CHEMICALLY ENHANCED THERMAL RECOVERY OF HEAVY OIL

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Abstract

Described herein are methods for removing heavy oils from underground reservoirs. The methods involve the use of chemical compositions in combination with steam techniques for the efficient removal of heavy oils.
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BACKGROUND OF THE INVENTION

[0001] Heavy oil sand, such as tar sand, is a major source of petroleum. Heavy oil-containing reservoirs, however, contain crude petroleum or bitumen of such high viscosity that it cannot be recovered by conventional petroleum recovery techniques. However, once the crude petroleum or bitumen is recovered, surface-milling processes can separate the bitumen from sand. The separated bitumen may be converted to light hydrocarbons using conventional refinery methods.

[0002] Steam has long been used in the recovery of oil from these heavy oil-containing reservoirs. For example, thermal recovery techniques such as cyclic steam simulation (CSS), Huff and Puff, and Steam Assisted Gravity Drainage (SAGD) have been used. Although these techniques have high recovery yields, their energy efficiency is poor.

[0003] Another approach involves enhanced oil recovery (EOR) techniques. These processes involve the use of surfactants in the presence of alkali solutions and salts to reduce the oil-water interfacial tension and alter the wettability of the reservoir rock, which ultimately results in enhanced recovery. In these processes, the temperature is usually below 80°C, which can limit the recovery of the heavy oils due to their high viscosity. The main objective of thermal recovery techniques is to reduce the heavy oil viscosity by increasing the temperature.

[0004] Thus, what is needed are enhanced oil recovery techniques that can be performed at the elevated temperatures typically used in steam applications to further increase or maintain the recovery yields by chemical means, but reduce the energy spent on recovery of heavy oils.

BRIEF SUMMARY OF THE INVENTION

[0005] Described herein are methods for removing heavy oils from underground reservoirs. The methods involve the use of chemical compositions in combination with steam techniques for the efficient removal of heavy oils. The advantages of the materials, methods, and articles described herein will be set forth in part in the description which follows, or may be learned by practice of the aspects described below. The advantages described below will be realized and attained by means of the elements and combinations particularly pointed out in the appended claims. It is to be understood that both the foregoing general description and the following detailed description are exemplary and explanatory only and are not restrictive.

BRIEF DESCRIPTION OF THE DRAWINGS

[0006] The accompanying Figures, which are incorporated in and constitute a part of this specification, illustrate several aspects described below.

[0007] FIGS. 1A-1D are schematics of different capillary phenomena in reservoirs.

[0008] FIGS. 2A and 2B show steam flux driven liquid flow (SFDLF) in a reservoir capillary, where there is a coupling between the steam and liquid flow.

[0009] FIG. 3 shows another form of SFDLF in a reservoir capillary.

DETAILED DESCRIPTION OF THE INVENTION

[0010] Before the present materials, articles, and/or methods are disclosed and described, it is to be understood that the aspects described below are not limited to specific compounds, synthetic methods, or uses, as such may, of course, vary. It is also to be understood that the terminology used herein is for the purpose of describing particular aspects only and is not intended to be limiting.

[0011] In this specification and in the claims that follow, reference will be made to a number of terms that shall be defined to have the following meanings:

[0012] Throughout this specification, unless the context requires otherwise, the word “comprise,” or variations such as “comprises” or “comprising,” will be understood to imply the inclusion of a stated integer or step or group of integers or steps but not the exclusion of any other integer or step or group of integers or steps.

[0013] It must be noted that, as used in the specification and the appended claims, the plural forms “a,” “an” and “the” include plural references unless the context clearly dictates otherwise. Thus, for example, reference to “an oil” includes a single oil or mixtures of two or more oils.

[0014] “Optional” or “optionally” means that the subsequently described event or circumstance may or may not occur, and that the description includes instances where the event or circumstance occurs and instances where it does not.

[0015] Described herein are methods for removal of heavy oils from underground reservoirs. The term “heavy oil” is any source or form of viscous oil. For example, a source of heavy oil includes tar sand. Tar sand, also referred to as oil sand or bituminous sand, is a combination of clay, sand, water, and bitumen. Thermal recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature. Once the viscosity is reduced, the mobilization of fluids by steam, hot water flooding, or gravity is possible. The reduced viscosity makes the drainage quicker and therefore directly contributes to the recovery rate.

[0016] The recovery rate is dependent on the drainage rate, which is controlled by the characteristics of multiphase flow (heavy oil and hot water) in porous media. Emulsion formation can severely limit the drainage rate when the droplet size is comparable to the pore size. One way to avoid this problem involves the formation of microemulsions having a droplet size is much smaller (20 nanometers) than the characteristic pore size of heavy oil reservoirs. A microemulsion phase can be in equilibrium with an organic phase, an aqueous phase, or simultaneously both an organic and an aqueous phase. The latter type of microemulsion phase, which can be found in Winsor III type systems, is known as a middle phase microemulsion. It has low viscosity, and is therefore beneficial for EOR or steam-assisted heavy oil recovery.

[0017] The contributing factors reducing recovery of heavy oils at elevated temperatures involve unfavorable wetting properties of the solid matrix and the high interfacial tension between the organic and aqueous phases. This is depicted in FIG. 1. The oil 10 is trapped in a narrow capillary 11 when the gravitational and hydrodynamic driving forces of water 12 cannot overcome the existing capillary forces (see FIG. 1A). The Laplace pressure difference keeps the oil phase trapped in the capillaries. When the oil-water interfacial tension is sufficiently reduced, most of the trapped oil can be removed (see FIG. 1B). The oil can also be trapped (due to the Laplace pressure difference) when there are narrow passes in the capillaries, even in the case of water-wet reservoir 13 (see
FIGS. 1C and 1D). High oil-water interfacial tension can also prevent the release of the organic phase from dead capillary ends. Additionally, variable permeability distribution (most of the McMurray formation in Alberta, Canada) also affects the trapping forces.

[0018] The methods described herein facilitate the recovery of heavy oils. For example, the methods reduce the oil-water interfacial tension and improve the mobility of heavy oils due to either microemulsion formation or the formation of emulsions having low interfacial tension using steam techniques (e.g., SAGD or CSS operations). Additionally, the methods described herein alter the wetting properties of the solid matrix that entraps the heavy oil. By reducing the viscosity and increasing the mobility of heavy oils, several advantages can be achieved, including, but not limited to, increased oil production rate, increased steam chamber dimensions resulting in reduced well density, reduced life cycle, and a reduction in residual oil after the total life cycle of the operation.

[0019] In one aspect, the method comprises: injecting into the reservoir (i) steam, (ii) an alkaline compound, (iii) a nonionic surfactant, and, optionally, (iv) an alcohol; and removing the oil from the reservoir.

[0020] In another aspect, the method comprises: injecting into the reservoir (i) steam, (ii) an alkaline compound, (iii) an acid, and, optionally, (iv) an alcohol; and removing the oil from the reservoir.

[0021] In a further aspect, the method comprises: injecting into the reservoir (i) steam, (ii) an ionic surfactant, and, optionally, (iii) an alcohol; and removing the oil from the reservoir.

[0022] In a further aspect, the method comprises: injecting into the reservoir (i) steam, (ii) a mixture comprising an ionic surfactant and a nonionic surfactant, and, optionally, (iii) an alcohol; and removing the oil from the reservoir.

[0023] In a further aspect, the method comprises: injecting into the reservoir (i) steam, (ii) an alcohol, and, optionally, (iii) an alkaline compound.

[0024] Steam techniques known in the art for removing heavy oils can be used herein. In general, steam is injected into the underground reservoir thereby heating the reservoir to mobilize and recover at least a fraction of reservoir hydrocarbons and to form a steam chamber in the reservoir. There is continuous steam condensation on the steam chamber boundaries. The condensation heat increases the temperature resulting in a viscosity drop of the heavy oil trapped in the reservoir. Next, chemical additives are introduced into the injection well, which is the input point to the steam chamber, either periodically or continuously. The injection can be made at the surface wellhead or deep in the reservoir with additional tubing (e.g., coiled tubing) inserted into the injection well. The oil may be recovered in a production well separate from the injection well.

[0025] When selecting chemical additives, the elevated temperatures used in the steam processes must be considered. For example, the temperature can reach as high as 350°C using SAGD, although this temperature can vary depending on the crude oil and reservoir properties. The residence time of the applied chemicals in the different temperature zones of the reservoir has a major influence on the selection as well, because the temperature and the residence time together determine the thermal strain. Since the residence time in the reservoir is orders of magnitude longer than that in the injection well, the reservoir conditions must be primarily considered. At steam flooding, reservoir temperatures measured in observation wells for three different fields in California, USA were 120, 160, and 180°C. (K. C. Hong, Steamflood Reservoir Management, PenWell, 1994, pages 386, 387, and 390). In the case of CSS, the temperature begins at 345°C, but after a period of time the temperature can be decreased from 85 to 100°C. Therefore, the thermal stability of the chemical additives can be relaxed to some extent when CSS is employed. In one aspect, the chemical additives are stable at temperatures greater than 200°C. Additionally, the chemical additives generally possess high vapor pressures. The high vapor pressure facilitates the delivery of the additives into the reservoir. As will be discussed below, additives that do not possess high vapor pressures can be formed in situ from high vapor pressure compounds. Thus, additives that are thermally stable and have a sufficiently high vapor pressure are "compatible" with the steam and useful herein. In cases where the vapor pressure of additives is low and not "compatible" with steam, the additives can be injected in the form of a liquid, aerosol, or suspension.

[0026] In one aspect, the chemical additives injected into the reservoir comprise an alkaline compound, a nonionic surfactant, and, optionally, an alcohol. The alkaline compound is any compound that can increase the pH of the steam and the reservoir. An increase in pH facilitates the release of natural surfactants present in heavy oils. These surfactants can reduce the oil-water interfacial tension. Additionally, reduced viscoelasticity of the oil-water interfaces has been observed at high pH which may be due to the released, naturally-occurring, surfactants.

[0027] In one aspect, the alkaline compound comprises an amine, such as a primary amine, a secondary amine, or a tertiary amine that is compatible with steam, or any combination of such amines. In another aspect, the steam-compatible alkaline compound is ammonia. In yet another aspect, the alkaline compound is an alkaline metal hydroxide, alkaline metal carbonate, alkaline metal hydrocarbonate, or ammonium carbonate, or any combination thereof, which compounds are not compatible with steam.

[0028] The amount of alkaline compound is sufficient to raise the pH of the steam to greater than 7, greater than 8, greater than 9, greater than 10, greater than 11, or greater than 12. Depending upon the selection of the alkaline compound, the compound can be introduced into the steam as a gas, a liquid, or a liquid solution of either gas, liquid, or solid. As well, the alkaline compound can be introduced into the steam as a liquid, a suspension of a solid, or as an aerosol. Additionally, the compound can be introduced in the form of a supercritical fluid where either the compound itself forms the supercritical fluid or the compound is one of the components of the supercritical fluid.

[0029] The nonionic surfactants, which generally have a higher vapor pressure than ionic surfactants (e.g., low molecular weight acetylenic surfactants), alter the wetting properties of the solid matrix. In certain aspects, when the nonionic surfactant is used in combination with an alcohol, which is a co-surfactant, the oil-water interfacial tension can approach zero. In this situation, microemulsions can be formed. Salts are often used in these formulations to achieve minimum interfacial tension. As described above, microemulsions can facilitate the removal of heavy oil. Examples of nonionic surfactants useful herein include, but are not limited to, an alkyl, aryl, or alkylaryl (ethylene oxide); an alkyl, aryl, or alkylaryl poly (propylene oxide); an alkyl, aryl,
or alkylaryl poly (propylene and ethylene oxide) block polymer; an alkylated amine or diamine; a polyetherol; a block polymer of carboxyldiamide polyoxoyalkylated glycol; an alkylarylpolyethylenol; an N-betaine (e.g., dodecyl N-betaine); a C-betaine (e.g., dodecyl C-betaine); an amine oxide (e.g., decyl dimethyl amine oxide); a phospholipid oxide (e.g., decyl dimethyl phosphine oxide); a sulfonilol (e.g., decyl sulfonylethanol); an ammonio carboxylate or sulfonate (e.g., decyl dimethylammonio-propane sulfonate); a sugar alky late (e.g., alpha-D-glucosyl octane); a polyol ether (e.g., octyl beta-D-glucoside); an oxyethylene sorbitan; a saccharide (e.g., lauryl saccharide); an acetylenic surfactant; an ethoxyalkyl alkanolamide; an alkyl amine; an alkyl imidazoline; a poloxamer; an alkyl polyglycoside; a fatty alcohol, or any combination thereof. With respect to the alcohol, the alcohol comprises a C_4 to C_6 alcohol. The alcohol can be branched or straight chain.

**[0030]** Nonionic surfactants or amines can typically be dissolved in aliphatic or aromatic hydrocarbons or in their mixtures, so these organic solvents are included in the delivered composition. The presence of these organic solvents can have an additional synergistic effect on oil recovery.

**[0031]** In another aspect, the chemical additives comprise an alkaline compound, an acid, and, optionally, an alcohol. In this aspect, an ionic surfactant is produced in situ when the alkaline compound reacts with the acid. The alkaline compound and the acid may be alternately injected into the reservoir. The alkaline compounds described above can be used in this aspect. In one aspect, the acid is an organic acid, which includes alkyl carboxylic acids, aryl carboxylic acids, cycloalkyl carboxylic acids, and aromatic and aliphatic carboxylic acids, or any combination thereof. The term organic acid also includes compounds possessing groups that can be converted to carboxylic acids. Examples of such compounds include, but are not limited to, amides, anhydrides, nitriles, and alcohols that can be converted to a carboxylic acid in situ during injection into the reservoir with the steam. Alternatively, the organic acid can be a polymer possessing a plurality of carboxylic acid groups.

**[0032]** In one aspect, the organic acid comprises a saturated fatty acid, an unsaturated fatty acid, or a combination thereof. Examples of fatty acids useful herein include, but are not limited to, butyric acid, caproic acid, caprylic acid, capric acid, lauric acid, myristic acid, palmitic acid, stearic acid, arachidic acid, behenic acid, myristoleic acid, palmitoleic acid, oleic acid, linoleic acid, alpha-linolenic acid, eicosapentaenoic acid, erucic acid, docosahexaenoic acid, arachidonic acid, or any combination thereof. Other examples of acids useful herein include, but are not limited to, an alkyl sulfonic acid, an aryl sulfonic acid, an alkylaryl sulfonic acid, a sulfo carboxylic acid, an alkyl naphthalene sulfonic acid, an olefinic sulfonic acid, a poly carboxylic acid, a sulfo carboxylic acid, a phosphono carboxylic acid, a thiosulfonic acid, or any combination thereof.

**[0033]** In another aspect, the chemical additives comprise an ionic surfactant and, optionally, an alcohol. A mechanism that can transport ionic compounds in the steam chamber despite their negligible vapor pressure is described below and depicted in FIG. 2. When saturated steam passes through the pores, a water film 20 forms on the surface of the pores (depicted as solid matrix 21 in FIG. 2). The steam transport 22 launches a liquid transport in the water film 20 (FIG. 2A). As the path narrows (i.e., constriction of the solid matrix 21), a multiphase flow of water 20 and steam 22 can occur (FIG. 2B). Therefore, ionic compounds can have a finite transport rate within the steam chamber via moving wetting liquid films on the capillary surfaces.

**[0034]** Turning to FIG. 3, in the presence of surface-active additives, the wettability of the solid matrix 21 increases and the formation of aqueous lamellas 31 formed from the water film 20 can occur. The lamellas will travel with the speed of the steam 22, which increases the steam flux driven liquid flow (SDFLP) considerably. Thus, ionic compounds can travel through the pores of the solid matrix in the form of a steam foam and remove heavy oils from the matrix.

**[0035]** The alcohols described above can be used in this aspect. In one aspect, the ionic surfactant comprises an anionic, cationic, amphoteric, or polymeric surfactant(s). Examples of anionic surfactants include, but are not limited to, sulfates, sulfonates, and carboxylates. The ionic surfactants can be naturally-occurring or synthetic. Sulfonates containing the C—O bond are more stable chemically than the C—O—P bond of the sulfates or the C—O—P bond of the phosphates. Thus, sulfonates and carboxylates are more stable to hydrolysis and extreme pH levels compared to sulfates and phosphates.

**[0036]** In one aspect, the anionic surfactant comprises an alkyl sulfate salt (e.g., sodium dodecyl sulfate, ammonium lauryl sulfate), an alkyl ether sulfate (e.g., sodium lauryl ether sulfate), an alkyl benzene sulfonate, or any combination thereof. In another aspect, the sulfonate comprises sulfonates of petroleum, oil and fatty acids, alkylaryls, α-olefins, benzene. In one aspect, condensed naphthenes, dodecyl and tridecyl benzenes, naphthalene, and alkyl naphthenes. In yet another aspect, the anionic surfactant comprises sulfoacetic, sulfosuccinic, sulfono carboxylic acids, alkyl naphthalene sulfonates, olefinic sulfonates, fatty acid sulfonates, polycarboxylates, sulfon sulfonates, phosphono carboxylic acids, thiosulfates.

**[0037]** Examples of useful cationic surfactants include, but are not limited to, a quaternary ammonium salt, an amine salt, an imidazoline salt, a betaine (e.g., octyl C-betaine hydrochloride or dodecyl N-betaine hydrochloride), a pyridinium derivative (e.g., dodecyl pyridinium chloride), or any combination thereof. A variety of different counterions can be used with the ionic surfactants, including alkali metal ions, alkaline earth metal ions, halides, nitrates, and carboxylates. Generally, the counterions are soluble in water.

**[0038]** In surfactant-containing systems, alcohols are considered to be co-surfactants, which enhance the performance of surfactants. One application of co-surfactants is the application of alcohols in microemulsion systems where the zero interfacial tension condition is often approached. A manifestation of the beneficial contribution of alcohol presence in microemulsion systems is the formation of highly flexible interfaces. This is one of the targeted areas of enhanced recovery of heavy oils by steam assisted techniques. Due to these beneficial effects, alcohols can be considered as part of surfactant-containing additives. For heavy oil systems, in which the concentration of natural surfactants could be considerable, the application of alcohols as additives to enhance recovery can also be beneficial, even in cases when no artificial surfactant is added. In these cases, the alcohol behaves as the co-surfactant of natural surfactants.

**[0039]** The chemical additives described above can be injected into the reservoir in any sequence, concurrently with, or separate from, the steam. For example, the chemical additives can be admixed prior to injection into the steam. In one aspect, the additives can be simultaneously injected with the
steam in order to ensure or maximize the amount of additives moving with the steam. In some instances it may be desirable to precede or follow a steam-additive injection stream with a steam-only injection stream. Alternatively, the additives can be introduced into the steam sequentially. In certain aspects, the additives are introduced alternatively into the steam. For example, the organic acid and alkaline compound (e.g., ammonia) can be alternatively introduced into the steam. The additives can be introduced continuously or periodically into the steam. The particular steam temperature and pressure actually used in the process will depend on such specific reservoir characteristics as depth, temperature, and oil viscosity, and thus will be worked out for each reservoir.

In certain aspects, it is desirable to inject the chemical additives as an aerosol or spray so that the chemicals do not remain at the bottom of the injection well. In this aspect, the chemical additives are carried into the reservoir rock containing heavy oils by the steam. Thus, the chemical additives are pushed deep into the pores of the reservoir rock, which ultimately facilitates the release and isolation of heavy oils. The use of aerosols prevents the chemical additives from being directed toward the production well instead of the upper walls of the steam chamber, which is desired. Techniques known in the art for producing and delivering aerosol formulations can be used herein. In one aspect, carbon dioxide can be used to make the aerosol spray. Carbon dioxide can condition the reservoir and increase the effectiveness of the methods described herein for removing heavy oils from the reservoir. Carbon dioxide also lowers the minimum miscibility pressure of the reservoir, which can enhance the recovery of heavy oil. The use of carbon dioxide to facilitate the removal of oil is disclosed in U.S. Pat. Nos. 5,358,052; 6,988,552; and 4,513,821, which are incorporated herein by reference.

Other additives can be used in combination with any of the additives described above. In one aspect, a chelating agent can be used. Chelating agents known in the art can be used to dissolve carbonates, minerals, and clays in order to create wormholes and other passageways without compromising the structure of the reservoir. The formation of these passageways can facilitate the injection of steam and the chemical additives into the reservoir, which will increase heavy oil removal. In one aspect, chelating acid includes a polycarboxylic acid, maleic acid, tartaric acid, citric acid, NTA (nitrilotriacetic acid), HEDTA (hydroxyethylendiaminetetraacetic acid), EDTA (ethylenediaminetetraacetic acid), CyDTA (cyclohexylenediaminetetraacetic acid), DTPA (diethylenetriaminopentaacetic acid), ammonium salts thereof, lithium salts thereof, sodium salts thereof, and/or mixtures of these acids and/or their partially or completely neutralized salts, with the same or different metal ions. The use of these chelating agents is disclosed in U.S. Pat. Nos. 6,911,418 and 6,436,880, which are incorporated herein by reference. The concentration of the chelating agent can vary depending upon the selection of chemical additives and the nature of the heavy oil reservoir. In one aspect, the concentration of the chelating agent is up to 50 percent by weight of the chemical additives injected into the reservoir. The chelating agent can be injected into the reservoir as needed in order to increase the permeability and heat conductivity of the reservoir. Thus, the chelating agent can be injected periodically or continuously.

In another aspect, one or more polymers that prevent water blocks in the injection and production lines can be used. Examples of such polymers include, but are not limited to, fluoropolymers, telomers, and fluorosilanes. By preventing water blocks in the lines, increased injection rates of steam and chemical additives are possible.

The additional additives can be added at different stages of the process. For example, the additives can be injected into the reservoir prior to injection of the other chemical additives. Alternatively, the additives can be added concurrently while the chemical additives and steam are introduced into the reservoir. The amounts of the additional additives can vary depending upon processing conditions.

The amount of chemical additives used to remove the heavy oil can vary depending upon the selection of the additives, processing conditions (e.g., rates of injection and temperature of steam), and the depth and composition of the reservoir. In one aspect, the amount of chemical additives (e.g., surfactant) is sufficient to produce an oil/water interfacial tension less than 0.3 milliNewton/meter, less than 0.2 milliNewton/meter, or less than 0.1 milliNewton/meter. In another aspect, the chemical additives are present in a sufficient amount to produce a microemulsion of heavy oil, where the droplet size is less than 20 nanometers. In other aspects, the chemical additives can be in the form of a microemulsion prior to injection into the reservoir. At this application the addition of organic solvent is needed. Aliphatic or aromatic hydrocarbons or their mixtures can be used as organic solvents. As described above, the presence of these organic solvents can have an additional synergistic effect on oil recovery. In a further aspect, when the chemical additives comprise a combination of anion and nonionic surfactant and, optionally, an alcohol, the amount of additives is sufficient to increase the SFDLF delivery mechanism described above.

In a further aspect, steam, an alcohol, and, optionally, an alkaline compound are injected into the reservoir.

After the heavy oil is removed from the reservoir as an oil-in-water or water-in-oil emulsion (e.g., a microemulsion), the emulsion is demulsified to isolate the heavy oil. Any conventional method may be used above ground for demulsifying the heavy oil-water emulsion and separating the heavy oil from water and sand. Demulsification can occur at or below the earth’s surface. For example, the heavy oil-water emulsion may be processed by settling to remove sand; dehydration, chemical, thermal, or electrical treatment; filtration, centrifuging, and various combinations thereof. The separated heavy oil serves as a raw material for the production of various petroleum products including heavy crude, asphalt, tar, solvents, and gases. The separated water stream can be upgraded by conventional methods, heated, and recycled to the injection well as wet steam or hot water.

Throughout this application, various publications are referenced. The disclosures of these publications are incorporated in their entirety by reference into this application in order to more fully describe the compounds, compositions, and methods described herein.

Various modifications and variations can be made to the compounds, compositions, and methods described herein. Other aspects of the compounds, compositions, and methods described herein will be apparent from consideration of the specification and practice of the compounds, compositions, and methods disclosed herein. It is intended that the specification and examples be considered as exemplary.

1-12. (canceled)
13. A process for removing heavy oil from an underground heavy oil reservoir, comprising:
inventing into the reservoir (i) steam, (ii) an alkaline compound, and (iii) an acid; and removing the oil from the reservoir.

14. The process of claim 13, further comprising injecting into the reservoir an alcohol.

15. The process of claim 13, wherein the alkaline compound and the acid are alternately injected into the reservoir.

16. The process of claim 13, wherein an ionic surfactant is produced in situ in the reservoir when the alkaline compound reacts with the acid.

17. The process of claim 13, wherein the alkaline compound is introduced into the steam as a gas, a liquid, or a solution of either gas, liquid, or solid.

18. The process of claim 13, wherein the alkaline compound is introduced into the steam as a suspension of a solid, or an aerosol.

19. The process of claim 13, wherein the alkaline compound is introduced into the steam as a supercritical fluid or a component of a supercritical fluid.

20. The process of claim 13, wherein the alkaline compound comprises a primary, secondary, or tertiary amine that is compatible with steam, or any combination of such amines.

21. The process of claim 13, wherein the alkaline compound is ammonia.

22. The process of claim 13, wherein the alkaline compound is an alkaline metal hydroxide, alkaline metal carbonate, alkaline metal hydrocarbonate, ammonium carbonate, or any combination thereof.

23. The process of claim 13, wherein the acid is an organic acid.

24. The process of claim 23, wherein the organic acid is an alkyl carboxylic acid, an aryl carboxylic acid, a cycloalkyl carboxylic acid, an aromatic carboxylic acid, an aliphatic carboxylic acid, or any combination thereof.

25. The process of claim 24, wherein the organic acid comprises compounds possessing groups that can be converted to carboxylic acids.

26. The process of claim 35, wherein the organic acid comprises an amide, an anhydride, a nitrile, or an alcohol that can be converted to a carboxylic acid in situ during injection into the reservoir with the steam.

27. The process of claim 35, wherein the organic acid is a polymer possessing a plurality of carboxylic acid groups.

28. The process of claim 35, the organic acid comprises a saturated fatty acid, an unsaturated fatty acid, or a combination thereof.

29. The process of claim 40, wherein the saturated fatty acid is butyric acid, caproic acid, caprylic acid, capric acid, lauric acid, myristic acid, palmitic acid, stearic acid, arachidic acid, behenic acid, myristoleic acid, palmitoleic acid, oleic acid, linoleic acid, alpha-linolenic acid, eicosapentaenoic acid, erucic acid, docosahexaenoic acid, arachidonic acid, or any combination thereof.

30. The process of claim 13, wherein the acid is an alkyl sulfonic acid, an aryl sulfonic acid, an alkylaryl sulfonic acid, a sulfo carboxylic acid, an alkyl naphthenol sulfonic acid, an olefinic sulfonic acid, a polycarboxylic acid, a sulfo carboxylic acid, a phosphono carboxylic acid, a thiosulfonic acid, or any combination thereof.

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