A method for mobilizing viscous hydrocarbons in a reservoir includes (a) injecting an aqueous solution into the reservoir with the reservoir at the reservoir ambient temperature. The aqueous solution includes water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the reservoir ambient temperature. In addition, the method includes (b) adding thermal energy to the reservoir at any time after (a) to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir. Further, the method includes (c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons.
Figure 6

Urea Reaction vs. Temperature

Wt. % of Urea Reacted vs. Temperature (°C)
SYSTEMS AND METHODS FOR ACCELERATING PRODUCTION OF VISCOUS HYDROCARBONS IN A SUBTERRANEAN RESERVOIR WITH THERMALLY ACTIVATED CHEMICAL AGENTS

CROSS-REFERENCE TO RELATED APPLICATIONS


STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

FIELD

[0003] The invention relates generally to thermal recovery techniques for producing viscous hydrocarbons such as heavy oil and bitumen. More particularly, the invention relates to the injection of chemical agents and subsequent thermal activation of the chemical agents to accelerate 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 typically 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. The commissioning processes can be time consuming, typically taking more than three months, which results in high costs and delays the ultimate production of oil. 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.

[0008] The application of steam in SAGD operations for the recovery of viscous hydrocarbons relies primarily on the transfer of thermal energy from the steam to the hydrocarbons to enhance mobility through the formation via decreased viscosity. However, in many cases, the heating and mobilization of the hydrocarbons 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.

BRIEF SUMMARY OF THE DISCLOSURE

[0009] These and other needs in the art are addressed in one embodiment by a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation. In an embodiment, the method comprises (a) injecting an aqueous solution into the reservoir with the reservoir at the reservoir ambient temperature. The aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir. In addition, the method comprises (b) adding thermal energy to the reservoir at any time after (a) to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir. Further, the method comprises (c) in response to the elevated temperature
in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons.

[0010] These and other needs in the art are addressed in another embodiment by a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation. In an embodiment, the method comprises (a) injecting an aqueous solution into the reservoir through an injection well or a production well of a SAGD well pair with the reservoir at the ambient temperature of the reservoir. The aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir. In addition, the method comprises (b) injecting steam into the reservoir after (a) through the injection well or the production well to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir. Further, the method comprises (c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons.

[0011] These and other needs in the art are addressed in another embodiment by a method for mobilizing viscous hydrocarbons from a reservoir in a subterranean formation. In an embodiment, the method comprises (a) injecting a volume of an aqueous solution into the reservoir with the reservoir at the ambient temperature. The aqueous solution comprises a brine and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir. The chemical agent in the aqueous solution has a concentration greater than or equal to 0.01 wt % and less than the solubility limit of the chemical agent in the brine at the ambient temperature of the reservoir. The volume is based on a pore volume of connate water in a portion of the reservoir to be produced. In addition, the method comprises (b) adding thermal energy to the reservoir at any time after (a) to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir. Further, the method comprises (c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir and allowing the chemical agent to enhance mobilization of the hydrocarbons.

[0012] These and other needs in the art are addressed in another embodiment by a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation. In an embodiment, the method comprises (a) injecting steam into the reservoir. The steam has a steam quality less than 100% and comprises a liquid phase and a vapor phase. Injecting the steam comprises delivering an aqueous solution to the reservoir in the liquid phase of the steam and injecting the aqueous solution into the reservoir with the steam. The aqueous solution comprises a surfactant. In addition, the method comprises (b) in response to the steam injected in (a), mobilizing the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons. Further, the method comprises (c) emulsifying the hydrocarbons with the surfactant during (b) to enhance the mobilization of the hydrocarbons.

[0013] These and other needs in the art are addressed in another embodiment by a method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation. In an embodiment, the method comprises (a) injecting steam into the reservoir. The steam has a steam quality less than 100% and comprises a liquid phase and a vapor phase. Injecting the steam comprises delivering an aqueous solution to the reservoir in the liquid phase of the steam and injecting the aqueous into the reservoir with the steam during (a). The aqueous solution comprises a non-volatile thermally activated chemical species. The liquid phase of the steam has a temperature. The thermally activated chemical species has a conversion rate less than 10 mol % over a time period less than 10 minutes in the presence of the steam and at the temperature of the liquid phase. In addition, the method comprises (b) decomposing or reacting the thermally activated chemical species in the reservoir to enhance the mobilization of the viscous hydrocarbons.

[0014] These and other needs in the art are addressed in another embodiment by a method for recovering viscous hydrocarbons from a reservoir in a subterranean formation using steam assisted gravity drainage (SAGD). In an embodiment, the method comprises (a) during a loading phase, loading a portion of the reservoir with an aqueous solution injected into the reservoir through an injection well or a production well of a SAGD well pair with the reservoir at the ambient temperature of the reservoir. The aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir. In addition, the method comprises (b) at any time after the loading phase in (a), commencing a start-up phase wherein steam is injected into the reservoir through the injection well or the production well to increase the temperature of the portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir. Further, the method comprises (c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons. Still further, the method comprises (d) continuing the start-up phase until fluid communication between the injection well and the production well is achieved. Moreover, the method comprises (e) in response to (d), ceasing the start-up phase and commencing a production phase wherein steam is injected into the reservoir through the injection well and at least a portion of the hydrocarbons are produced from the reservoir through the production well.

[0015] 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

[0016] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0017] FIG. 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;

[0018] FIG. 2 is a schematic cross-sectional end view of the system of FIG. 1 taken along section II-II of FIG. 1;

[0019] FIG. 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 FIG. 1 using the system of FIG. 1;

[0020] FIG. 4 is a schematic cross-sectional end view of the system of FIG. 1 taken along section II-II of FIG. 1 illustrating a loaded zone formed by injecting an aqueous solution into the reservoir of FIG. 1 according to the method of FIG. 3;

[0021] FIG. 5 is a schematic cross-sectional end view of the system of FIG. 1 taken along section II-II of FIG. 1 illustrating a steam chamber formed by injecting steam into the reservoir of FIG. 1 according to the method of FIG. 3; and

[0022] FIG. 6 is a graphical illustration of the amount of urea reacted versus temperature.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0023] 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.

[0024] 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 a somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

[0025] 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.

[0026] Referring now to FIGS. 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 FIGS. 1 and 2).

[0027] 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.

[0028] Referring now to FIG. 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 one or more chemical agents prior to initiating start-up of the SAGD well pair 20, 30. 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 agent(s) 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 performance, and accelerating production from well 30. As will be described in more detail below, since the chemical agent(s) are injected in an aqueous solution, method 200 is particularly suited for use with reservoirs exhibiting a native permeability to water and is generally independent of the native wettability of the reservoir.

[0029] 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, nonthermal, in situ recovery methods.

[0030]  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 105 in response to thermal energy added during start-up of the SAGD well pair 20, 30. Thus, selection of the particular chemical agent(s) is based, at least in part, on its ability to enhance the mobility of the hydrocarbons in the particular formation of interest (e.g., reservoir 105 in formation 101) at an elevated temperature greater than the ambient reservoir temperature. 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. In this embodiment, each selected chemical agent is water soluble such that it can be injected into reservoir 105 in an aqueous solution as will be described in more detail below. The cost and availability of various chemical agent(s) may also impact the selection in block 201.

[0031]  Although a variety of chemical additives may be useful as chemical agents, in embodiments described herein, each chemical agent selected in block 201 is a water soluble surfactant or a water soluble thermally activated chemical species. Each selected chemical agent can be used alone (e.g., surfactant alone or thermally activated chemical species alone), with one or more other chemical agents (e.g., surfactant in combination with a thermally activated chemical species, multiple surfactants used together, multiple thermally activated chemical species used together, etc.), with one or more other chemical additives (e.g., surfactant in combination with another chemical, thermally activated chemical species in combination with another chemical, etc.), or combinations thereof.

[0032]  Each surfactant selected for use as a chemical agent in block 201 is a surface active agent that is generally unable to emulsify immobile hydrocarbons in reservoir 105 at ambient reservoir temperatures, owing to the relatively high viscosity of the hydrocarbons but is capable of emulsifying hydrocarbons in reservoir 105 once they become mobile (i.e., at temperatures above the ambient reservoir temperature). In general, bitumen (e.g., bitumen of the Canadian oil sands of Alberta) is immobile at ambient reservoir temperatures (typically 8-12°C), and must be heated to a temperature of at least 40°C to 60°C to be converted into sufficiently mobile hydrocarbons within reservoir 105. For example, as disclosed in Ivory et al., Handbook of Canadian Heavy Oil and Oil Sand Properties For Reservoir Simulation, 2nd Ed, Report #0708-22, AERI/ARC Core Industry Research Program (2008) (FIG. 3-1), which is hereby incorporated herein by reference in its entirety for all purposes, heating a typical Athabasca bitumen from 10°C to 50°C will reduce its viscosity from about 2,000,000 cP to about 5,000 cP. Consequently, each surfactant selected as a chemical agent in block 201 is generally unable to emulsify immobile bitumen at ambient reservoir temperatures, but is capable of emulsifying bitumen once it is warmed to at least 40°C to 60°C and converted to mobile hydrocarbons. Examples of suitable surfactants that can be selected as a chemical agent in block 201 include, without limitation, branched alcohol propoxylated sulfates (APS) (e.g., Alifoterra® series surfactants available from Sasol North American Inc. of Houston, Tex.); alkyl ether sulfates (e.g., Petrostep E55SA from Stepan Chemical Company of Northfield, Ill.); internal olein sulfonates (e.g., ENORET™ O Series from Shell Chemicals); branched alpha olein sulfonates (e.g. Bio-Terge® series surfactants available from Stepan Chemical Company of Northfield, Ill.); alkylaryl sulfonate (e.g. BioSoft D-40 from Stepan Chemical Company of Northfield, Ill.); polyoxyethylene alkyl phenyl ether (e.g. Triton X-100™ available from The DOW Chemical Company of Midland, Mich.); sodium/potassium oleate preferably with a chelating agent such as Na-EDTA; gemini (dimeric) surfactants; and polyoxyethylene sorbitan esters (e.g., TWEEN® 20 or TWEEN® 40 available from Croda Inc. of Edison, N.J.).

[0033]  Each thermally activated chemical species selected for use as a chemical agent in block 201 is a chemical species that (1) is non-decomposable or substantially non-decomposable in reservoir 105 at ambient reservoir temperatures and (2) is non-reactive or substantially non-reactive in reservoir 105 at ambient reservoir temperatures, but decomposes and/or reacts at an elevated temperature that is greater than the ambient reservoir temperature and less than the operating temperature of the thermal recovery process employed (e.g., SAGD operating temperature) to form one or more of: (a) a gas or gasses; (b) an alkaline compound or compounds, which can react with naturally occurring acids in hydrocarbon reservoir to form surfactant-like compounds; (c) a compound miscible with hydrocarbons to some extent; (d) a compound that controls the wettability of solid surfaces; (e) a surfactant or surfactant-like compound; or (f) combinations thereof. As used herein, the phrases "substantially non-decomposable" and "substantially non-reactive" refer to a chemical species that has a conversion rate (via decomposition and/or reaction) of less than 1 mol % over a 24 hour period in an aqueous solution at ambient reservoir temperatures as prepared according to block 202 described in more detail below, and in the presence of hydrocarbons in a reservoir at the ambient reservoir temperature.

[0034]  It should be appreciated that the reaction of the thermally activated chemical species at the elevated temperature (i.e., temperature greater than the ambient reservoir temperature and less than the operating temperature of the thermal recovery process) may be directly or indirectly thermally driven. For example, the thermal energy from the elevated temperature may sufficiently mobilize the viscous hydrocarbons to enable the thermally activated chemical species to access and react with the hydrocarbons. In this example, the thermal energy does not directly trigger the thermally activated chemical species to react, but rather, sufficiently mobilizes the hydrocarbons to enable the thermally activated chemical species to sufficiently combine and react with the hydrocarbons. As another example, the decomposition or reaction of the thermally activated chemical species (or decomposition or reaction product(s) thereof) may form carbon-dioxide gas (CO₂) or other compound(s) miscible with hydrocarbons, which increase the mobility of the hydrocarbons.

[0035]  For most reservoirs containing viscous hydrocarbons and most thermal recovery processes (e.g., SAGD, steam flooding, cyclic steam stimulation (CSS), electric res-
reservoir heating operations, etc.), each thermally activated chemical species selected as chemical agent in block 201 decomposes and/or reacts at a temperature preferably between 40° and 200° C, and more preferably between 60° and 120° C. For example, the typical ambient reservoir temperature in the Canadian oil sands is about 8° to 12° C, and the typical operating temperature of a SAGD thermal recovery process is 180° to 220° C. Thus, each thermally activated chemical species selected as a chemical agent in block 201 for viscous hydrocarbons in the Canadian oil sands to be produced using SAGD is a chemical species that is non-decomposable (or substantially non-decomposable) and non-reactive (or substantially non-reactive) in the Canadian oil sands between 8° and 12° C (i.e., at ambient reservoir temperatures), but decompose and/or react at a temperature above 8° and 12° C (i.e., the ambient reservoir temperature) and below 180° to 220° C (i.e., the operating temperature of the SAGD thermal recovery process). Examples of suitable thermally activated chemical species that can be selected as a chemical agent in block 201 include, without limitation, urea; ammonium salts (e.g., ammonium carbonate, ammonium bicarbonate, ammonium acetate, ammonium nitrate, ammonium chloride, etc.); thiourea dioxide; bicarbonates (e.g. sodium bicarbonate, etc.); nitrates; nitrites; oxalates (e.g., ammonium oxalate); alkali metal carbonates (e.g., sodium carbonate, potassium carbonate, cesium carbonate, lithium carbonate, etc.); and carbonate salts of alkali metals (e.g., sodium carbonate, potassium carbonate, sodium carbonate, lithium carbonate, etc.) and carbonate salts of alkali metals (e.g., sodium carbonate, potassium carbonate, etc.). As determined with compatibility tests, it may be beneficial to use a metal chelating agent (e.g., Na-EDTA) in combination with any chemical agent that is an alkali metal carbonate or a carbonate salt of alkali metal to reduce the likelihood of divalent cation carbonate precipitation.

Table 1 below lists some exemplary thermally activated chemical species (which undergo thermal decomposition), the temperature at which such thermally activated chemical species decompose, and the product(s) that result from the thermal decomposition. At least one of the decomposition products of each thermally activated chemical species listed in Table 1 is a gas. The decomposition temperatures provided in Table 1 are the temperatures at which dry solid samples of the exemplary thermally activated chemical species thermally decompose. Although the decomposition products resulting from the thermal decomposition of the thermally activated chemical species listed in Table 1 in aqueous solution are the same as the decomposition products listed in Table 1, the temperatures at which the thermally activated chemical species listed in Table 1 in aqueous solutions decompose may be different than those shown in Table 1, but can be experimentally determined.

### TABLE 1-continued

<table>
<thead>
<tr>
<th>Thermally Activated Chemical Species</th>
<th>Decomposition Temperature</th>
<th>Thermal Decomposition Product(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ammonium bicarbonate</td>
<td>~107° C.</td>
<td>ammonia, carbon dioxide, and water</td>
</tr>
<tr>
<td>ammonium nitrate</td>
<td>~210° C.</td>
<td>nitrous oxide (N₂O) and water</td>
</tr>
<tr>
<td>ammonium nitrate</td>
<td>~60° C.</td>
<td>Nitrogen and water</td>
</tr>
<tr>
<td>acetic acid</td>
<td>~53° C.</td>
<td>Ammonia and acetic acid</td>
</tr>
</tbody>
</table>

| sodium carbonate                    | ~50° C.                   | sodium carbonate, carbon dioxide, and water |
| potassium bicarbonate               | ~100° C.                  | potassium carbonate, carbon dioxide, and water |
| ammonium oxalate                    | ~175° C.                  | ammonia, carbon dioxide, carbon monoxide, and water |

*RC: Handbook of Chemistry and Physics, 84th.*

[0037] Moving now to block 202, the selected chemical agent(s) is/are mixed with a brine (i.e., solution of salt in water) to form an aqueous solution. 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. 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. In general, an aqueous solution is preferred as water is generally mobile within a reservoir comprising viscous hydrocarbons such as heavy oil and bitumen (e.g., reservoir 105). The composition of each chemical agent in the aqueous solution can be varied depending on a variety of factors, but is preferably at least about 0.01 wt % and less than or equal to the solubility limit of the chemical agent in the brine under ambient reservoir conditions (i.e., at the ambient temperature and pressure of reservoir 105).

[0038] Referring still to FIG. 3, in block 203, the parameters for loading or injecting the reservoir 105 with the aqueous solution 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 aqueous solution will be injected into reservoir 105. The injection pressure of the aqueous solution is preferably sufficient 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 of the aqueous solution is preferably greater than the freezing point of the aqueous solution and less than 40° C, and more preferably greater than the freezing point of the aqueous solution and less than or equal to the ambient temperature of reservoir 105. It should be appreciated that the ambient temperature at the surface 5 may be greater than the ambient temperature of reservoir 105, and thus, the aqueous solution stored at the surface 5 may have a temperature greater than the ambient temperature of reservoir 105 (i.e., the injection temperature of the aqueous solution stored at the surface 5 may be greater than the ambient temperature of reservoir 105). However, as noted above, even in such cases, the injection temperature of the aqueous solution is preferably greater than the freezing point of the aqueous solution and less than 40° C.

[0039] Referring still to FIG. 3, moving now to block 204, reservoir 105 is loaded or injected with the aqueous solution according to the injection parameters determined in block.
203. Since the aqueous solution 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 aqueous solution according to block 204 may be referred to herein as "cold" loading of reservoir 105.

[0040] Since SAGD well pair 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 aqueous solution can be injected into reservoir 105 utilizing one well 20, 30, both wells 20, 30, or combinations thereof over time. The aqueous solution 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 aqueous solution is injected into the reservoir 105 in block 204 before commissioning SAGD well pair 20, 30, the aqueous solution 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 aqueous solution 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 of the aqueous solution offers the potential to enhance distribution of the aqueous solution in reservoir 105 and facilitate dilution 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.

[0041] In implementations where production well 30 is not employed for injection of the aqueous solution, 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 injected aqueous solution) 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 aqueous solution through reservoir 105 and the saturation of reservoir 105 with the aqueous solution.

[0042] Injection of the aqueous solution in block 204 is performed until reservoir 105 (or portion of reservoir 105 to be loaded) is sufficiently charged. Ideally, the aqueous solution is injected into reservoir 105 until the total pore volume in reservoir 105 (or portion of reservoir 105 to be loaded) available for water is filled with the aqueous solution. However, practically, this may be extremely difficult, costly, and/or time consuming to achieve owing to the very large volume, the displacement efficiency, and/or the sweep efficiency, for example. Accordingly, in embodiments described herein, the volume of aqueous solution injected into reservoir 105 in block 204 is preferably at least equal to the pore volume of connate water in reservoir 105 (or portion of reservoir 105 to be loaded). The pore volume of connate water in a reservoir (or portion of a reservoir to be loaded) can be calculated using techniques known in the art.

[0043] In general, the duration of injection in block 204 will depend on the volume of reservoir 105 to be pretreated (i.e., the entire reservoir 105 vs. a portion of reservoir 105), the permeability to water, the water saturation, and the maximum injection pressure. As will be described in more detail below, injection of the aqueous solution in block 204 is preferably performed as quickly as possible and as close as possible to commencing start-up in block 205 to minimize and/or avoid natural dispersion of the aqueous solution outside of the portion of reservoir 105 into which they were injected in block 204.

[0044] Referring briefly to FIG. 4, reservoir 105 and formation 101 are shown following injection of the aqueous solution according to block 204. In FIG. 4, the aqueous solution is represented with reference numeral 110. The injected aqueous solution 110 forms a loaded zone 111 extending radially outward and longitudinally along the portion of horizontal section(s) 22, 32 from which the solution 110 was injected into reservoir 105. Loaded zone 111 defines the volume of reservoir 105 that has had its connate water replaced (or at least partially replaced) with the aqueous solution 110.

[0045] As previously described, the selected chemical agents are (a) surfactants unable to emulsify immobile hydrocarbons in reservoir 105 at the ambient reservoir temperature; and/or (b) thermally activated chemical species that are (1) non-decomposable or substantially non-decomposable and (2) non-reactive or substantially non-reactive in reservoir 105 at the ambient reservoir temperature. In addition, the selected chemical agents are injected into reservoir 105 at the ambient reservoir temperature in block 204. Thus, the chemical agent(s) in the aqueous solution do not substantially react with or alter the viscous hydrocarbons in reservoir 105 upon injection. It should be appreciated that this is in contrast to chemical compounds that are designed to or inherently react with or alter the hydrocarbons in a reservoir at ambient reservoir temperatures, which may generally be described as "preconditioning" the reservoir. Thus, chemical compounds that react with or alter the hydrocarbons in a reservoir at ambient reservoir temperature are sometimes referred to as "preconditioning" agents.

[0046] Referring again to FIG. 3, once reservoir 105 (or the portion of reservoir 105 being loaded) is sufficiently charged with the aqueous solution 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.

[0047] To limit and/or avoid the natural dispersion of the aqueous solution out of reservoir 105, commencing start-up in block 205 is preferably performed immediately after injection in block 204. In particular, commencing start-up in block 205 preferably begins within 50 days after loading reservoir 105 in block 204, or preferably within 10 days after loading reservoir 105 in block 204, and even more preferably as soon as loading reservoir 105 in block 204 ceases.

[0048] Referring briefly to FIG. 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. In embodiments described herein, the elevated temperature is sufficient to (a) reduce the viscosity of the viscous hydrocarbons in reservoir 105 and mobilize at least a portion of the hydrocarbons in reservoir 105; and (b) thermally “activate” or “trigger” the chemical agent(s) in the aqueous solution. More specifically, for each chemical agent that is a surfactant, the elevated temperature sufficiently mobilizes the hydrocarbons in reservoir 105 to allow the surfactant in the aqueous solution to emulsify the hydrocarbons in reservoir 105; and for each chemical agent that is a thermally activated chemical species, the elevated temperature is sufficient to decompose and/or react the thermally activated chemical species(s) in the aqueous solution. The thermal energy from steam chamber 120 in combination with the thermal activation of the chemical agent(s) (e.g., the surfactant(s) and/or thermally activated chemical species(s) in the aqueous solution enables the chemical agent(s) to enhance the mobility of the hydrocarbons above and beyond what the thermal energy can do alone. This offers the potential to accelerate start-up of the SAGD well pair 20, 30 (i.e., accelerates the establishment of pressure and fluid communication between wells 20, 30), as well as accelerate production of hydrocarbons in reservoir 105 according to block 206 described in more detail below. It should be appreciated that the front of the thermal energy generated from steam chamber 120 moves through the reservoir 105 ahead of the steam chamber 120 itself, and thus, the reduction in the viscosity of the hydrocarbons in the reservoir 105, the mobilization of the hydrocarbons in the reservoir 105, and the thermal activation of the chemical agent(s) in the aqueous solution begins prior to the arrival of steam chamber 120 (e.g., in response to the thermal front that moves ahead of the edge of steam chamber 120) and after the arrival of the steam chamber 120.

[0049] For example, after injection in block 204 of an aqueous solution including an alkali metal carbonate, one type of thermally activated chemical species, the injection of steam in block 205 and associated thermal energy reduces the viscosity of the viscous hydrocarbons in reservoir 105. The reduced viscosity of the hydrocarbons enhances their mobility, which in turn allows the alkali metal carbonate in the aqueous solution to access and react with the organic acids in the hydrocarbons to form surfactants in-situ. Such surfactants formed in-situ enhance the release of hydrocarbons from the formation surface and emulsify the hydrocarbons into oil-in-water emulsions, thereby offering the potential to further enhance hydrocarbon mobility. Although alkali metal carbonates can be used alone in the aqueous solution to form surfactants in-situ, they can also be used in combination with surfactants in the aqueous solution. Since alkali metal carbonates react to form surfactants in-situ upon injection of steam, they can be used to reduce the amount of surfactants in the aqueous solution and/or to supplement the surfactants in the aqueous solution.

[0050] Referring again to FIG. 3, in block 206, steam continues to be injected through injection well 20 as the mobilized hydrocarbons in reservoir 105 drain under gravity through reservoir 105 and formation 101 into horizontal section 32. Artificial lift (e.g., pumping via an electric submersible pump, progressive cavity pump, or rod pump, gas lift, etc.) is typically employed to produce hydrocarbons collected in production well 30 to the surface 5. Injection of steam while hydrocarbons are being collected in production well 30 and produced to the surface 5 is referred to as “production” or the “production” phase.

[0051] Referring still to FIG. 3, according to block 207, an aqueous solution comprising one or more surfactants can optionally be injected with steam during the start-up phase in block 205 and/or injected with steam during the production phase in block 206. Although the injection of surfactant(s) in aqueous solution with steam according to block 207 is shown in connection with the loading of reservoir 105 in block 204 (prior to the injection of steam in block 205), the injection of one or more surfactant(s) in aqueous solution with steam according to block 207 can be performed independent of blocks 201-204 (i.e., without loading the reservoir in block 204).

[0052] As is known in the art, steam delivered to and injected into a reservoir (e.g., reservoir 105) is often characterized by its steam or vapor “quality,” which refers to the mass fraction of the steam that is vapor (as opposed to liquid). For example, steam having a steam quality of 100% is completely vapor phase, steam having a steam quality of 0% is completely liquid, and steam having a steam quality of 75% is 75% (by mass) vapor phase and 25% (by mass) liquid phase. Thus, steam having a steam quality less than 100% comprises a vapor phase and a liquid phase. In embodiments described herein, when an aqueous solution comprising one or more surfactants is injected with steam according to block 207, the injected steam preferably has a steam quality less than 100%, and thus, comprises both a vapor phase and a liquid phase. The liquid phase in the injected steam provides the medium to carry and deliver the aqueous solution (including the surfactant) to reservoir 105. Accordingly, references herein to the injection of an aqueous solution comprising one or more surfactants “with steam” refer to the injection or delivery of the aqueous solution (including the surfactant(s)) in the liquid phase of steam that has a quality less than 100%.

[0053] The selection of the surfactant(s) and the formation of the aqueous solution for use in block 207 are generally performed in the same manner as previously described with regard to blocks 201, 202. Thus, selection of the particular surfactant(s) for use in block 207 is based, at least in part, on its ability to enhance the mobility of the hydrocarbons in the particular formation of interest (e.g., reservoir 105 in formation 101) at an elevated temperature greater than the ambient reservoir temperature. In embodiments described herein, each surfactant selected for use in block 207 is preferably water soluble, and further, is preferably an emulsifier of mobile hydrocarbons in reservoir 105. As previously described, bitumen (e.g., bitumen of the Canadian oil sands of Alberta) is immobile at ambient reservoir temperatures, and must be heated to a temperature of at least 40°C to 60°C C. to be converted into mobile hydrocarbons within reservoir 105. Thus, for example, any surfactant(s) injected with steam in block 205 and/or block 206 is preferably capable of emulsifying bitumen once the bitumen is warmed to at least 40°C to 60°C C. and mobilized. Examples of suitable surfactants that can be used in block 207 for injection with steam include, without limitation, the surfactants previously described that are suitable for selection as chemical agent(s) in block 201—branched alcohol propoxylated sulfates (APS) (e.g., Alforterr® series surfactants available from Sasol North American Inc. of Houston, Tex.); alkyl ether sulfates (e.g., Petrostep
ES65A from Stepan Chemical Company of Northfield, Ill.); internal olefin sulfonates (e.g., ENOROETM O Series from Shell Chemicals); branched alpha olefin sulfonates (e.g., Bio-Terge® series surfactants available from Stepan Chemical Company of Northfield, Ill.); allylaryl sulfonate (e.g., Biosoft D-40 from Stepan Chemical Company of Northfield, Ill.); polyoxyethylene alkyl phenyl ether (e.g., Triton X-100™ available from The DOW Chemical Company of Midland, Mich.); sodium/potassium oleate preferably with a chelating agent such as Na2EDTA; gemini (dimeric) surfactants; and polyoxyethylene sorbitan esters (e.g., TWEEN® 20 or TWEEN® 40 available from Croda Inc. of Edison, N.J.). Each selected surfactant for use in block 207 can be used alone, with one or more other chemical agents (e.g., surfactant in combination with a thermally activated chemical species, multiple surfactants used together, etc.), with one or more chemical additives (e.g., surfactant in combination with another chemical, etc.), or combinations thereof.

[0054] To form the aqueous solution for injection with steam according to block 207, the selected surfactant(s) is/are mixed with a brine (i.e., solution of salt in water) to form the aqueous solution. The brine preferably has a salt concentration and composition analogous to (a) the liquid phase of the steam injected (i.e., the steam injected in block 205 and/or block 206) or (b) the reservoir 105. The concentration of each surfactant in the aqueous solution for use in block 207 is preferably determined taking into account its subsequent dilution by the liquid water in the injected steam and condensed liquid water from the injected steam, and thus, will typically be greater than the concentration of the same surfactant in the aqueous solution loaded into the reservoir in block 204. In block 207, the aqueous solution comprising one or more surfactants is injected with steam during startup (block 205) and/or production (block 206), and thus, the injection parameters are those selected for the steam itself—the steam pressure and temperature, the steam flow rate, etc.

[0055] Referring still to FIG. 3, according to block 208, an aqueous solution comprising one or more thermally activated chemical species can optionally be injected with steam during the start-up phase in block 205 and/or injected with steam during the production phase in block 206. Although the injection of a thermally activated chemical species in aqueous solution with steam according to block 208 is shown in connection with the loading of reservoir 105 in block 204 (prior to injecting steam in block 205), the injection of a thermally activated chemical species in aqueous solution with steam according to block 208 can be performed independent of blocks 201-204 (i.e., without loading the reservoir in block 204).

[0056] In embodiments described herein, when one or more thermally activated chemical species in aqueous solution is injected with steam according to block 208 (during startup phase and/or production phase), the injected steam preferably has a steam quality less than 100%, and thus, comprises both a vapor phase and a liquid phase. The liquid phase in the injected steam provides the medium to carry and deliver the aqueous solution (including the thermally activated chemical species) to reservoir 105. Accordingly, references herein to the injection of an aqueous solution comprising one or more thermally activated chemical species “with steam” refer to the injection or delivery of the aqueous solution (including the thermally activated chemical species) in the liquid phase of steam that has a quality less than 100%.

[0057] The selection of the thermally activated chemical species and the formation of the aqueous solution for use in block 208 are generally performed in the same manner as previously described with regard to blocks 201, 202. Thus, selection of the particular thermally activated chemical species for use in block 208 is based, at least in part, on its ability to enhance the mobility of the hydrocarbons in the particular formation of interest (e.g., reservoir 105 in formation 101) at an elevated temperature greater than the ambient reservoir temperature. In embodiments described herein, each thermally activated chemical species injected with steam according to block 208 is preferably a water soluble chemical species that (1) is non-decomposable or substantially non-decomposable in reservoir 105 at ambient reservoir temperatures and (2) is non-reactive or substantially non-reactive in reservoir 105 at ambient reservoir temperatures, but decomposes and/or reacts at a temperature greater than the ambient reservoir temperature and less than the operating temperature of the thermal recovery process employed (e.g., SAGD operating temperature) to form one or more of: (a) a gas or gases; (b) an alkaline compound or compounds, which can react with naturally occurring acids in hydrocarbon reservoir to form surfactant-like compounds; (c) a compound miscible with hydrocarbons to some extent; (d) a compound that controls the wettability of solid surfaces; (e) a surfactant or surfactant-like compound; or (f) combinations thereof. As used herein, the phrases “substantially non-decomposable” and “substantially non-reactive” refer to a chemical species that has a conversion rate (via decomposition and/or reaction) of less than 1 mol % over a 24 hour period in an aqueous solution at ambient reservoir temperatures in the presence of hydrocarbons in a reservoir at the ambient reservoir temperature. It should be appreciated that the reaction of the thermally activated chemical species at the elevated temperature (i.e., temperature greater than the ambient reservoir temperature and less than the operating temperature of the thermal recovery process) may be directly or indirectly thermally driven. For example, the thermal energy from the elevated temperature may sufficiently decrease the viscosity of the viscous hydrocarbons to mobilize the hydrocarbons, which enables the thermally activated chemical species to access and react with the hydrocarbons. In other words, the thermal energy does not directly trigger the thermally activated chemical species to react, but rather, sufficiently mobilizes the hydrocarbons to enable the thermally activated chemical species to sufficiently comingle and react with the hydrocarbons. As another example, the decomposition or reaction of the thermally activated chemical species (or decomposition or reaction product(s) thereof) may form carbon-dioxide gas (CO2) or other compound(s) miscible with hydrocarbons, which increase the mobility of the hydrocarbons.

[0058] For most reservoirs containing viscous hydrocarbons and most thermal recovery processes (e.g., SAGD, steam flooding, cyclic steam stimulation (CSS), electric reservoir heating operations, etc.), each thermally activated chemical species selected for use in block 208 decomposes and/or reacts at a temperature preferably between 40° and 200° C., and more preferably between 60° and 120° C. For example, the typical operating temperature of a SAGD thermal recovery process is 180° to 220° C. Thus, each thermally activated chemical species injected with steam in block 205 and/or block 206 for viscous hydrocarbons in the Canadian oil sands to be produced using SAGD is a chemical species that is non-decomposable (or substantially non-decompos-
able) and non-reactive (or substantially non-reactive) in the Canadian oil sands between 8° and 12° C. (i.e., at ambient reservoir temperatures), but decompose and/or react at a temperature above 8° and 12° C. (i.e., the ambient reservoir temperature) and below 180° to 220° (i.e., the operating temperature of the SAGD thermal recovery process). Examples of suitable thermally activated chemical species that can be selected for use in block 208 include, without limitation, urea; ammonium salts (e.g., ammonium carbonate, ammonium bicarbonate, ammonium acetate, ammonium nitrate, ammonium chloride, etc.); thionine dioxide; bicarbonates (e.g., sodium bicarbonate, etc.); nitrates; nitrates; oxalates (e.g., ammonium oxalate); and alkali metal carbonates (e.g., sodium carbonate, potassium carbonate, cesium carbonate, lithium carbonate, etc.) or metabolite salts of alkali metals (e.g., sodium metaborate, potassium metaborate, etc.). As determined with compatibility tests, it may be beneficial to use a metal chelating agent (e.g., Na-EDTA) in combination with any chemical agent that is an alkali metal carbonate or a metabolite salt of an alkali metal to reduce the likelihood of divalent cation precipitation. Each selected thermally activated chemical species for use in block 208 can be used alone, with one or more other chemical agents (e.g., thermally activated chemical species in combination with a surfactant, multiple thermally activated chemical species used together, etc.), with one or more other chemical additives (e.g., thermally activated chemical species in combination with another chemical, etc.), or combinations thereof.

As previously described, each thermally activated chemical species injected in aqueous solution with steam according to block 208 decomposes and/or reacts at a temperature preferably between 40° and 200° C., and more preferably between 60° and 120° C. In addition, as previously described, for injecting one or more thermally activated chemical species in aqueous solution with steam in block 208, the injected steam preferably comprises a vapor phase and liquid phase, with the thermally activated chemical species being carried and delivered in the liquid phase. The temperature of the vapor phase of the injected steam and the liquid phase of the injected steam will be the substantially the same, typically greater than 180° C. Thus, injecting a thermally activated chemical species in aqueous solution with steam according to block 208 may result in the premature decomposition and/or reaction of the thermally activated chemical species within the injection system that delivers the steam and the thermally activated chemical species to the reservoir (i.e., within injection well 20 and/or production well 30 before it is injected into the surrounding formation and reservoir 105). However, in embodiments described herein, each thermally activated chemical species selected for injection with steam in block 208 is preferably non-volatile at the temperature of the injected steam and preferably has a relatively low rate of decomposition and reaction at the temperature of the injected steam such that it remains substantially unchanged within the injection conduit (within injection well 20 and/or production well 30) during its short residence time within the injection system. For most thermal recovery processes, the residence time within the injection system (i.e., the time within the injection well 20 and/or production well 30 before being injected into the surrounding formation and reservoir 105) is less than 10 minutes. Thus, in embodiments described herein, each thermally activated chemical species selected for injection with steam in block 208 preferably has a conversion rate less than 10 mol % at the temperature of the injected steam and in the presence of the liquid water in the injected steam over a time period up to 10 minutes, and more preferably has a conversion rate less than 1 mol % at the temperature of the injected steam and in the presence of the liquid water in the injected steam over a time period up to 10 minutes. For steam based thermal recovery processes described herein, the term “non-volatile” is used to describe chemical agents (e.g., thermally activated chemical species) that have a boiling point greater than 200° C. at standard pressure (1.0 bar absolute).

To form the aqueous solution for use in block 208, the selected thermally activated chemical species are mixed with a brine (i.e., solution of salt in water) to form the aqueous solution. The brine preferably has a salt concentration and composition analogous to (a) the liquid phase of the steam injected (i.e., the steam injected in block 205 and/or block 206) or (b) the reservoir 105. The concentration of each thermally activated chemical species in the aqueous solution for use in block 208 is preferably determined taking into account its subsequent dilution by the liquid water in the injected steam and condensed liquid water from the injected steam, and thus, will typically be greater than the concentration of the same thermally activated chemical species in the aqueous solution loaded into the reservoir in block 204. In block 208, the aqueous solution comprising one or more thermally activated chemical species is injected with steam during startup (block 205) and/or production (block 206), and thus, the injection parameters are those selected for the steam itself—the steam pressure and temperature, the steam flow rate, etc.

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 aqueous solution containing 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). At the ambient reservoir temperature, prior to the injection of steam, the chemical agents in the aqueous solution loaded into the reservoir are generally inert—the surfactants are generally unable to emulsify the immobile hydrocarbons, and the thermally activated chemical species do not decompose or react. However, sufficient thermal energy from steam injected during the start-up phase (and associated elevated temperature) initiates the mobilization of the hydrocarbons and activates/triggers the chemical agents, which further enhances the mobilization of the hydrocarbons. Thus, the chemical agent in the aqueous solution is activated or triggered in situ by the increase in temperature.

In the manner described, embodiments described herein (e.g., system 10 and method 200) are employed to produce viscous hydrocarbons in a subsurface 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 FIG. 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.

[0063] To further illustrate various illustrative embodiments disclosed herein, the following examples are provided.

Example 1

[0064] Certain thermally activated chemical species, as described above, in aqueous solution undergo a hydrolysis reaction upon heating (i.e., thermal activation) and produce gas(es) and/or liquid(s). The production of gas(es) upon thermal activation of such thermally activated chemical species loaded into the formation increase the pressure within the formation and enhance the mobilization of hydrocarbons in the formation. Urea is one exemplary thermally activated chemical species that undergoes hydrolysis in aqueous solution upon thermal activation to produce carbon dioxide gas and ammonia, which exist in equilibrium between the gas and liquid phases. Experiments were conducted to analyze the thermal activation of urea and the associated hydrolysis. Each experiment was carried out in a stainless steel reactor vessel having a total cell volume of ~400 cm³. A Teflon® liner was installed in the vessel to avoid any reactions between stainless steel wall and aqueous solution comprising urea. A series of pressure transducers were set up for measuring the pressure within the reactor vessel during each experiment. To achieve a stable temperature, the reactor vessel was placed in an oven.

[0065] For each experiment, a sample of approximately 60 cm³ of an aqueous solution comprising urea at predetermined concentration (5 wt% urea, 10 wt% urea, 15 wt% urea, and 20 wt% urea) was weighed (i.e., the weight of the 60 cm³ of aqueous solution comprising the urea was determined) and fed into the reactor vessel. The air in the reactor vessel was replaced with nitrogen (N₂) gas at 10 psig. The oven temperature was then gradually increased to a specific, predetermined target temperature (50°C, 80°C, 100°C, and 150°C), and then kept at the target temperature for an extended period of time until little to no pressure increase within the reactor vessel was observed (i.e., approaching the equilibrium pressure). Next, the reactor was allowed to cool to ambient temperature, and then the concentration of urea, dissolved carbon dioxide (CO₂) and ammonia (NH₃) in the water, and carbon dioxide (CO₂) in the gas phase were determined.

[0066] As a baseline for comparison purposes, and to investigate whether any hydrolysis of urea occurred at 10°C, bottles of aqueous solutions of urea at predetermined concentrations (10 wt% urea) were kept at 10°C in a refrigerator for 8 months, and then the concentrations of urea dissolved carbon dioxide (CO₂) and ammonia (NH₃) in the water, and carbon dioxide (CO₂) in the gas phase were determined.

[0067] FIG. 6 illustrates the wt % of urea reacted as a function of temperature (at 10°C, 50°C, 100°C, and 150°C) when samples of aqueous solutions, each comprising 10 wt% of urea were heated (to 50°C, 100°C, and 150°C) in the reactor vessel in the manner previously described. The experimental results shown in FIG. 6 indicated that the hydrolysis of urea in aqueous solution strongly depends on the temperature, and further, that the hydrolysis of urea in aqueous solution can be thermally triggered when the aqueous solution is heated up to above approximately 50°C.

[0068] Table 2 below illustrates the measured equilibrium pressure within the reactor vessel and the wt % of urea reacted (via hydrolysis) when samples of aqueous solutions having different concentrations of urea (5 wt% urea, 10 wt% urea, 15 wt% urea, and 20 wt% urea) were heated to 150°C in the manner as previously described. The experimental results shown in Table 2 indicated that the increase in pressure (the difference between the equilibrium/final pressure and the initial 10 psig pressure) due to reaction of urea (via hydrolysis) was strongly dependent on the urea concentration—the greater the urea concentration in the aqueous solution, the greater the increase in pressure. In addition, the experimental results shown in Table 2 indicated that all or substantially all of the urea in the aqueous solution was reacted (via hydrolysis).

<table>
<thead>
<tr>
<th>Urea Concentration in Aqueous Solution Sample (wt %)</th>
<th>Pressure Increase (psi)</th>
<th>WT % of Urea Reacted</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>72.8</td>
<td>100.0</td>
</tr>
<tr>
<td>10</td>
<td>135.5</td>
<td>99.6</td>
</tr>
<tr>
<td>15</td>
<td>184.3</td>
<td>98.1</td>
</tr>
<tr>
<td>20</td>
<td>234.7</td>
<td>98.0</td>
</tr>
</tbody>
</table>

[0069] Table 3 below illustrates the wt % of urea reacted (via hydrolysis), the volumes of gas(es) produced by the reaction of urea, and the time allowed for the reaction when samples of aqueous solutions having different concentrations of urea (5 wt%, 10 wt%, 15 wt%, and 20 wt%) were heated (to 50°C, 80°C, 100°C, and 150°C) in the manner previously described. The experimental results shown in Table 3 indicated that urea is very stable in aqueous solution at ambient temperatures, and further, that the hydrolysis of urea in aqueous solution does not occur until the aqueous solution is heated to a certain temperature. For instance, the sample of aqueous solution including urea at a concentration of 10 wt% was heated to 50°C for several days and no gas was produced. The sample of aqueous solution including urea at a concentration of 10 wt% maintained at 10°C for 8 months exhibited no reactions of urea (i.e., no reduction in urea concentration was found).

<table>
<thead>
<tr>
<th>Urea Concentration in Aqueous Solution Sample (wt %)</th>
<th>Temperature (°C)</th>
<th>WT % Urea Reacted</th>
<th>Volume of Produced Gas at Standard Conditions³ (cm³)</th>
<th>Time Allowed for Reaction³</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>10</td>
<td>0</td>
<td>0</td>
<td>8 months</td>
</tr>
<tr>
<td>10</td>
<td>50</td>
<td>0</td>
<td>0</td>
<td>70 hours</td>
</tr>
<tr>
<td>10</td>
<td>80</td>
<td>0</td>
<td>0</td>
<td>18 days</td>
</tr>
<tr>
<td>10</td>
<td>100</td>
<td>14</td>
<td>120</td>
<td>120 hours</td>
</tr>
<tr>
<td>10</td>
<td>100</td>
<td>22</td>
<td>363</td>
<td>158 hours</td>
</tr>
<tr>
<td>5</td>
<td>150</td>
<td>100</td>
<td>864</td>
<td>30 hours</td>
</tr>
<tr>
<td>10</td>
<td>150</td>
<td>100</td>
<td>1620</td>
<td>40 hours</td>
</tr>
<tr>
<td>15</td>
<td>150</td>
<td>98</td>
<td>2208</td>
<td>36 hours</td>
</tr>
<tr>
<td>20</td>
<td>150</td>
<td>98</td>
<td>2886</td>
<td>7.5 hours</td>
</tr>
</tbody>
</table>

³Standard Conditions are 273K and 1 bar (absolute).

Example 2

[0070] Aqueous solutions comprising chemical agents as described herein (e.g., surfactants and thermally activated chemical species) offer the potential to enhance and accelerate the recovery of viscous hydrocarbons from subterranean
formations during thermal recovery processes such as SAGD. Experiments were conducted to assess the impact of certain chemical agents on hydrocarbon recovery from oil sand cores at elevated temperatures representative of temperatures employed in thermal recovery techniques. In each experiment, a sample of ~10.0 g of high grade oil sand core (containing bitumen) was packed into a vial made of PTFE, and then ~12.0 ml aqueous solutions comprising a chemical agent was injected into the oil sand core in the vial. Then, the vial containing the oil sand core and the aqueous solution was sealed in a reactor and heated to 200°C for 2 hrs. During each experiment, the reactor and vial were allowed to cool down to ambient temperature, and then the vial was opened and the produced hydrocarbons (i.e., the hydrocarbons that separated from the oil sands core) were collected and quantified. The cores tested were high grade oil sand cores acquired from wells drilled in the Canadian oil sands of Northern Alberta, Canada.

As a baseline for comparison purposes, in one experiment, water alone without any chemical agent was tested. Table 4 below illustrates the chemical agents tested, the concentration of each chemical agent in the corresponding aqueous solution, and the hydrocarbons recovered as a percent of the initial amount of hydrocarbons in the core sample. In general, the initial amount of hydrocarbons in the core sample can be determined by any technique known in the art such as via Dean-Stark analysis (ASTM D95). As shown in Table 4, each chemical agent tested yielded a greater hydrocarbon recovery than water alone.

### TABLE 4

<table>
<thead>
<tr>
<th>Chemical Class</th>
<th>Chemical Agent</th>
<th>Concentration of the Chemical Agent in the Aqueous Solution (wt%)</th>
<th>Hydrocarbon Recovery (wt % of the original hydrocarbons in the oil sand core)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water alone (no chemical agent)</td>
<td>NA</td>
<td>NA</td>
<td>17.0</td>
</tr>
<tr>
<td>Urea</td>
<td>Urea</td>
<td>1.0</td>
<td>22.0</td>
</tr>
<tr>
<td>Ammonium salt</td>
<td>Ammonium bicarbonate</td>
<td>1.0</td>
<td>28.0</td>
</tr>
<tr>
<td>Bicarbonate</td>
<td>Sodium bicarbonate</td>
<td>1.0</td>
<td>33.0</td>
</tr>
<tr>
<td>Oxalate</td>
<td>Ammonium oxalate</td>
<td>1.0</td>
<td>22.0</td>
</tr>
<tr>
<td>Surfactants Tested</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Polyoxyethylene alkyl phenyl ether</td>
<td>Triton X-100</td>
<td>1.0</td>
<td>30.0</td>
</tr>
<tr>
<td>Alpha olefin sulfonates</td>
<td>Bio-Terge AS60</td>
<td>1.0</td>
<td>33.0</td>
</tr>
<tr>
<td>Alkyl ether sulfates</td>
<td>Petrostep E855A</td>
<td>1.0</td>
<td>41.0</td>
</tr>
<tr>
<td></td>
<td>Alpha Oxamer</td>
<td>1.0</td>
<td>36.0</td>
</tr>
<tr>
<td></td>
<td>Steel CS-270</td>
<td>1.0</td>
<td>43.0</td>
</tr>
<tr>
<td></td>
<td>Polystep B-11</td>
<td>1.0</td>
<td>48.0</td>
</tr>
<tr>
<td></td>
<td>Polystep B-1</td>
<td>1.0</td>
<td>44.0</td>
</tr>
<tr>
<td>Nonylphenol Ethoxylate</td>
<td>Polystep B-1</td>
<td>1.0</td>
<td></td>
</tr>
<tr>
<td>Sulfate</td>
<td>Oleate</td>
<td>1.0</td>
<td>31.0</td>
</tr>
<tr>
<td></td>
<td>Sodium Oleate</td>
<td>1.0</td>
<td>41.0</td>
</tr>
</tbody>
</table>

Example 3

Aqueous solutions comprising surfactants as described herein offer the potential to emulsify mobilized hydrocarbons in subterranean formations to enhance and accelerate the recovery of such hydrocarbons during thermal recovery processes such as SAGD. Experiments were conducted to assess the ability of certain surfactants to emulsify bitumen upon mobilization of the bitumen at elevated temperatures. In each experiment, ~1.0 g of bitumen recovered from SAGD operations in Northern Alberta was placed in a vial. Next, a 10.0 ml aqueous solution comprising a brine and a predetermined concentration of surfactant (e.g., 1000 ppmw) was added to the vial. The brine had a pH and composition representative of water produced at the Northern Alberta SAGD operations. In particular, the brine was an aqueous solution having a pH of 7.8 and including the salts shown in Table 5 below.

### TABLE 5

<table>
<thead>
<tr>
<th>Salts in Brine</th>
<th>Concentration of Salts (mM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NaCl</td>
<td>13.40</td>
</tr>
<tr>
<td>KCl</td>
<td>0.46</td>
</tr>
<tr>
<td>CaCl2</td>
<td>0.25</td>
</tr>
<tr>
<td>Na2SO4</td>
<td>0.60</td>
</tr>
<tr>
<td>NaHCO3</td>
<td>3.95</td>
</tr>
</tbody>
</table>

Next, the vial was placed in an oven and heated to an elevated temperature (50°C or 80°C) for 30 minutes. After this time, the vial was removed from the oven and gently turned from end-to-end 10 times in an effort to avoid high shear. The vials were then placed back in the oven at the elevated temperature (50°C or 80°C) for 1 hour, then taken out and gently turned 10 times, and then placed back into the oven at the elevated temperature (50°C or 80°C) for another 1 hour. After the additional hour, the vial was removed from the oven and gently turned 10 times, and then placed back into the oven at the elevated temperature (50°C or 80°C) for another 24 hours. If a stable emulsion formed, the vial was placed back into the oven at the elevated temperature (50°C or 80°C) for an additional 24 hours, taken out, and turned...
gently 10 times. An optical microscope was then used to image the emulsion formed in the vial. The volumetric percentage (vol%) of the hydrocarbons in the emulsion, which represented the hydrocarbons released from the initial sample, were not able to emulsify the bitumen by themselves. In addition, the results showed that metaborate salts of alkali metals alone (e.g., sodium metaborate) in aqueous solution were able to emulsify the bitumen.

### TABLE 6

<table>
<thead>
<tr>
<th>Aqueous Solution (concentration of surfactant, if any)</th>
<th>Temperature (°C)</th>
<th>Hydrocarbons in the Emulsion (vol% of the initial bitumen)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brine with no surfactant</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine with no surfactant</td>
<td>50°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine and Bio-Terge AS60 (1000 ppmw)</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine and Triton X-100 (1000 ppmw)</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine and Sodium Dodecylbenzene</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Sulfonate (1000 ppmw)</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine and Bio-Terge PAS 7S (1000 ppmw)</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine and Sodium Metaborate (9000 ppmw)</td>
<td>25°C.</td>
<td>0 (no emulsion)</td>
</tr>
<tr>
<td>Brine and Bio-Terge AS60 (1000 ppmw) + Na₂CO₃ (1500 ppmw)</td>
<td>50°C.</td>
<td>3.2</td>
</tr>
<tr>
<td>Brine and Triton X-100 (1000 ppmw) + Na₂CO₃ (1500 ppmw)</td>
<td>50°C.</td>
<td>27.0</td>
</tr>
<tr>
<td>Brine and Sodium Dodecylbenzene</td>
<td>50°C.</td>
<td>14.2</td>
</tr>
<tr>
<td>Sulfonate (1000 ppmw)</td>
<td>50°C.</td>
<td>28.9</td>
</tr>
<tr>
<td>Brine and Sodium Dodecylbenzene</td>
<td>50°C.</td>
<td>28.9</td>
</tr>
<tr>
<td>Sulfonate (1000 ppmw) + Na₂CO₃ (1500 ppmw)</td>
<td>50°C.</td>
<td>0 (no stable emulsion)</td>
</tr>
<tr>
<td>Brine and Bio-Terge PAS 7S (1000 ppmw)</td>
<td>50°C.</td>
<td>40.1</td>
</tr>
<tr>
<td>Brine and Bio-Terge PAS 7S (1000 ppmw) + Na₂CO₃ (1500 ppmw)</td>
<td>50°C.</td>
<td>52.7</td>
</tr>
<tr>
<td>Brine and Bio-Terge PAS 8S (1000 ppmw)</td>
<td>50°C.</td>
<td>0 (no stable emulsion)</td>
</tr>
<tr>
<td>Brine and Polystep B12 (1000 ppmw) + Na₂CO₃ (1500 ppmw)</td>
<td>50°C.</td>
<td>24.4</td>
</tr>
<tr>
<td>Brine and Sodium Metaborate (9000 ppmw)</td>
<td>80°C.</td>
<td>3.2</td>
</tr>
</tbody>
</table>

As a baseline for comparison purposes, select surfactants were tested at ambient temperature (25°C) and the brine without any surfactant was tested. Such experiments, a ~1.0 g of bitumen recovered from SAGD operations in Northern Alberta, Canada was placed in a vial. Next, (a) a 10.0 mL aqueous solution comprising the brine previously described and a predetermined concentration of surfactant was added to the vial, and then the vial was gently turned 10 times; or (b) a 10.0 mL of the brine previously described without any surfactant was added to the vial, and then the vial was gently turned 10 times.

**[0074]** 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.

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) injecting an aqueous solution into the reservoir with the reservoir at the ambient temperature, wherein the aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and
substantially non-reactive in the reservoir at the ambient temperature of the reservoir; and
(b) adding thermal energy to the reservoir at any time after (a) to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir;
(c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons.
2. The method of claim 1, wherein the hydrocarbons have a viscosity greater than 10,000 cP before (b);
wherein (c) comprises decreasing the viscosity of the hydrocarbons to a viscosity less than 10,000 cP.
3. The method of claim 1, wherein (b) is performed within 50 days after (a).
4. The method of claim 3, wherein (b) is performed immediately after (a).
5. The method of claim 1, wherein the aqueous solution is injected at an injection pressure during (a) that is greater than the ambient pressure of the reservoir and below a fracturing pressure of the formation.
6. The method of claim 5, wherein the injection pressure is less than a displacement pressure of the hydrocarbons in the reservoir.
7. The method of claim 5, further comprising pulsing the injection pressure during (a).
8. The method of claim 1, wherein the chemical agent is a surfactant or a thermally activated chemical species, wherein the surfactant emulsifies the mobilized hydrocarbons at the elevated temperature and the thermally activated chemical species decomposes or reacts at the elevated temperature.
9. The method of claim 8, wherein the elevated temperature is between 40° and 200° C.
10. The method of claim 9, wherein the chemical agent is urea.
11. The method of claim 9, wherein the chemical agent comprises an alkali metal carbonate or a metaborate salt of an alkali metal.
12. The method of claim 11, wherein the aqueous solution comprises a metal chelating agent.
13. The method of claim 1, further comprising:
(a) determining a salt concentration and a salt composition in the reservoir;
(b) forming a brine having a salt concentration and a salt composition analogous to the salt concentration and the salt composition of the reservoir; and
(c) mixing the chemical agent and the brine to form the aqueous solution prior to (a).
14. The method of claim 1, wherein (b) comprises injecting steam into the reservoir.
15. The method of claim 14, wherein the steam injected into the reservoir has a steam quality less than 100% and comprises a liquid phase and a vapor phase;
wherein (b) comprises:
(a) injecting an aqueous solution into the reservoir through an injection well or a production well of a SAGD well pair, wherein the reservoir is at the ambient temperature, and wherein the aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir;
(b) injecting steam into the reservoir after (a) through the injection well or the production well to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir;
(c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons.
16. The method of claim 15, further comprising:
(d) injecting steam into the reservoir after (b) through the injection well;
(e) collecting hydrocarbons in the production well during (d); and
(f) producing the collected hydrocarbons in the production well to the surface.
17. The method of claim 15, wherein the water-soluble chemical agent injected into the reservoir during (a) is different than the water-soluble surfactant injected into the reservoir with the steam in (b).
18. The method of claim 14, wherein the steam injected into the reservoir has a steam quality less than 100% and comprises a liquid phase and a vapor phase;
wherein (b) comprises:
(a) injecting an aqueous solution into the reservoir through a first well extending through the reservoir.
(b) injecting steam into the reservoir through the first well and a second well extending through the reservoir.
20. The method of claim 23, further comprising:
(a) injecting an aqueous solution into the reservoir through an injection well or a production well of a SAGD well pair, wherein the reservoir is at the ambient temperature, and wherein the aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir;
(b) injecting steam into the reservoir after (a) through the injection well or the production well to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir;
(c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons.
21. The method of claim 1, wherein (a) comprises injecting the aqueous solution into the reservoir through a first well extending through the reservoir.

wherein (c) comprises decreasing the viscosity of the hydrocarbons between the injection well and the production well to a viscosity less than 10,000 cp.

26. The method of claim 23, wherein (b) is performed less than 50 days after (a).

27. The method of claim 26, wherein (b) is performed immediately after (a).

28. The method of claim 23, wherein (a) comprises:
   (a1) injecting the aqueous solution into the reservoir through both the injection well and the production well of the SAGD well pair.

29. The method of claim 28, wherein (a) further comprises:
   (a2) injecting the aqueous solution into the reservoir only through the injection well after (a1).

30. The method of claim 23, wherein (a) comprises injecting the aqueous solution into the reservoir at a pressure that is greater than the ambient pressure of the reservoir and below a fracturing pressure of the formation.

31. The method of claim 30, further comprising varying the pressure of the aqueous solution during (a).

32. The method of claim 23, wherein (c) comprises decomposing the chemical agent with thermal energy from the steam or reacting the chemical agent with the hydrocarbons.

33. The method of claim 23, wherein the chemical agent is a surfactant or a thermally activated chemical species, wherein the surfactant emulsifies the mobilized hydrocarbons and the thermally activated chemical species decomposes or reacts at the elevated temperature.

34. The method of claim 33, wherein the elevated temperature is between 40° and 200° C.

35. The method of claim 23, wherein the chemical agent comprises urea.

36. The method of claim 33, wherein the chemical agent comprises an alkali metal carbonate or a metaborate salt of an alkali metal.

37. The method of claim 36, wherein the aqueous solution comprises a metal chelating agent to the aqueous solution during (a).

38. The method of claim 24, wherein the steam injected into the reservoir during (d) has a steam quality less than 100% and comprises a liquid phase and a vapor phase; wherein (d) further comprises:
   delivering a water-soluble surfactant to the reservoir in the liquid phase of the steam; and
   injecting the water-soluble surfactant and the steam into the reservoir at the same time.

39. The method of claim 38, wherein (d) further comprises:
   delivering a water-soluble thermally activated chemical species to the reservoir in the liquid phase of the steam; and
   injecting the water-soluble thermally activated chemical species and the steam into the reservoir at the same time.

40. The method of claim 38, wherein the water-soluble chemical agent injected into the reservoir during (a) is different than the water-soluble surfactant injected into the reservoir with the steam during (d).

41. The method of claim 24, wherein the steam injected into the reservoir during (d) has a steam quality less than 100% and comprises a liquid phase and a vapor phase; wherein (d) further comprises:
   delivering a water-soluble thermally activated chemical species to the reservoir; and
   injecting the water-soluble thermally activated chemical species and the steam into the reservoir at the same time.

42. The method of claim 41, wherein the liquid phase of the steam has a temperature, and wherein the water-soluble thermally activated chemical species has a conversion rate less than 10 mol % over a time period less than 10 minutes in the presence of the steam and at the temperature of the liquid phase.

43. The method of claim 41, wherein the water-soluble chemical agent injected into the reservoir during (a) is different than the water-soluble thermally activated chemical species injected into the reservoir with the steam during (d).

44. A method for mobilizing viscous hydrocarbons from a reservoir in a subterranean formation, the reservoir having an ambient temperature and an ambient pressure, the method comprising:
   (a) injecting a volume of an aqueous solution into the reservoir with the reservoir at the ambient temperature, wherein the aqueous solution comprises a brine and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir, wherein the chemical agent in the aqueous solution has a concentration greater than or equal to 0.01 wt % and less than the solubility limit of the chemical agent in the brine at the ambient temperature of the reservoir, and wherein the volume is based on a pore volume of connate water in a portion of the reservoir to be produced;
   (b) adding thermal energy to the reservoir at any time after (a) to increase the temperature of at least a portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir;
   (c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir and allowing the chemical agent to enhance mobilization of the hydrocarbons.

45. The method of claim 44, wherein the volume is at least equal to the pore volume of connate water in the portion of the reservoir to be produced.

46. The method of claim 44, wherein (a) comprises injecting the aqueous solution at a pressure that is greater than the ambient pressure of the reservoir and less than a fracture pressure of the formation.

47. The method of claim 44, wherein the chemical agent is a surfactant or a thermally activated chemical species, wherein the surfactant emulsifies the mobilized hydrocarbons at the elevated temperature and the thermally activated chemical species decomposes or reacts at the elevated temperature.

48. The method of claim 47, wherein the elevated temperature is between 40° and 200° C.

49. The method of claim 47, wherein the chemical agent comprises urea.

50. The method of claim 47, wherein the chemical agent comprises an alkali metal carbonate or a metaborate salt of an alkali metal.

51. The method of claim 50, wherein the aqueous solution further comprises a metal chelating agent.

52. The method of claim 44, wherein the hydrocarbons are immobile in the reservoir before (b).

53. The method of claim 52, wherein the hydrocarbons in the reservoir have a viscosity greater than 10,000 cp before (b).
wherein (c) comprises decreasing the viscosity of the viscous hydrocarbons to a viscosity less than 10,000 cp.

54. The method of claim 44, wherein (a) comprises injecting the volume of the aqueous solution into the reservoir through an injection well or a production well of a SAGD well pair;

wherein (b) comprises injecting steam into the reservoir through the injection well or the production well.

55. The method of claim 54, further comprising:

(d) injecting steam into the reservoir after (b) through the injection well;
(e) collecting hydrocarbons in the production well during (d); and
(f) producing the collected hydrocarbons in the production well to the surface.

56. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the method comprising:

(a) injecting steam into the reservoir, wherein the steam has a steam quality less than 100% and comprises a liquid phase and a vapor phase, wherein injecting the steam comprises delivering an aqueous solution to the reservoir in the liquid phase of the steam and injecting the aqueous solution into the reservoir with the steam, wherein the aqueous solution comprises a surfactant;

(b) in response to the steam injected in (a), mobilizing the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons;

(c) emulsifying the hydrocarbons with the surfactant during (b) to enhance the mobilization of the hydrocarbons.

57. The method of claim 56, further comprising:

(d) collecting mobilized hydrocarbons in a production well of a SAGD well pair; and
(e) producing the collected hydrocarbons in the production well to the surface.

58. The method of claim 57, further comprising injecting the aqueous solution into the reservoir with the steam during (a) and before (e).

59. The method of claim 57, further comprising injecting the surfactant into the reservoir with the steam during (e).

60. The method of claim 56, wherein (a) comprises injecting the steam into the reservoir through an injection well or a production well of a SAGD well pair.

61. The method of claim 60, wherein (a) comprises injecting the steam into the reservoir through both the injection well and the production well.

62. The method of claim 60, wherein (a) comprises injecting the steam into the reservoir through the injection well and injecting the aqueous solution into the reservoir through the injection well.

63. The method of claim 56, wherein (a) further comprises:

(a) delivering an aqueous solution comprising a water-soluble thermally activated chemical species to the reservoir in the liquid phase of the steam and injecting the aqueous solution comprising the water-soluble thermally activated chemical species and the steam into the reservoir at the same time.

64. A method for mobilizing viscous hydrocarbons in a reservoir in a subterranean formation, the method comprising:

(a) injecting steam into the reservoir, wherein the steam has a steam quality less than 100% and comprises a liquid phase and a vapor phase, wherein injecting the steam comprises delivering an aqueous solution to the reservoir in the liquid phase of the steam and injecting the aqueous into the reservoir with the steam during (a), wherein the aqueous solution comprises a non-volatile thermally activated chemical species, wherein the liquid phase of the steam has a temperature, and wherein the thermally activated chemical species has a conversion rate less than 10 mol % over a time period less than 10 minutes in the presence of the steam and at the temperature of the liquid phase; and

(b) decomposing or reacting the thermally activated chemical species in the reservoir to enhance the mobilization of the viscous hydrocarbons.

65. The method of claim 64, wherein the thermally activated chemical species decomposes or reacts at a temperature between 40° and 200° C.

66. The method of claim 64, further comprising:

(c) collecting mobilized hydrocarbons in a production well of a SAGD well pair; and

(d) producing the collected hydrocarbons in the production well to the surface.

67. The method of claim 66, further comprising injecting the aqueous solution into the reservoir with the steam during (a) and before (d).

68. The method of claim 66, further comprising injecting the aqueous solution into the reservoir with the steam during (d).

69. The method of claim 64, wherein (a) comprises injecting the steam into the reservoir through an injection well or a production well of a SAGD well pair.

70. The method of claim 69, wherein (a) comprises injecting the steam into the reservoir through both the injection well and the production well.

71. The method of claim 69, wherein (a) comprises injecting the steam into the reservoir through the injection well and injecting the aqueous solution into the reservoir through the injection well.

72. A method for recovering viscous hydrocarbons from a reservoir in a subterranean formation using steam assisted gravity drainage (SAGD), the reservoir having an ambient temperature and an ambient pressure, the method comprising:

(a) during a loading phase, loading a portion of the reservoir with an aqueous solution injected into the reservoir through an injection well or a production well of a SAGD well pair, wherein the reservoir is at the ambient temperature, and wherein the aqueous solution comprises water and a water-soluble chemical agent that is substantially non-decomposable and substantially non-reactive in the reservoir at the ambient temperature of the reservoir;

(b) at any time after the loading phase in (a), commencing a start-up phase wherein steam is injected into the reservoir through the injection well or the production well to increase the temperature of the portion of the reservoir to an elevated temperature greater than the ambient temperature of the reservoir;

(c) in response to the elevated temperature in (b), mobilizing at least a portion of the hydrocarbons in the reservoir by reducing the viscosity of the hydrocarbons and allowing the chemical agent to enhance mobilization of the hydrocarbons;

(d) continuing the start-up phase until fluid communication between the injection well and the production well is achieved;
(e) in response to (d), ceasing the start-up phase and commencing a production phase wherein steam is injected into the reservoir through the injection well and at least a portion of the hydrocarbons are produced from the reservoir through the production well.

73. The method of claim 72, wherein the hydrocarbons in the reservoir have a viscosity greater than 10,000 cP before (b);

wherein (c) comprises decreasing the viscosity of the hydrocarbons between the injection well and the production well to a viscosity less than 10,000 cP.

74. The method of claim 72, wherein (b) is performed less than 50 days after (a).

75. The method of claim 74, wherein (b) is performed immediately after (a).

76. The method of claim 72, wherein the elevated temperature is between 40° and 200° C.

77. The method of claim 72, wherein the chemical agent comprises urea.

78. The method of claim 72, wherein the chemical agent comprises an alkali metal carbonate or a metaborate salt of an alkali metal.

79. The method of claim 72, wherein the steam injected during (b) has a quality less than 100% and includes a vapor phase and a liquid phase;

wherein (b) further comprises injecting a surfactant into the reservoir via the liquid phase of the steam.

80. The method of claim 72, wherein the steam injected during (d) has a quality less than 100% and includes a vapor phase and a liquid phase

wherein (d) further comprises injecting a surfactant into the reservoir via the liquid phase of the steam.