontal well, wherein the second horizontal well is vertically offset from the first horizontal well. A cyclic production system is configured to establish fluid communication between the wells. A continuous injection and production system is configured to inject a vertical mobilizing fluid into the reservoir, use a lateral mobilizing agent in the reservoir, and produce a fluid from the first horizontal well.

[0015] Another embodiment described herein provides a method for producing hydrocarbons. The method includes producing fluids from a number of production wells in a reservoir and imposing a lateral mobilizing agent on the reservoir from a number of injection wells. Each of the injection wells is adjacent to one of the production wells and each of the injection wells is laterally offset from each of the adjacent production wells. Fluid communication has been established between each injection well and an adjacent production well using a cyclic production process. A vertical mobilizing agent is heated using heat transferred from the lateral mobilizing agent and a hydrocarbon stream is separated from the fluids produced from the plurality of production wells.

[0015a] Another embodiment described herein provides a method for harvesting resources in a reservoir, comprising: drilling a first horizontal well substantially proximate to a base of a reservoir; drilling a second horizontal well at a horizontal offset from the first horizontal well, wherein the second horizontal well is greater than about three metres shallower than the first well, establishing fluid

communication between the first horizontal well and the second horizontal well through a cyclic production process; after establishing fluid communication between the first horizontal well and the second horizontal, converting the first horizontal well into an injection well and the second horizontal well into a production well and operating the first horizontal well and the second horizontal under a continuous injection/production process; injecting a vertical mobilizing agent into the reservoir, wherein the vertical mobilizing agent comprises a light hydrocarbon vapour under reservoir conditions which promotes the rise of a depleted bitumen chamber within the reservoir; contacting the mobilizing agent with bitumen located at the top and sides of the depleted bitumen chamber, thereby condensing the vertical mobilizing agent, lowering the viscosity of the bitumen, and expanding the depleted bitumen chamber; injecting a lateral mobilizing agent into the reservoir, wherein the lateral mobilizing agent comprises hot water; using the heat from the lateral mobilizing agent to flash the condensed vertical mobilizing agent back into a vapour; and producing fluids from the first horizontal well.

[0015b] Another embodiment described herein provides a system for harvesting resources in a reservoir, comprising: a first horizontal well substantially proximate to the base of the reservoir; a second horizontal well at a horizontal offset from the first horizontal well, wherein the second horizontal well is vertically offset from the first horizontal well and wherein the second horizontal well is greater than about three metres shallower than the first well; a cyclic production system configured to establish fluid communication between the wells; and the cyclic production system reconfigured into a continuous injection and production system, wherein the continuous injection and production system is configured to: inject a vertical mobilizing fluid into the reservoir wherein the vertical mobilizing agent comprises a light hydrocarbon vapour under reservoir conditions which promotes the rise of a depleted bitumen chamber within the reservoir; allow the mobilizing agent to contact with bitumen located at the top and sides of the depleted bitumen chamber, thereby condensing the vertical mobilizing agent, lowering the viscosity of the bitumen, and expanding the depleted bitumen chamber; inject a lateral mobilizing agent into the reservoir, wherein the lateral mobilizing agent comprises hot water; use the heat

from the lateral mobilizing agent in the reservoir to flash the vertical mobilizing agent back into a vapour; and produce a fluid from the first horizontal well.

DESCRIPTION OF THE DRAWINGS

[0016] The advantages of the present techniques are better understood by referring to the following detailed description and the attached drawings, in which:

[0017] Fig. 1 is a drawing of a steamflood process using basal planar gravity drainage (BPGD);

[0018] Figs. 2(A), (B), and (C) are perspective views of a cyclic production process showing the establishment of fluid communications between adjoining wells;

[0019] Fig. 3 is a cross sectional view of a cyclic production process showing the establishment of fluid communications between adjoining wells;

[0020] Fig. 4 is a cross-section of a portion of a reservoir, showing two horizontal wells through the reservoir;

[0021] Fig. 5 is a plot showing the efficacy of dry and wet steam in a BPGD process where the steam volume for the wet steam (60% quality) has been adjusted to be equivalent thermally equivalent to dry steam (90% quality) (i.e. a dry steam equivalent basis);

[0022] Fig. 6 is a plot showing an increase in total production that can be obtained using a BPGD process;

[0023] Fig. 7 is a plot showing an increase in efficiency that can be obtained using a BPGD process; and

[0024] Fig. 8 is process flow diagram of a method for using dual mobilizing agents in BPGD to produce hydrocarbons.

DETAILED DESCRIPTION

[0025] In the following detailed description section, specific embodiments of the present techniques are described. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present techniques, this is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the techniques are not limited to the specific embodiments described below, but rather, include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

[0026] At the outset, for ease of reference, certain terms used in this application and their meanings as used in this context are set forth. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments, and terms or techniques that serve the same or a similar purpose are considered to be within the scope of the present claims.

[0027] As used herein, the term a "base" of a reservoir indicates a lower boundary of the resources in a reservoir that are practically recoverable, by a gravity-

assisted drainage technique, for example, using an injected mobilizing fluid, such as steam, solvents, hot water, gas, and the like. The base may be considered a lower boundary of a pay zone, e.g., the zone from which hydrocarbons may generally be removed by gravity drainage. The lower boundary may be an impermeable rock layer, including, for example, granite, limestone, sandstone, shale, and the like. The lower boundary may also include layers that, while not completely impermeable, impede the formation of fluid communication between a well on one side and a well on the other side. Such layers may include broken shale, mud, silt, and the like. The resources within the reservoir may extend below the base, but the resources below the base may not be recoverable with gravity assisted techniques.

[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, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

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

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

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

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

some amount of sulphur (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. %. As used herein, the term "heavy oil" includes bitumen, as well as lighter materials that may be found in a sand or carbonate reservoir.

[0029] As used herein, two locations in a reservoir are in "fluid communication" when a preferential path for fluid flow exists between the locations. Fluid communication can be manifested as a rapid pressure change at one well in response to a pressure, fluid injection or fluid withdrawal at another well. Fluid communication may also be manifested as temperature change at the production well or the arrival at the production well of fluids that are known to have been injected at another well. For example, the establishment of fluid communication between a well and a latterly or vertically offset injection well may allow steam or

solvent to flow rapidly and with limited pressure drop from the injection well to the production well where it can be collected and produced. As used herein, a fluid includes a gas or a liquid and may include, for example, a produced hydrocarbon, an injected mobilizing fluid, or water, among other materials.

[0030] As used herein, a "cyclic recovery process" uses an intermittent injection of injected mobilizing fluid selected to lower the viscosity of heavy oil in a hydrocarbon reservoir. The injected mobilizing fluid may include steam, solvents, gas, water, or any combinations thereof. After a soak period, intended to allow the injected material to interact with the heavy oil in the reservoir, the material in the reservoir, including the mobilized heavy oil and some portion of the mobilizing agent may be harvested from the reservoir. Cyclic recovery processes use multiple recovery mechanisms, in addition to gravity drainage, early in the life of the process. The significance of these additional recovery mechanisms, for example dilation and compaction, solution gas drive, water flashing, and the like, declines as the recovery process matures. Practically speaking, gravity drainage is the dominant recovery mechanism in most mature thermal, thermal-solvent and solvent based recovery processes used to develop heavy oil and bitumen deposits, such as steam assisted gravity drainage (SAGD). For this reason the approaches disclosed here are equally applicable to all recovery processes in which at the current stage of depletion gravity drainage is the dominant recovery mechanism.

[0031] "Facility" as used in this description is a tangible piece of physical equipment through which hydrocarbon fluids are either produced from a reservoir or injected into a reservoir, or equipment which can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, steam generation plants, processing plants, and delivery outlets. In some instances, the term "surface facility" is used to distinguish those facilities other than wells.

[0032] As used herein, "heavy oil" includes both oils that are classified by the American Petroleum Institute (API) as heavy oils and extra heavy oils, which are also known as bitumen. In general, a heavy oil has an API gravity between 22.3° (density

of 920 kg/m^3 or 0.920 g/cm^3) and 10.0° (density of 1,000 kg/m^3 or 1 g/cm^3). An extra heavy oil, or bitumen, in general, has an API gravity of less than 10.0° (density greater than 1,000 kg/m^3 or greater than 1 g/cm^3). For example, a common source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water, and heavy oil. The thermal recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature. Solvent-based recovery processes are based on reducing the liquid viscosity by mixing heavy oil with a solvent. Once the viscosity is reduced, the movement or drive of the fluids may be forced by steam or hot water flooding, and gravity drainage becomes possible. The reduced viscosity makes the drainage quicker and therefore directly contributes to the recovery rate.

[0033] As used herein, a "horizontal well" generally refers to a well bore with a section having a centerline which departs from vertical by at least about 65°. This nearly horizontal section is often used for harvesting hydrocarbons in a reservoir. Generally, the nearly horizontal section of a well bore that is used for gravity production of heavy oils extends for several hundred meters in a reservoir from the "heel" to the "toe." The heel is closest to the portion of the well bore that leads to the surface, while the toe is farthest from the portion of the well bore that leads to the surface. In practice, the horizontal well will often be drilled such that it conforms to the base of the reservoir so that the toe may be shallower or deeper than the heel of the well.

[0034] A "hydrocarbon" is an organic compound that primarily includes the elements hydrogen and carbon, although nitrogen, sulphur, oxygen, metals, or any number of other elements may be present in small amounts. As used herein, hydrocarbons generally refer to components found in heavy oil, or other oil sands. Liquid hydrocarbon solvents are hydrocarbons that are substantially in the liquid phase under the temperature and pressure conditions found in an oil-sands reservoir, such as hexane, heptanes, heavier hydrocarbons, or mixtures thereof. Light hydrocarbon solvents, such as ethane, propane, butane, pentanes, or mixture thereof, are hydrocarbons that are substantially in the gas phase or cycling between the liquid and gas phase, under the temperature and pressure conditions found in an oil-sands reservoir.

[0035] A non-condensable gas is a gas that is in the gas phase under the temperature and pressure conditions found in an oil-sands reservoir. Such gases can include carbon dioxide (CO_2), methane (CH_4), and nitrogen (N_2), among others.

[0036] "Permeability" is the capacity of a rock or sand to transmit fluids through the interconnected pore spaces. The customary unit of measurement is the millidarcy. Relative permeability refers to the fractional permeability of the absolute permeability for a specific phase, such as oil, water or gas.

[0037] As used herein, a "reservoir" is a subsurface rock or sand formation from which a production fluid, or resource, can be harvested. The rock formation may include sand, sandstone, granite, silica, carbonates, clays, shales and organic matter, such as oil, gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 m) to hundreds of feet (hundreds of m). The common feature of a reservoir is that it has pore space within the rock that may be impregnated with a heavy oil.

[0038] As discussed above, "steam assisted gravity drainage" (SAGD), is a thermal recovery process in which steam, or combinations of steam and solvents, is injected into a first well to lower a viscosity of a heavy oil, and fluids are recovered from a second well. Both wells are generally horizontal in the formation and the first well lies above the second well. Accordingly, the reduced viscosity heavy oil flows down to the second well under the force of gravity, although pressure differential may provide some driving force in various applications.

[0039] "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.

[0040] As used herein, "thermal recovery processes" include any type of hydrocarbon recovery process that uses a heat source to enhance the recovery, for example, by lowering the viscosity of a hydrocarbon. These processes may use injected mobilizing fluids, such as hot water, wet steam, dry steam, or solvents alone, or in any combinations, to lower the viscosity of the hydrocarbon. Such processes may include subsurface processes, such as cyclic steam stimulation (CSS), cyclic solvent stimulation, steamflooding, solvent injection, and SAGD, among others, and processes that use surface processing for the recovery, such as

sub-surface mining and surface mining. Any of the processes referred to herein, such as SAGD may be used in concert with solvents.

[0041] A "wellbore" is a hole in the subsurface made by drilling and inserting a conduit into the subsurface. A wellbore may have a substantially circular cross section or any other cross-sectional shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore." Further, multiple pipes may be inserted into a single wellbore, for example, as a liner configured to allow flow from an outer chamber to an inner chamber.

Overview

[0042] Current techniques for harvesting heavy oils may require a significant number of wells to produce hydrocarbons over a large area of a reservoir. As the costs associated with these wells can be very high, the techniques may become prohibitively expensive as a reservoir ages. Further, current techniques may bypass significant amounts of hydrocarbons as the reservoir ages.

[0043] In an embodiment, a basal planar gravity drainage (BPGD) process is implemented by drilling at least two horizontal wells through the reservoir. A first horizontal well is drilled at or close to the base of the reservoir. A second horizontal well is laterally offset and may be vertically offset from the first well, for example, with an axis that is around 50 to 200 metres laterally away from the axis of the first well and may be about three metres, or more, shallower than the first well. Both wells are initially used to produce from the reservoir using cyclic production techniques, such as injecting a mobilizing fluid, letting the mobilizing fluid soak in the reservoir, and then producing the mobilizing fluid and hydrocarbons from the wells. The mobilizing fluid may be steam, water, solvents, or mixtures of both.

[0044] Over time, as production cycles are completed, the first horizontal well and the second horizontal well will achieve fluid communication, allowing fluids injected through one well to pass to the other well. After fluid communication is achieved, a continuous production process may be implemented in which the second, or higher, horizontal well may be used as an injection well, and the first, or lower, horizontal well may be used as a production. As for the cyclic production process, the

continuous production process may use steam, solvents, water, or mixtures, as mobilizing agents.

[0045] In an embodiment, a dual mobilizing agent recovery process is used to enhance production. One mobilizing agent, termed herein a vertical mobilizing agent, promotes the rise of the depleted bitumen chamber and the vertical drainage of the bitumen. A second mobilizing agent, termed the lateral mobilizing agent, promotes the lateral flow of bitumen along a basal plane between the second horizontal well and the first horizontal well. The lateral mobilizing agent is not limited to a fluid, but may include water, solvent, or electrical heating, for example, using a brine injection to carry a current. The lateral mobilizing agent and the vertical mobilizing agent can be selected to balance a volumetric rate of vertical drainage and lateral drainage to maintain a vapour chamber between an injection well and a production well.

[0046] The combination of a BPGD process and dual mobilizing agents may increase the amount of hydrocarbons that can be harvested from a reservoir. The combination may also increase the efficiency of steam, solvent usage, or electrical usage in the recovery process.

[0047] Fig. 1 is a drawing of a hydrocarbon recovery process 100 in accordance with embodiments. In the hydrocarbon recovery process 100, a reservoir 102 is accessed by a first set 104 and a second set 106 of horizontal wells. As described herein, the wells can have a lateral spacing 108 of about 50 to 200 metres between each of the wells. The first set 104 may be drilled substantially proximate to a base 110 of the reservoir 102. The second set 106 of horizontal wells may be drilled at a vertical spacing 112 of about three metres, or more, above the first set 104. Although only two wells of each type are shown in the hydrocarbon recovery process 100, any number may be used, for example, from one well of each type to several hundred wells of each type, depending on the size of the reservoir 102. The first set 104 of horizontal wells may be coupled together by lines 114 at the surface. Similarly, the second set 106 of horizontal wells may be coupled together by lines 118 at the surface. One or more surface facilities 120 produce steam or solvent streams that can be injected into the reservoir through the sets of wells 104 or 106 and produce fluids from the sets of wells 104 or 106. The produced fluids may be separated at the surface facility 120 to produce a hydrocarbon stream 122, which

can then be sent on for further processing. The surface facility 120 can also include electrical generation equipment or connections that can be configured to impose an electrical current in the reservoir 102. The electric current can provide resistive heating to the reservoir contents and may be used to flash a vertical mobilizing agent and also to lower the viscosity of heavy oil, e.g., acting as a lateral mobilizing agent.

[0048] After the sets of wells 104 and 106 are drilled, a cyclic production process, such as cyclic steam stimulation, may be used on both sets 104 and 106 of horizontal wells in concert. During this period, the surface lines 114 and 118 may be tied together so that the sets of wells 104 and 106 are used in concert. The cyclic production process is repeated until fluid communication between the first set 104 and the second set 106 of wells is detected.

[0049] After fluid communication is established, dual mobilizing agents can be used to perform a continuous recovery operation. In some embodiments, a vertical mobilizing agent can be injected into the second set 106 of wells. The vertical mobilizing agent can include a low flashpoint solvent, which can flash into a vapour in the reservoir. The vertical mobilizing agent may condense in contact with the bitumen at the top and sides of the chamber and condense, lowering the viscosity of the fluid and expanding the chamber. A horizontal mobilizing agent, such as hot water, may be injected to carry fluids that flow down to the first set 104 of wells. The heat from the horizontal mobilizing agent can be used to flash the vertical mobilizing agent back into a vapour, repeating the cycle.

Establishing Fluid Communication

[0050] Figs. 2(A), (B), and (C) are 3D seismic views of a cyclic production process 200 showing the establishment of fluid communications between adjoining wells. In Fig. 2, the particular cyclic production process used was cyclic steam stimulation (CSS), although any cyclic production technique could be used in techniques described herein. Fig. 2(A) is an initial view showing accessed areas 202, for example, areas that may be in heated and in fluid communication with horizontal wells 204 after one cycle of cyclic steam injection and production has been performed from the reservoir 206. The accessed areas 202 may be termed the steam invaded region. The darker, shaded areas indicate regions 208 are not yet in fluid communication with the wells 204. As can be seen, the wells 204 are not substantially in fluid communication with each other at this point in the process, as

indicated by the lack of overlap of the accessed areas 202 across adjacent wells 204.

[0051] After a second cycle of steam injection and production, heated features extend out to at least about 25m from each well. In this example, the wells are about 170 metres apart and fluid communication has not been completely established. However, if the wells had been placed about 50 to 75 metres apart, basal connections would have been established at this point. Thus, after two cycles of CSS the shown in Fig. 2(B), the accessed area 202 has substantially increased in size, and is overlapping a number of adjacent wells 204, for example, as indicated by reference number 210.

[0052] After a third cycle of injection and production, as shown in Fig. 2(C), the accessed region 202 has placed all adjacent wells 204 in fluid communication, allowing fluid flow from any well to an adjacent well 204. Creating uniform connections along the wells may present a challenge. For example, reference number 212 identifies a region where the fluid communication is not extensive, indicating that further cycles may be useful. However, the fluid communication may be extensive enough to begin continuous steamflooding. The wells shown in Figures 2 (A), (B) and (C) were completed with specially designed completion which facilitated uniform steam distribution, such as limited entry perforations (LEPs) which may be used in concert with a wire screen.

[0053] Fig. 3(A), (B), and (C) are cross sectional views 300 of the cyclic production processes of Fig. 2(A), (B), and (C), respectively, showing the establishment of fluid communications between adjoining wells 204. In Fig. 3, like numbers are as discussed above. In this figure, not every well 204 is labelled in order to simplify the diagram. The center 302 of the production zone 304 around each well 204 is at a lateral spacing 108 of about 170 metres apart in this example. The increase in the accessed area 202 (Fig. 2) after each year of cyclic production is shown as the increase in size of the production zones 304 around each well 204. Further, other layers 306 may develop accessed zones 308, which can contribute to fluid communication between wells. If the lateral spacing 108 between were closer, fluid communications between wells 204 would be established more quickly. For example, if the spacing around the production zones 304 was at 100 metres, as indicated by reference number 310, the wells 204 could start to interact after only

two cycles of injection and production. The wells 204 could be converted to alternating injectors and producers, as discussed with respect to Fig. 4. In some embodiments, the lateral well spacing 108 will be about 50 metres. The lateral well spacing 108 may range from about 20 metres to about 200 metres.

Changing to Continuous Production

[0054] Fig. 4 is a cross-section of a portion 400 of a reservoir 102, showing two horizontal wells 104 and 106 in the reservoir 102 used in a continuous production process, e.g., after fluid communication is established by a cyclic production process. A first horizontal well 104 is drilled near a base of the reservoir 102. A second horizontal well 106 is drilled at a lateral offset 108 and at a shallower level, i.e., with a positive vertical offset 112. In an embodiment, the vertical offset 112 is greater than about three metres. The second horizontal well 106 may be used as an injection well to inject a mobilizing fluid to move hydrocarbons in the reservoir 102 towards the first horizontal well 104.

[0055] This may be performed by using a lateral mobilizing agent 402. The lateral mobilizing agent 402 may be a fluid, such as water, that remains a fluid at reservoir conditions and acts to sweep hydrocarbons towards the production well 104. The lateral mobilizing agent 402 may also provide heat into the formation, which may be used to flash a vertical mobilizing agent 404 into a vapour. In some embodiments, the lateral mobilizing agent 402 is not an injected fluid, but is, instead, an electric current flowing between the wells 104 and 106. The current can add heat to the reservoir, flashing the vertical mobilizing agent 402 into a vapour.

[0056] The vertical mobilizing agent 404 rises forming a production chamber 406. Liquids 408, including mobilized bitumen, condensate, condensed solvents, and the like, fall back towards the basal plane. The liquids 408 drain to the first horizontal well 104, which is used as a production well to remove the fluids from the production chamber 410. In contrast to a typical steam assisted gravity drainage (SAGD) process, which has no lateral spacing between the injection and production well, the production chamber 406, at or near the base of the reservoir, is formed by the vertical mobilizing agent 404 rising from the basal plane between the two horizontal wells 102 and 104.

Various combinations of lateral mobilizing agents 402 and vertical mobilizing agents 404 may be used in embodiments, such as those shown in Table 1. The

agents 402 and 404 may be independently selected for specific purposes, such as temperature of flashing, among others, allowing the recovery to be adjusted for the conditions in a reservoir. For example, hot water may be used as a lateral mobilizing agent 402 in a system in which a light hydrocarbon is used as the vertical mobilizing agent 404. In this embodiment, the hot water flashes the light hydrocarbon and sweeps recovered bitumen to the second horizontal well 106 for production. Further, the lateral mobilizing agents 402 and vertical mobilizing agents 404 can be changed over time, for example, to different types of agents, different compositions, and the like.

Table 1: Dual mobilizing agents for BPGD

Lateral Mobilizing Agent 402	Vertical Mobilizing Agent 404
Hot Water (liquid)	Water Vapour (steam)
Liquid hydrocarbon solvents (C_{5+})	Light hydrocarbon vapour (C_2 to C_7)
Electric resistive heating between injector and producer	Non-condensible additive gases such as methane (C_1) or carbon-dioxide (CO_2)
Electric resistive heating between injector and producer, with injection of an electrically conductive liquid such as brine	

[0057] The selection of mobilizing agents 402 and 404 may be separately considered based on the desired conditions. For example, hot water, or steam condensate, can be used as the lateral mobilizing agent 402 as they flow along the basal plane and can transfer energy to a vertical mobilizing agent 404. Other lateral mobilizing agent 402 that can perform these functions include non-vaporising liquid solvents, such as paraffinic oils, among others. The non-vaporising liquid solvents may also mix with draining hydrocarbons, reducing the viscosity of the recovered hydrocarbons. The lateral mobilizing agent 402 is not limited to a physical material added to the reservoir. In an embodiment, the lateral mobilizing agent 402 may be heat, generated in the reservoir by a current flow between the wells 104 and 106. The heating effect may be enhanced by a continuous or intermittent injection of a brine to enhance the current flow. In another embodiment, the heating may be performed using a fixed fracture location with a conductive proppant.

[0058] Similar considerations may influence the selection of the vertical mobilizing agent 404. The vertical mobilizing agent 404 may be water vapour injected as wet steam. In SAGD applications, dry steam is more effective than wet steam, but this is

not necessarily the case for a BPGD recovery. This is discussed further with respect to Fig. 5.

[0059] As noted above, solvent vapour may be used as the vertical mobilizing agent 404. The solvent vapour tends to rise vertically and mobilize the heavy oil with heat. Thus, one consideration to be accounted for in the selection of the mobilizing agents 402 and 404 is the amount of heat to be provided by the lateral mobilizing agent 402 for vaporising the vertical mobilizing agent 404. The mobilizing effect may vary from a predominately solvent mixing effect to a predominately heating effect, depending on the selection of solvent, operating temperature, and operating pressure.

[0060] The elongated production chamber 406 in the basal planar recovery process may increase the total amount of hydrocarbons that can be produced from the reservoir in a given period of time, versus a vertical SAGD steam chamber. This may increase the efficiency of the injected mobilizing fluid. This is discussed in further detail with respect to Figs. 6 and 7.

[0061] The production changes that may result from the techniques may be modeled by creating a geologic model of the reservoir and using the geologic model to calculate the amounts of hydrocarbons produced. The geologic model may include open hole log data, cased hole log data, core data, recovery process well trajectories, 2D seismic data, 3D seismic data, or other remote surveying data, or any combinations thereof. For example, prior to the start of recovery operations, a geologic model can be created for the development area. Available open hole and cased hole log, core, 2D and 3D seismic data, and knowledge of the depositional environment setting can all be used in the construction the geologic model. The information generated by the geologic model may then be used in a reservoir simulation model to provide predictions of fluid flow, reservoir geometry, and the like.

[0062] The geologic model, reservoir model, and knowledge of surface access constraints can then be used to complete the layout of the spaced horizontal wells and surface pads. After the horizontal wells have been drilled, data collected during their drilling as well as data collected during the operation of the recovery process, such as cased hole logs including temperature logs, observation wells, additional time lapse seismic or other remote surveying data, can be used to update the geologic model, which may be used to predict the evolution of the depletion patterns

as the recovery process matures. The depletion patterns within the reservoir will be influenced by well placement decisions, geological heterogeneity, well failures, and day to day operating decisions.

[0063] Following the operation of the thermal, thermal-solvent or solvent based recovery process for a suitable period of time, intervals of high hydrocarbon depletion will create a series of discrete connections between adjacent wells or well pairs, depending on the recovery process. Knowledge of these connections is gained through observances of interwell or interpattern communication of fluids, convergence of operating pressures, as well as via ongoing reservoir depletion monitoring with tools such as time lapse 3D seismic. This information may then be used to determine the appropriate time to convert from a cyclic production process to a continuous production process.

[0064] Fig. 5 is a plot 500 showing the efficacy of dry and wet steam in a BPGD process where the steam volume for the wet steam (60% quality) has been adjusted to be equivalent thermally equivalent to dry steam (90% quality) (i.e. a dry steam equivalent basis). The x-axis 502 represents cumulative production from a field in units of volume (m^3 or barrels), while the y-axis 504 represents the SOR (steam-to-oil ratio), which is the volume of steam injected per volume of oil produced. SOR is a key measure of the performance of a thermal process where a lower SOR is typically a more economic process. On this plot 500, a SOR of two 506 is good, while a SOR of four 508 is acceptable. For a SAGD process, in which the injection well is nearly directly above the production well, 90% quality steam provides the steam-to-oil ratio shown in curve 510. As used herein, the quality of steam is a ratio of the weight of the steam flow that is water vapour versus the weight of entrained water droplets. A higher number represents a larger amount of water vapour in the steam flow. In contrast, if 60% quality is utilized with SAGD it will have a higher (poorer) steam-to-oil ratio as shown by curve 512. Accordingly, SAGD recovery processes are generally developed using the highest steam quality available.

[0065] The facilities designed for SAGD usually generate high quality steam because any injected liquid condensate does not enhance production. Since BPGD makes effective use of the liquid condensate simpler lower cost facilities steam generation facilities can be employed.

[0066] Lower quality or "wet" steam provides an example of the use of a dual mobilizing agent, in which steam is the vertical mobilizing agent, while the hot water and condensate is the lateral mobilizing agent. The steam-to-oil ratio for the use of 60 % quality steam (wet steam) in a basal planar recovery process is shown by curve 514. By comparison, the steam-to-oil ratio for the use of dry steam, shown as curve 516, is nearly identical. Both curves 514 and 516 are lower than the curves 510 and 512 for SAGD, indicating that wet steam acts as an effective dual mobilizing agent. The increased efficiency for BPGD over SAGD is further indicated by the plots discussed with respect to Figs. 6 and 7. It can be noted that these plots were generated using dry steam for both cases.

[0067] Fig. 6 is a plot 600 showing a simulation of the increase in total production rate that may be obtained using a BPGD process. In the plot 600, the x-axis 602 represents the time since production was started, while the y-axis 604 represents the cumulative oil volume produced from the reservoir using BPGD. The total production 606 that could be achieved using the present techniques 606 quickly reaches a maximum, allowing a much faster production of the resources. In contrast, the production 608 from a SAGD process may reach the same amounts, but only after many years.

[0068] Fig. 7 is a plot 700 showing a simulation of the increase in efficiency relative to the steam volume employed that can be obtained using a BPGD process. The x-axis 702 represents the total amount of steam injected into the reservoir, while the y-axis represents the total volume of oil produced from the reservoir. As can be seen in the plot 700, if large volumes of steam are injected the SAGD and BPGD processes result in the same recovery levels. However, economic limits will dictate the actual volume of steam that can be practically injected. The benefit of the BPGD process is indicated by comparing curve 706 to a normal SAGD process, as indicated by curve 708. For example, comparing the two cases at 200,000 m^3 of steam injection volume, SAGD will have produced about 75,000 m^3 of oil whereas the BPGD process will have produced about 110,000 m^3 of oil.

[0069] An assumption inherent in a BPGD process is that a connection can be created between the injection well and the production well early in the recovery process. In the SAGD process a connection is typically established through a warm-up phase during which conductive heating is used to establish the connection.

Because conductive heating is a relatively slow process the wells are spaced about 5 metres apart. It may also be useful to establish a distributed connection along the full length of the wells. If the connection or heated zone does not extend over the full length of the well then steam override may occur. For example, in areas within the reservoir, the steam chamber will rise to the top of the reservoir quickly and will then flow along the top of the reservoir to the producer. A similar situation often occurs when vertical wells are utilized for steamflooding. In order for a BPGD process to be most effective, the well can be configured such that the well lengths are much longer than the well spacing. Further, the wells can be completed with some form of flow control devices on the injector and producer such that the spacing of such devices is less than the well spacing, such as less than half than a distance between adjacent wells or less than a quarter of the distance between adjacent wells. The tighter the spacing of the perforations, the better the basal conformance. For example, the well lengths may be in the 300 to 1500 metres range, the well spacing in the 50 to 150 metres range and the flow control devices spaced every 10 to 50 metres along the well.

[0070] Fig. 8 is process flow diagram of a method 800 for using dual mobilizing agents in a BPGD production of hydrocarbons. The method 800 begins at block 802 with the drilling of a first horizontal well proximate to the base of the reservoir. The first horizontal well may be around 500 to 1500 metres long. The base of the reservoir, or target production zone, may be determined by vertical evaluation wells, a geological model, seismic imaging, or any number of techniques. The first horizontal well, which will be a production well during continuous operations, may be completed with LEP screen-type completions that are sized to allow distributed liquid in-flow along the length of the well. The total area of the perforations may be selected to limit the influx of vapour during continuous production.

[0071] At block 804, a second horizontal well is drilled parallel to the first horizontal well and can be of the same length. The second horizontal well may be laterally offset between about 50 and 200 metres from the first horizontal well. The second horizontal well may be drilled three or more metres above the completion depth of the first horizontal well. In a field having multiple horizontal wells, the depths of the horizontal wells may vary, depending on the base of the reservoir. However, neighbouring horizontal wells will generally have alternating depths. The second horizontal well, which will be an injection well during continuous operations,

may be completed with limited-entry perforation (LEP) screen-type completions that provide for evenly distributed steam injection where the steam is injected in the vapour phase. Typically, the LEP's in the second horizontal well will have a larger open area than those in the first horizontal well when the mobilizing fluid is injected as predominantly a vapour, for example, as steam, and produced as a liquid.

[0072] At block 806, fluid communication may be established between the wells. This may be performed by any number of cyclic production processes. For example, as discussed with respect to Fig. 2, cyclic steaming of horizontal wells with LEP's completions can create uniform basal heating that establishes fluid communications between adjacent wells. In other embodiments, continuous solvent injection or cyclic solvent recovery processes may be used to establish fluid communication. After about two to three cycles of CSS, the heated features between wells may overlap, and the wells may be converted to a BPGD process.

[0073] In some types of reservoirs, a basal plane gravity-drainage layer may be established by injecting a fluid at rates that induce fracturing. As such, this connection process is particularly suited to reservoirs where the stress state favours horizontal fractures. Most commonly reservoirs that favour horizontal fractures are found at depths shallower than about 500 m. It may also be possible in some reservoirs to precondition the reservoir to favour horizontal fractures through pressurization. This may allow horizontal fractures to be generated at greater depths. For example, this may be performed by injecting water, steam, or solvents to raise the reservoir pressure.

[0074] In reservoirs where the stress state may not favour horizontal fractures, solvent fingering may offer an alternate mechanism for generating connections. Solvent fingering is a mechanism whereby a less viscous injected fluid invades a reservoir that is saturated with a more viscous fluid, and occurs when solvent is injected into heavy oil. It is known that solvent fingers will propagate towards regions of lower pressure. The connection can be generated by the cyclic injection and production of solvent into the first horizontal, or production, well in order to establish a finger network of high mobility. Solvent may then be injected into the second horizontal, or injection well, generating a second network of fingers while producing from the first horizontal well. The shortest pathways between the injection well and

production well would be expected to dominate the flow paths and establish a basal communication path.

[0075] Once fluid communication is established between the first and second horizontal wells, at block 808, the dual mobilizing agents may be used. In some embodiments, this includes a single injection of vertical and lateral mobilizing agents. For example, the injection may include a mixture of a solvent that vaporizes at a low temperature, such as about 50 – 75 °C and hot water. The hot water can vaporize the solvent as it enters the reservoir or the solvent may be vaporized in the facilities before entering the formation, providing a vertical mobilizing agent. The hot water acts as the lateral mobilizing agent, as it flows from injection well to production well near the base of the reservoir. As additional hot water is injected any solvent that has condensed and flowed down may once again be vaporized. This mechanism of repeated condensation and vaporization within the reservoir can be termed refluxing. As another example, wet steam may be injected, with or without an added solvent.

[0076] At block 810, a vertical mobilizing agent may be separately injected into the reservoir, for example, using the second horizontal well. After the injection of the vertical mobilizing agent, at block 812, a lateral mobilizing agent may be injected into the reservoir, or imposed on the reservoir. In some embodiments, the lateral mobilizing agent may be an electric current that is flowed through the reservoir, for example, between the injection and production wells. A non-vaporizing, electrically conductive fluid, such as a brine, may be injected continuously or intermittently such that it flows between the injection and production well and acts to concentrate electric current at the base of the reservoir. The electric current can cause resistive heating of the reservoir contents flashing a vertical mobilizing agent and lowering the viscosity of heavy oils in the basal plane, assisting in their flow to the first horizontal well. The injected mobilizing fluids could be steam, solvent, hot water, brine, or mixtures thereof. At block 814, fluids may be continuously produced from the first horizontal, or production, well.

[0077] The lateral and vertical mobilizing agents can be selected to create a process that is more efficient than, for example, SAGD. It is general practice in the industry to inject high quality steam in a thermal process. A commonly observed result is what is termed as steam override. Steam override occurs when the vertical mobilizing agent acts more quickly than the reservoir can drain the produced fluids.

Thus, a lateral mobilizing agent may be useful for increasing the drainage rate. Relative to wet steam injection, a slower acting vertical mobilizing agent and a faster acting lateral mobilizing agent may limit override that can occur near the injector.

[0078] The vertical mobilizing agent can be selected to control the rate of rise of the vapour chamber. For example, different condensable hydrocarbon solvents, steam and non-condensable gases, or combinations thereof, can be used to control the temperature and pressure of the vapour zone. Similarly, the effectiveness of the lateral mobilizing agent can be managed by mechanisms such as injecting higher temperature fluids, larger solvent volumes, varying fractions of water and hydrocarbon solvents or additional electrical heating.

[0079] While the present techniques may be susceptible to various modifications and alternative forms, the embodiments discussed above have been shown only by way of example. However, it should again be understood that the techniques is not intended to be limited to the particular embodiments disclosed herein. Indeed, the present techniques include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

Embodiments

[0080] An embodiment described herein provides a method for harvesting resources in a reservoir. The method includes drilling a first horizontal well substantially proximate to a base of a reservoir and drilling a second horizontal well at a horizontal offset from the first horizontal well. Fluid communication is established between the first horizontal well and the second horizontal well through a cyclic production process. A vertical mobilizing agent is injected into the reservoir and a lateral mobilizing agent is used in the reservoir. Fluids are produced from the first horizontal well.

[0081] The horizontal offset may be between about 50 and 200 metres. The second horizontal well can be greater than about three metres shallower than the first well.

[0082] Using a lateral mobilizing agent can include flowing an electric current through the reservoir. An electrically conductive, non vaporizing fluid may be injected into the reservoir, for example, to assist in carrying the electric current. Further, using a lateral mobilizing agent may include injecting hot water into the reservoir.

[0083] The lateral mobilizing agent may include a liquid hydrocarbon solvent injected into the reservoir. The liquid hydrocarbon solvent can be heated before injection and hot water, steam, or both, may be injected in combination with the liquid hydrocarbon solvent. Wet steam may be injected into the reservoir, for example, functioning as both a lateral mobilizing agent and a vertical mobilizing agent.

[0084] Fluid communication can be established between the first horizontal well and the second horizontal well by creating solvent fingers using cyclic solvent injection and production or using a continuous solvent injection. In some embodiments, fluid communication is established by cyclic steam stimulation, cyclic solvent stimulation, or both.

[0085] Injecting a vertical mobilizing agent can include injecting steam vapour, a light hydrocarbon solvent, or both into the second horizontal well. A non-condensable gas may be injected with the vertical mobilizing agent. The lateral mobilizing agents, or the vertical mobilizing agent, or both over time.

[0086] Another embodiment described herein provides a system for harvesting resources in a reservoir. The system includes a first horizontal well substantially proximate to the base of the reservoir and a second horizontal well at a horizontal offset from the first horizontal well, wherein the second horizontal well is vertically offset from the first horizontal well. A cyclic production system is configured to establish fluid communication between the wells. A continuous injection and production system is configured to inject a vertical mobilizing fluid into the reservoir, use a lateral mobilizing agent in the reservoir, and produce a fluid from the first horizontal well.

[0087] The system can include a steam generation system configured to provide steam for injection. A separation system can be configured to separate a hydrocarbon stream from a produced fluid. The vertical mobilizing agent can include steam, solvents, or combinations thereof.

[0088] The system can include an electrical system configured to flow an electrical current through the reservoir. The electrical system may be configured to flow a current between the first horizontal well and the second horizontal well. The lateral mobilizing agent can include hot water, solvent, electric current, or any combinations thereof.

[0089] Another embodiment described herein provides a method for producing hydrocarbons. The method includes producing fluids from a number of production wells in a reservoir and imposing a lateral mobilizing agent on the reservoir from a number of injection wells. Each of the injection wells is adjacent to one of the production wells and each of the injection wells is laterally offset from each of the adjacent production wells. Fluid communication has been established between an injection well and an adjacent production well using a cyclic production process. A vertical mobilizing agent is heated using heat transferred from the lateral mobilizing agent and a hydrocarbon stream is separated from the fluids produced from the plurality of production wells.

[0090] Each of the injection wells may be drilled at a shallower level than each of the adjacent production wells. The lateral offset may be between about 50 and 200 metres, and each of the injection wells can be about three metres higher than a neighbouring production well. An electric current can be passed between the plurality of injection wells and the plurality of production wells.

CLAIMS

What is claimed is:

1. A method for harvesting resources in a reservoir, comprising:

drilling a first horizontal well substantially proximate to a base of a reservoir;

drilling a second horizontal well at a horizontal offset from the first horizontal well, wherein the second horizontal well is greater than about three metres shallower than the first well,

establishing fluid communication between the first horizontal well and the second horizontal well through a cyclic production process;

after establishing fluid communication between the first horizontal well and the second horizontal, converting the first horizontal well into an injection well and the second horizontal well into a production well and operating the first horizontal well and the second horizontal under a continuous injection/production process;

injecting a vertical mobilizing agent into the reservoir, wherein the vertical mobilizing agent comprises a light hydrocarbon vapour under reservoir conditions which promotes the rise of a depleted bitumen chamber within the reservoir;

contacting the mobilizing agent with bitumen located at the top and sides of the depleted bitumen chamber, thereby condensing the vertical mobilizing agent, lowering the viscosity of the bitumen, and expanding the depleted bitumen chamber;

injecting a lateral mobilizing agent into the reservoir, wherein the lateral mobilizing agent comprises hot water;

using the heat from the lateral mobilizing agent to flash the condensed vertical mobilizing agent back into a vapour; and

producing fluids from the first horizontal well.

2. The method of claim 1, wherein the horizontal offset is between about 50 and 200 metres.

3. The method of claim 1, comprising establishing fluid communication between the first horizontal well and the second horizontal well by creating solvent fingers using cyclic solvent injection and production or using a continuous solvent injection.

4. The method of claim 1, wherein establishing fluid communication is performed by cyclic steam stimulation, cyclic solvent stimulation, or both.

5. The method of claim 4, wherein a non-condensable gas is injected with the vertical mobilizing agent.

6. The method of claim 1, comprising changing the lateral mobilizing agents, or the vertical mobilizing agent, or both over time.

7. A system for harvesting resources in a reservoir, comprising:

a first horizontal well substantially proximate to the base of the reservoir;

a second horizontal well at a horizontal offset from the first horizontal well, wherein the second horizontal well is vertically offset from the first horizontal well and wherein the second horizontal well is greater than about three metres shallower than the first well;

a cyclic production system configured to establish fluid communication between the wells; and

the cyclic production system reconfigured into a continuous injection and production system, wherein the continuous injection and production system is configured to:

inject a vertical mobilizing fluid into the reservoir wherein the vertical mobilizing agent comprises a light hydrocarbon vapour under reservoir conditions which promotes the rise of a depleted bitumen chamber within the reservoir;

allow the mobilizing agent to contact with bitumen located at the top and sides of the depleted bitumen chamber, thereby condensing the vertical mobilizing agent, lowering the viscosity of the bitumen, and expanding the depleted bitumen chamber;

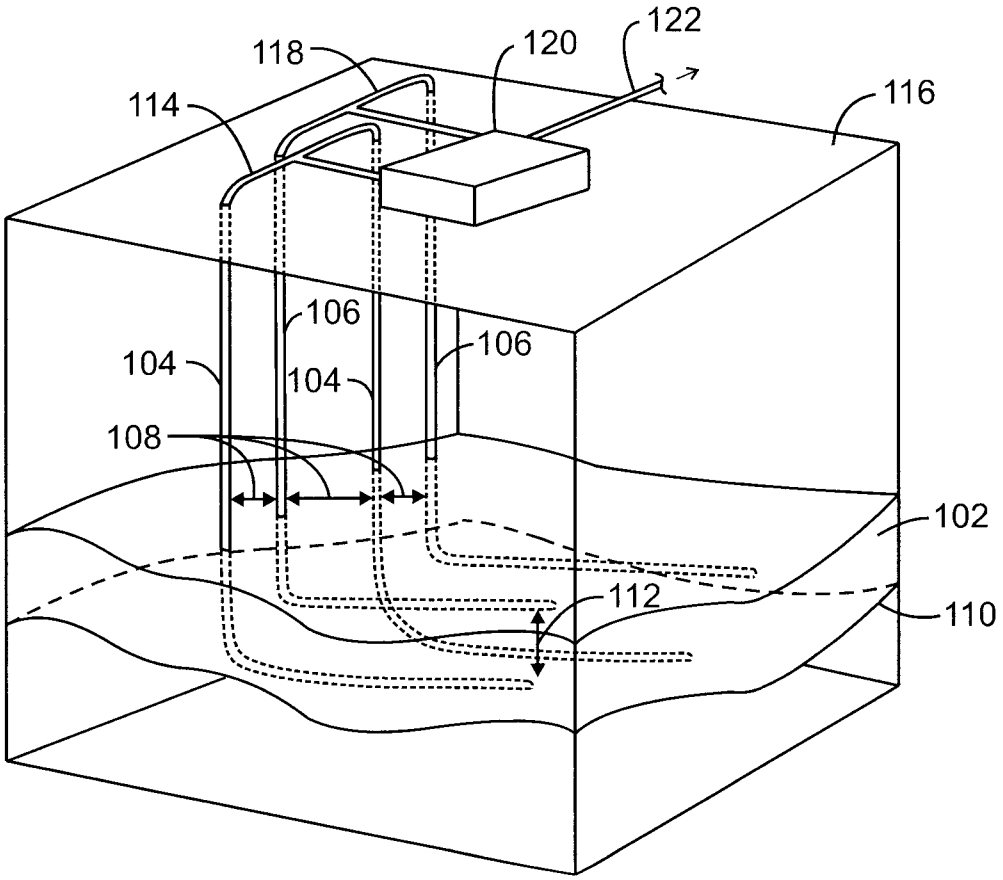
inject a lateral mobilizing agent into the reservoir, wherein the lateral mobilizing agent comprises hot water;

use the heat from the lateral mobilizing agent in the reservoir to flash the vertical mobilizing agent back into a vapour; and

produce a fluid from the first horizontal well.

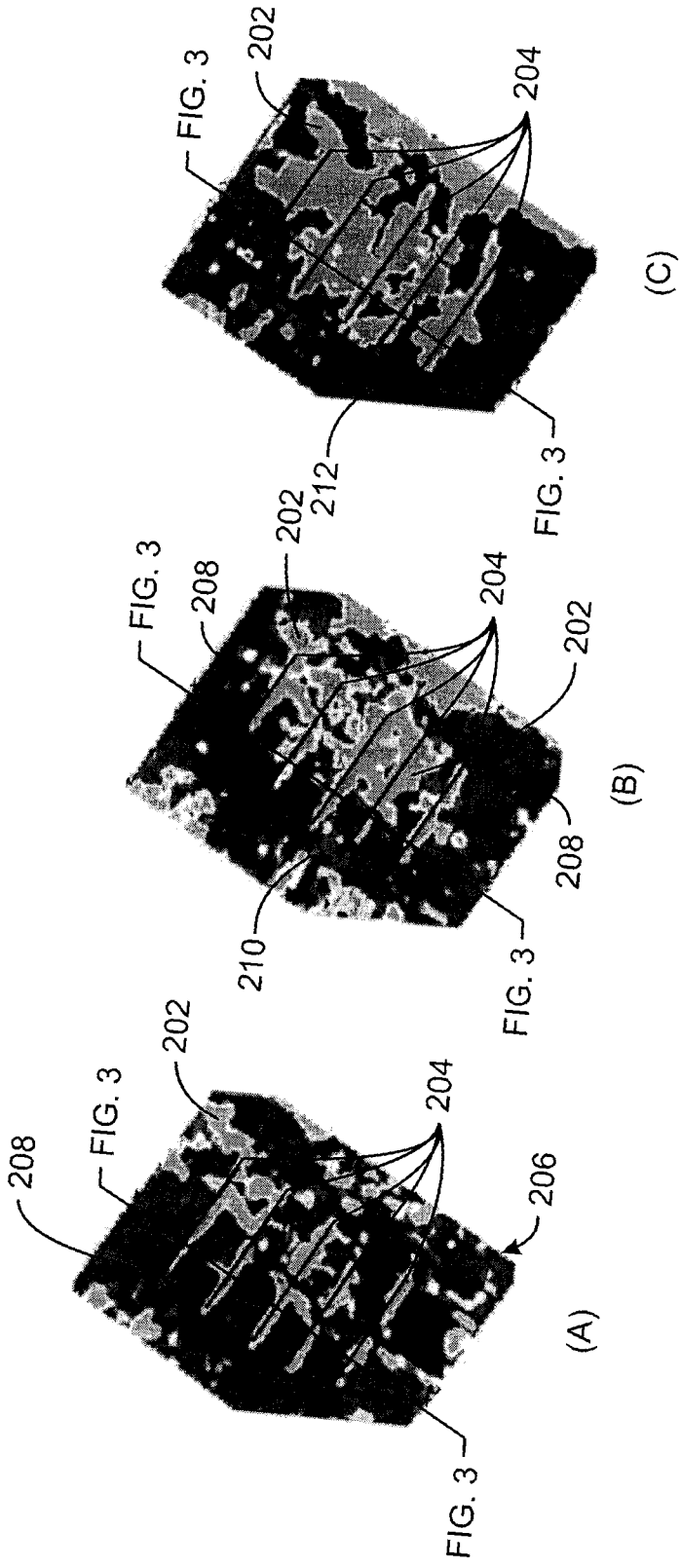
8. The system of claim 7, comprising a steam generation system configured to provide steam for injection.

9. The system of claim 7, comprising a separation system configured to separate a hydrocarbon stream from a produced fluid.

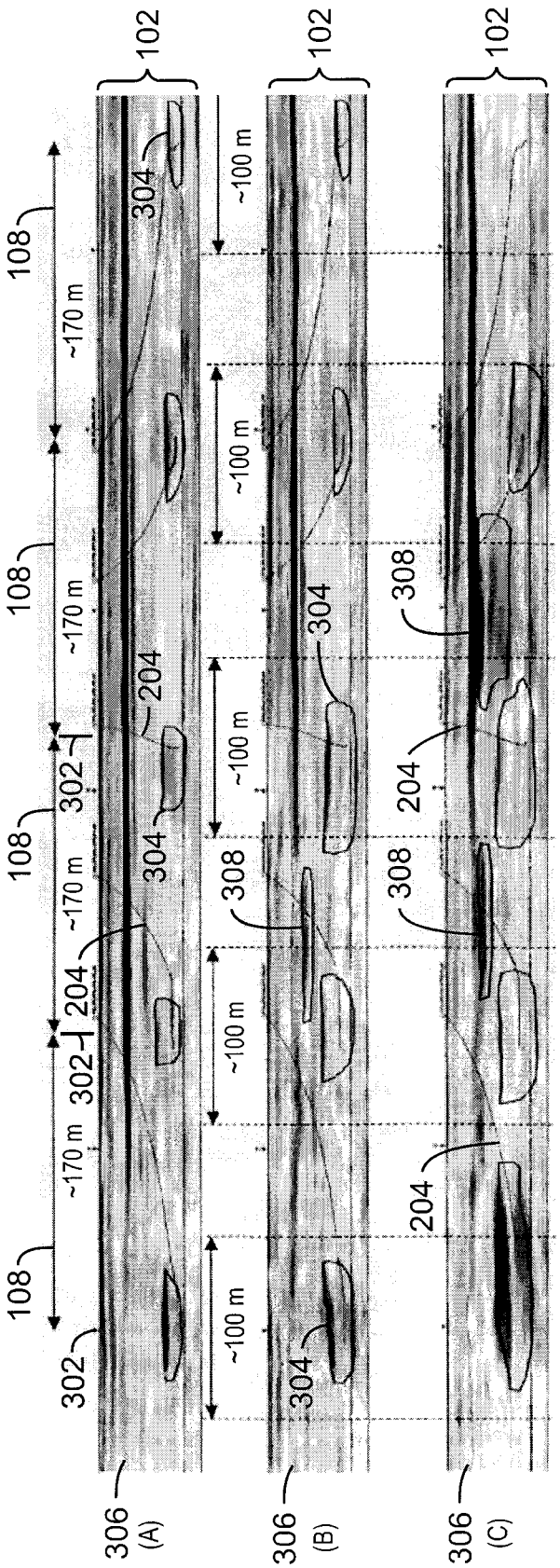


100

FIG. 1

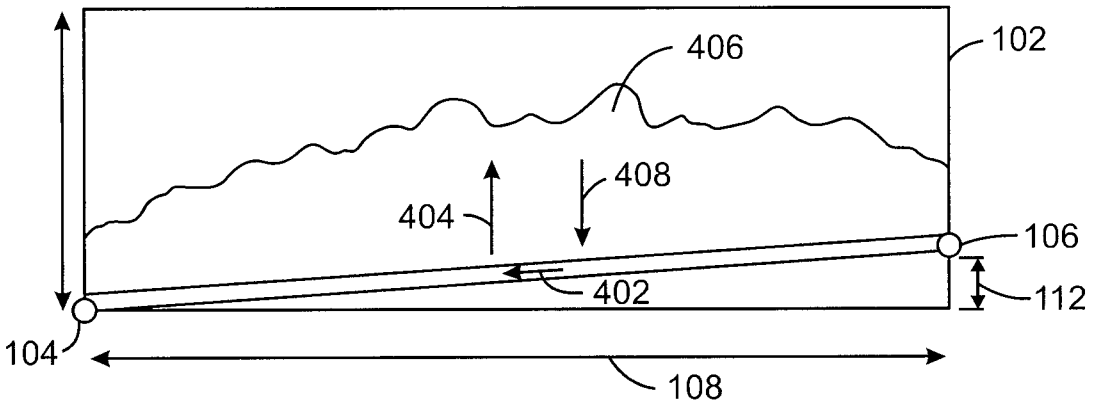

FIG. 3
202
204
212
FIG. 3
(C)
FIG. 3
208
202
204
202
210
208
FIG. 3
(B)
FIG. 3
202
204
208
206
FIG. 3
(A)

200
FIG. 2


102
102
102
108
108
108
108
~170 m
~170 m
~170 m
~170 m
~100 m
~100 m
~100 m
~100 m
~100 m
302
302
204
204
304
304
304
304
308
308
308
306
(A)
306
(B)
306
(C)

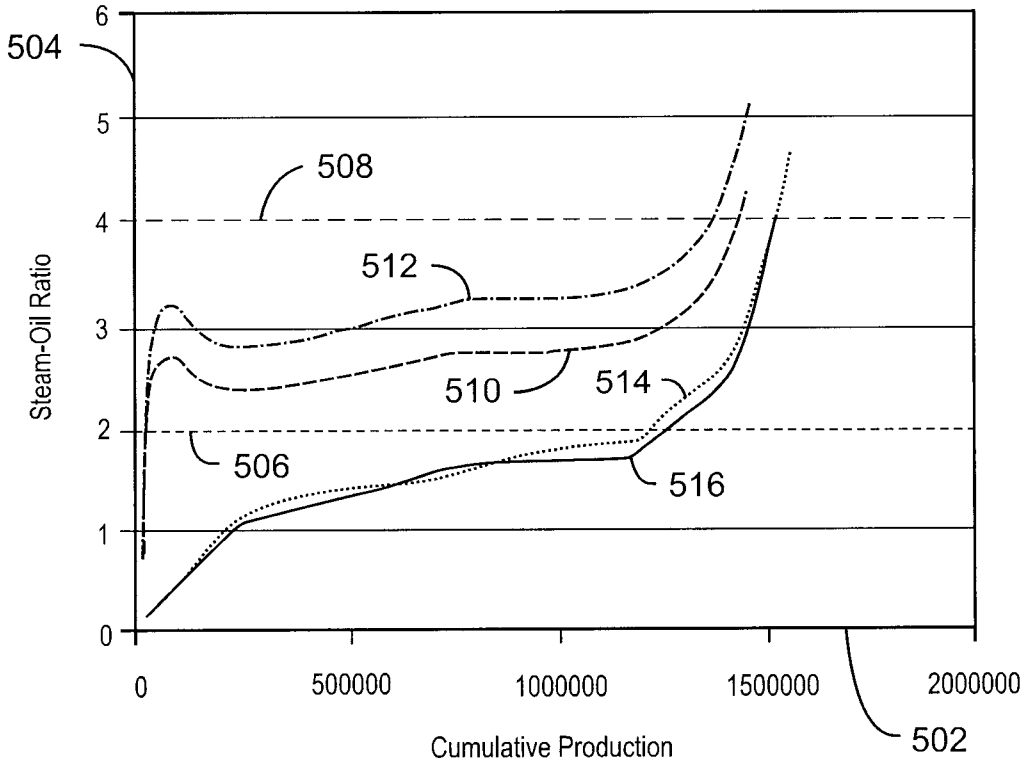
300

FIG. 3



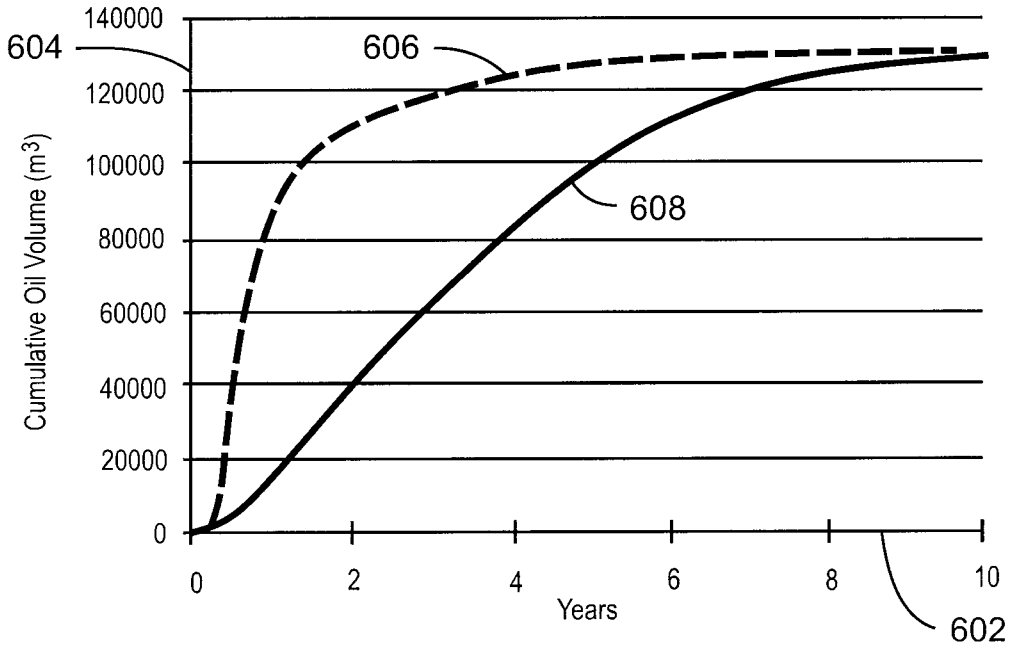
400

FIG. 4



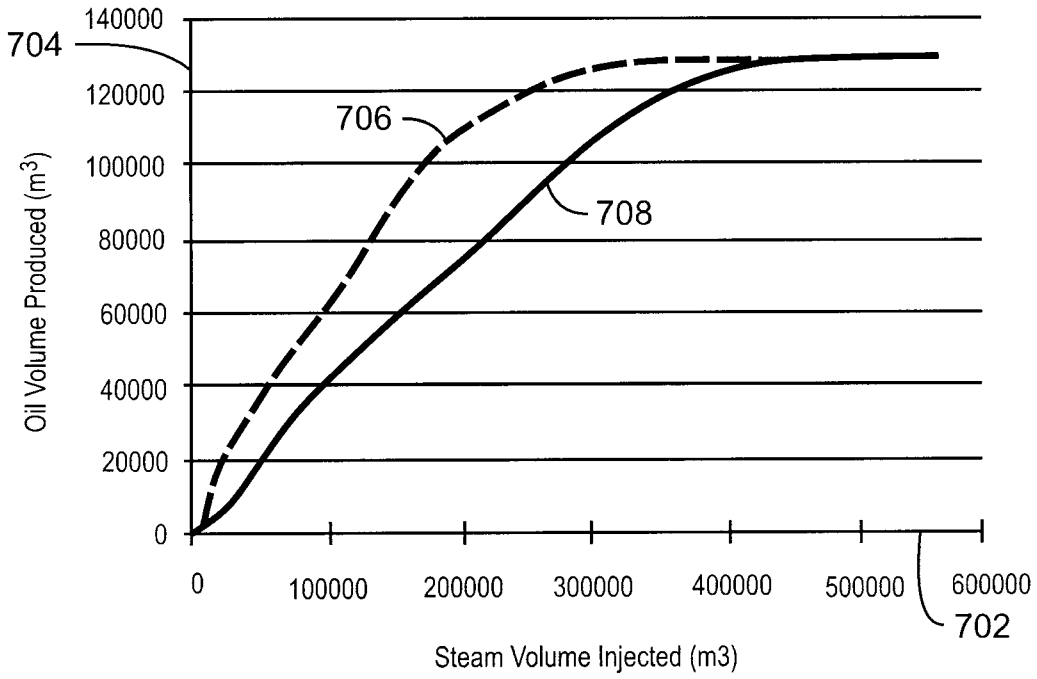
500

FIG. 5


604
606
608
602
140000
120000
100000
80000
60000
40000
20000
0
Cumulative Oil Volume (m3)
0
2
4
6
8
10
Years

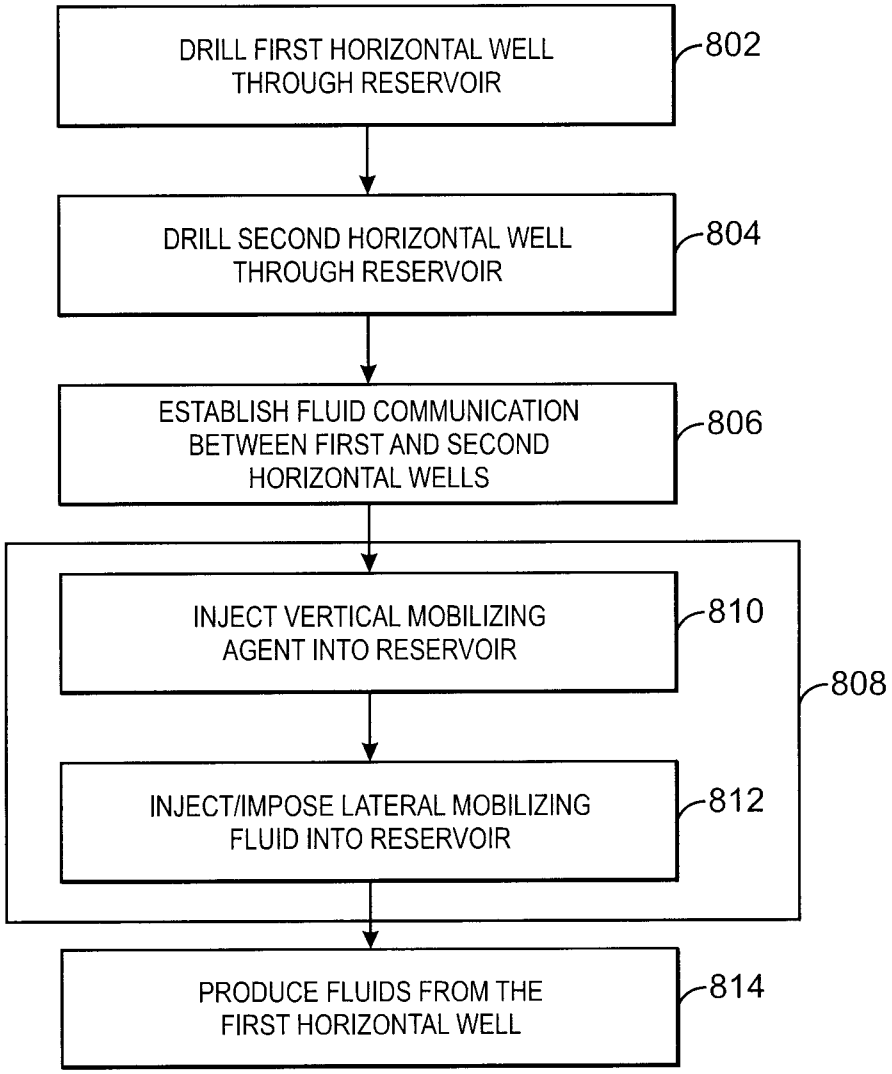
600

FIG. 6


704
140000
120000
100000
80000
60000
40000
20000
0
706
708
Oil Volume Produced (m3)
0
100000
200000
300000
400000
500000
600000
702
Steam Volume Injected (m3)

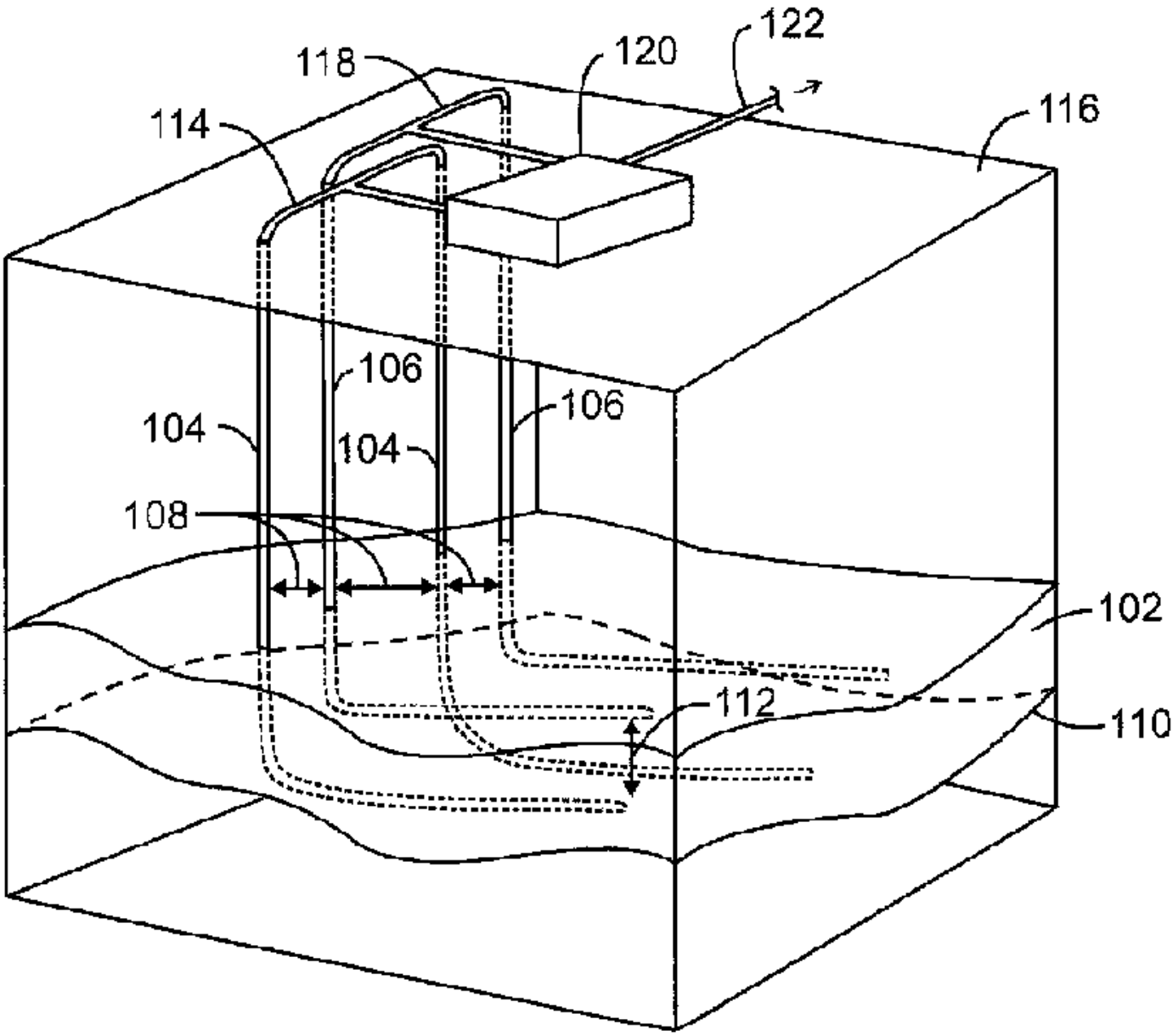
700

FIG. 7


DRILL FIRST HORIZONTAL WELL THROUGH RESERVOIR
802
DRILL SECOND HORIZONTAL WELL THROUGH RESERVOIR
804
ESTABLISH FLUID COMMUNICATION BETWEEN FIRST AND SECOND HORIZONTAL WELLS
806
INJECT VERTICAL MOBILIZING AGENT INTO RESERVOIR
810
808
INJECT/IMPOSE LATERAL MOBILIZING FLUID INTO RESERVOIR
812
PRODUCE FLUIDS FROM THE FIRST HORIZONTAL WELL
814

800

FIG. 8



100