Solvent may be injected into a hydrocarbon reservoir at an increasingly elevated vertical level to allow vapor of the solvent to contact and mobilize viscous hydrocarbons in the reservoir, for producing mobilized hydrocarbons. Solvent may be injected into a mobile zone below a viscous hydrocarbon zone, to allow solvent vapor to ascend to mobilize viscous hydrocarbons in the viscous hydrocarbon zone. A vertical or slanted injection well may be used to inject the solvent into the reservoir, and a production well spaced horizontally apart from the injection well may be used to produce fluids from the reservoir. A bottom-up solvent-aided process may comprise injecting water and liquid solvent into the mobile zone, and then injecting heated water and solvent into the mobile zone.
FIG. 3
BOTTOM-UP SOLVENT-AIDED PROCESS AND SYSTEM FOR HYDROCARBON RECOVERY

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims benefit of, and priority from, U.S. provisional patent application No. 61/737,489 filed Dec. 14, 2012, the entire contents of which are incorporated herein by reference.

FIELD OF THE INVENTION

[0002] The present invention relates generally to in situ processes and systems for recovering hydrocarbons from reservoirs containing viscous hydrocarbons, and particularly to bottom-up solvent-assisted in situ recovery processes and systems.

BACKGROUND OF THE INVENTION

[0003] Some subterranean deposits of viscous hydrocarbons, such as in the form of viscous petroleum, can be extracted in situ by lowering the viscosity of the petroleum to mobilize it so that it can be moved to, and be recovered from, a production well. Reservoirs of such deposits may be referred to as reservoirs of heavy hydrocarbons, heavy oil, bitumen, tar sands, or oil sands.

[0004] One type of in situ process for recovering hydrocarbons from such reservoirs involves the use of injection and production wells drilled into the reservoir, and is assisted or aided by injecting a solvent into the reservoir formation from an injection well. For example, a process known as VAPEX (Vapor Extraction Process) utilizes injected solvent vapor to dilute bitumen in oil sands reservoirs to enable the diluted bitumen to flow to the production well for recovery.

[0005] In one particular potential implementation, solvent vapor can be injected from a planar well at the bottom of the reservoir using horizontal wells in a process known as Bottom-Up Solvent-Aided Process, or Bottom-Up SAP (see, e.g., Gupta and Gittins, “Effect of Solvent Sequencing and Other Enhancements on Solvent Aided Process,” Journal of Canadian Petroleum Technology, 2007, vol. 46, pp. 57-61; and Gupta and Gittins, “Optimization of Solvent Aided Process,” Journal of Canadian Petroleum Technology, 2009, vol. 48, pp. 49-53, and the references cited therein). Bottom-Up SAP may be performed when an underlying zone with native mobility, such as a water zone, is present immediately below the viscous hydrocarbon formation. In such a process, a solvent vapor is injected through the water zone, and the solvent vapor rises up from the water zone to meet viscous hydrocarbons above, and condenses at the solvent vapor front. The viscous hydrocarbons are mobilized by the condensed solvent and the mobilized hydrocarbons and condensed solvent drain downward toward the water zone due to gravity. The hydrocarbons and the solvent collected at the bottom water zone can then be produced using a production well. However, successful commercial implementation of such a process achieving the initial expectations of performance has not been reported to date.

[0006] A gravity assisted solvent flooding process has also been contemplated in U.S. Pat. No. 4,398,602 to Anderson, issued Aug. 16, 1983. In this contemplated process, a reservoir containing very viscous petroleum is penetrated by an injection well and a production well, which have fluid communication with the bottom of the reservoir. An intermediate well is drilled between the injection and production wells and is completed to have fluid communication with the top of the reservoir. A solvent or fluid miscible with the viscous petroleum which has a specific gravity substantially less than the specific gravity of viscous petroleum is introduced into the lower part of the reservoir. The intermediate well is used to induce vertical flow of solvent into the heavy crude oil part of the reservoir, by opening the intermediate well and applying pressure to the injection or production well or both. This is contemplated to result in solvent flow from the bottom of the reservoir to the top and increases the surface area between the crude oil and the solvent. This is expected to improve mixing of the solvent and the crude oil and to reduce the soak time required in the solvent flooding process. After the desired mixing of solvent with crude oil has taken place, the intermediate well is shut and the oil is produced from the formation through the production well such as by water flooding. However, this process is not expected to be sufficiently efficient or effective for commercial implementations to recover viscous hydrocarbons from a formation in which the mobility of fluids is very low. Further, the fluid flows induced in this process tend to result in low conformance in the reservoir.

SUMMARY OF THE INVENTION

[0007] An aspect of the present disclosure relates to a method, in which a solvent is injected into a hydrocarbon reservoir at an increasingly elevated vertical level to allow vapor of the solvent to contact and mobilize viscous hydrocarbons in the reservoir, and mobilized hydrocarbons are produced from the reservoir.

[0008] In selected embodiments, the solvent may be vaporized to allow vapor of the solvent to ascend in the reservoir, and the vertical level at which the solvent enters the reservoir may be increasingly elevated as viscous hydrocarbons are mobilized by the solvent and are displaced from their original location. The solvent may be injected into a mobile zone below a viscous hydrocarbon zone in the reservoir, and the vertical level of solvent injection may be increasingly elevated as the mobile zone expands upward due to mobilization of viscous hydrocarbons in the hydrocarbon zone, gravity drainage of mobilized viscous hydrocarbons, and lateral displacement of mobilized viscous hydrocarbons. The solvent may be injected through an injection well having a plurality of injection openings distributed at different vertical levels. The injection openings may be distributed between a top level and a bottom level of the hydrocarbon reservoir. The solvent and a heated aqueous fluid may be fed to the injection well for injection into the reservoir through the injection openings. The heated aqueous fluid may comprise heated water, steam, or both. A mixture of the solvent and the heated aqueous fluid may be fed to the injection well. The solvent and the heated aqueous fluid may be fed separately to the injection well. The solvent and the heated aqueous fluid may be fed alternately to the injection well. The solvent may be at least partly vaporized in the injection well. The solvent may be at least partly vaporized in the reservoir. The heated aqueous fluid may be conditioned to facilitate vaporization of the solvent before the solvent contacts viscous hydrocarbons in the reservoir and subsequent condensation of the solvent when the solvent comes into contact with viscous hydrocarbons. The solvent may comprise an alkane or alkene having 2 to 9 carbon atoms. The mobile zone may be a pre-existing water zone at a base portion of the reservoir. The mobile zone
may be created at a base portion of the reservoir prior to injecting the solvent. A non-condensing gas may also be injected into the mobile zone. Mobilized hydrocarbons may be produced from a vertical or slanted production well. A plurality of wells extending into the mobile zone through the hydrocarbon zone may be provided. The plurality of wells may comprise a production well for producing fluids from the mobile zone, and an injection well for injecting the solvent into the reservoir at different vertical levels. The plurality of wells may comprise spaced apart first and second wells each configured for use alternately as the injection well or the production well. The solvent may be alternately injected through one of the first or second wells, and the mobilized hydrocarbons may be alternately produced through the other of the first and second wells. The solvent may be injected with a heated aqueous fluid and mobilized hydrocarbons may be produced at different horizontal locations within the mobile zone, facilitating horizontal fluid flow within the mobile zone. The solvent and heated aqueous fluid may be injected concurrently with production of mobilized hydrocarbons. The method may comprise alternately injecting the solvent and heated aqueous fluid and producing mobilized hydrocarbons.

Another aspect of the present disclosure relates to a system for recovering hydrocarbons from a subterranean reservoir comprising an overlying viscous hydrocarbon zone and an underlying mobile zone. The system comprises an injection well extending into the mobile zone through the hydrocarbon zone, the injection well having injection openings distributed at different vertical levels in both the hydrocarbon zone and the mobile zone; and a production well spaced horizontally apart from the injection well and extending into the mobile zone for producing mobilized hydrocarbons from the mobile zone. The injection well is configured to inject a solvent and a heated aqueous liquid into the mobile zone through injection openings adjacent to the mobile zone to mobilize hydrocarbons in the hydrocarbon zone, such that the solvent will be injected into the reservoir at increasingly elevated vertical levels when mobilized hydrocarbons in the hydrocarbon zone drain downward due to gravity.

In selected embodiments, the injection well may be configured to inject a non-condensing gas into the reservoir. The injection well and the production well may be vertical or slanted wells. The system may comprise an array of injection and production wells spaced horizontally apart from one another. Each one of the injection well and the production well may be configured for use alternately as an injection well or a production well.

A further aspect of the present invention relates to a method comprising injecting a solvent into a hydrocarbon reservoir through a mobile zone below a viscous hydrocarbon zone in the hydrocarbon reservoir, to allow vapor of the solvent to ascend in the reservoir to mobilize viscous hydrocarbons in the viscous hydrocarbon zone, wherein the solvent is injected through an injection well completed to provide a plurality of injection openings distributed over a vertical extent that initially extends into both the mobile zone and the viscous hydrocarbon zone; and producing mobilized hydrocarbons from the reservoir through the mobile zone with a production well, wherein the production well is horizontally spaced from the injection well to provide a horizontal pressure gradient in the mobile zone for inducing horizontal movement of fluids within the mobile zone. In selected embodiments, the method may comprise vaporizing the solvent to allow vapor of the solvent to ascend in the reservoir. The method may comprise increasingly elevating the vertical level of solvent injection as the mobile zone expands upward due to mobilization of viscous hydrocarbons in the hydrocarbon zone, gravity drainage of mobilized viscous hydrocarbons, and lateral displacement of mobilized viscous hydrocarbons. The injection openings may be distributed between a top level and a bottom level of the hydrocarbon reservoir. The solvent and a heated aqueous fluid, such as heated water, may be fed to the injection well for injection into the reservoir through the injection openings. A mixture of the solvent and the heated aqueous fluid may be fed to the injection well. The solvent may be at least partly vaporized in the injection well. The solvent may be at least partly vaporized in the reservoir. The solvent may comprise an alkane or alkene having 2 to 9 carbon atoms. The mobile zone may be a pre-existing water zone at a base portion of the reservoir. The mobile zone may be created at a base portion of the reservoir prior to injecting the solvent. A non-condensing gas may also be injected into the mobile zone. Mobilized hydrocarbons may be produced from a vertical or slanted production well. A plurality of wells extending into the mobile zone through the hydrocarbon zone may be provided.

In a further aspect, there is provided a method for recovery of hydrocarbons in a bottom-up solvent-aided process from a hydrocarbon reservoir comprising an overlying viscous hydrocarbon zone and an underlying mobile zone. The method comprises injecting water and liquid solvent into the mobile zone, to improve and maintain fluid communication within the mobile zone; injecting heated water and solvent into the mobile zone to allow vapor of the solvent to ascend in the hydrocarbon reservoir to mobilize viscous hydrocarbons in the viscous hydrocarbon zone, wherein the heated water and solvent are injected through an injection well completed to provide a plurality of injection openings distributed over a vertical extent in at least the mobile zone; and producing mobilized hydrocarbons from the reservoir through the mobile zone with a production well, wherein the production well is horizontally spaced from the injection well to provide a horizontal pressure gradient in the mobile zone for inducing horizontal movement of fluids within the mobile zone. In selected embodiments, a mixture of the heated water and solvent may be fed into the injection well. The heated water may be heated to a temperature sufficient to vaporize at least a substantial portion of the solvent in the injection well. The heated water may be heated to a temperature sufficient to vaporize at least a substantial portion of the solvent when the solvent is injected into the mobile zone. The heated water may be conditioned to facilitate vaporization of the solvent before the solvent contacts viscous hydrocarbons in the reservoir and subsequent condensation of the solvent when the solvent comes into contact with viscous hydrocarbons. The solvent may comprise an alkane or alkene having 2 to 9 carbon atoms. The injection well and production well may be vertical or slanted wells. The method may comprise concurrently producing mobilized hydrocarbons and injecting the heated water and solvent. The method may comprise alternately injecting the heated water and solvent and producing mobilized hydrocarbons.

Other aspects and features of the present invention will become apparent to those of ordinary skill in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.
BRIEF DESCRIPTION OF THE DRAWINGS

[0014] In the figures, which illustrate, by way of example only, embodiments of the present invention. Additionally, the patent or application file contains at least one drawing presented in color photograph(s). Color copies of this patent or patent application publication with color drawings/photographs will be provided by the Office upon request and payment of the necessary fee.

[0015] FIGS. 1, 2, 3, 4, 5, and 6 are schematic diagrams illustrating processes for hydrocarbon recovery from a hydrocarbon reservoir, exemplary of embodiments of the present invention.

[0016] FIG. 7 is a schematic view of a well pattern for an embodiment of the present invention.

[0017] FIG. 8 is a schematic top view of a portion of a well pattern for an embodiment of the present invention.

[0018] FIG. 9 is a data graph showing initial gas saturation in a volume of a computer simulated reservoir with vertical wells to be subjected to a hydrocarbon recovery process according to an embodiment of the present invention.

[0019] FIGS. 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, and 50 are data graphs showing results for the simulated recovery process from the reservoir volume of FIG. 8; and

[0020] FIGS. 51, 52, and 53 are line graphs showing representative results of the simulated recovery process.

DETAILED DESCRIPTION

[0021] Selected embodiments of the present invention relate to a bottom-up gravity drainage (BUGD) solvent aided process (SAP) for recovering hydrocarbons from a subterranean hydrocarbon reservoir 100, as illustrated in FIGS. 1, 2, 3, 4, 5, and 6. In these embodiments, a solvent is injected into reservoir 100 at increasingly elevated vertical levels.

[0022] An injection level refers to the vertical level at which the solvent enters into the reservoir formation. The solvent may be considered to be injected into the reservoir at increasingly elevated vertical levels if the highest injection level is elevated over a period of time, regardless of whether the solvent also enters into the reservoir at lower vertical levels.

[0023] The solvent may be selected from solvents that are known to be suitable for in-situ solvent-aided processes (SAP) of hydrocarbon recovery. A suitable solvent should be sufficiently volatile so that the solvent can be vaporized by heating under reservoir operating conditions and the solvent vapor can ascend within a mobile zone of the reservoir. A suitable solvent should also be condensable at a lower temperature zone within the reservoir, and the condensed solvent should be miscible with oil or bitumen.

[0024] In selected embodiments, the solvent may be selected from solvents that contain one or more of C2 to C9 alkanes and alkenes. For example, a suitable solvent may include propane, butane, hexane, or mixtures thereof. The solvent may also contain less than about 20 wt % of aromatics. In some embodiments, the solvent may contain up to 20 wt % of one or more of alkenes, or C9+ alkenes. In some embodiments, the solvent may contain up to 20 wt % of a combination of aromatics, alkanes or C9+ alkenes.

[0025] Reservoir 100 has a hydrocarbon zone 102 containing viscous hydrocarbons. The viscous hydrocarbons may exist in the form of bitumen or heavy oil, and have a viscosity of higher than about 1000 centipoise (mPas) under native reservoir conditions. In various embodiments, the term “reservoir” refers to a subterranean or underground formation comprising recoverable hydrocarbons. In a reservoir of bituminous sands at least some of the hydrocarbons are viscous and immobile and are disposed between or attached to sands. In various embodiments, the terms “hydrocarbons” and “hydrocarbon” relate to mixtures of varying compositions comprising hydrocarbons in the gaseous, liquid or solid states, which may be in combination with other fluids (liquids and gases) that are not hydrocarbons. For example, “heavy oil”, “extra heavy oil”, and “bitumen” refer to hydrocarbons occurring respectively in viscous fluid, semi-solid or solid form and having a viscosity in the range of about 1000 to over 1,000,000 centipoise (mPas) measured at original in situ reservoir temperature. The term “hydrocarbons” is used in the broad sense that includes “heavy oil”, “oil” and “bitumen.” Depending on the in situ density and viscosity of the hydrocarbons, the hydrocarbons may contain, for example, a combination of heavy oil, extra heavy oil and bitumen. Heavy crude oil, for example, may be defined as any liquid petroleum hydrocarbon having an American Petroleum Institute (API) Gravity of less than about 20° and a viscosity greater than 1000 mPas. Oil may be defined, for example, as hydrocarbons mobile at typical reservoir conditions. Extra heavy oil, for example, may be defined as having a viscosity of over 10,000 mPas and about 10° API Gravity. The API Gravity of bitumen ranges from about 12° to about 5° and the viscosity is greater than about 1,000,000 mPas. Bitumen is generally non-mobile at typical native reservoir conditions. Another term that has been used to characterize bitumen, with its large but measurable viscosity and solid-like nature, is “viscoelastic”. In hydrocarbon zone 102, fluids such as gases and water have limited mobility due to a relatively high degree of viscous hydrocarbon saturation.

[0026] A mobile zone 104, which is a zone characterized by relatively higher effective mobility, is below hydrocarbon zone 102, which is a zone of relatively lower effective mobility. Effective mobility can be calculated by dividing effective permeability by fluid viscosity. In a mobile zone, a fluid such as oil, water or gas, or combinations thereof, can move about. In particular, in mobile zone 104, lighter gases such as heated solvent vapor will rise up, and liquids such as liquid hydrocarbons, condensed water and solvents will drain downward due to gravity. Mobile zone 104 may already exist or may be formed just above the base 106 of reservoir 100, as depicted in FIG. 1. However, in some embodiments, mobile zone 104 may be just below the base 106. For example, a mobile zone may be initially a water zone naturally formed below the reservoir base. In some embodiments, mobile zone 104 initially extends horizontally over a substantial portion of reservoir base 106. In some embodiments, a mobile zone may be expanded horizontally to extend over a substantial portion of reservoir base 106. A mobile zone may be a water zone, or a zone of high water or gas saturation sufficient to permit injection of mobile fluids, such as water and solvent, at rates that will allow a process described herein to be implemented on an economic basis. For example, in a high permeability oil sand, water saturation as low as 40% or even lower may be sufficient to provide the required mobility. In some embodiments, a mobile zone may have water saturation from about 20% to about 30%. A mobile zone may also be a depleted zone where a substance originally in the zone, such as hydrocarbons or water, has been removed.
The solvent is injected into the underlying mobile zone 104 to increase the mobility of the hydrocarbons in the overlying hydrocarbon zone 102. The interface region 110 at the bottom of hydrocarbon zone 102 and the top of mobile zone 104 is initially at a vertical level near the base 106 of reservoir 100. At interface region 110 a solvent vapor front forms when the solvent is injected into mobile zone 104. The solvent vapor contacts the viscous hydrocarbons, condenses and mobilizes viscous hydrocarbons at the interface region 110. Once sufficiently mobilized, the mobilized hydrocarbons, which comprise solvent and viscous hydrocarbons, will drain downward due to gravity along with any condensed water vapor. Interface region 110 can thus also be referred to as the solvent vapor front or the hydrocarbon drainage front. As hydrocarbons continue to drain, interface region 110 will rise up over time. As a result, mobile zone 104 will expand upwards over time; and hydrocarbon zone 102 will shrink over time. The recovery process may be terminated after mobile zone 104 reaches the top 108 of reservoir 100, or at such earlier time as economic considerations dictate.

In selected embodiments, the solvent is injected at a level below but close to interface region 110, and as interface region 110 moves upward over time, the solvent injection level is increasingly elevated to keep the injection level close to interface region 110.

In selected embodiments, an injection well (also referred to as an injector) 120 may be provided to conveniently inject the solvent at different vertical levels. As depicted in FIG. 1, injection well 120 is completed with a number of injection openings at vertical levels 122, 124, through which the solvent can be injected into reservoir 100. As depicted, some injection openings are at levels 122 initially above interface region 110; and some openings are at levels 124 below interface region 110. As can be appreciated, as interface region 110 rises, more injection openings will be at levels below interface region 110. Thus, solvent can be conveniently injected into reservoir 100 through the injection openings of injection well 120 at increasingly elevated levels as more and more injection openings are exposed to the expanded mobile zone 104. As progressively higher openings at the injector are exposed to the ascending mobile zone and are thus able to accept fluids, lower openings may continue to be left open. Alternatively, those lower openings may be closed off by application of an existing technology known to those skilled in the art.

For purposes of illustrating a feature of selected embodiments, the description above notes that hydrocarbon zone 102 may be effectively immobile or of limited mobility. However, in the near-wellbore region of the injector, a combination of thermal and fluid mechanisms may occur which can modify this situation somewhat. For example, when the solvent is exposed to hydrocarbon zone 102 through wellbore openings above the interface region 110, the solvent is not expected to move radially outward from injection well 120 more than a limited radial extent. However, as the zone immediately surrounding the wellbore of injection well 120 in the hydrocarbon zone 102 may have limited mobility due to heating, a limited volume of the solvent may be able to exit the wellbore and enter hydrocarbon zone 102. The limited volume of the solvent can subsequently move downward along the near-wellbore region of hydrocarbon zone 102 and into the underlying mobile zone 104. However, even under such circumstances, most of the solvent is still expected to enter reservoir 100 through perforations or openings of the wellbore portion that is within, or opposite to, mobile zone 104. In some embodiments, the injection openings above interface region 110 may be sealed or covered to prevent any solvent injection directly into hydrocarbon zone 102, and the seal or cover on a particular injection opening may be removed after the interface region 110 moves above that particular injection opening. In some embodiments, injection well 120 may be periodically re-completed to provide further injection openings as mobile zone 104 expands upward.

The solvent may be co-injected with a heated aqueous fluid or medium, which may be hot water or steam. When hot water is used, it may be heated to a temperature that is below the critical temperature at the selected downhole pressure. For example, in selected embodiments, the hot water may be heated to a temperature of about 212 to about 215 C° and the downhole pressure may be as high as 5 MPa.

In different embodiments, the temperature of the heated aqueous fluid or medium will be different but it should be sufficiently high to ensure that the solvent will be substantially in the vapor phase in mobile zone 104 of reservoir 100. The solvent may be vaporized prior to, or after, entering mobile zone 104, but should be able to substantially remain in the vapor phase before ascending to interface region 110. In some embodiments, the solvent may be vaporized by the heated fluid or medium in injection well 120 or upon exiting injection well 120 due to pressure change. In some embodiments, a solvent vapor may be injected with the heated fluid or medium into injection well 120.

In different embodiments, the injection pressure may be different and may be selected depending on a number of factors which will be understood by those skilled in the art. For example, in selected embodiments, the injection pressure may be maintained below formation fracture pressure. Within a given pressure range, the injection pressure may be selected to optimize production performance.

Additionally, a non-condensing gas (NCG) may be injected into mobile zone 104 to optimize the relationship between temperature, pressure and solvent type. Also, at some stage, NCG may be injected to assist in the recovery of solvent.

A production well (also referred to as a producer) 130 is also provided, which may extend to the mobile zone 104 for producing fluids such as oil. The produced fluids may include viscous hydrocarbons that have been mobilized by heating, viscous hydrocarbon-solvent mixtures, as well as solvent, water and non-condensing gases. Production of fluids from the base of mobile zone 104 may be concurrent with solvent injection, or fluids may be produced through production well 130 at selected time intervals. Convenitely, the injection at injection well 120 and production at production well 130 will generate a substantially horizontal fluid flow towards the production well 130, which can be beneficial as discussed below.

Wells 120 and 130 are depicted as vertically extending in the drawings. However, it will be understood that suitable injection and production wells may include slanted wells and wells that have a horizontally extending portion. A vertical well is a well that extends downward vertically or substantially vertically. A slanted well is one that extends downward at a slanted angle and is neither vertical nor horizontal. However, suitable wells may have one or more sec-
tions or portions that are vertical or horizontal. Different portions of the wells may also extend at different angles.

[0039] As the solvent injection levels are kept close to the solvent vapor front (or the drainage front), it is less likely that the solvent will condense and lose thermal energy will be lost before the solvent vapor reaches the vapor front. Thus, a more efficient recovery process may be provided by embodiments of the present invention.

[0040] As noted above, the solvent may be vaporized downhole in injection well 120, such as by introducing a mixture of the solvent and a heated aqueous fluid, e.g., hot water. In some embodiments, the heated aqueous fluid may be steam, or another hot aqueous medium.

[0041] In some embodiments, the hydrocarbons within hydrocarbon zone 102 may be present initially in the form of a bitumen, which is substantially immobile in its native state. In some embodiments, the hydrocarbons within hydrocarbon zone 102 may be present initially in the form of heavy oil with high viscosity so that the heavy oil is only marginally producible or is not commercially producible in its native state.

[0042] In some embodiments, an array of vertical or slanted wells spaced horizontally apart from one another may be drilled into reservoir 100 to provide the injection and production wells, as will be further discussed below.

[0043] A single unconfined element of the well array may consist of one injection well and one production well. With an array of wells, or on a confined pattern basis, many injection/production well patterns are possible, as will be further described below.

[0044] In some cases, there may be a naturally pre-existing mobile zone immediately underlying the hydrocarbon zone.

[0045] In some cases, such a natural mobile zone is not present below the reservoir (at or near its base). In those cases, various techniques may be used to establish a mobile zone at or near the base of the reservoir and immediately underlying the hydrocarbon zone. For example, such a mobile zone may be created by water injection, injection of conventional fracturing fluids, steam injection, solvent injection, or combinations thereof. Many techniques for creating mobile zones in hydrocarbon reservoirs are known to those skilled in the art, and may be adopted by those skilled in the art for the present purposes.

[0046] Regardless of whether the mobile zone is pre-existing or specifically created, the top of the mobile zone defines the base of the hydrocarbon zone.

[0047] The injection and production wells can be completed over an interval whose base is below the base of the hydrocarbon zone and is therefore at a level within the underlying mobile zone.

[0048] The highest point of the completion interval may be at or near the top of the hydrocarbon zone (or the top of the reservoir). Alternatively, for various reasons, such as reasons related to the reduction of eventual heat losses to the overburden as the high temperature region ascends within the reservoir, the highest point of the completion interval may be selected so that it is within but below the top of the hydrocarbon zone (or the reservoir).

[0049] In selected embodiments, a suitable hydrocarbon solvent is used. The solvent may be injected along with a hot (heated) aqueous medium, such as steam or hot water. The solvent may be vaporized by the hot aqueous medium during the injection process. The hot aqueous medium and the solvent form the injected fluids, or injectants. In some embodiments, a non-condensing gas may also be co-injected, as will be further discussed below.

[0050] Hot water may be conveniently used as the aqueous medium in some embodiments. Generally, treatment requirements for hot water prior to injection into the reservoir are much less stringent and thus less costly than those for steam.

[0051] Without being limited to any particular theory, it is expected that the following occurs during the recovery process illustrated in FIGS. 1, 2, 3, 4, 5, and 6.

[0052] As illustrated in FIG. 2, the injected fluids (solvent and hot aqueous medium as depicted) are fed into injection well 120, and will preferentially enter reservoir 100 over the completion interval at levels within mobile zone 104, in which the injected fluids can move about. Initially, the injected fluids will enter the reservoir 100 through the initial mobile zone 104 at injection levels 124, whether the mobile zone is pre-existing or created. Cold mobile fluids are produced at production well 130. As injected fluids enter the mobile zone from the injector, and produced fluids are produced at the producer from the mobile zone, a substantially horizontal fluid flow path is established between the injector and the producer.

[0053] As illustrated in FIG. 3, the injected solvent, having been vaporized by heat from the hot aqueous medium, and being less dense than the accompanying hot water or condensing aqueous fluid, is expected to rise within the mobile zone 104 and thereby contact the base of the overlying hydrocarbon zone 102, whereupon the solvent condenses.

[0054] As illustrated in FIG. 4, the warm condensed solvent mixes with and dilutes hydrocarbons in the interface region 110 (at the base of the hydrocarbon zone), thereby creating a hydrocarbon mixture with enhanced mobility (e.g., lower viscosity) relative to the mobility of the hydrocarbons in their original state. As a result, a countercurrent flow is established in the reservoir below the hydrocarbon zone: the solvent vapor phase ascends within the mobile zone (as indicated by the upward pointing arrows), and a liquid mixture of the condensed solvent and mobilized hydrocarbons descends within the mobile zone (as indicated by the downward pointing arrows). There is also lateral sweeping of fluids toward production well 130 (as indicated by the lower arrows pointing toward the right side), due to production of fluids from production well 130. This lateral sweeping force, in combination with the fact that solvent vapor movement is confined by the base of hydrocarbon zone, encourages the solvent vapor to be dispersed over the horizontal extent of mobile zone 104, as indicated by the upper arrows pointing toward the right side. For simplicity and illustration purposes, the demarcations and interfaces between different zones are illustrated in the figures as horizontal lines. However, it should be understood that in actual reservoirs the interface regions may have various thickness and non-uniformities occasioned by geology or operations, or both, which may result in curvilinear or otherwise non-uniform demarcations.

[0055] In some cases, at least some non-condensing gases (NCG) present in the reservoir 100 will flow downward and be produced from the producer 130.

[0056] It is thus expected that the descender liquid mixture, and some vapor phase or gaseous phase components, will be displaced more or less horizontally within the mobile zone, towards the production well 130, where they will be produced.
[0057] Due to removal of hydrocarbons from the base of the hydrocarbon zone 102, which may be replaced with mobile fluids, the base of the hydrocarbon zone 102 (and correspondingly the top of the mobile zone 104) gradually moves up and the mobile zone 102 expands upward. That is, interface region 110 will continuously move upward as hydrocarbons at the base of hydrocarbon zone 102 are mobilized by the solvent and drain downward. As depicted, after a certain period of solvent injection, interface region 110 may rise to a higher vertical level 110'. As mobile zone 104 expands upward, the thickness of the mobile zone 104 increases. One or more injection openings at levels 122, such as levels 122A, 122B as depicted in FIG. 4, will become exposed to mobile zone 104, so that the effective injection interval extends further upward, and the levels at which the solvent is injected are elevated, such as to levels 122A, 122B as depicted.

[0058] Conveniently, the ongoing horizontal displacement of the mobile fluids can prevent or inhibit the formation of overlying gas accumulation with built-in trapping geometry. The injected fluids, which may be able to react with the overlying hydrocarbons (e.g. bitumen) by virtue of buoyancy effects (i.e., a gravity mechanism), are concurrently moved along horizontally by the displacement process. Accordingly, the tendency of low density fluids, such as non-condensing gases, to accumulate within the reservoir can be conveniently mitigated or negated by the convection forces in this process.

[0059] In the embodiments depicted, as the injection openings of the injection well 120 are distributed at different vertical levels that span a substantial vertical extent of the reservoir 100 or the initial hydrocarbon zone 102, they allow the injection levels to be increasingly elevated to follow or track the upward-migrating interface region 110 (at the base of the hydrocarbon zone 102).

[0060] As now can be appreciated, the fluid flow geometry in reservoir 100 may involve concurrent mechanisms that are integrally related. For example, the horizontal fluid displacement can accomplish the following: providing a fresh supply of injectants to the reservoir; allowing the injectants to move laterally along an interface at or near the base of the hydrocarbon zone so that the solvent may ultimately contact oil on a substantially continuous basis; and displacing the mixture of mobilized hydrocarbons, injectants, and other reservoir fluids, to a laterally spaced production well.

[0061] In addition to the substantially horizontal fluid movement, and concurrent with it, a vertical fluid movement also occurs, where the injected solvent ascends to the base of the hydrocarbon zone, dilutes the hydrocarbons so as to enhance their mobility, and descends as a dense but mobile mixture or blend into the mobile zone where the horizontal stream flow carries it to the production well. Non-condensing gases, whether injected or evolved, may also form a part of this flow stream.

[0062] As noted, when an underlying mobile zone does not pre-exist, different techniques can be used to establish a mobile zone with elevated mobility within the basal portion of the original hydrocarbon zone. As can be appreciated, heating can reduce viscosity of hydrocarbons in bitumen. For example, one possible technique for creating a mobile zone may involve the drilling of an array of horizontal wells in the basal portion of the hydrocarbon zone, applying heat through the wells using known techniques (e.g., circulating steam in the wells, or using electrical heating elements), and heating the hydrocarbon formation by conduction to form a zone of elevated mobility. As an alternative to, or concomitant of, heating, elevated pressures may be applied to the basal portion of the hydrocarbon zone to improve mobility therein. For example, applied pressures can cause fracturing or dilation in the reservoir formation, which can improve permeability. These techniques are known to those skilled in the art, and could utilize vertical, slant or horizontal wells, or combinations thereof.

[0063] In some embodiments, prior to commencement of an early stage of the recovery process, or on an intermittent or ongoing basis, a non-condensing gas (NCG) may be injected into the underlying mobile zone. For example, when the mobile zone contains a large amount of water, the water can impede dispersion of the solvent vapor and can absorb a large amount of heat from the injected solvent and hot aqueous medium. Injecting NCG can facilitate displacement of a portion of the water, such as to the production well where the water can be produced. Subsequently, when the solvent and the hot aqueous medium are injected, heat absorption by the lower temperature resident water phase within the mobile zone is reduced, since the water saturation has been reduced in favour of gas saturation.

[0064] Non-condensing (or non-condensable) gases refer to gaseous substances with relatively low condensation (boiling) points. As examples, under standard conditions methane condenses at about 161°C and nitrogen condenses at about 196°C. Non-condensing gases include, but are not limited to air, nitrogen, carbon dioxide, methane, and other light hydrocarbons. In a particular embodiment, the NCG may be methane or natural gas.

[0065] In a particular embodiment, a cold or ambient temperature solvent may be first injected into the reservoir before injection of heated fluids. A potential benefit of prior injection of cold solvent is that it can avoid or minimize flow inhibition or stoppage due to banking of thermally mobilized but otherwise still highly viscous hydrocarbons and consequent plugging of the pores in the reservoir. Without being limited to any theory, it is expected that this avoidance or minimization of banking reflects the difference in mobilization mechanisms between a cold solvent and a hot fluid. On the one hand, mobilization of bitumen with a hot fluid depends on the maintenance of an elevated temperature. Once bitumen mobilized by the hot fluid descends into the high mobility zone where the temperature is lower, the bitumen can cool down and return to a high viscosity condition, with possible concomitant plugging of reservoir pores. Mobilization of bitumen by solvent, on the other hand, does not require a high temperature, so that subsequent movement of the solvent-bitumen blend into cooler regions of the reservoir is not expected to result in pore plugging. Although the injection of cold solvent into the reservoir is not likely to result in the formation of gas hydrates, or clathrates, the possibility exists. In that event, a clathrate inhibitor, which is a type of chemical known in the petroleum industry, may be injected either concurrently or alternately with the solvent. Accordingly, for this particular embodiment, it will be understood that cold or ambient temperature solvent injection can include clathrate inhibitors. A mixture of cold water and liquid solvent may be used to inject the cold solvent.

[0066] In a further embodiment, a hot aqueous medium may be injected into the mobile zone for a period of time before introducing the solvent, to heat the reservoir and increase the reservoir temperature in the mobile zone and the lower portion of the hydrocarbon zone.
In some embodiments, throughout the injection-production process, the solvent and aqueous medium may be injected concurrently. Alternatively, in some embodiments, solvent and aqueous medium may be injected alternately from time to time.

In selected embodiments, during the recovery process, the injection and production rates may be varied. For example, the injection rate may be temporarily reduced, even to zero; and the production rate may be temporarily reduced, even to zero. The respective variations in the injection rate and production rate may be implemented with some degree of synchrony, or may be carried out independently.

In some embodiments, wells 120 and 130 may be completed such that each well can function as both an injector and producer. During operation, the functions of wells 120 and 130 may be alternated from time to time. The wells may also be re-completed in order to switch functions. Such alternation of the roles of the wells may occur at any time before or during the recovery operation, may occur for a specified time or indefinitely, and may repeatedly occur. Variations in injection and production rates, and alternation of roles as injectors and producers, are techniques known to those skilled in the art for improving reservoir conformance.

The wells for use in embodiments of the present invention, such as wells 120, 130 may be configured or completed in different ways as long as they provide the necessary solvent and aqueous medium injection levels and the ability to produce fluids from the mobile zones.

For example, in one embodiment, the injection well 120 may be completed initially for injection over the interval corresponding to some or all of the vertical extent of the initial mobile zone. As the interface region 110 between the mobile zone and the hydrocarbon zone ascends, the injection well can be re-completed to provide higher injection openings. The higher injection openings may be initially sealed or isolated from the injection fluids, and are opened when the interface region rises above the particular injection opening. The injection openings may be managed and opened to ensure that the heated injected fluids are injected close to the upwardly migrating interface region and can come into intimate contact with the interface region without having to travel a long distance.

In another embodiment, the injection well may be completed at the outset over a vertical interval which spans some or all of the initial mobile zone, and the hydrocarbon zone. In a further embodiment, a portion of the wellbore in the injection well may be blanked off (i.e., closed to the reservoir) over a vertical interval corresponding to an upper portion of the hydrocarbon zone. Conveniently, with such blank-off, heat losses to the overburden above the reservoir can be reduced.

Even if no injection openings are provided in the vertical interval adjacent to the hydrocarbon zone, some heat may be conducted into the regions of the hydrocarbon zone in the immediate vicinity of the wellbore when a hot fluid mixture traverses the blanked off portion of the wellbore that penetrates the reservoir. In the case where there are injection openings adjacent to the hydrocarbon zone, more heat may be transferred to the adjacent hydrocarbon zone, because heat may be transferred by both conduction and convection when the injected fluid can come into contact with the hydrocarbon formation, as illustrated in FIGS. 5 and 6.

As illustrated in FIGS. 5 and 6, hydrocarbons adjacent to injection well 120 (in the region radially immediately around the wellbore) can be mobilized by heating due to conduction (and convection, if not blanked off) of heat from injection well 120. Over time, the radially mobilized hydrocarbons in this region may move downward and enter the mainly horizontal fluid stream below the base of the hydrocarbon zone that moves the fluids from the injection well 120 to the production well 130.

Alternating, varying, cycling, or sequencing the injection or production operations of wells 120 and 130 from time to time can encourage movement of mobilized hydrocarbons near the wellbore toward the horizontal fluid stream and, as noted above, can improve conformance.

Some or all completion features of injection wells discussed herein may also be implemented on a production well, such as well 130. In some embodiments, however, wells dedicated as injector or producer may be used and the completion design and strategy of the injector and producer may be different.

It should be understood that to effect the various types of completion intervals at a wellbore, techniques known to those skilled in the art may be employed, individually or in combination. Examples of such techniques include perforated casing, slotted liners, wire-wrap screens, precise punched screens, and gravel packs.

It can now be understood that increasing the vertical level of injection of the solvent does not necessarily require any change in the completion interval of the injection openings in the injection well. In some embodiments, the completion interval(s) of the injection openings on the injection well may remain unchanged and the solvent injection level can still be increasingly elevated over time due to the drainage of mobilized hydrocarbons in regions around the injection openings that initially limit entry of the solvent into the reservoir through these openings. It should also be understood that in some embodiments, it is not necessary that the injection levels are continuously elevated or increasingly elevated over the entire production process.

It is also intended that an increasingly elevated level of solvent injection may include, in some embodiments, injecting the solvent at a level above a barrier in the formation after injecting the solvent below the same barrier. The barriers may be partial or local barriers, in which case, the solvent injection level may be progressively increased, such as through progressively elevated or activated injection openings. The barriers may also include complete barriers that separate the reservoir into layered sections, in which case, the solvent may be injected at a higher section after hydrocarbons have been mobilized and drained in the lower section(s) by solvent injection.

In bituminous sands or heavy oil reservoirs, there may be present partial or total impediments to vertical fluid flow, such as shale barriers or shale lenses.

In some cases, the reservoir may have a shale barrier, e.g. in the middle portion of the hydrocarbon zone, which stretches over the entire horizontal extent of the reservoir, or over the entire horizontal portion of the reservoir to which the recovery process is to be applied. In such a case, the original reservoir may be considered to be two reservoirs separated by the shale barrier. That is, the shale barrier would represent a boundary between two sub-units of the original reservoir, each sub-unit acting as an independent reservoir because of the hydraulic isolation effected by the barrier. The two separate sub-reservoirs may each be subjected to a separate recovery process as described herein.
For example, if at the base of the original reservoir, there is a naturally existing mobile zone below the lower reservoir sub-unit, the lower reservoir sub-unit may be subjected to a recovery process as described above. During this operation, the heated zone in the reservoir will gradually rise and reach the upper reservoir sub-unit, such as when the mobile zone reaches the shale barrier. The lower sub-unit may be heated until such time as the heat has ascended to the top of the lower sub-unit (i.e., to the base of the barrier which separates the upper and lower sub-units). The upper reservoir sub-unit may also be heated due to at least conduction heating from the lower sub-unit. Even if there is no pre-existing mobile zone at the upper reservoir sub-unit, the heat transfer from the lower reservoir sub-unit may be sufficient to create, or facilitate the creation of, a separate mobile zone at the base of the upper reservoir sub-unit.

Alternatively, a mobile zone may be created within the upper reservoir sub-unit using other techniques as discussed earlier.

Some embodiments, separate sets of injection and production wells may be provided in each reservoir sub-unit. A distinct injector and producer may be provided for each sub-unit.

In some embodiments, the same well may penetrate both reservoir sub-units and may be used for recovery of hydrocarbons in both sub-units, either concurrently or at different times. A well may be completed so that each sub-unit could be operated independently within the given individual wellbore.

If a reservoir contains intermittent shale lenses or features throughout the reservoir, such that vertical flow is impeded but not prevented, hydrocarbons can still be produced from the reservoir using a process as described herein but the recovery process may operate at a reduced production rate. In some embodiments in which this vertical flow is present, the vertical or slanted wells may be placed and configured so that the wellbore is continually exposed to the active zones in the reservoir. By virtue of vertical countercurrent fluid flow, the upwardly advancing interface region, and the concurrent and integrated horizontal fluid displacement, the vertical distances over which the mobilizing fluids (solvent and heated medium) will have to ascend, and over which the mobilized hydrocarbons will have to descend before they can enter the horizontal flow stream, are reduced as compared to a process in which fluids are injected and produced at fixed, or necessarily fixed, completion intervals, such as would occur in horizontal wells or wells that are completed over horizontal sections.

It is well established that, for reasons based in geology, operations and design, movement of fluids and heat along the axial dimension of long horizontal wells, and thence outward into the reservoir, is typically non-uniform. This non-uniformity of heat and fluid distribution can result in reduced reservoir conformance and hydrocarbon yield. Applying this knowledge, it has been recognized that one of the possible reasons that it is difficult to achieve satisfactory levels of performance using a horizontal well configuration in a Bottom-Up Solvent-Aided Process is that, it will be difficult to achieve uniform displacement along the length of the horizontal wells.

In embodiments of the present invention described herein, and for the reasons discussed above, the solvent vapor front may be conveniently developed upward relatively more uniformly using vertical or slanted wells, as compared to a conventional bottom-up solvent aided process using horizontal wells placed at the bottom of the reservoir. Accordingly, it is expected that lateral sweep will be improved by using vertical or slanted wells.

Many vertical or slant well patterns can be used and, as described earlier, can undergo operational modifications or can be re-assigned operating roles (e.g., can undergo a temporary or permanent role reversal from injector to producer, or vice versa). FIG. 7 illustrates a possible pattern/arrangement of vertical wells 702 distributed in arrays of uniform intervals across a reservoir 700. For illustrative purposes, one of many possible arrangements of production gathering/injection distribution lines 706 radiating outward to the wells from a central well pad 704 is also shown. Lines 706 may be surface pipe lines and each line 706 may include one or more separate pipe lines for transferring fluids. The exploitable reservoir 700 may have a boundary 708.

Wells 702 may be drilled from different well pads. However, in some embodiments, some or all of wells 702 may be drilled from a single well pad to minimize surface footprint.

As noted above, in different embodiments the heated aqueous fluid may be hot water or steam. However, in some embodiments using hot water may be more convenient, or may reduce operating costs, as compared to using steam. For example, the purity of the feed water is either not critical or is less critical when using hot water. Further, more heat energy can be recycled from hot water, as low grade heat may need to be rejected when using steam but can be recycled when using hot water. In embodiments where hot water is used to heat the solvent, operating costs and requirements for surface equipments (such as water treatment equipment) can be reduced, as compared to processes in which steam is the heated aqueous medium.

In selected embodiments, the heated aqueous fluid to be injected into the injection well, such as injection well 120, is conditioned to facilitate vaporization of the solvent before the solvent contacts viscous hydrocarbons in the hydrocarbon zone of the reservoir, and to facilitate subsequent condensation of the solvent upon contacting viscous hydrocarbons in the hydrocarbon zone. The heated aqueous fluid may be conditioned by heating and pressurizing the fluid. For example, when hot water is used, properties of the injected water, such as its pressure and temperature, may be selected to promote initial vaporization and subsequent condensation of the solvent. When steam is used, properties of the injected steam, such as its pressure, temperature, and steam quality, may be selected to promote initial vaporization and subsequent condensation of the solvent.

It is expected that a person of ordinary skill in the art would be able to select a suitable well pattern configuration in a given situation based on reservoir and operating considerations.

FIG. 8 shows an example of a possible arrangement of vertical wells 802A, 802B, 802C, 802D, 804 across a reservoir in a top plan view. Vertical wells 802A, 802B, 802C, 802D (also collectively referred to as wells 802) at the corners of the generally square region 806 may be injection wells and vertical well 804 at the center of region 806 may be a production well. The distance between adjacent injection wells such as wells 802A and 802B may be selected for performance and economic considerations, and may be, for example, about 100 m.
Computer simulation has been performed based on a set of realistic parameters for an example reservoir, and representative simulation results are shown in FIGS. 9-53 and summarized below.

For the simulation, the reservoir and well configuration conditions are assumed to be as follows.

Oil is to be produced from a portion of the reservoir formation having a cubic volume with dimensions of 50 m in the x horizontal direction, 50 m in the y horizontal direction, and 34.5 m in vertical direction, as illustrated in FIG. 9.

For ease of description, the corners of the cubic volume are assumed to be at coordinates: (0, 0, 0), (0, 50, 0), (50, 50, 0), (50, 0, 0), (0, 0, 34.5), (0, 50, 34.5), (50, 50, 34.5), and (50, 0, 34.5). The reservoir is initially divided (at the height of 9 m from the bottom) into a lower portion (z<9 m) and an upper portion (z>9 m). The initial conditions of the simulated reservoir are listed in Table 1.

<table>
<thead>
<tr>
<th>Initial Conditions of the Simulated Reservoir</th>
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</thead>
<tbody>
<tr>
<td>Water saturation in the upper portion</td>
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<tr>
<td>Water saturation in the lower portion</td>
</tr>
<tr>
<td>Oleic saturation in the upper portion</td>
</tr>
<tr>
<td>Oleic saturation in the lower portion</td>
</tr>
<tr>
<td>API Gravity of Oil</td>
</tr>
<tr>
<td>horizontal permeability</td>
</tr>
<tr>
<td>vertical permeability</td>
</tr>
<tr>
<td>gas saturation</td>
</tr>
<tr>
<td>Mole fraction of dissolved gas (methane) in oil</td>
</tr>
<tr>
<td>solvent content in liquid phase</td>
</tr>
<tr>
<td>Formation pressure</td>
</tr>
<tr>
<td>Formation temperature</td>
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</tbody>
</table>

A mixture containing hot water and the solvent at 212 to 215° C is injected into the reservoir through well 802A, at a maximum downhole pressure of 5000 kPa. The mixture has the same weight ratio of water to solvent of about 1:1.

Fluids are produced from well 804 operated at the pressure of 1200 kPa.

Simulation results show that upon injection the mixture is initially partially flashed in to the reservoir as the reservoir initially has a lower pressure. After entering the reservoir, the resultant temperature of the fluids drops slightly (to around 208° C.).

To simulate real life operational variance in injection volume, the mixture is injected with fluctuating volumes with 2 months on and 2 months off. When injection is on, the injection rates are 200 t/d for hot water and 200 t/d for the solvent. The average injection rates are 100 t/d of hot water and 100 t/d of solvent over the entire period.

Simulation Results

Representative simulation results are shown in FIGS. 9 to 53.

FIG. 9 shows the simulated reservoir volume, the location of the vertical wells and the initial gas saturation in the reservoir.

FIGS. 10 and 11 show the initial water and oleic saturation in the reservoir, respectively.

FIGS. 12 to 19 show the reservoir conditions after six months of injection, for pressure, temperature, gas saturation, NCG fraction in gas saturation, solvent fraction in gas saturation, water saturation, oleic saturation, and solvent fraction in oleic saturation, respectively.

FIGS. 20 to 26 show the reservoir conditions after 12 months of injection, for pressure, gas saturation, NCG fraction in gas saturation, solvent fraction in gas saturation, water saturation, oleic saturation, and solvent fraction in oleic saturation, respectively.

FIGS. 27 to 34 show the reservoir conditions after 18 months of injection, for pressure, temperature, gas saturation, NCG fraction in gas saturation, solvent fraction in gas saturation, water saturation, oleic saturation, and solvent fraction in oleic saturation, respectively.

FIGS. 35 to 42 show the reservoir conditions after 24 months of injection, for pressure, temperature, gas saturation, NCG fraction in gas saturation, solvent fraction in gas saturation, water saturation, oleic saturation, and solvent fraction in oleic saturation, respectively.

FIGS. 43 to 50 show the reservoir conditions after 36 months of injection, for pressure, temperature, gas saturation, NCG fraction in gas saturation, solvent fraction in gas saturation, water saturation, oleic saturation, and solvent fraction in oleic saturation, respectively.

As shown, the downhole reservoir pressures are in the range of 2100 kPa to 3900 kPa for the first 6 months of injection, and in the range of 2100 kPa to 1200 kPa after the first 6 months of injection.

FIG. 51 shows rates of injection and production over time for the simulated process. The top solid line represents the water injection rate, which is the same as the solvent injection rate. The lighter bottom solid line represents the equivalent steam injection rate. The dashed line represents the solvent production rate. The darker bottom line represents the oil production rate.
FIG. 52 shows cumulated oil recovery (light line), solvent recovery (darker line), and CSOR (darkest line) over time for the simulated process.

FIG. 53 shows NCG movement in the reservoir during the simulated process, where the dashed line represents cumulative gas oil ratio (GOR) and the solid line represents in situ GOR. It can be concluded from the results that NCG does not tend to accumulate in the reservoir but is mostly produced during the simulated process.

The above simulation results are for region 808 as shown in FIG. 8, which is one fourth of the entire reservoir until 806. For the full unit, the rates of injection and production will be four times of the rates for region 808.

Based on the simulated results, the reservoir related indicators of economics after two years of injection are: oil recovery reaches ~85%, CSOR reaches ~0.91, and solvent recovery is ~95%. From this, it is expected that in practice solvent injection may be terminated after around two (2) years of injection.

The time for termination of injection and production may be determined for economical optimization, taking into account of reservoir performance and market indicators.

While the surface conditions such as the surface injection pressure are not included in the simulation parameters, it can be expected that surface injection pressures can be adjusted to accommodate the simulated rates and downhole conditions used in the simulation.

Temperatures of the produced fluids are close to the initial reservoir temperature during the first 6 months, but increase over time to about 1100 °C after about 12 months, and to about 1300 °C after about 18 months, and gradually to about 1500 °C over the next 18 months. The temperature of the produced fluids does not appear to affect the recovery process. In some embodiments, the produced fluid can be conveniently used to pre-heat the fluids to be injected.

Simulation results show that, using an embodiment of the processes described herein, about 75% of the hydrocarbons in the reservoir may be recovered; recovery may be completed within a couple of years depending on the operating parameters and the solvent used; the cumulative steam (water) to oil ratio (CSOR) can be lower than 1.5, and as low as about 1; as high as more than 90% of the injected solvent can be recovered.

It will be understood that any singular form is intended to include plurals herein. For example, the word “a”, “an” or “the” is intended to mean “one or more” or “at least one.” Plural forms may also include a singular form unless the context clearly indicates otherwise.

It will be further understood that the term “comprise”, including any variation thereof, is intended to be opened-ended and means “include, but not limited to,” unless otherwise specifically indicated to the contrary.

When a list of items is given herein with an “or” before the last item, any one of the listed items or any suitable combination of two or more of the listed items may be selected and used. For any list of possible elements or features provided in this specification, any sub-list falling within the given list is also intended.

Similarly, any range of values given herein is intended to specifically include any intermediate value or sub-range within the given range, and all such intermediate values and sub-ranges are individually and specifically disclosed.

Of course, the above described embodiments are intended to be illustrative only and in no way limiting. The described embodiments are susceptible to many modifications of form, arrangement of parts, details and order of operation. The invention, rather, is intended to encompass all such modification within its scope, as defined by the claims.

What is claimed is:

1. A method comprising:
   - injecting a solvent into a hydrocarbon reservoir at an increasingly elevated vertical level to allow vapor of the solvent to contact and mobilize viscous hydrocarbons in the reservoir; and
   - producing mobilized hydrocarbons from the reservoir.

2. The method of claim 1, comprising vaporizing the solvent to allow vapor of the solvent to ascend in the reservoir, wherein the vertical level at which the solvent enters the reservoir is increasingly elevated as viscous hydrocarbons are mobilized by the solvent and are displaced from their original location.

3. The method of claim 1 wherein the injecting comprises injecting the solvent into a mobile zone below a viscous hydrocarbon zone in the reservoir, and increasingly elevating the vertical level of solvent injection as the mobile zone expands upward due to mobilization of viscous hydrocarbons in the hydrocarbon zone, gravity drainage of mobilized viscous hydrocarbons, and lateral displacement of mobilized viscous hydrocarbons.

4. The method of claim 1 wherein the solvent is injected through an injection well having a plurality of injection openings distributed at different vertical levels.

5. The method of claim 4 wherein the injection openings are distributed between a top level and a bottom level of the hydrocarbon reservoir.

6. The method of claim 4, comprising feeding a solvent and a heated aqueous fluid to the injection well for injection into the reservoir through the injection openings.

7. The method of claim 6 wherein the heated aqueous fluid comprises heated water.

8. The method of claim 6 wherein the heated aqueous fluid comprises steam.

9. The method of claim 6 wherein the feeding comprises feeding a mixture of the solvent and the heated aqueous fluid to the injection well.

10. The method of claim 6 wherein the feeding comprises feeding the solvent and the heated aqueous fluid separately to the injection well.

11. The method of claim 6 wherein the feeding comprises alternately feeding the solvent and the heated aqueous fluid to the injection well.

12. The method of claim 4 wherein the solvent is at least partly vaporized in the injection well.

13. The method of claim 1 wherein the solvent is at least partly vaporized in the reservoir.

14. The method of claim 4 wherein the heated aqueous fluid is conditioned to facilitate vaporization of the solvent before the solvent contacts viscous hydrocarbons in the reservoir and subsequent condensation of the solvent when the solvent comes into contact with viscous hydrocarbons.

15. The method of claim 1 wherein the solvent comprises an alkane or alkene having 2 to 9 carbon atoms.

16. The method of claim 3 wherein the mobile zone is a pre-existing water zone at a base portion of the reservoir.
17. The method of claim 3, comprising creating the mobile zone at a base portion of the reservoir prior to injecting the solvent.

18. The method of claim 3, comprising injecting a non-condensing gas into the mobile zone.

19. The method of claim 4, wherein the mobilized hydrocarbons are produced from a vertical or slanted production well.

20. The method of claim 3, comprising providing a plurality of wells extending into the mobile zone through the hydrocarbon zone, the plurality of wells comprising a production well for producing fluids from the mobile zone, and an injection well for injecting the solvent into the reservoir at different vertical levels.

21. The method of claim 20, wherein the plurality of wells comprises spaced apart first and second wells each configured for use alternately as the injection well or the production well, and wherein the solvent is alternately injected through one of the first or second wells, and the mobilized hydrocarbons are alternately produced through the other of the first and second wells.

22. The method of claim 1, comprising injecting the solvent with a heated aqueous fluid and producing mobilized hydrocarbons at different horizontal locations within the mobile zone, thus facilitating horizontal fluid flow within the mobile zone.

23. The method of claim 22, comprising concurrently injecting the solvent and heated aqueous fluid and producing mobilized hydrocarbons.

24. The method of claim 22, comprising alternately injecting the solvent and heated aqueous fluid and producing mobilized hydrocarbons.

25. A system for recovering hydrocarbons from a subterranean reservoir comprising an overlying viscous hydrocarbon zone and an underlying mobile zone, the system comprising:

an injection well extending into the mobile zone through the hydrocarbon zone, the injection well having injection openings distributed at different vertical levels in both the hydrocarbon zone and the mobile zone; and a production well spaced horizontally apart from the injection well and extending into the mobile zone for producing mobilized hydrocarbons from the mobile zone; wherein the injection well is configured to inject a solvent and a heated aqueous liquid into the mobile zone through injection openings adjacent to the mobile zone to mobilize hydrocarbons in the hydrocarbon zone, such that the solvent can be injected into the reservoir at increasingly elevated vertical levels when mobilized hydrocarbons in the hydrocarbon zone drain downward due to gravity.

26. The system of claim 25 wherein the injection well is configured to inject a non-condensing gas into the reservoir.

27. The system of claim 25, wherein the injection well and the production well are vertical or slanted wells.

28. The system of claim 25, comprising an array of injection and production wells spaced horizontally apart from one another.

29. The system of claim 25, wherein each one of the injection well and the production well is configured for use alternately as an injection well or a production well.

30. A method comprising:

injecting a solvent into a hydrocarbon reservoir through a mobile zone below a viscous hydrocarbon zone in the hydrocarbon reservoir, to allow vapor of the solvent to ascend in the reservoir to mobilize viscous hydrocarbons in the viscous hydrocarbon zone, wherein the solvent is injected through an injection well completed to provide a plurality of injection openings distributed over a vertical extent that initially extends into both the mobile zone and the viscous hydrocarbon zone; and producing mobilized hydrocarbons from the reservoir through the mobile zone with a production well, wherein the production well is horizontally spaced from the injection well to provide a horizontal pressure gradient in the mobile zone for inducing horizontal movement of fluids within the mobile zone.

31. The method of claim 30, comprising vaporizing the solvent to allow vapor of the solvent to ascend in the reservoir.

32. The method of claim 30, comprising increasing the vertical level of solvent injection as the mobile zone expands upward due to mobilization of viscous hydrocarbons in the hydrocarbon zone, gravity drainage of mobilized viscous hydrocarbons, and lateral displacement of mobilized viscous hydrocarbons.

33. The method of claim 30, wherein the injection openings are distributed between a top level and a bottom level of the hydrocarbon reservoir.

34. The method of claim 30, comprising feeding the solvent and a heated aqueous fluid to the injection well for injection into the reservoir through the injection openings.

35. The method of claim 34, wherein the heated aqueous fluid comprises heated water.

36. The method of claim 34, wherein the feeding comprises feeding a mixture of the solvent and the heated aqueous fluid to the injection well.

37. The method of claim 30, wherein the solvent is at least partly vaporized in the injection well.

38. The method of claim 30, wherein the solvent is at least partly vaporized in the reservoir.

39. The method of claim 30, wherein the solvent comprises an alkane or alkene having 2 to 9 carbon atoms.

40. The method of claim 30, wherein the mobile zone is a pre-existing water zone at a base portion of the reservoir.

41. The method of claim 30, comprising creating the mobile zone at a base portion of the reservoir prior to injecting the solvent.

42. The method of claim 30, comprising injecting a non-condensing gas into the mobile zone.

43. A method for recovery of hydrocarbons in a bottom-up solvent-aided process from a hydrocarbon reservoir comprising an overlying viscous hydrocarbon zone and an underlying mobile zone, the method comprising:

injecting water and liquid solvent into the mobile zone, to improve and maintain fluid communication within the mobile zone;

injecting heated water and solvent into the mobile zone to allow vapor of the solvent to ascend in the hydrocarbon reservoir to mobilize viscous hydrocarbons in the viscous hydrocarbon zone, wherein the heated water and solvent are injected through an injection well completed to provide a plurality of injection openings distributed over a vertical extent in at least the mobile zone; and producing mobilized hydrocarbons from the reservoir through the mobile zone with a production well, wherein the production well is horizontally spaced from the injection well to provide a horizontal pressure gradient.
in the mobile zone for inducing horizontal movement of fluids within the mobile zone.

44. The method of claim 43, wherein a mixture of the heated water and solvent is fed into the injection well.

45. The method of claim 43, wherein the heated water is heated to a temperature sufficient to vaporize at least a substantial portion of the solvent in the injection well.

46. The method of claim 43, wherein the heated water is heated to a temperature sufficient to vaporize at least a substantial portion of the solvent when the solvent is injected into the mobile zone.

47. The method of claim 43, wherein the water is conditioned to facilitate vaporization of the solvent before the solvent contacts viscous hydrocarbons in the reservoir and subsequent condensation of the solvent when the solvent comes into contact with viscous hydrocarbons.

48. The method of claim 43, wherein the solvent comprises an alkane or alkene having 2 to 9 carbon atoms.

49. The method of claim 43, wherein the injection well and production well are vertical or slanted wells.

50. The method of claim 43, comprising concurrently producing mobilized hydrocarbons and injecting the heated water and solvent.

51. The method of claim 43, comprising alternately injecting the heated water and solvent and producing mobilized hydrocarbons.