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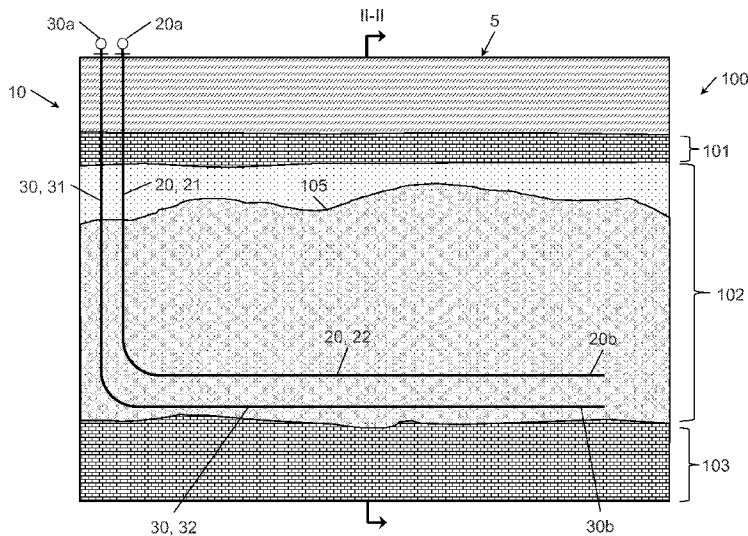


Figure 1

(57) Abstract: A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation includes (a) forming an aqueous solution with a non-ionic surfactant. In addition, the method includes (b) making an oil-in-water emulsion with the aqueous solution and a water insoluble solvent or diluent. Further, the method includes (c) injecting the oil-in-water emulsion into the reservoir with the reservoir at the ambient temperature. Still further, the method includes (d) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (c).



**SYSTEMS AND METHODS FOR ACCELERATING PRODUCTION OF VISCOUS
HYDROCARBONS IN A SUBTERRANEAN RESERVOIR WITH EMULSIONS
COMPRISING CHEMICAL AGENTS**

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of U.S. provisional patent application Serial No. 61/976,915 filed April 8, 2014, and entitled “Systems and Methods for Accelerating Production of Viscous Hydrocarbons in a Subterranean Reservoir with Emulsions Comprising Chemical Agents,” which is hereby incorporated herein by reference in its entirety. This application also claims benefit of U.S. provisional patent application Serial No. 62/042,632 filed August 27, 2014, and entitled “Systems and Methods for Accelerating Production of Viscous Hydrocarbons in a Subterranean Reservoir with Emulsions Comprising Chemical Agents,” which is hereby incorporated herein by reference in its entirety.

**STATEMENT REGARDING FEDERALLY SPONSORED
RESEARCH OR DEVELOPMENT**

[0002] Not applicable.

FIELD

[0003] This disclosure relates generally to thermal recovery techniques for producing viscous hydrocarbons such as heavy oil and bitumen. More particularly, this disclosure relates to the injection of emulsions comprising chemical agents before heating the formation (e.g., before injecting steam) to accelerate the production of viscous hydrocarbons with thermal recovery techniques.

BACKGROUND

[0004] As existing reserves of conventional light liquid hydrocarbons (e.g., light crude oil) are depleted and prices for hydrocarbon products continue to rise, there is a push to find new sources of hydrocarbons. Viscous hydrocarbons such as heavy oil and bitumen offer an alternative source of hydrocarbons with extensive deposits throughout the world. In general, hydrocarbons having an API gravity less than 22° are referred to as “heavy oil” and hydrocarbons having an API gravity less than 10° are referred to as “bitumen.” Although recovery of heavy oil and bitumen present challenges due to their relatively high viscosities and

limited mobility, there are a variety of processes that can be employed to recover such viscous hydrocarbons from underground deposits.

[0005] Many techniques for recovering heavy oil and bitumen utilize thermal energy to heat the hydrocarbons, decrease the viscosity of the hydrocarbons, and mobilize the hydrocarbons within the formation, thereby enabling the extraction and recovery of the hydrocarbons. Accordingly, such production and recovery processes may generally be described as “thermal” techniques. A steam-assisted gravity drainage (SAGD) operation is one thermal technique for recovering viscous hydrocarbons such as bitumen and heavy oil.

[0006] SAGD operations typically employ two vertically spaced horizontal wells drilled into the reservoir and located close to the bottom of the reservoir. Steam is injected into the reservoir through an upper, horizontal injection well, referred to as the injection well, to form a “steam chamber” that extends into the reservoir around and above the horizontal injection well. Thermal energy from the steam reduces the viscosity of the viscous hydrocarbons in the reservoir, thereby enhancing the mobility of the hydrocarbons and enabling them to flow downward through the formation under the force of gravity. The mobile hydrocarbons drain into the lower horizontal well, also referred to as the production well. The hydrocarbons are collected in the production well and are produced to the surface via artificial lift.

[0007] The commissioning of a SAGD well pair requires fluid communication between the injection well and the production well. The process of establishing fluid communication between the injection well and the production well of SAGD well pair is referred to as “start-up” or the “start-up” phase. Typically, start-up is achieved by steam circulation or “bullheading” of steam, provided the formation is sufficiently permeable to water. Steam circulation and bullheading can occur in both the injection and the production wells. The objective of both techniques is to heat and mobilize the viscous hydrocarbons in the zone between the well pair to allow fluid communication from the injection well to the production well. Once fluid communication is achieved in the interwell zone (i.e., region between the injection well and the production well), then steam is injected through only the injection well and the production well is used to produce fluid, thereby transitioning the well pair from the start-up phase into the “production” phase.

BRIEF SUMMARY OF THE DISCLOSURE

[0008] Embodiments disclosed herein are directed to a methods and systems for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure. In one embodiment disclosed herein, a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation comprises (a) forming an aqueous solution with a non-ionic surfactant. In addition, the method comprises (b) making an oil-in-water emulsion with the aqueous solution and a water insoluble solvent or diluent. Further, the method comprises (c) injecting the oil-in-water emulsion into the reservoir with the reservoir at the ambient temperature. Still further, the method comprises (d) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (c).

[0009] In another embodiment disclosed herein, a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation comprises (a) forming a SAGD well pair extending through the formation. The SAGD well pair includes an injection well and a production well. Each well has a vertical section extending from the surface of the formation and a horizontal section traversing the reservoir. In addition, the method comprises (b) forming an oil-in-water emulsion comprising an aqueous solution and a water insoluble solvent or diluent. The aqueous solution includes a non-ionic surfactant that is water-soluble and substantially non-reactive in the reservoir at the ambient temperature of the reservoir. Further, the method comprises (c) injecting the oil-in-water emulsion into the reservoir with the reservoir at the ambient temperature. Still further, the method comprises (d) injecting steam into the reservoir after (c) to increase the temperature of the reservoir to a SAGD operating temperature.

[0010] In another embodiment disclosed herein, a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation comprises (a) forming an aqueous solution with a water-soluble chemical agent that is substantially non-reactive in the reservoir at the ambient temperature. In addition, the method comprises (b) making a water-in-oil emulsion with the aqueous solution and a water insoluble solvent or diluent. Further, the method comprises (c) injecting the water-in-oil emulsion into the reservoir with the reservoir at the ambient temperature. Still further, the method comprises (d) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (c).

[0011] In another embodiment disclosed herein, a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation comprises (a) forming a SAGD well pair extending

through the formation. The SAGD well pair includes an injection well and a production well. Each well has a vertical section extending from the surface of the formation and a horizontal section traversing the reservoir. In addition, the method comprises (b) forming a water-in-oil emulsion comprising an aqueous solution mixed in an oil phase. The aqueous solution includes a water soluble chemical agent and the oil phase comprises a water insoluble diluent or solvent. Further, the method comprises (c) injecting the water-in-oil emulsion into the reservoir with the reservoir at the ambient temperature. Still further, the method comprises (d) injecting steam into the reservoir after (c) to increase the temperature of the reservoir to a SAGD operating temperature.

[0012] In another embodiment disclosed herein, a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation comprises (a) making a micro-emulsion comprising a solvent, a brine, and a surfactant. In addition, the method comprises (b) injecting the micro-emulsion into the reservoir with the reservoir at the ambient temperature. Further, the method comprises (c) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (b).

[0013] Embodiments described herein comprise a combination of features and advantages intended to address various shortcomings associated with certain prior devices, systems, and methods. The foregoing has outlined rather broadly the features and technical advantages of the invention in order that the detailed description of the invention that follows may be better understood. The various characteristics described above, as well as other features, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings. It should be appreciated by those skilled in the art that the conception and the specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the invention. It should also be realized by those skilled in the art that such equivalent constructions do not depart from the spirit and scope of the invention as set forth in the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0015] Figure 1 is a schematic cross-sectional side view of an embodiment of a system in accordance with the principles described herein for producing viscous hydrocarbons from a subterranean formation;

[0016] Figure 2 is a schematic cross-sectional end view of the system of Figure 1 taken along section II–II of Figure 1;

[0017] Figure 3 is a graphical illustration of an embodiment of a method in accordance with the principles described herein for producing viscous hydrocarbons in the reservoir of Figure 1 using the system of Figure 1;

[0018] Figure 4 is a schematic cross-sectional end view of the system of Figure 1 taken along section II–II of Figure 1 illustrating a loaded zone formed by injecting the emulsion into the reservoir of Figure 1 according to the method of Figure 3; and

[0019] Figure 5 is a schematic cross-sectional end view of the system of Figure 1 taken along section II–II of Figure 1 illustrating a steam chamber formed by injecting steam into the reservoir of Figure 1 according to the method of Figure 3.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0020] The following discussion is directed to various exemplary embodiments. However, one skilled in the art will understand that the examples disclosed herein have broad application, and that the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment.

[0021] Certain terms are used throughout the following description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names. This document does not intend to distinguish between components or features that differ in name but not function. The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

[0022] In the following discussion and in the claims, the terms "including" and "comprising" are used in an open-ended fashion, and thus should be interpreted to mean "including, but not limited to..." Also, the term "couple" or "couples" is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be

through a direct connection, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms "axial" and "axially" generally mean along or parallel to a central axis (e.g., central axis of a body or a port), while the terms "radial" and "radially" generally mean perpendicular to the central axis. For instance, an axial distance refers to a distance measured along or parallel to the central axis, and a radial distance means a distance measured perpendicular to the central axis. Any reference to up or down in the description and the claims will be made for purposes of clarity, with "up", "upper", "upwardly" or "upstream" meaning toward the surface of the borehole and with "down", "lower", "downwardly" or "downstream" meaning toward the terminal end of the borehole, regardless of the borehole orientation.

[0023] The process of establishing fluid communication between the injection well and the production well of SAGD well pair during "start-up" (via steam circulation or "bullheading" of steam) is often time consuming. For example, start-up typically takes more than three months. In many cases, the heating and mobilization of the viscous hydrocarbons during start-up is not uniform due to local variations in permeability and porosity, which may result in a protracted start-up and poor initial conformance of the steam chamber. Limitations on the temperature and pressure of the steam injected in SAGD operations (e.g., due to the reservoir being shallow, poor caprock integrity, etc.) can also lengthen start-up and negatively affect initial conformance of the steam chamber. Protracted start-up operations result in high costs and delays the ultimate production of oil. However, embodiments of systems and methods described herein offer the potential to accelerate mobilization of the viscous hydrocarbons during start-up, thereby decreasing the time to achieve fluid communication between SAGD wells 20, 30, increasing start-up quality through improved conformance, and accelerating production.

[0024] Referring now to Figures 1 and 2, an embodiment of a system 10 for producing viscous hydrocarbons (e.g., bitumen and heavy oil) from a subterranean formation 100 using a thermal recovery technique is shown. In this embodiment, system 10 is configured to employ steam-assisted gravity drainage (SAGD) thermal recovery techniques to produce generally immobile, viscous hydrocarbons. Moving downward from the surface 5, formation 100 includes an upper overburden layer or region 101 of consolidated cap rock, an intermediate layer or region 102 of rock, and a lower underburden layer or region 103 of consolidated rock. Layers 101, 103 are formed of generally impermeable formation material (e.g., limestone). However, layer 102 is formed of a generally porous, permeable formation material (e.g., sandstone), thereby enabling

the storage of hydrocarbons therein and allowing the flow and percolation of fluids therethrough. In particular, layer 102 contains a reservoir 105 of viscous hydrocarbons (reservoir 105 shaded in Figures 1 and 2).

[0025] System 10 mobilizes, collects and produces viscous hydrocarbons in reservoir 105 using SAGD techniques. In this embodiment, system 10 includes a steam injection well 20 extending downward from the surface 5 and a hydrocarbon production well 30 extending downward from the surface 5 generally parallel to injection well 20. Each well 20, 30 extends through overburden layer 101 and includes an uphole end 20a, 30a, respectively, disposed at the surface 5, a downhole end 20b, 30b, respectively, disposed in formation 100, a generally vertical section 21, 31, respectively, extending into the formation 100 from the surface 5, and a horizontal section 22, 32, respectively, extending horizontally through layer 102 and reservoir 105. Horizontal sections 22, 32 are both positioned proximal the bottom of reservoir 105 and above underburden layer 103, with section 32 of production well 30 located below section 22 of injection well 20. In addition, horizontal sections 22, 32 are lined with perforated or slotted liners, and thus, are both open to reservoir 105.

[0026] Referring now to Figure 3, an embodiment of a method 200 for producing viscous hydrocarbons (e.g., heavy oil and/or bitumen) from reservoir 105 (or portion of reservoir 105) using system 10 is shown. In this embodiment, reservoir 105 is loaded with an emulsion including one or more chemical agents prior to initiating start-up of the SAGD well pair 20, 30. As will be described in more detail below, the subsequent addition of thermal energy during start-up of the SAGD well pair 20, 30 and/or production operations in combination with the chemical agents facilitates an accelerated mobilization of the viscous hydrocarbons, thereby decreasing the time to achieve fluid communication between SAGD wells 20, 30, increasing start-up quality through improved conformance, and accelerating production from well 30.

[0027] Although embodiments of method 200 can be used to produce hydrocarbons having any viscosity under ambient reservoir conditions (ambient reservoir temperature and pressure) including, without limitation, light hydrocarbons, heavy hydrocarbons, bitumen, etc., embodiments of method 200 are particularly suited to producing viscous hydrocarbons having a viscosity greater than 10,000 cP under ambient reservoir conditions. In general, viscous hydrocarbons having a viscosity greater than 10,000 cP under ambient reservoir conditions are immobile within the reservoir and typically cannot be produced economically using conventional, non-thermal, in situ recovery methods.

[0028] Beginning in block 201 of method 200, one or more chemical agents for injection into reservoir 105 are selected. The purpose of the chemical agent(s) is to accelerate and enhance the initial mobilization of the viscous hydrocarbons in reservoir. In general, the ability of a chemical agent to enhance the mobility of hydrocarbons depends on a variety of factors including, without limitation, the type of formation, its oil saturation, water saturation, the native permeability to water, physical and chemical properties of the oil, etc. Core and/or oil samples from the formation of interest can be tested with various chemical agents to facilitate the selection in block 201. The cost and availability of various chemical agent(s) may also impact the selection in block 201.

[0029] In block 202, an emulsion including the selected chemical agent(s) is formed. In one embodiment, the emulsion formed in block 202 is an oil-in-water emulsion stabilized by one or more surfactant(s). In such embodiments, each chemical agent is an oil soluble diluent or organic solvent that defines the oil phase of the oil-in-water emulsion, and the surfactant(s) function as the emulsifier(s). According to Bancroft's rule, the phase in which the emulsifier is more soluble constitutes the continuous phase. As will be described in more detail below, in this embodiment, the surfactant (i.e., the emulsifier) is more soluble in the water phase than the oil phase, and thus, the water defines the continuous phase of the emulsion and the oil soluble diluent(s) or organic solvent(s) (i.e., the chemical agent(s)) define the dispersed phase of the emulsion.

[0030] Examples of suitable oil soluble diluents and organic solvents that can be used as chemical agents in the oil-in-water emulsions include, without limitation, gas condensate, light crude oil, naphtha, kerosene, toluene, xylene, and the like. The water is preferably a brine having a salt concentration and composition analogous to that of reservoir 105 to reduce the potential for the aqueous solution to negatively alter reservoir 105. In general, the salt concentration and composition of the reservoir 105 can be determined from core samples and/or from samples of fluids that naturally migrate from reservoir 105 into a wellbore traversing reservoir 105.

[0031] Each stabilizing surfactant(s) in the oil-in-water emulsion is a non-ionic surfactant that is water soluble or substantially water soluble at ambient reservoir temperatures, but has a reduced solubility at a temperature above the ambient reservoir temperature, referred to herein as the "phase inversion temperature." Thus, at the ambient reservoir temperature, the oil-in-water emulsion is relatively stable, however, above the phase inversion temperature, the oil-in-

water emulsion is destabilized due to the reduced solubility of the surfactant(s). More specifically, many nonionic surfactants include a polyoxyethylene (POE) group. At ambient temperature, these surfactants are soluble in water through hydrogen bonding with the POE chain, which enables the surfactant to be water-soluble. However, without being limited by this or any particular theory, as the temperature increases, the hydrogen bonds weaken, resulting in decreased solubility of the surfactants. At the phase inversion temperature, the surfactants become more soluble in the oil phase of the emulsion than the water phase such that the original oil-in-water emulsion transitions to a water-in-oil emulsion. Destabilization of the oil-in-water emulsion (i.e., transition of the oil-in-water emulsion to a water-in-oil emulsion) results in the release of the oil phase (i.e., diluent or organic solvent). At the phase inversion temperature, the oil phase of the emulsion begins to separate from the water phase resulting in the oil-in-water emulsion becoming a cloudy two-phase system. Accordingly, the phase inversion temperature may also be referred to as the “cloud point.”

[0032] Each surfactant(s) preferably has a phase inversion temperature between 37°C and 90°C. Several non-ionic surfactants have a phase inversion temperatures within this preferred range, and thus, are generally preferred as compared to other types of surfactants. Examples of water soluble non-ionic surfactants suitable for use as stabilizing surfactants in the oil-in-water emulsion include, without limitation, ethoxylated non-ionic surfactants, octylphenol ethoxylates (e.g. Triton™ X series surfactants available from The DOW Chemical Company of Midland, Michigan), secondary alcohol ethoxylates (e.g. Tergitol™ 15-S series surfactants available from The DOW Chemical Company of Midland, Michigan), branched secondary alcohol ethoxylates (e.g. Tergitol™ TMN series surfactants available from The DOW Chemical Company of Midland, Michigan), nonylphenol ethoxylates (e.g. Tergitol™ NP series surfactants available from The DOW Chemical Company of Midland, Michigan), polyoxyethylenesorbitan esters (e.g., TWEEN® 20 or TWEEN® 40 available from Croda Inc. of Edison, New Jersey), and the like. A list of exemplary water soluble non-ionic surfactants suitable for use as stabilizing surfactants in the oil-in-water emulsion, associated phase inversion temperatures, and associated hydrophilic-lipophilic balances (HLB) are provided in Table 1 below. It should be appreciated that the phase inversion temperature or cloud point can be changed by varying the surfactant concentration, the electrolytes in the brine, the salinity of the brine, or combinations thereof. Thus, for a specific non-ionic surfactant, the cloud point is controllably adjustable or tunable within a certain range.

TABLE 1

Surfactant	Phase Inversion Temperature (°C) for 1 wt % surfactant in aqueous solution	HLB
Tergitol NP-7	20	12.0
Triton X-114	25	12.3
Tergitol 15-S-7	37	12.1
Tergitol NP-8	43	12.6
Tergitol NP-9	54	12.9
Tergitol NP-10	63	13.2
Tergitol TMN-100X (90%)	65	14.0
Triton X-100	66	13.4
Tergitol NP-11	72	13.5
Tergitol NP-12	78	13.8
Tergitol NP-13	82	13.9
Triton X-102	88	14.4
Tergitol 15-S-12	89	14.5
Tergitol NP-15	>100	15.0
Tergitol 15-S-15	>100	15.5
Triton X-165 (50%)	>100	15.5

[0033] The oil-in-water emulsion preferably comprises 30.0 to 50.0 wt % water phase, 50.0 to 70.0 wt % oil phase, and less than or equal to 5.0 wt % surfactant(s). The size of the droplets of oil in the oil-in-water emulsion are preferably less than 20.0 μm , more preferably less than 10.0 μm , and even more preferably between 1.0 and 10.0 μm . Other chemical additive(s) that offer the potential to reduce the viscosity of the viscous hydrocarbons may also be added to oil phase or water phase of the oil-in-water emulsion.

[0034] In embodiments where the emulsion formed in block 202 is an oil-in-water emulsion stabilized by one or more surfactant(s), the emulsion has a relatively low viscosity, which offers the potential for easy injection into reservoir 105 according to block 204 described in more detail below. Embodiments in which the emulsion formed in block 202 is an oil-in-water emulsion are generally preferred for use in reservoirs that exhibit good native water mobility as such an emulsion relies on the high mobility of the water continuous phase, relative to the viscous hydrocarbons, in the reservoir for dispersal in the reservoir 105 described in more detail below.

[0035] In another embodiment, the emulsion formed in block 202 is a water-in-oil emulsion. In such embodiments, each chemical agent is a chemical additive dissolved or dispersed in the

water phase of the emulsion, and one or more water insoluble diluent(s) and/or solvent(s) define the oil phase of the emulsion. In addition, the oil phase is the continuous phase and the water phase containing the chemical agent(s) is the dispersed phase. The water-in-oil emulsions preferably comprises 40.0 to 60.0 wt % oil phase, with the balance being the water phase. The size of the droplets of the dispersed phase (i.e., the water phase) are preferably between 1.0 and 20.0 μm .

[0036] The diluent(s) and/or solvent(s) defining the oil phase of the water-in-oil emulsion are miscible with the viscous hydrocarbons in the reservoir 105, and thus, offer the potential to mix with the viscous hydrocarbons and reduce the viscosity of the viscous hydrocarbons upon injection of the water-in-oil emulsion in block 204 described in more detail below. Examples of suitable diluent(s) and solvent(s) for the oil phase include, without limitation, used engine oil, gas condensate, naphtha, biofuel, and the like. In embodiments where the oil phase comprises used engine oil, the used engine oil preferably contains surface active agents (e.g., soot particles, oxidized oil, and residual detergent).

[0037] The water phase of the water-in-oil emulsion comprises a brine and one or more chemical agent(s). The chemical agent(s) preferably make up 5.0 to 20.0 wt % of the water phase, with the balance being the brine. The brine preferably has a salt concentration and composition analogous to that of reservoir 105 to reduce the potential for the aqueous solution to negatively alter reservoir 105. As previously described, the salt concentration and composition of the reservoir 105 can be determined from core samples and/or from samples of fluids that naturally migrate from reservoir 105 into a wellbore traversing reservoir 105. Each chemical agent is preferably a water soluble chemical additive that enhances the performance of steam in displacing the viscous hydrocarbons in the reservoir 105. Examples of suitable chemical agent(s) includes, without limitation, water soluble urea, ammonium carbonate, ammonium bicarbonate, (ammonium acetate plus sodium carbonate or sodium bicarbonate), and the like.

[0038] Embodiments in which the emulsion formed in block 202 is a water-in-oil emulsion are generally preferred for use in reservoirs that exhibit poor native water mobility.

[0039] In yet another embodiment, the emulsion is a micro-emulsion. In general, micro-emulsions are thermodynamically stable, isotropic mixtures of oil, water, and surfactant. In this embodiment, the micro-emulsion comprises one or more solvent(s) defining the oil phase, a brine defining the water phase, and one or more surfactant(s). Thus, in such embodiments, the

chemical agent(s) selected in block 201 are the solvent(s) and the surfactant(s). The brine preferably has a salt concentration and composition analogous to that of reservoir 105 to reduce the potential for the aqueous solution to negatively alter reservoir 105. In general, the salt concentration and composition of the reservoir 105 can be determined from core samples and/or from samples of fluids that naturally migrate from reservoir 105 into a wellbore traversing reservoir 105.

[0040] Formation of a micro-emulsion typically requires an ultra-low interfacial tension between the water phase and the oil phase of the emulsion. Without being limited by this or any particular theory, interfacial tension between the water phase and the oil phase can be varied by adjusting the relative volumetric ratios of the oil phase, the water phase, and the surfactant(s). As will be described in more detail below, the solvent(s) defining the oil phase and the surfactant(s) in the micro-emulsion are the active components that facilitate mobilization of the viscous hydrocarbons, and thus, in embodiments where the emulsion is a micro-emulsion, the relative volumetric ratios of the solvent(s) and/or surfactant(s) are preferably relatively high. In one exemplary embodiment, the micro-emulsion comprises a mixture of xylene (solvent), Triton X-100TM (surfactant) available from The DOW Chemical Company of Midland, Michigan, and brine in a volume ratio capable of forming a micro-emulsion (e.g., 8:1:1).

[0041] In general, micro-emulsions can be oil-in-water emulsions, water-in-oil emulsions, or bicontinuous. In embodiments described herein, the size of the droplets of the dispersed phase are preferably less than 5.0 μm , more preferably less than 1.0 μm , and even more preferably less than 0.1 μm .

[0042] Unlike ordinary emulsions or macro-emulsions, micro-emulsions form upon mixing of the components and do not require the high shear conditions typically employed to form ordinary emulsions. Accordingly, embodiments of micro-emulsions described herein can be formed via mixing by slight agitation. Alternatively, embodiments of micro-emulsions described herein can be formed in-situ during via a chemical reaction and/or soaking.

[0043] Embodiments in which the emulsion formed in block 202 is a micro-emulsion are generally preferred for use in reservoirs that exhibit good native water mobility.

[0044] In block 203, the parameters for loading or injecting the reservoir 105 with the emulsion are determined. In general, the injection parameters can be determined by any suitable means known in the art such as by completing an "injectivity test." The injection parameters include,

without limitation, the pressure, the temperature, and the flow rate at which the emulsion will be injected into reservoir 105. The injection pressure of the emulsion is preferably sufficiently high enough to enable injection into reservoir 105 (i.e., the pressure is greater than or equal to the ambient pressure of reservoir 105), and less than the fracture pressure of overburden 102, the fracture pressure of reservoir 105 (if one exists), and the pressure at which hydrocarbons in reservoir 105 will be displaced. The injection temperature is preferably greater than the freezing point and less than the thermal recovery technique operating temperature (e.g., SAGD operating temperature).

[0045] Referring still to Figure 3, moving now to block 204, reservoir 105 is loaded or injected with the emulsion according to the injection parameters determined in block 203. Since the emulsion is injected prior to start-up in block 205, and is not injected with steam, but rather, is injected into reservoir 105 with reservoir 105 at its ambient temperature, injection of the emulsion according to block 204 may be referred to herein as “cold” loading of reservoir 105.

[0046] In embodiments where the emulsion is an oil-in-water emulsion stabilized by one or more surfactant(s) as previously described, the emulsion is delivered easily into the reservoir at ambient reservoir temperature due to the relatively low viscosity of the water continuous phase. In addition, in cases where reservoir 105 exhibits good native water mobility, the continuous water phase offers the potential for improved mobility and dispersion of the oil-in-water emulsion through reservoir 105. As the oil-in-water emulsion moves through reservoir 105, it carries the chemical agent(s) (i.e., the diluent(s) and/or solvent(s) defining the oil phase) with it.

[0047] In embodiments where the emulsion is a water-in-oil emulsion as previously described, the diluent(s) and/or solvent(s) defining the oil phase are miscible with the viscous hydrocarbons in the reservoir 105, and thus, mix with the viscous hydrocarbons in reservoir 105 upon injection in block 204, thereby reducing the viscosity of the viscous hydrocarbons. In addition, in cases where reservoir 105 exhibits poor native water mobility, the continuous oil phase offers the potential for improved mobility and dispersion of the water-in-oil emulsion through reservoir 105 and the viscous hydrocarbons therein. As the water-in-oil emulsion moves through reservoir 105, it carries the chemical agent(s) with it.

[0048] In general, micro-emulsions can mix with water and oil. Consequently, in embodiments where the emulsion formed in block 202 is a micro-emulsion, the emulsion can mix with both the water and the viscous hydrocarbons in reservoir 105, thereby offering the potential for improved mobility and dispersion of the emulsion through reservoir 105 upon

injection in block 204. As the micro-emulsion moves through reservoir 105, it carries the chemical agent(s) with it. In addition, since the micro-emulsion can mix with the viscous hydrocarbons in reservoir 105, the chemical agent(s) (i.e., the solvent(s) and the surfactant(s)) can mix with the viscous hydrocarbons upon injection in block 204, thereby offering the potential to reduce the viscosity of the viscous hydrocarbons in reservoir 105.

[0049] Since SAGD wells 20, 30 are not yet commissioned, and thus, are not injecting steam and collecting hydrocarbons, respectively, during the cold loading of reservoir 105 in block 204, the emulsion can be injected into reservoir 105 utilizing one well 20, 30, both wells 20, 30, or combinations thereof over time. The emulsion is preferably injected into reservoir 105 via injection well 20 alone, via both wells 20, 30 at the same time, or via both wells 20, 30 at the same time followed by injection well 20 alone. It should be appreciated that since the emulsion is injected into the reservoir 105 in block 204 before commissioning SAGD well pair 20, 30, the emulsion can be injected into the reservoir in block 204 through one of the wells 20, 30 while the other well 20, 30 is being formed (e.g., drilled).

[0050] Following the formation of the second well 20, 30 (whichever of the two well 20, 30 is formed second), the emulsion can be injected solely through the first well 20, 30, solely through the second well 20, 30, or simultaneously through both wells 20, 30. In general, the emulsion can be injected into the reservoir 105 continuously, intermittently, or pulsed by controllably varying the injection pressure within an acceptable range of pressures as determined in block 203. Pulsing the injection pressure offers the potential to enhance distribution of the emulsion in reservoir 105 and facilitates dilation of reservoir 105. It should be appreciated that any one or more of these injection options can be performed alone or in combination with other injection options.

[0051] In implementations where production well 30 is not employed for injection of the emulsion, production well 30 is preferably maintained at a pressure lower than the ambient pressure of reservoir 105 (e.g., with a pump) to create a pressure differential and associated driving force for the migration of fluids (e.g., connate water and/or the emulsion) into production well 30. Pumping fluids out of production well 30 to maintain the lower pressure also enables chemical analysis and monitoring of the fluids flowing into production well 30 from the surrounding formation 101, which can provide insight as to the migration of the emulsion through reservoir 105 and the saturation of reservoir 105 with the emulsion. Injection

of the emulsion in block 204 is performed until reservoir 105 (or portion of reservoir 105 to be loaded) is sufficiently charged.

[0052] Referring briefly to Figure 4, reservoir 105 and formation 101 are shown following injection of the emulsion according to block 204. In Figure 4, the emulsion is represented with reference numeral 110. The emulsion 110 forms a loaded zone 111 extending radially outward and longitudinally along the portion of horizontal section(s) 22, 32 from which the emulsion 110 was injected into reservoir 105.

[0053] Referring again to Figure 3, once reservoir 105 (or the portion of reservoir 105 being loaded) is sufficiently charged with the emulsion according to block 204, start-up of the SAGD well pair 20, 30 is commenced in block 205. In general, start-up of SAGD well pair 20, 30 is performed by injecting steam through injection well 20 and production well 30 in either circulation or “bullheading” modes until appropriate pressure and fluid communication between wells 20, 30 is achieved. Then, injection of steam into production well 30 is ceased, while steam continues to be injected through injection well 20.

[0054] Referring briefly to Figure 5, the steam and associated hot water percolate through reservoir 105, thereby forming a steam chamber 120 that extends horizontally outward and vertically upward from horizontal section 22 of injection well 20. Steam chamber 120 is generally shaped like an inverted triangular prism that extends along and upward from the full length of horizontal section 22. Thermal energy from steam chamber 120 increases the temperature of reservoir 105. In other words, the thermal energy from steam chamber 120 raises the temperature of reservoir 105 and loaded zone 111 to an elevated temperature greater than the ambient temperature of reservoir 105. The elevated temperature and associated thermal energy are sufficient to reduce the viscosity of the viscous hydrocarbons in reservoir 105.

[0055] In embodiments where emulsion 110 is an oil-in-water emulsion stabilized by one or more surfactant(s) as previously described, emulsion 110 is generally stable upon injection at the reservoir ambient temperature in block 204, however, once the temperature of the reservoir exceeds the phase inversion temperature (i.e., the cloud point), destabilization of the oil-in-water emulsion results in the release of the diluent(s) and organic solvent(s) (i.e., the oil phase of the emulsion begins to separate from the water phase of the emulsion). The released diluent(s) and organic solvent(s) mix with the viscous hydrocarbons to further reduce their viscosity and further enhancing their mobility. It should also be appreciated that the any

released surfactant(s) can facilitate emulsification of the mobilized hydrocarbons in reservoir 105.

[0056] In embodiments where emulsion 110 is a water-in-oil emulsion as previously described, the diluent(s) and/or solvent(s) defining the oil phase mix with the viscous hydrocarbons to reduce the viscosity of the viscous hydrocarbons prior to injection of steam in block 205, as well as during injection of steam in block 205. By reducing the viscosity of the viscous hydrocarbons via the thermal energy from the steam and the diluent(s) and/or solvent(s), the hydrocarbons in reservoir 105 are mobilized, thereby allowing chemical agent(s) in the water phase of the water-in-oil emulsion to access and interact with the hydrocarbons (e.g., react with the hydrocarbons, emulsify the hydrocarbons, etc.) to further reduce viscosity and enhance mobilization. For example, select chemical agents described above are thermally activated by the steam to produce gaseous products (e.g., urea thermally decomposes in presence of water to form gaseous ammonia and carbon-dioxide), which further reduce the viscosity and enhance mobilization of the hydrocarbons in reservoir 105.

[0057] As previously described, micro-emulsions can mix with water and oil. Consequently, in embodiments where the emulsion 110 is micro-emulsion as previously described, the steam injected in block 205 is miscible with the micro-emulsion, thereby offering the potential for improved dispersion of the injected steam in reservoir 105. As previously, the injected steam increases the temperature in reservoir 105, thereby reducing the viscosity of the viscous hydrocarbons. In addition, the chemical agent(s) (i.e., the diluent(s) and solvent(s)) in the micro-emulsion mix with the viscous hydrocarbons to reduce the viscosity of the viscous hydrocarbons. Still further, the surfactant(s) in the micro-emulsion can access and emulsify the mobilized hydrocarbons, thereby further reducing viscosity and enhancing mobilization.

[0058] The conventional approach to start-up of a SAGD well pair via injection of steam to initiate mobilization of viscous hydrocarbons and allow fluid communication between the SAGD well pair may take several months. During this lengthy start-up period before production of hydrocarbons, money and resources are being invested into the SAGD operations. In embodiments described herein, the injection of an emulsion comprising one or more chemical agents described herein into the reservoir (e.g., reservoir 105) prior to injection of steam in the start-up phase offers the potential to accelerate subsequent start-up of the SAGD well pair (e.g., SAGD well pair 20, 30).

REPLACEMENT SHEET

What is claimed is:

1. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure, the method comprising:
 - (a) forming an aqueous solution with a non-ionic surfactant;
 - (b) making an oil-in-water emulsion with the aqueous solution and a water insoluble solvent or diluent;
 - (c) injecting the oil-in-water emulsion into the reservoir with the reservoir at the ambient temperature; and
 - (d) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (c).
2. The method of claim 1, wherein the water insoluble solvent or diluent comprises gas condensate, light crude oil, naphtha, kerosene, toluene, or xylene.
3. The method of claim 1, further comprising:
 - determining a salt concentration and a salt composition in the reservoir;
 - forming a brine having a salt concentration and a salt composition analogous to the salt concentration and the salt composition of the reservoir; and
 - mixing the brine and the non-ionic surfactant to form the aqueous solution in (a).
4. The method of claim 1, wherein the non-ionic surfactant is has a first solubility in water at the ambient temperature and a second solubility in water at a phase inversion temperature that is greater than the ambient temperature, wherein the second solubility is less than the first solubility.
5. The method of claim 4, wherein the phase inversion temperature is between 37°C and 90°C.
6. The method of claim 4, wherein the non-ionic surfactant comprises an octylphenol ethoxylate, a secondary alcohol ethoxylate, a branched secondary alcohol ethoxylate, a nonylphenol ethoxylate, or a polyoxyethylenesorbitan ester.

7. The method of claim 1, wherein the oil-in-water emulsion comprises a water phase and an oil phase, wherein the water phase comprises a brine and the non-ionic surfactant, wherein the water phase is 30.0 to 50.0 wt % of the oil-in-water emulsion, the oil phase is 50.0 to 70.0 wt % of the oil-in-water emulsion, and the surfactant is less than or equal to 5.0 wt % of the oil-in-water emulsion.

8. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure, the method comprising:

(a) forming a steam assisted gravity drainage (SAGD) well pair extending through the formation, wherein the SAGD well pair includes an injection well and a production well, wherein each well has a vertical section extending from the surface of the formation and a horizontal section traversing the reservoir;

(b) forming an oil-in-water emulsion comprising an aqueous solution and a water insoluble solvent or diluent, wherein the aqueous solution includes a non-ionic surfactant that is water-soluble and substantially non-reactive in the reservoir at the ambient temperature of the reservoir;

(c) injecting the oil-in-water emulsion into the reservoir with the reservoir at the ambient temperature; and

(d) injecting steam into the reservoir after (c) to increase the temperature of the reservoir to a SAGD operating temperature.

9. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure, the method comprising:

(a) forming an aqueous solution with a water-soluble chemical agent that is substantially non-reactive in the reservoir at the ambient temperature;

(b) making a water-in-oil emulsion with the aqueous solution and a water insoluble solvent or diluent;

(c) injecting the water-in-oil emulsion into the reservoir with the reservoir at the ambient temperature; and

(d) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (c).

10. The method of claim 9, wherein the water insoluble solvent or diluent comprises used engine oil, gas condensate, naphtha, or biofuel.

11. The method of claim 9, further comprising:
determining a salt concentration and a salt composition in the reservoir;
forming a brine having a salt concentration and a salt composition analogous to the salt concentration and the salt composition of the reservoir; and
mixing the brine and the chemical agent to form the aqueous solution in (a).

12. The method of claim 9, wherein the water-soluble chemical agent comprises urea, ammonium carbonate, or ammonium bicarbonate.

13. The method of claim 9, wherein the water-in-oil emulsion comprises a water phase and an oil phase, wherein the water phase comprises a brine and the water-soluble chemical agent, and wherein the water-soluble chemical agent is 5.0 to 20.0 wt % of the water phase.

14. The method of claim 9, wherein the water-soluble chemical agent thermally decomposes during (d) to form a gas.

15. The method of claim 14, wherein the water-soluble chemical agent is urea, and wherein the urea thermally decomposes during (d) to form ammonia gas and carbon-dioxide gas.

16. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure, the method comprising:

(a) forming a steam assisted gravity drainage (SAGD) well pair extending through the formation, wherein the SAGD well pair includes an injection well and a production well, wherein each well has a vertical section extending from the surface of the formation and a horizontal section traversing the reservoir;

(b) forming a water-in-oil emulsion comprising an aqueous solution mixed in an oil phase, wherein the aqueous solution includes a water soluble chemical agent and the oil phase comprises a water insoluble diluent or solvent;

(c) injecting the water-in-oil emulsion into the reservoir with the reservoir at the ambient temperature; and

(d) injecting steam into the reservoir after (c) to increase the temperature of the reservoir to a SAGD operating temperature.

17. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure, the method comprising:

(a) making a micro-emulsion comprising a solvent, a brine, and a surfactant;

(b) injecting the micro-emulsion into the reservoir with the reservoir at the ambient temperature; and

(c) adding thermal energy to the reservoir to increase the temperature of the reservoir to an operating temperature after (b).

18. The method of claim 17, further comprising:

determining a salt concentration and a salt composition in the reservoir; and

forming the brine, wherein the brine has a salt concentration and a salt composition analogous to the salt concentration and the salt composition of the reservoir.

19. The method of claim 17, wherein the solvent comprises xylene and the surfactant comprises an octylphenol ethoxylate.

20. The method of claim 17, wherein the micro-emulsion comprises a continuous phase and a dispersed phase, wherein the dispersed phase comprises a plurality of droplets dispersed in the continuous phase, wherein each droplet has a size less than 1.0 μm .

[0059] In the manner described, embodiments described herein (e.g., system 10 and method 200) are employed to produce viscous hydrocarbons in a subterranean reservoir. Although such embodiments can be used to recover and produce heavy oil having any viscosity under ambient reservoir conditions, it is particularly suited for the recovery and production of viscous hydrocarbons having an API gravity greater than 10,000 cP under ambient reservoir conditions. In addition, although method 200 shown in Figure 3 is described in the context of well system 10 including SAGD well pair 20, 30, in general, embodiments of methods described herein (e.g., method 100) can be used in connection with other types of thermal recovery technique for viscous hydrocarbons such as steam flooding, cyclic steam stimulation (CSS), electric reservoir heating operations, etc.

[0060] While preferred embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the invention. For example, the relative dimensions of various parts, the materials from which the various parts are made, and other parameters can be varied. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

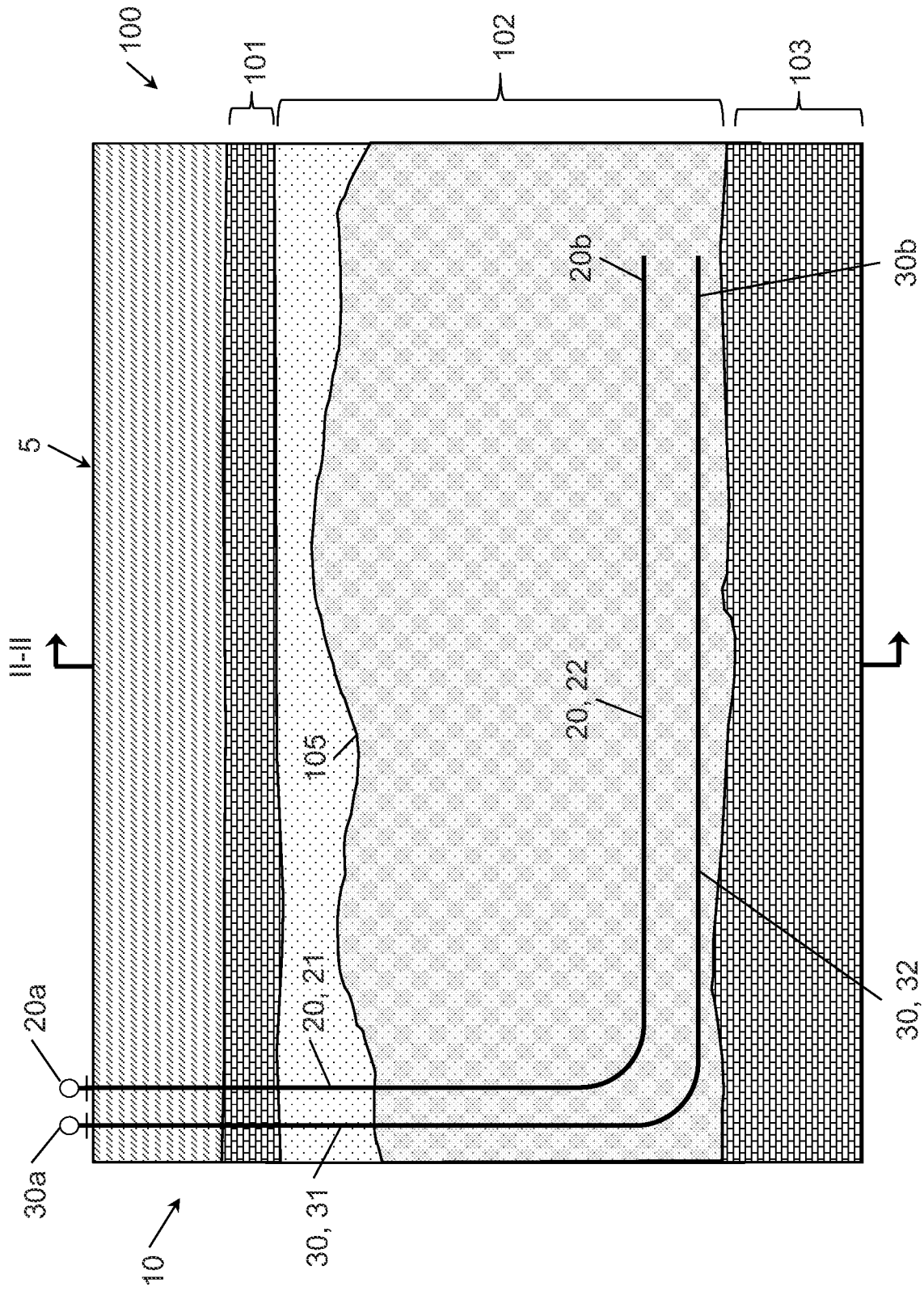


Figure 1

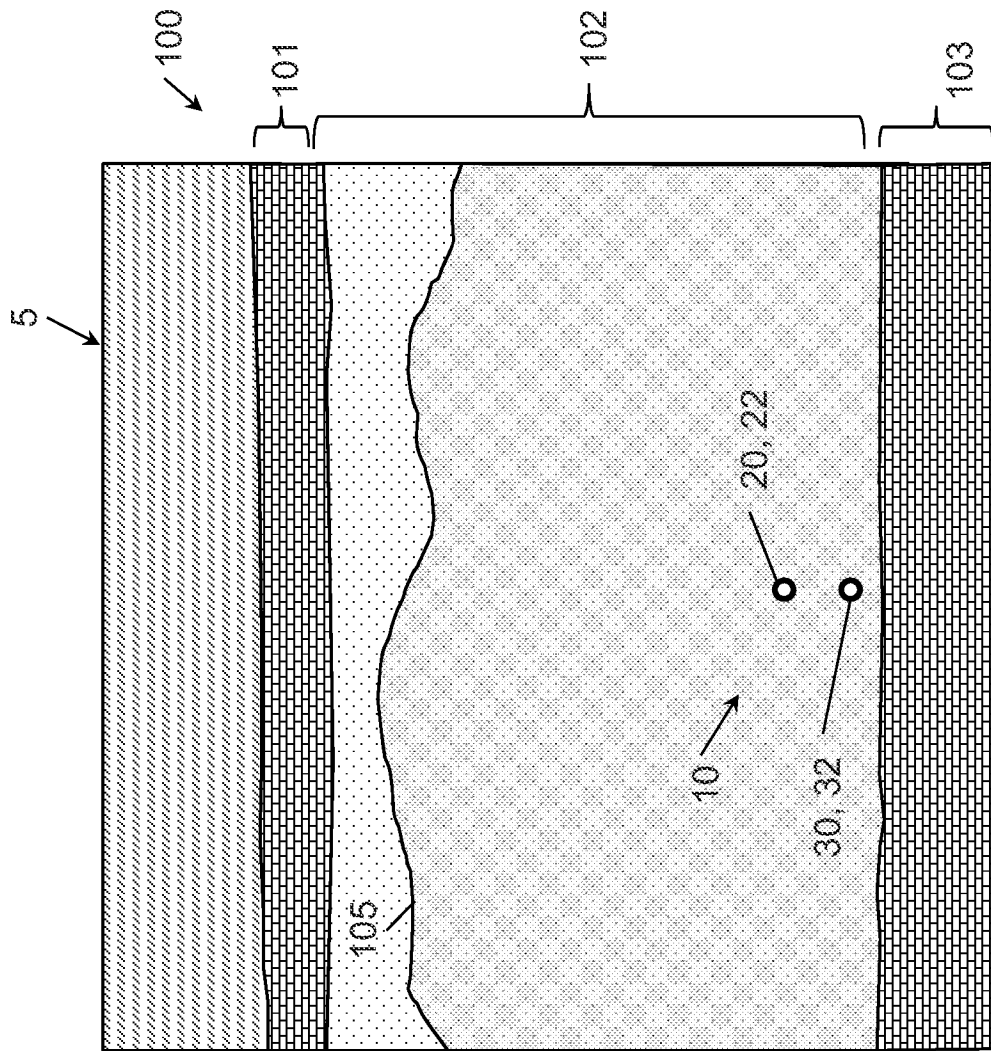


Figure 2

200 →

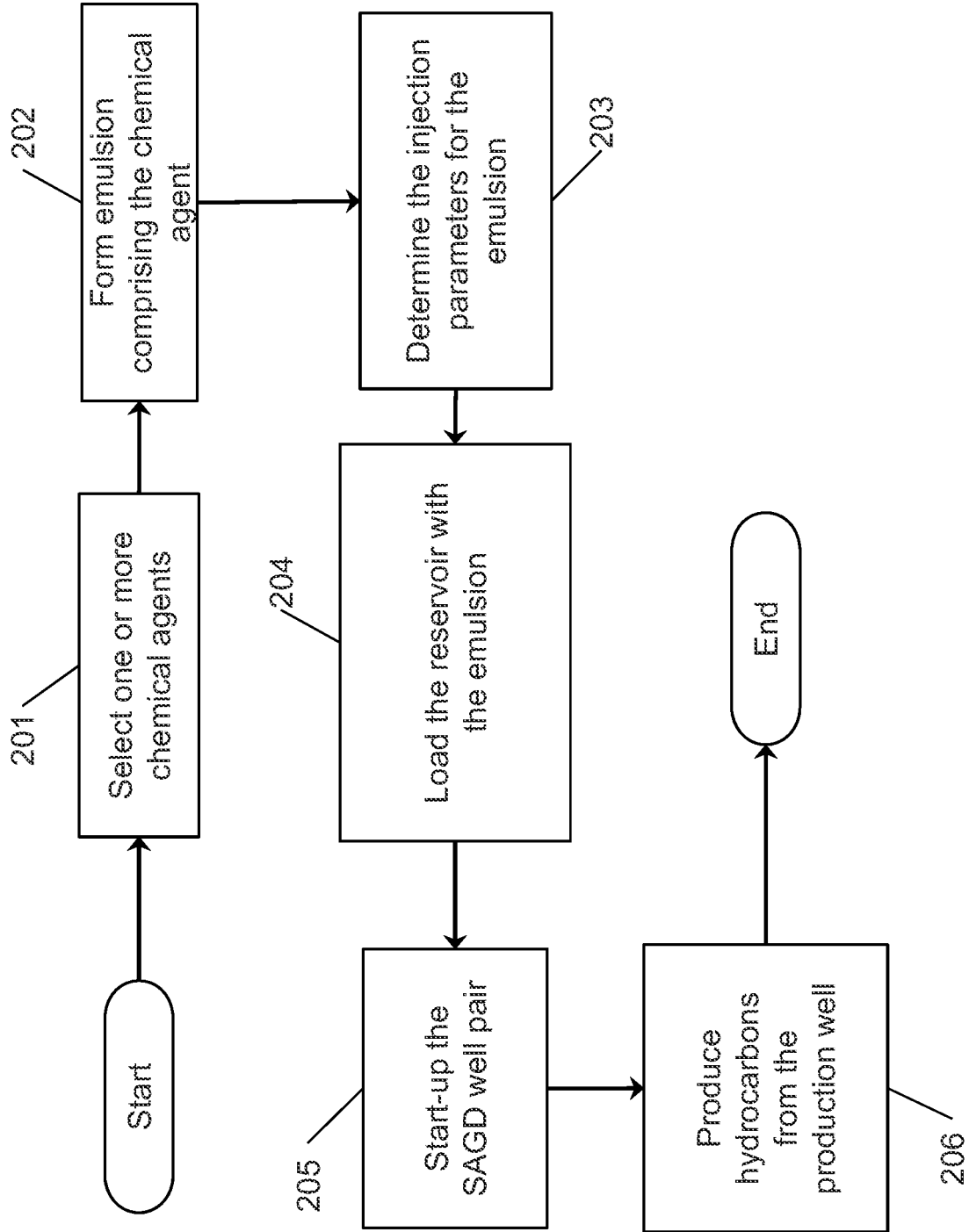


Figure 3

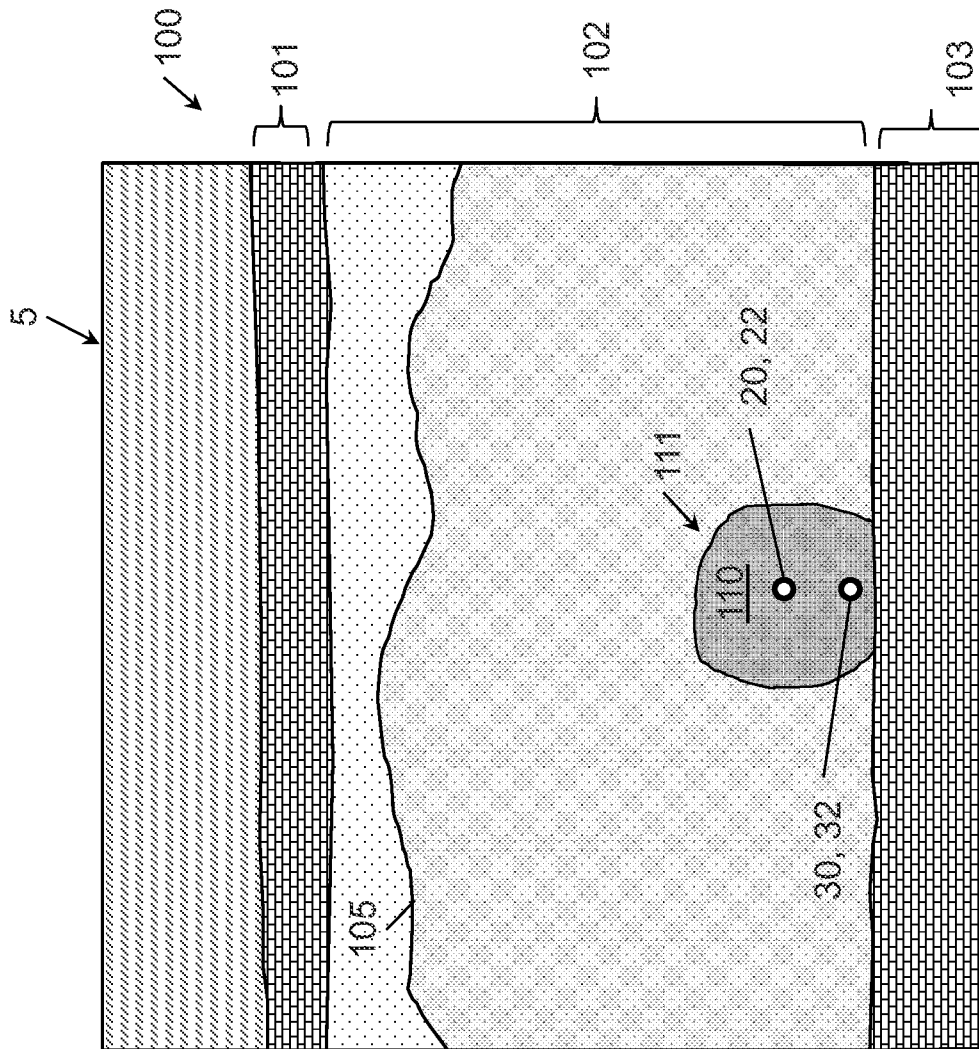


Figure 4

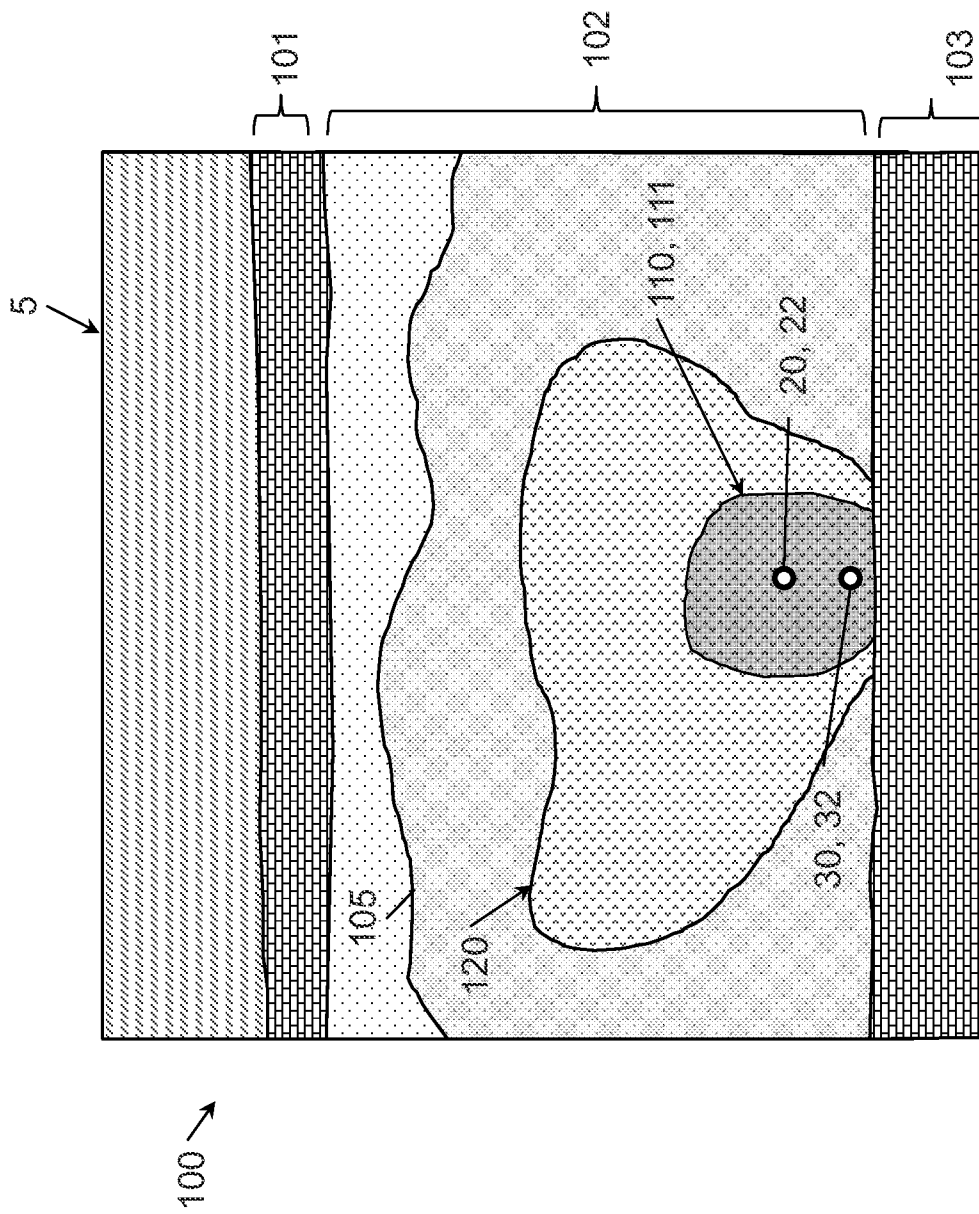


Figure 5

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2015/024476

A. CLASSIFICATION OF SUBJECT MATTER
INV. C09K8/584 C09K8/592 C09K8/524
ADD.
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED
Minimum documentation searched (classification system followed by classification symbols)
C09K
Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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Further documents are listed in the continuation of Box C.

See patent family annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance	"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"E" earlier application or patent but published on or after the international filing date	"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)	"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"O" document referring to an oral disclosure, use, exhibition or other means	"&" document member of the same patent family
"P" document published prior to the international filing date but later than the priority date claimed	

Date of the actual completion of the international search 3 June 2015	Date of mailing of the international search report 29/06/2015
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Name and mailing address of the ISA/ European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Authorized officer Zimpfer, Emmanuel
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INTERNATIONAL SEARCH REPORT

International application No
PCT/US2015/024476

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT		
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X,P	WO 2014/134535 A1 (UNIV TEXAS [US]) 4 September 2014 (2014-09-04) claims paragraph [0104] - paragraph [0107] paragraph [0126] -----	1-21
X,P	WO 2014/201367 A1 (CESI CHEMICAL INC [US]) 18 December 2014 (2014-12-18) claims -----	1-21

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